NEWFOUNDLAND POWER
A FORTIS COMPANY

Newfoundland Power Inc.

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DELIVERED BY HAND

June 29, 2007

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 2008 Capital Budget Application

A. Enclosures

Enclosed are 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") 2008 Capital Budget Application (the "Application") and supporting materials (the "Filing").

B. 2008 Capital Budget Plan

As anticipated in the *2007 Capital Budget Plan*, filed with the 2007 Capital Budget Application, the level of proposed 2008 capital expenditures is more consistent with recent historic expenditure levels. This follows the significant capital expenditure increase in 2007 resulting from the Rattling Brook Refurbishment Project, approved in Order No. P.U. 30 (2006) (the "2007 Capital Order"). At $50,754,000, the 2008 Capital Budget expenditure is actually below the average capital budget expenditure for the past five years.

The 2008 Capital Budget addresses the anticipated growth of the power system and the refurbishment of deteriorated assets. Approximately 26% of the proposed 2008 capital expenditures will address customer growth, while approximately 59% of the proposed capital expenditures will address the replacement and refurbishment of deteriorated plant.

The first phase of the Rattling Brook Refurbishment Project is now underway. This project was scheduled to be completed over 2 years, with the bulk of the work being completed during the 2007 construction season. The second phase of the project, originally scheduled for completion in 2008, consists of upgrades to dam and spillway structures. Although the Company is actively seeking all necessary approvals for this work, certain federal regulatory matters remain unresolved at this time. Consequently, the second phase of the Rattling Brook Refurbishment Project is not included in the 2008 Capital Budget.

C. Compliance Matters

C.1 Board Orders

In the 2007 Capital Order, the Board required specific information to be filed with the Application. The Filing complies with the requirements of the 2007 Capital Order.

In Order No. P.U. 35 (2003) (the "2004 Capital Order"), the Board required specific information, and in particular a 5-year capital plan, to be provided with the Application. The Filing complies with the requirements of the 2004 Capital Order.

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 the Application. The Filing complies with the requirements of the 2003 Rate Order.

The Filing contains the following specific reports:

1. *2008 Capital Budget Plan*: this is filed in compliance with the 2004 Capital Order;

2. *2007 Capital Expenditure Status Report*: this is filed in compliance with the 2007 Capital Order;

3. *Deferred Charges and Rate Base*: this is filed in compliance with the 2003 Rate Order.

C.2 The Provisional Guidelines

In the June 2005 Provisional Capital Budget Application Guidelines (the "Provisional Guidelines"), the Board outlined certain directions on how to define and categorize capital expenditures. Although compliance with the Provisional Guidelines necessarily requires the exercise of a degree of judgment, the Filing, in the Company's view, complies with the Provisional Guidelines while remaining reasonably consistent and comparable with past filings.

Section 3 of the *2008 Capital Budget Plan* provides a breakdown of the overall 2008 Capital Budget by definition, classification, costing method and materiality segmentation as described in the Provisional Guidelines.

D. Order Sought in the Application

In the Application, Newfoundland Power essentially seeks (i) approval of a 2008 capital budget in the amount of $50,754,000; (ii) approval of 2008 leases in the amount of $70,000 per year, and (iii) the fixing and determining of a 2006 rate base in the amount of $752,917,000.

E. Filing Details and Circulation

The Filing will be posted on the Company's website (www.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.

F. 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 Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland & Labrador Hydro

Thomas Johnson
O'Dea Earle Law Offices

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

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

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

(a) approving its 2008 Capital Budget of $50,754,000; and

(b) fixing and determining its average rate base for 2006 in the amount of $752,917,000

2008 Capital Budget Application

NEWFOUNDLAND POWER
A FORTIS COMPANY

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2008 Capital Budget of $50,754,000; and
(b) fixing and determining its average rate base for 2006 in the amount of $752,917,000

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 2008 Capital Budget in the amount of $50,754,000 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 2008. All contributions to be recovered from customers shall be calculated in a manner approved by the Board.

3. Schedule B to this Application is a list of 2008 capital expenditures, by project, which comprise Newfoundland Power's 2008 Capital Budget.

4. Schedule C to this Application is a list of leases in excess of $5,000 per year which Newfoundland Power proposes to proceed with in 2008.

5. Schedule D to this Application is an estimate of future required expenditures on improvements or additions to the property of Newfoundland Power that are included in the 2008 Capital Budget but will not be completed in 2008.

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 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 2006 of $752,917,000.

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 2008 of the improvements and additions to its property in the amount of $50,754,000 as set out in Schedules A and B to the Application;

    (b) pursuant to Section 41 of the Act, approving Newfoundland Power's lease of improvements to its property in the amount of $70,000 per year as set out in Schedule C to the Application; and

    (c) pursuant to Section 78 of the Act, fixing and determining Newfoundland Power's average rate base for 2006 in the amount of $752,917,000 as set out in Schedule E to the Application.

DATED at St. John's, Newfoundland and Labrador, this 29th day of June, 2007.

NEWFOUNDLAND POWER INC.

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

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

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

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

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to Sections 41 and 78 of the Act:
(a) approving its 2008 Capital Budget of $50,754,000; and
(b) fixing and determining its average rate base for 2006 in the amount of $752,917,000

AFFIDAVIT

I, Phonse Delaney, of St. John's in the Province of Newfoundland and Labrador, Professional Engineer, make oath and say as follows:

1. That I am Vice-President, Engineering and Operations, 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 29th day of June, 2007,
before me:

Barrister

Phonse Delaney

Newfoundland Power Inc.
2008 Capital Budget Application
Filing Contents

Application

Supporting Materials

Generation

Substations

Transmission

Distribution

Telecommunications

Information Systems

Deferred Charges

2008 CAPITAL BUDGET SUMMARY

Asset Class	Budget (000s)
1. Generation - Hydro	$ 3,385
2. Generation - Thermal	100
3. Substations	5,276
4. Transmission	4,890
5. Distribution	26,636
6. General Property	977
7. Transportation	2,214
8. Telecommunications	224
9. Information Systems	3,502
10. Unforeseen Allowance	750
11. General Expenses Capitalized	2,800
Total	**$ 50,754**

2008 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
1. Generation - Hydro		
Hydro Plant Facility Rehabilitation	3,260	2
Engineering to Increase Plant Production	125	4
Total – Generation - Hydro	**$ 3,385**	
2. Generation - Thermal		
Thermal Plant Facility Rehabilitation	100	7
Total – Generation – Thermal	**$100**	
3. Substations		
Substation Refurbishment and Modernization	$ 3,703	10
Replacements Due to In-Service Failures	1,340	12
Convert 403L to 66KV to Reduce Losses	233	15
Total - Substations	**$ 5,276**	
4. Transmission		
Transmission Line Rebuild	$ 4,890	18
Total - Transmission	**$ 4,890**	

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

2008 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	Budget (000s)	Description[1]
5. Distribution		
Extensions	$ 7,791	21
Meters	986	23
Services	2,004	26
Street Lighting	1,361	29
Transformers	5,811	32
Reconstruction	3,129	34
Rebuild Distribution Lines	3,385	36
Relocate/Replace Distribution Lines for Third Parties	606	39
Distribution Reliability Initiative	1,286	41
Install Capacitors to Reduce Losses	200	44
Interest During Construction	77	46
Total - Distribution	**$ 26,636**	
6. General Property		
Tools and Equipment	$ 690	49
Additions to Real Property	122	51
Standby Diesel generators	165	53
Total - General Property	**$ 977**	
7. Transportation		
Purchase Vehicles and Aerial Devices	$ 2,214	56
Total - Transportation	**$ 2,214**	

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

2008 CAPITAL PROJECTS (BY ASSET CLASS)

Capital Projects	**Budget (000s)**	**Description**[1]
8. Telecommunications		
Replace/Upgrade Communications Equipment	$ 104	59
Fibre Optic Circuit Replacement	$ 120	61
Total - Telecommunications	**$ 224**	
9. Information Systems		
Application Enhancements	$ 1,389	64
System Upgrades	487	66
Personal Computer Infrastructure	408	68
Shared Server Infrastructure	889	71
Network Infrastructure	119	73
Microsoft Enterprise Agreement[2]	210	
Total – Information Systems	**$ 3,502**	
10. Unforeseen Allowance		
Allowance for Unforeseen Items	$ 750	76
Total – Unforeseen Allowance	**$ 750**	
11. General Expenses Capitalized		
General Expenses Capitalized	$ 2,800	78
Total – General Expenses Capitalized	**$ 2,800**	

[1] Project descriptions can be found in Schedule B at the page indicated.
[2] This is a multi-year project approved with the 2006 Capital Budget Application. Details found in Schedule A page 5 of 5, and in Schedule D.

2008 CAPITAL PROJECTS: MULTI-YEAR

Capital Project	**Approved**	**2006**	**2007**	**2008**
Microsoft Enterprise Agreement[3]	Order No. P.U. 30 (2005)	$210,000	$210,000	$210,000

3 The scope, nature, and amount of this expenditure are consistent with the original approval.

GENERATION - HYDRO

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

Project Cost: **$3,260,000**

Project Description

This Generation 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. The project includes work on the following:

- Hydro dams;
- Replacements due to in-service failures;
- Mobile wicket gates and bushings;
- Pierre's Brook governor controls;
- Heart's Content runner and wicket gates;
- Cape Broyle protection and control systems; and
- Engineering for Rocky Pond penstock replacement.

Details on 2008 proposed expenditures are included in ***1.1*** *2008 Facility Rehabilitation*.

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's 23 hydroelectric plants range in age from eight years old to 107 years old. These facilities provide energy to the Island interconnected electrical system. Maintaining these generating facilities reduces the need for additional, more expensive, generation. In many cases, these generating facilities provide local 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 Company's hydro generation facilities produce a combined normal annual production of 419.6 GWh. The alternative to maintaining these facilities would be to retire them. Replacing the energy produced by these facilities by increasing production at Newfoundland and Labrador Hydro's Holyrood generation facility would require approximately 670,000 barrels of fuel annually. At oil prices of $55.40 per barrel, this translates into approximately $37 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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 2,428	-	-	-
Labour – Internal	315	-	-	-
Labour – Contract	-	-	-	-
Engineering	440	-	-	-
Other	77	-	-	-
Total	**$ 3,260**	**$2,410**	**$7,818**	**$12,913**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2003	2004	2005	2006	2007F
Total	**$2,510**	**$1,909**	**$2,283**	**$1,234**	**$946**

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

Project Cost: **$125,000**

Project Description

Newfoundland Power operates 23 hydroelectric plants in 19 developments across the province. The annual normal production of these developments is 419.6 GWh which is less than 10% of Newfoundland Power customers' electricity requirements. The remainder of the required electricity is purchased from Newfoundland and Labrador Hydro ("Hydro"). A significant portion of the electricity purchased from Hydro is generated at the Holyrood thermal generating plant which utilizes Bunker C oil. Bunker C oil is a more costly source of electricity than that generated at hydroelectric plants.

Prior to the Island interconnected electrical system, the majority of the 23 hydroelectric plants were operated as small isolated systems across the province. When constructed, these plants were the only source of generation for local systems. The plants were designed for year round operation with maximum utilization of available water resources. Today, the hydroelectric plants are connected to the Island interconnected electrical system and are operated to their maximum efficiency, providing low cost electricity to the entire electrical system.

Due to the high cost of producing electricity at Holyrood, Newfoundland Power is looking at alternative ways to improve the efficiency and energy production of existing hydroelectric plants. There is potential to increase the annual production of existing hydroelectric plants by modifying existing dams, penstocks and turbines. For example, the Rattling Brook refurbishment project approved with the 2007 Capital Budget Application will provide an additional 6.2 GWhs of energy annually by increasing the diameter of the penstock and replacement of the butterfly valves.

This project will (1) produce a project inventory including economic analysis using the current cost of energy, and (2) optimize and provide final engineering design for the most feasible projects with the potential to increase energy production at existing Newfoundland Power hydroelectric plants. The objective of the project is to produce more energy from the existing hydro plants, thereby reducing the need for more expensive thermal generation.

Justification

The Company's 23 hydroelectric plants provide energy to the Island interconnected electrical system. Operating these generating facilities efficiently reduces the need for additional, more expensive, generation.

The Company's hydroelectric plants produce a combined normal annual production of 419.6 GWh. Increasing energy production at Newfoundland Power's existing hydroelectric plants would replace energy produced at Hydro's Holyrood thermal generating plant. At oil prices of approximately $55.40 per barrel, an additional gigawatt hour of hydroelectric production translates into approximately $88,000 in fuel savings. This project is justified upon those future energy savings.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	-	-	-	-
Labour – Internal	25	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	100	-	-	-
Total	**$ 125**	**-**	**-**	**$125**

Costing Methodology

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

Future Commitments

This is not a multi-year project.

GENERATION - THERMAL

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

Project Cost: **$100,000**

Project Description

This Generation Thermal project is necessary for the replacement or rehabilitation of deteriorated thermal plant components that have been identified through routine inspections, operating experience and engineering studies.

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

Justification

The Company maintains 43.5 MW of thermal generation consisting of gas turbine and diesel units. These units are generally used to provide emergency generation, both locally and for the 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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 60	-	-	-
Labour – Internal	20	-	-	-
Labour – Contract	-	-	-	-
Engineering	15	-	-	-
Other	5	-	-	-
Total	**$ 100**	**$350**	**$425**	**$875**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2003	2004	2005	2006	2007F
Total	$93	$142	$135	$0	$0

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.

SUBSTATIONS

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

Project Cost: **$3,703,000**

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*** *Substation Refurbishment and Modernization*.

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.

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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$1,916	-	-	-
Labour – Internal	732	-	-	-
Labour – Contract	-	-	-	-
Engineering	753	-	-	-
Other	302	-	-	-
Total	**$ 3,703**	**$3,680**	**$14,047**	**$21,430**

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	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$2,088**	**$2,168**	**$2,072**	**$2,107**	**$2,190**

The Company has 130 substations varying in age from six years to greater than 100 years. Infrastructure to be replaced was identified as a result of inspections, engineering studies and operating experience.

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: **$1,340,000**

Project Description

This Substations project is necessary to replace substation equipment that is retired due to vandalism, storm damage, lightning strikes, 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.

Table 1 shows the required replacement equipment for 2008.

Table 1
2008 Replacement Equipment

Description	Quantity
Battery banks	9
Battery chargers	9
Potential transformers	9
Current transformers	3
Combination CT/PT unit	3
Reclosers	2
Voltage regulators	9
VR Control panels	10
Breakers	1
Switches	6
Fuse Disconnects	6

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 2 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 2

Project Expenditures (000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 834	-	-	-
Labour – Internal	314	-	-	-
Labour – Contract	14	-	-	-
Engineering	109	-	-	-
Other	69	-	-	-
Total	**$1,340**	**$1,370**	**$4,281**	**$6,991**

Costing Methodology

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

Table 3

Expenditure History (000s)

Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$1,159**	**$1,284**	**$1,194**	**$1,273**	**$1,550**

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: **Convert 403L to 66KV to Reduce Losses (Other)**

Project Cost: **$233,000**

Project Description

This Substation project is proposed to improve the energy efficiency of transmission line 403L between Lookout Brook plant and St. George's and Robinson's substations. Increasing the transmission line voltage from 33,000 volts to 66,000 volts will reduce line losses, thereby making more of the energy produced at the Lookout Brook plant available to the Island interconnected system.

Engineering details of this project are included in report ***2.2** Convert 403L to 66KV*.

Justification

The project is justified on the energy savings as shown in the economic analysis included with the report ***2.2** Convert 403L to 66KV*. The project will provide an additional 529,870 kWh of energy to the system at a levelized unit cost of 3.81¢/kWh.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008. There are no expenditures expected after 2008.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 85	-	-	-
Labour – Internal	73	-	-	-
Labour – Contract	-	-	-	-
Engineering	41	-	-	-
Other	34	-	-	-
Total	**$ 233**	**-**	**-**	**$233**

Costing Methodology

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

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

Future Commitments

This is not a multi-year project.

TRANSMISSION

Project Title: Transmission Line Rebuild (Pooled)

Project Cost: $4,890,000

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 ($3,045,000).

   Proposed transmission line rebuilding work will take place on sections of 20L and 111L. Details of the rebuilds can be found in ***3.1*** *Transmission Line Rebuild*.

2. The replacement of poles, crossarms, conductors, insulators and miscellaneous hardware due to deficiencies identified during inspections and engineering reviews or due to in-service and imminent failures ($1,595,000).

3. Work associated with the relocation of transmission lines at the request of third parties ($250,000).

Justification

Thirty per cent of the Company's 104 transmission lines are in excess of 40 years of age. Many of these lines are experiencing pole, crossarm, conductor, insulator and hardware deterioration. Replacement is required to maintain the strength and integrity of these lines.

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

The portion of this project related to relocations at the request of third parties is justified based on the need to accommodate the legitimate requirements of governments, other utility service providers and the public.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012. Appendix A of ***3.1*** *Transmission Line Rebuild* details the transmission line rebuilds planned for each year.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 1,650	-	-	-
Labour – Internal	509	-	-	-
Labour – Contract	1,999	-	-	-
Engineering	219	-	-	-
Other	513	-	-	-
Total	**$ 4,890**	**$6,216**	**$20,528**	**$31,634**

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	2003	2004	2005	2006	2007F
Total	**$4,026**	**$2,061**	**$2,651**	**$4,456**	**$4,283**

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: **$7,791,000**

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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$2,514	-	-	-
Labour – Internal	1,863	-	-	-
Labour – Contract	2,411	-	-	-
Engineering	799	-	-	-
Other	204	-	-	-
Total	**$7,791**	**$8,014**	**$24,672**	**$40,477**

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 2008.

Table 2
Expenditure History and Unit Cost Projection

Year	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008B**
Total Exp. (000s)	**$ 6,586**	**$ 8,406**	**$ 7,962**	**$11,136**	**$ 7,931**	**$ 7,791**
Adjusted Cost (000s)[1]	$ 7,421	$ 9,144	$ 8,412	$ 8,185[2]	7,036[2]	-
New Customers	3,833	4,294	4,149	3,496[3]	3,307[3]	3,453
Unit Cost ($/customer)[1]	$ 1,936	$ 2,129	$ 2,027	$ 2,341	$ 2,128	$ 2,256

1 2007 Dollars.
2 Excludes expenditure for extensions to cottage areas.
3 Excludes customer connections in cottage areas.

The project cost for the connection of new customers is calculated on the basis of historical data. Historical annual expenditures over the most recent five-year period, including the current year, expressed in current-year dollars ("Adjusted Cost") 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 modified by the GDP Deflator for Canada before being multiplied by the forecast number of new customers for the budget year to determine the budget estimate. The forecast number of new customers is derived from economic projections provided by independent agencies.

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

Future Commitments

This is not a multi-year project.

Project Title: **Meters (Pooled)**

Project Cost: **$986,000**

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 meters required in 2008.

Table 1
2008 Proposed Meter Acquisition

Program	Number of Meters
Energy Only Domestic Meters	8,868
Other Energy Only and Demand Meters	1,097

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.

No expenditure has been explicitly budgeted for the installation of automated meter reading ("AMR") technology. However, AMR meters will be installed where it is determined that the higher cost is justified by the savings provided in the *Metering Strategy* filed with the 2006 Capital Budget Application.

Justification

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

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 2 **Project Expenditures** **(000s)**				
Cost Category	**2008**	**2009**	**2010 - 2012**	**Total**
Material	$ 867	-	-	-
Labour – Internal	99	-	-	-
Labour – Contract	20	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$ 986**	**$1,023**	**$3,492**	**$5,501**

Costing Methodology

Table 3 shows the annual expenditures for the most recent five-year period, as well as a projection for 2008.

Table 3 **Expenditure History and Unit Cost Projection**							
Year	**2003**	**2004**	**2005**	**2006**	**2007F**	**Avg**	**2008B**
Meter Requirements							
New Connections	3,833	4,294	4,149	3,952	3,676	-	3,453
GROs/CSOs	1,455	8,544	12,399	13,371	2,944	-	4,733
Other	1,055	1,064	2,175	1,677	2,943	-	1,779
Total	6,343	13,902	18,723	19,000	9,543	-	9,965
Meter Costs							
Actual (000s)	$ 595	$1,297	$1,342	$1,463	$1,091	-	$ 986
Adjusted[1] (000s)	$ 662	$1,403	$ 885[2]	$ 982[2]	$1,091	-	-
Unit Cost[1]	$ 104	$ 101	$ 79[2]	$ 85[2]	$ 114	$ 97	$ 99

1 2007 dollars.

2 Excludes two groups of meters which failed compliance sampling testing as required by Measurement Canada in 2005 and 2006.

The budget estimate for Meters is calculated using the inflation adjusted average historical unit cost per installed meter multiplied by the expected number of 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 of customer growth. 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: **$2,004,000**

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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$ 603	-	-	-
Labour – Internal	1,112	-	-	-
Labour – Contract	97	-	-	-
Engineering	168	-	-	-
Other	24	-	-	-
Total	**$2,004**	**$1,997**	**$6,187**	**$10,188**

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 2008.

Table 2

Expenditure History and Unit Cost Projection
New Services

Year	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008B**
Total (000s)	**$ 1,421**	**$ 1,659**	**$ 1,894**	**$ 1,863**	**$ 1,628**	**$ 1,602**
Adjusted Cost (000s)[1]	$ 1,603	$ 1,806	$ 2,002	$ 1,911	-	-
New Customers	3,833	4,294	4,149	3,952	3,676	3,453
Unit Cost ($/customer)[1]	$ 418	$ 421	$ 483	$ 484	$ 443	$ 464

1 2007 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") and 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 modified 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* services for the most recent five-year period, as well as a projected unit cost for 2008.

Table 3

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

Year	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008B**
Total	**$568**	**$349**	**$339**	**$399**	**$393**	**$402**
Exclusions[1]	200	-	-	-	-	-
Adjusted Cost[2]	$415	$380	$358	$409	$393	-

1 Exclusions in 2003 included program replacement of underground services in St. John's and program replacement of aerial services in Lark Harbour and Port aux Basques.
2 2007 dollars.

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$1,361,000**

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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$ 737	-	-	-
Labour – Internal	485	-	-	-
Labour – Contract	105	-	-	-
Engineering	20	-	-	-
Other	14	-	-	-
Total	**$1,361**	**$1,315**	**$3,946**	**$6,622**

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 2008.

Table 2

Expenditure History and Unit Cost Projection
New Street Lights

Year	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008B**
Total (000s)	**$ 892**	**$ 1,020**	**$ 1,363**	**$ 1,131**	**$ 853**	**$ 915**
Exclusions[1] (000s)	-	-	$ 380	-	-	-
Adjusted Cost (000s)[2]	$ 1,000	$ 1,107	$ 1,037	$ 1,157	$ 853	-
New Customers	3,833	4,294	4,149	3,952	3,676	3,453
Unit Cost ($/cust.)[2]	$ 261	$ 258	$ 250	$ 293	$ 232	$ 265

1 Exclusions in 2005 reflect the unusually high quantity of new Street Lights installed for the City of St. John's.
2 2007 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, expressed in current-year dollars ("Adjusted Cost") 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 modified 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 2008.

Table 3

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

Year	2003	2004	2005	2006	2007F	2008B
Total	**$395**	**$379**	**$489**	**$451**	**$411**	**$446**
Exclusions[1]	-	-	70	-	-	-
Adjusted Cost[2]	$443	$411	$442	$461	$411	-

[1] Exclusions in 2005 reflect the Company's program replacement of underground wiring for streetlights in the St. John's area at a cost of $70,000.
[2] 2007 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: **$5,811,000**

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.

Transformers 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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$5,811	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$5,811**	**$5,916**	**$18,335**	**$30,062**

Costing Methodology

Table 2 shows the annual expenditures for the most recent five-year period, as well as an estimate for 2008.

Table 2

Expenditure History and Budget Estimate (000s)

Year	2003	2004	2005	2006	2007F	2008B
Total	**$5,529**	**$5,449**	**$4,976**	**$5,643**	**$5,728**	**$5,811**
Adjusted Cost[1]	$6,038	$5,810	$5,223	$5,739	$5,728	-

[1] 2007 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, expressed in current-year dollars ("Adjusted Cost") are modified by the GDP Deflator for Canada for the budget year to determine the budget 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: **Reconstruction (Pooled)**

Project Cost: **$3,129,000**

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 as a result of line inspections, 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 that are identified and planned in advance of the annual capital budget preparation.

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 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$ 740	-	-	-
Labour – Internal	1,260	-	-	-
Labour – Contract	706	-	-	-
Engineering	316	-	-	-
Other	107	-	-	-
Total	**$3,129**	**$3,213**	**$10,155**	**$16,497**

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 2008.

Table 2

Expenditure History and Budget Estimate (000s)

Year	**2003**	**2004**	**2005**	**2006**	**2007F**	**2008B**
Total	**$2,846**	**$2,420**	**$2,898**	**$2,989**	**$3,239**	**$3,129**
Adjusted Cost[1]	$3,213	$2,636	$3,065	$3,065	$3,159	-

[1] 2007 dollars.

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

Project Cost: **$3,385,000**

Project Description

This Distribution project involves the replacement of deteriorated distribution structures and electrical equipment that have been previously identified through ongoing line inspections, engineering reviews, or day to day operations.

Distribution rebuild projects are preventative capital maintenance projects which are either the complete rebuilding of deteriorated distribution lines or the selective replacement of various line components based on inspections or engineering reviews. These typically include the replacement of poles, crossarms, conductor, cutouts, surge/lightning arrestors, insulators and transformers.

The work for 2008 includes feeder improvements on 42 of the Company's 303 feeders, as well as the replacement of deteriorated padmount transformers.

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 maintaining a safe, reliable electrical system.

The Company has over 8,600 kilometres of distribution lines in service and has an obligation to maintain this plant in good condition to safeguard the public and its employees and to maintain reliable electrical service. The replacement of deteriorated distribution structures and equipment is an important element of this obligation.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2008**	**2009**	**2010 - 2012**	**Total**
Material	$1,635	-	-	-
Labour – Internal	1,371	-	-	-
Labour – Contract	194	-	-	-
Engineering	25	-	-	-
Other	160	-	-	-
Total	**$3,385**	**$3,670**	**$11,521**	**$18,576**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$3,351**	**$3,382**	**$3,545**	**$2,811**	**$3,625**

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

a) Deficiencies that are a risk to public or employee safety, or that are likely to result in imminent failure of a structure or hardware;
b) Locations where lightning arrestors are required as observed in the *2003 Lightning Arrestor Review*;[1]
c) Locations where CP8080 and 2-piece insulators still exist. These insulators have a history of failure;[2]
d) Locations where current limiting fuses are required in accordance with the internal memo dated January 11, 2000;[3] and

[1] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment B for further detail on lightning arrestor requirements.
[2] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment C for further detail on problem insulators.
[3] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment D for further detail on current limiting fuse requirements.

e) Hardware for which a high risk of failure has been identified, such as automatic sleeves and porcelain cutouts.[4]

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

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

Future Commitments

This is not a multi-year project.

[4] See the 2004 Capital Budget Application, Volume III, Distribution, Appendix 2, Attachment E and Attachment F for further detail on automatic sleeves and porcelain cutouts.

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

Project Cost: **$606,000**

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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$ 212	-	-	-
Labour – Internal	194	-	-	-
Labour – Contract	127	-	-	-
Engineering	62	-	-	-
Other	11	-	-	-
Total	**$ 606**	**$622**	**$1,965**	**$3,193**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$330**	**$440**	**$630**	**$ 1,801**	**$ 2,110**
Adjusted Cost[1]	$373	$479	$666	$ 823[2]	$ 590[3]

[1] 2007 dollars.
[2] Excludes $999,000 for Persona cross island project.
[3] Excludes $1,520,000 for Persona cross island project.

The budget estimate is based on historical expenditures and specific project estimates for extraordinary requirements. 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, expressed in current-year dollars ("Adjusted Cost") are modified by the GDP Deflator for Canada for the budget year to determine the budget estimate. To ensure consistency from year to year, expenditures related to past extraordinary requirements are excluded from the calculation.

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

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

Future Commitments

This is not a multi-year project.

Project Title: **Distribution Reliability Initiative (Pooled)**

Project Cost: **$1,286,000**

Project Description

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

This project is a continuation of the Distribution Reliability Initiative project from 2006 that was postponed in 2007. Three projects were undertaken in 2006 that were planned to be completed over three years. The second year of these projects was postponed from 2007 to 2008 to accommodate the Rattling Brook Refurbishment project.

Table 1 identifies the feeders where upgrading will continue in 2008. It shows the number of customers affected, and the average unscheduled distribution yearly interruption statistics for the five-year period ending December 31, 2006. These SAIFI[1] and SAIDI[2] statistics exclude planned power interruptions and interruptions due to all causes other than distribution system failure. An analysis of each feeder to be upgraded is contained in report ***4.1** Distribution Reliability Initiative*.

Table 1

Distribution Interruption Statistics
5-Years to December 31, 2006

Feeder	Number of Customers	Distribution SAIFI	Distribution SAIDI
Botwood (BOT-01)	1,625	3.11	7.07
Lewisporte (LEW-02)	1,384	3.82	9.74
Glovertown (GLV-02)	1,251	3.19	7.36
Company Average	**-**	**1.45**	**2.03**

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

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

While the work on different feeders is not inter-dependent, the various components of this project 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 provide reliable electrical service. Customers supplied by these feeders experience power interruptions more often, or of longer duration, than the Company average. Individual feeder projects have been prioritized based on their historic SAIFI and SAIDI statistics.

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

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 2

Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 621	-	-	-
Labour – Internal	521	-	-	-
Labour – Contract	74	-	-	-
Engineering	10	-	-	-
Other	60	-	-	-
Total	**$1,286**	**$1,489**	**$4,673**	**$7,448**

Cost Methodology

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

Table 3

Expenditure History (000s)

Year	2003	2004	2005	2006	2007F[1]
Total	$1,546	$763	$1,065	$3,365	$0

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

The budget estimate is based on detailed engineering estimates of individual feeder upgrade requirements.

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

Future Commitments

This is not a multi-year project.

Project Title: **Install Capacitors to Reduce Losses (Pooled)**

Project Cost: **$200,000**

Project Description

This Distribution project involves the installation of distribution capacitors on selected feeders to reduce line losses. Reducing line loss improves the energy efficiency of the distribution system by reducing loss of energy.

Report ***4.2*** *Install Capacitors to Reduce Distribution Losses* identifies the feeders to be completed in 2008, the energy savings to be targeted and the associated cost savings.

Justification

The project costs are justified by the savings in energy from the reduction in losses at the feeder level. The project will provide approximately 732,000 kWh of energy to the system at a levelized unit cost of 2.38¢/kWh.

Projected Expenditures

Table 1 provides the breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$ 150	-	-	-
Labour – Internal	10	-	-	-
Labour – Contract	-	-	-	-
Engineering	35	-	-	-
Other	5	-	-	-
Total	**$ 200**	-	-	**$200**

Cost 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: **Interest During Construction (Pooled)**

Project Cost: **$77,000**

Project Description

This Distribution project is an allowance for interest during construction that 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.

Justification

The interest incurred during construction 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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	-	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	77	-	-	-
Total	**$77**	**$78**	**$243**	**$398**

Cost Methodology

Table 2 shows the annual expenditures for the most recent five-year period. The 2007 forecast amount and the 2008 budget amount are based on the average of the annual expenditures for the period 2003 to 2006.

Table 2 **Expenditure History and Budget Estimate** **(000s)**					
Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$74**	**$66**	**$73**	**$68**	**$81**

The budget estimate for interest during construction is based on an estimated monthly average of total distribution work in progress of $1.0 million. The interest rate which is applied each month is dependent on the source of funds used to finance the capital expenditure and is calculated in accordance with Order No. P.U. 37 (1981).

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.

GENERAL PROPERTY

Project Title: **Tools and Equipment (Pooled)**

Project Cost: **$690,000**

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 ($225,000)*: 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 ($400,000)*: This project 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 ($65,000)*: This project is the replacement of office furniture that has deteriorated. The Company has approximately 600 full time employees. The office furniture utilized by these employees deteriorates through normal use and must be replaced.

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 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures (000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 580	-	-	-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	10	-	-	-
Other	100	-	-	-
Total	**$ 690**	**$703**	**$2,177**	**$3,570**

Costing Methodology

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

Table 2

Expenditure History (000s)

Year	2003	2004	2005	2006	2007F
Total	**$865**	**$570**	**$693**	**$659**	**$600**

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.

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: **$122,000**

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 repairs and correcting major drainage problems.

The individual budget items 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 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 111	-	-	-
Labour – Internal	11	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$ 122**	**$236**	**$732**	**$1,090**

Costing Methodology

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

Table 2
Expenditure History
(000s)

Year	2003	2004	2005	2006	2007F
Total	**$237**	**$336**	**$334**	**$150**	**$125**
Exclusions	157	211	224	-	-
Adjusted Cost	$ 80	$125	$110	$150	$125

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 planned additions are excluded from the historical average calculation.

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

Future Commitments

This is not a multi-year project.

Project Title: **Standby Diesel Generators (Other)**

Project Cost: **$165,000**

Project Description

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

The 2006 Capital Budget Application included the report *Standby Generation at Newfoundland Power Facilities*. This report identified the need for standby generation at the Company's area operations buildings across the province.

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

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

At a more fundamental level, employees involved with a major restoration effort require a workspace with adequate lighting, heating or cooling. A reliable source of standby generation is required to provide employees with a supportive workspace where they can analyze, organize, prioritize and plan the recovery efforts, provide customer service, allocate materials and communicate instructions to crews working in the field.

Justification

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 150	-	-	-
Labour – Internal	15	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$ 165**	**$142**	**$142**	**$449**

Costing Methodology

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

Table 2

Expenditure History
(000s)

Year	2003	2004	2005	2006	2007F
Total	**-**	**-**	**-**	**$653**	**-**

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: **$2,214,000**

Project Description

This Transportation project involves the necessary replacement of heavy fleet, passenger and off-road vehicles. Detailed evaluation of the units to be replaced indicates they have reached the end of their useful lives.

Table 1 lists the units to be acquired in 2008.

Table 1
2008 Proposed Vehicle Replacements

Category	No. of Units
Heavy fleet vehicles[1]	4
Passenger vehicles[2]	36
Off-road vehicles[3]	11
Total	**51**

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 capital items that have reached the end of their useful service lives.

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

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.

Table 2 **Project Expenditures** **(000s)**				
Cost Category	**2008**	**2009**	**2010 - 2012**	**Total**
Material	$2,154	-	-	-
Labour – Internal	50	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	10	-	-	-
Total	**$2,214**	**$2,264**	**$7,165**	**$11,643**

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

Table 3 **Expenditure History** **(000s)**					
Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$3,429**	**$2,660**	**$2,838**	**$2,751**	**$2,206**

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: **$104,000**

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 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 72	-	-	-
Labour – Internal	1	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	31	-	-	-
Total	**$ 104**	**$ 121**	**$ 376**	**$ 601**

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 2007.

Table 2

Expenditure History (000s)

Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$41**	**$150**	**$102**	**$173**	**$101**
Adjusted Cost[1]	$46	$162	$107	$176	$101

[1] 2007 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 GDP Deflator for Canada for the budget year to determine the budget estimate. To ensure consistency from year to year, expenditures related to planned projects are excluded from the calculation of the historical average.

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$120,000**

Project Description

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

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

Newfoundland Power has completed an engineering review of these fibre optic communication circuits. Over the next few years, lease agreements will expire and new agreements for ten year terms will need to be established. Details of the engineering review are found in report ***5.1** Fibre Optic Circuit Replacement.*

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 Net Present Value analysis provided in ***5.1** Fibre Optic Circuit Replacement.*

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$ 99	-	-	-
Labour – Internal	5	-	-	-
Labour – Contract	-	-	-	-
Engineering	16	-	-	-
Other	-	-	-	-
Total	**$ 120**	**$ 215**	**$ 522**	**$ 857**

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: **$1,389,000**

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.

Of the software applications proposed to be enhanced in 2008, some, such as the Customer Service System, are custom-developed while others, such as the Asset Management System, are vendor-provided.

The application enhancements proposed for 2008 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*** *2008 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*** *2008 Application Enhancements*.

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2008**	**2009**	**2010 - 2012**	**Total**
Material	$ 95	-	-	-
Labour – Internal	922	-	-	-
Labour – Contract	-	-	-	-
Engineering	42	-	-	-
Other	330	-	-	-
Total	**$1,389**	**$1,325**	**$4,220**	**$6,934**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$920**	**$1,313**	**$1,185**	**$1,540**	**$1,281**

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: **$487,000**

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 or to maintain support provided by the vendors.

For 2008, the project includes upgrades to the Great Plains Financial Management System, the Company's Intranet, and Substation Design software. The project also includes improvements to the Information Technology Change Management and Configuration Management software.

The system upgrades proposed for 2008 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 2008 proposed expenditures are included in ***6.2*** *2008 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 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures
(000s)

Cost Category	2008	2009	2010 – 2012	Total
Material	$ 50	-	-	-
Labour – Internal	347	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	90	-	-	-
Total	**$ 487**	**$850**	**$2,670**	**$4,007**

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	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$721**	**$861**	**$779**	**$1,017**	**$689**

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: **Personal Computer Infrastructure (Pooled)**

Project Cost: **$408,000**

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 2008, 104 PCs will be purchased consisting of 76 desktop computers and 28 laptop computers. This project also covers the purchase of additional peripheral equipment such as monitors, scanners, and mobile devices, and the purchase of printers to replace existing printers that have reached the end of their useful lives.

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.

Minimum 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 minimum specifications.

Newfoundland Power is currently able to achieve a four to six year life cycle for its PCs before they require replacement. This is achieved through the Company's practice of cascading PCs to employees who do not require the computing power of newer PCs, thereby maximizing the asset life of the PC.

Table 1 outlines the PC additions and retirements for 2006 and 2007, as well as the proposed additions and retirements for 2008.

Table 1

PC Additions and Retirements
2006 – 2008

	2006			**2007F**			**2008B**		
	Add	**Retire**	**Total**	**Add**	**Retire**	**Total**	**Add**	**Retire**	**Total**
Desktop	47	65	469	57	57	469	76	76	469
Laptop	15	9	129	23	23	129	28	28	129
Total	**62**	**74**	**598**	**80**	**80**	**598**	**104**	**104**	**598**

Justification

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

Projected Expenditures

Table 2 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 2
Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	$217	-	-	-
Labour – Internal	85	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	106	-	-	-
Total	**$408**	**$425**	**$1,335**	**$2,168**

Costing Methodology

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

Table 3
Expenditure History
(000s)

Year	2003	2004	2005	2006	2007F
Total	$518	$424	$412	$380	$400

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: **$889,000**

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, disks, processors, and memory as well as security upgrades.

The shared server infrastructure requirements for 2008 are not inter-dependent. However, they are similar in nature and justification, and are therefore pooled for consideration as a single capital project.

Further details on shared server infrastructure requirements for 2008 are provided in ***6.3*** *2008 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 2008 and a projection of expenditures through 2012.

Table 1 Project Expenditures (000s)				
Cost Category	**2008**	**2009**	**2010 – 2012**	**Total**
Material	$ 445	-	-	-
Labour – Internal	339	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	105	-	-	-
Total	**$ 889**	**$850**	**$2,700**	**$4,439**

Costing Methodology

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

Table 2 Expenditure History (000s)					
Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$1,608**	**$699**	**$593**	**$493**	**$877**

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

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

Future Commitments

This is not a multi-year project.

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

Project Cost: **$119,000**

Project Description

This Information Systems project involves the replacement of network components that have reached the end of their useful life and are no longer supported by the vendor.

Network components such as routers and switches interconnect shared servers and personal computers across the Company, enabling the transport and sharing of data such as SCADA data, VHF radio signals, and customer service and corporate data.

The Company plans to replace twelve network switches located in the Company's offices across the province that are no longer supported by the vendor. This project is necessary to maintain current performance of the Company's internal network.

The individual network infrastructure requirements for 2008 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. The replacement or upgrade of network components will ensure the continued stability of the corporate network, thereby avoiding disruptions to customer service and critical communications.

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

Projected Expenditures

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1 **Project Expenditures** **(000s)**				
Cost Category	**2008**	**2009**	**2010 – 2012**	**Total**
Material	$ 85	-	-	-
Labour – Internal	34	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	-	-	-	-
Total	**$ 119**	**$150**	**$500**	**$769**

Costing Methodology

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

Table 2 **Expenditure History** **(000s)**					
Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$533**	**$432**	**$286**	**$0**	**$0**

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.

UNFORESEEN ALLOWANCE

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

Project Cost: **$750,000**

Project Description

This Unforeseen Allowance project is necessary to cover any unforeseen capital expenditures which have not been budgeted elsewhere. The purpose of the account is to permit the Company to act expeditiously to deal with events affecting the electrical system in advance of seeking specific approval of the Board. Examples of such expenditures are the replacement of facilities and equipment due to major storm damages or equipment failure.

While the contingencies for which this budget allowance is intended may be unrelated, it is appropriate that the entire allowance be considered as a single capital budget item.

Justification

This project provides funds for timely service restoration.

Projects for which these funds are intended are justified on the basis of reliability, or on the need to immediately replace deteriorated or damaged equipment.

Costing Methodology

An allowance of $750,000 for unforeseen capital expenditures has been included in all of Newfoundland Power's capital budgets in recent years.

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

Future Commitment

This is not a multi-year project.

GENERAL EXPENSES CAPITALIZED

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

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

Project Description

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

Justification

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

Costing Methodology

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

Future Commitment

This is not a multi-year project.

Newfoundland Power Inc.
2008 Capital Budget
Leases

Lease	Annual Cost	Term
Photocopiers	$70,000	36 Months

Title: **Photocopiers**

Lease Cost: **$70,000/Year**

Project Description

This lease is for the replacement of 17 low to medium volume photocopiers located at various offices across the province. These general use photocopiers produce in excess of 100,000 copies per month in total.

Justification

This project is justified on the need to provide employees with the ability to photocopy business use documents on a daily basis.

Projected Expenditures

The estimated annual cost for the lease of these photocopiers is $70,000 per year for a three-year term. The lease will end in 2010.

Table 1 provides a breakdown of the proposed expenditures for 2008 and a projection of expenditures through 2012.

Table 1

Project Expenditures
(000s)

Cost Category	2008	2009	2010 - 2012	Total
Material	-	-		-
Labour – Internal	-	-	-	-
Labour – Contract	-	-	-	-
Engineering	-	-	-	-
Other	$70	$70	$70	$210
Total	**$70**	**$70**	**$70**	**$210**

Future Commitments

This is multi-year project, with commitments expected for a lease term of 3 years.

Newfoundland Power Inc.
2008 Capital Budget
Future Required Expenditures

Improvement to Property	Estimated Annual Expenditure	Timing
Microsoft Enterprise Agreement[1]	$210,000	3 Years: 2006 through 2008

[1] This is a multi-year project approved in Order No. P.U. 30 (2005).

Newfoundland Power Inc.
2008 Capital Budget
Rate Base
(000s)

	Historical Data	
	2005	**2006**
Plant Investment	$ 1,148,621	$ 1,186,614
Deduct:		
Accumulated Depreciation	476,937	494,851
Contributions in Aid of Construction	21,192	23,142
Future Income Taxes	1,375	-
Weather Normalization Reserve	(10,100)	(11,808)
Purchase Power Unit Cost Variance Reserve	-	1,342
	489,404	507,527
	659,217	679,087
Add - Contributions Country Homes	580	1,001
Balance - Current Year	659,797	680,088
Balance - Previous Year	639,297	659,797
Average	649,547	669,943
Cash Working Capital Allowance	5,514	5,522
Materials and Supplies	4,322	4,510
Average Deferred Charges	86,063	94,338
Average Unrecognized 2005 Unbilled Revenue	-	(21,396)
Average Rate Base at Year End	$ 745,446	$ 752,917

2008 Capital Budget Plan

June 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

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Page

1.0 Introduction

To provide a broad context for the Board's consideration of its 2008 capital budget application, Newfoundland Power's 2008 Capital Budget Plan provides overviews of (i) the Company's capital management practice and how it is reflected in its annual capital budgets, (ii) the 2008 capital budget and (iii) the 5-year capital outlook through 2012.

1.1 Capital Assets

Newfoundland Power's ability to meet its obligations to provide reliable electricity service to its customers at least cost is largely dependant upon the quality and condition of its capital assets. The original capital cost of Newfoundland Power's assets is approximately $1.2 billion. Table 1 provides a breakdown by class of the Company's capital assets.

Table 1
Capital Assets by Class
2006

Asset	**(000s)**
Generation	$ 138,211
Substations	130,134
Transmission	92,489
Distribution	700,743
General Property	52,656
Transportation	21,543
Telecommunications	11,704
Information Systems	39,134
Total	**$ 1,186,614**

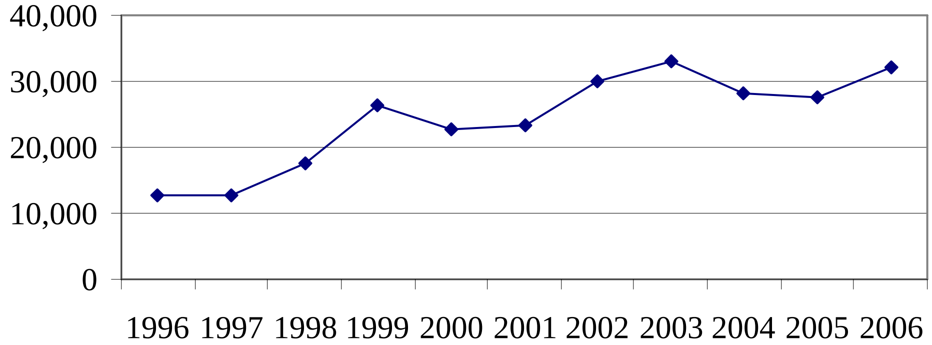
These assets are geographically dispersed throughout the Company's service territory and include: 23 hydroelectric plants; 6 thermal plants; 130 substations with almost 4,000 pieces of critical electrical equipment; approximately 270,000 distribution poles; 27,000 transmission poles; and approximately 10,000 km of distribution and transmission circuitry.

Newfoundland Power's annual capital budgets reflect the management of this relatively large number of components spread over a broad geographical area that make up the electrical system.

1.2 Reliability

A primary driver of Newfoundland Power's capital budgets is reliability. Reliability is, to a large extent, a function of system condition.[1] Graph 1 shows the Company's capital budget expenditure for asset replacement since 1996.

Graph 1
Asset Replacement 1996 - 2006
($000's)



Average capital expenditure for asset replacement for the most recent 5 year period[2] was $30.2 million. This represents approximately 2.5% of the capital cost of installed plant at 2006.[3]

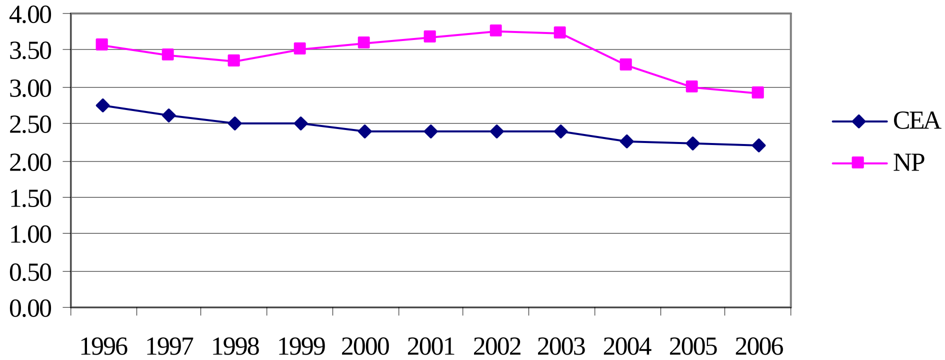
1 George Baker, P.Eng in his 1991 *Report* on *the Technical Performance of Newfoundland Light & Power Co. Limited*, prepared for the Board of Commissioners of Public Utilities, recognized that reliability was largely dependent on the quality of the system and weather.

2 D. G. Brown, P.Eng in his 1998 report *Newfoundland Light & Power Co. Limited Quality of Service and Reliability of Supply*, prepared for the Board of Commissioners of Public Utilities, identified the need for Newfoundland Power to improve reliability.

3 Capital cost of installed plant is $1.2 billion at December 31, 2006.

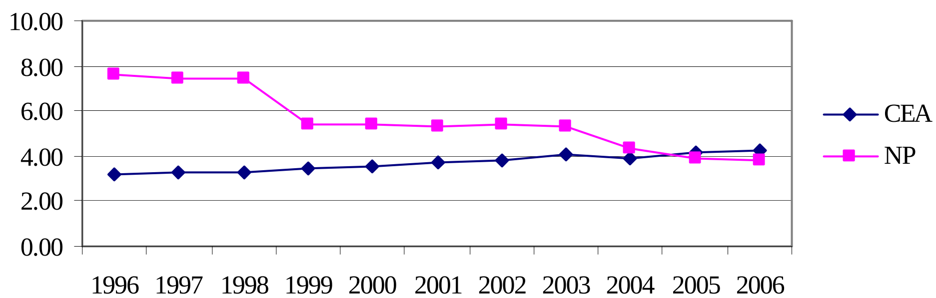
Graph 2 shows the 5 year average annual frequency of outages experienced by Newfoundland Power's customers since 1996 expressed in terms of SAIFI.[4]

Graph 2
5 Year Average SAIFI



Graph 3 shows the 5 year average annual duration of outages experienced by Newfoundland Power's customers since 1996 expressed in terms of SAIDI.[5]

Graph 3
5 Year Average SAIDI



Newfoundland Power continues to show improvement in reducing both the frequency and duration of customer outages.

4 SAIFI refers to System Average Interruption Frequency Index.
5 SAIDI refers to System Average Interruption Duration Index.

1.3 The 2008 Capital Budget Plan

The 2008 Capital Budget Plan (the "Plan") provides a broad overview of how Newfoundland Power assesses its annual capital requirements.

In addition, the Plan specifically includes an overview of the 2008 capital budget by the definitions and categories set out in the Board's provisional guidelines of June 2005. Finally, the Plan is intended to provide an overview of Newfoundland Power's 2008 capital budget within the context of a 2008 to 2012 five-year outlook.

2.0 Capital Budgeting

Newfoundland Power's annual capital budgets reflect the Company's capital management practices. The annual budgets are principally aimed at the prudent refurbishment of existing capital assets and the extension of the electricity network to meet increasing customer service requirements.

2.1 Overview

In creating its annual capital budgets, Newfoundland Power's principal purposes are to (i) prudently maintain existing assets in a safe, reliable manner and (ii) extend the electricity network to meet customers' service requirements.

This section, *2.0 Capital Budgeting*, outlines how the Company practically achieves these broad purposes in its annual capital budgeting process.

2.2 Capital Management Practice

Newfoundland Power must manage its capital assets in a way that results in the lowest possible cost to customers consistent with reliable service.

Conceptually, the Company's approach to capital management of existing assets attempts to balance the maximization of asset lives with the proactive replacement of deteriorated plant and equipment. Maximizing asset lives tends to lower overall costs. However, the longer facilities are in the field and exposed to climatic stresses, the greater the likelihood of failure which often results in increased operating cost and reduced reliability of service.

Due to the long life of utility assets, the replacement cost of plant will generally exceed the historical capital cost of plant particularly due to inflation. Therefore, the Company will continue to balance the maximization of asset lives with the proactive replacement of defective or deteriorated plant. Capital expenditures to replace deteriorated plant typically accounts for 50% to 60% of Newfoundland Power's annual capital budgets.

In addition to maintaining or replacing existing capital assets, Newfoundland Power must invest capital to meet the new service requirements of its customers. Meeting these requirements principally involves investment in the distribution system to connect customers in a cost effective way. Capital expenditures to serve new customers or increased customer requirements typically account for 20 to 25% of Newfoundland Power's annual capital budgets.

Due to the increasing cost of producing electricity on the system, Newfoundland Power is identifying opportunities to improve the efficiency of existing assets. The 2008 Capital Budget contains two projects that are justified on energy efficiency savings resulting from the reduction of system losses.

The conversion of transmission line 403L from 33 kV to 66 kV is justified on the energy savings resulting from reduced losses associated with higher voltage transmission. Transmission line 403L connects Lookout Brook hydro plant to the Island interconnected electrical system at St. Georges and Robinson's substations. Since there will be fewer losses over the transmission line, more energy will be delivered from the Lookout Brook plant to the system, thereby reducing the amount of energy required from more expensive sources. Details on this project are included in the report ***2.2*** *Convert 403L to 66 KV to Reduce Losses*.

The *Install Capacitors to Reduce Losses* project involves the installation of capacitors on selected distribution feeders to reduce line losses. Line losses are an inherent characteristic of electricity transmission and distribution systems. The main contributor of line loss is heat dissipation that results from current passing through conductors. Capacitors reduce the amount of current delivered from the power source along distribution feeder conductors thereby reducing line losses. Details on this project are included in the report ***4.2*** *Install Capacitors to Reduce Distribution Losses*.

The *Engineering to Increase Hydro Plant Production* project will produce an inventory of opportunities to increase the annual production of existing hydroelectric plants and complete engineering design work on the most feasible projects.

Decreasing line losses and increasing the energy production of existing hydroelectric plants will reduce the need for more expensive energy that is currently produced at the Holyrood thermal generating station.

2.3 Concluding

Newfoundland Power's capital budgeting practices for all budget classes ensure the prudent maintenance of existing assets, which provides least cost electricity service to customers. The 2008 Capital Budget contains expenditures to respond to inevitable failures of plant and equipment, and expenditures to carry out a preventive capital maintenance program. The 2008 Capital Budget also includes projects to address the energy efficiency of the system.

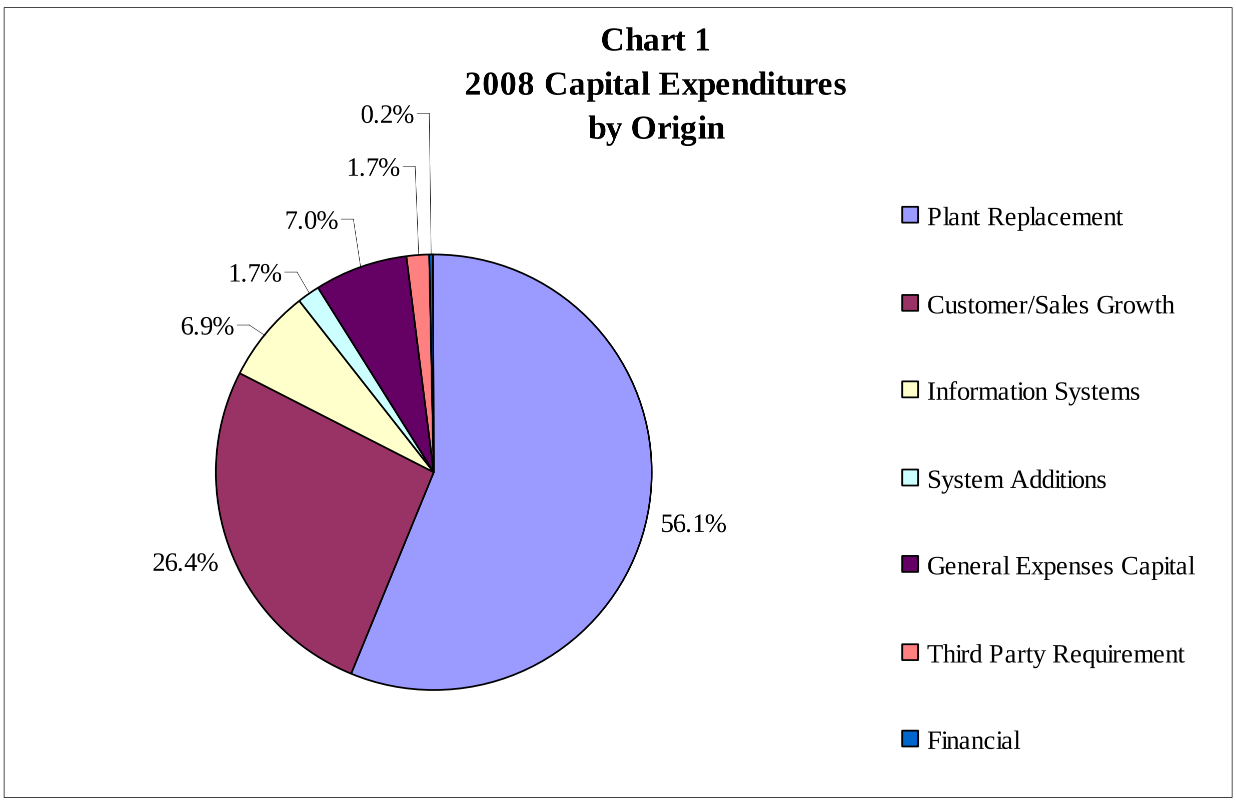
3.0 2008 Capital Budget

Newfoundland Power's 2008 capital budget is $50,754,000. This section of the 2008 Capital Budget Plan provides an overview of the 2008 capital budget by origin (root cause) and asset class. In addition, this section summarizes 2008 capital projects by the various categories set out in the Board's June 2005 provisional capital filing guidelines.

3.1 2008 Capital Budget Overview

Newfoundland Power's 2008 capital budget contains 32 projects totalling $50,754,000. The budget is consistent with budgets prior to 2007. The 2007 capital budget was different from budgets proposed in recent years in that a single project, the *Rattling Brook Hydro Plant Refurbishment* project, which was budgeted at $18,820,000, constituted 30% of the overall capital budget.

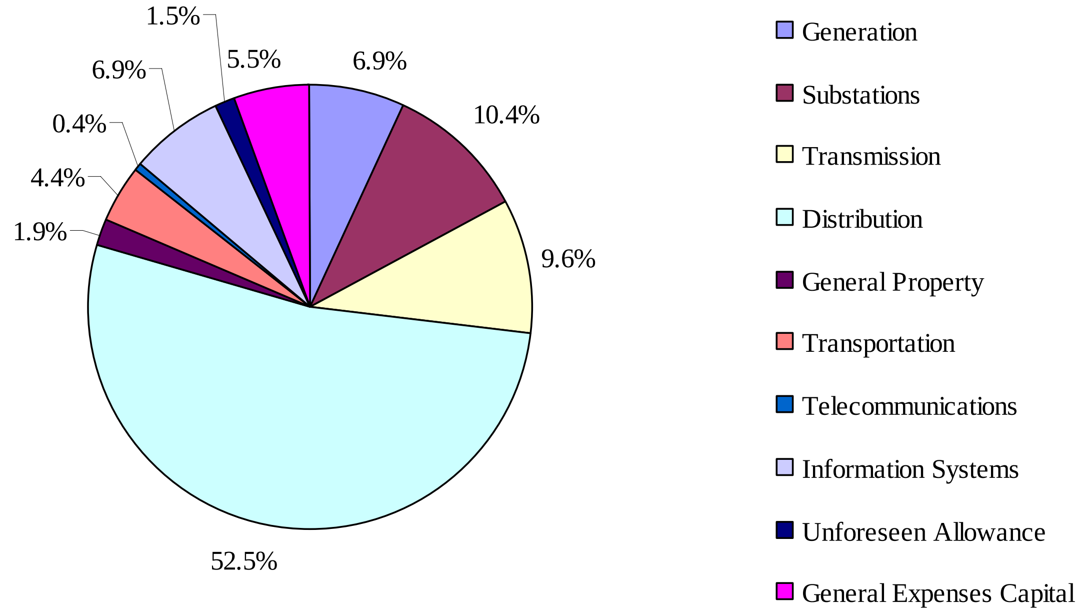
Chart 1 shows the 2008 capital budget by origin, or root cause.



Approximately 56% of proposed 2008 capital expenditure is related to the replacement of plant. A further 26% of proposed 2008 capital expenditure is required to meet the Company's obligation to provide service to new customers.

Chart 2 shows the 2008 capital budget by asset class.

Chart 2
2008 Capital Expenditures
by Asset Class



As in past years, Distribution capital expenditure accounts for the greatest percentage of overall expenditure at $26.6 million, or 52% of the 2008 capital budget. Substations and Transmission capital expenditures account for a further $10.2 million, or 20% of the 2008 capital budget.

3.2 The Provisional Guidelines

In June 2005, the Board provided guidelines on the definition and categorization of capital expenditures for which a public utility requires prior approval of the Board (the "Provisional Guidelines").

Newfoundland Power's 2008 capital budget application complies with the Provisional Guidelines.

3.2.1 2008 Capital Projects by Definition

Table 3 summarizes Newfoundland Power's proposed 2008 capital projects by definition as set out in the Provisional Guidelines.

Table 3
2008 Capital Projects
by Definition

Definition	No.	($000s)
Pooled	29	47,039
Clustered	0	0
Other	3	3,715
Total	**32**	**50,754**

3.2.2 2008 Capital Projects by Classification

Table 4 summarizes Newfoundland Power’s proposed 2008 capital projects by classification as set out in the Provisional Guidelines.

Table 4
2008 Capital Projects
by Classification

Classification	No.	($000s)
Mandatory	0	0
Normal	27	48,687
Justifiable	5	2,067
Total	**32**	**50,754**

3.2.3 2008 Capital Projects Costing

Table 5 summarizes Newfoundland Power’s proposed 2008 capital projects by costing method (i.e., identified need vs. historical pattern) as set out in the Provisional Guidelines.

Table 5
2008 Capital Projects
Costing Method

Method	No.	($000s)
Identified Need	17	20,528
Historical Pattern	15	30,226
Total	**32**	**50,754**

3.2.4 2008 Capital Projects Materiality

Table 6 segments Newfoundland Power's proposed 2008 capital projects by materiality as set out in the Provisional Guidelines.

Table 6
2008 Capital Projects
Segmentation by Materiality

Segment	**No.**	**($000s)**
Under $200,000	8	932
$200,000 - $500,000	3	841
Over $500,000	21	48,981
Total	**32**	**50,754**

4.0 5-Year Outlook

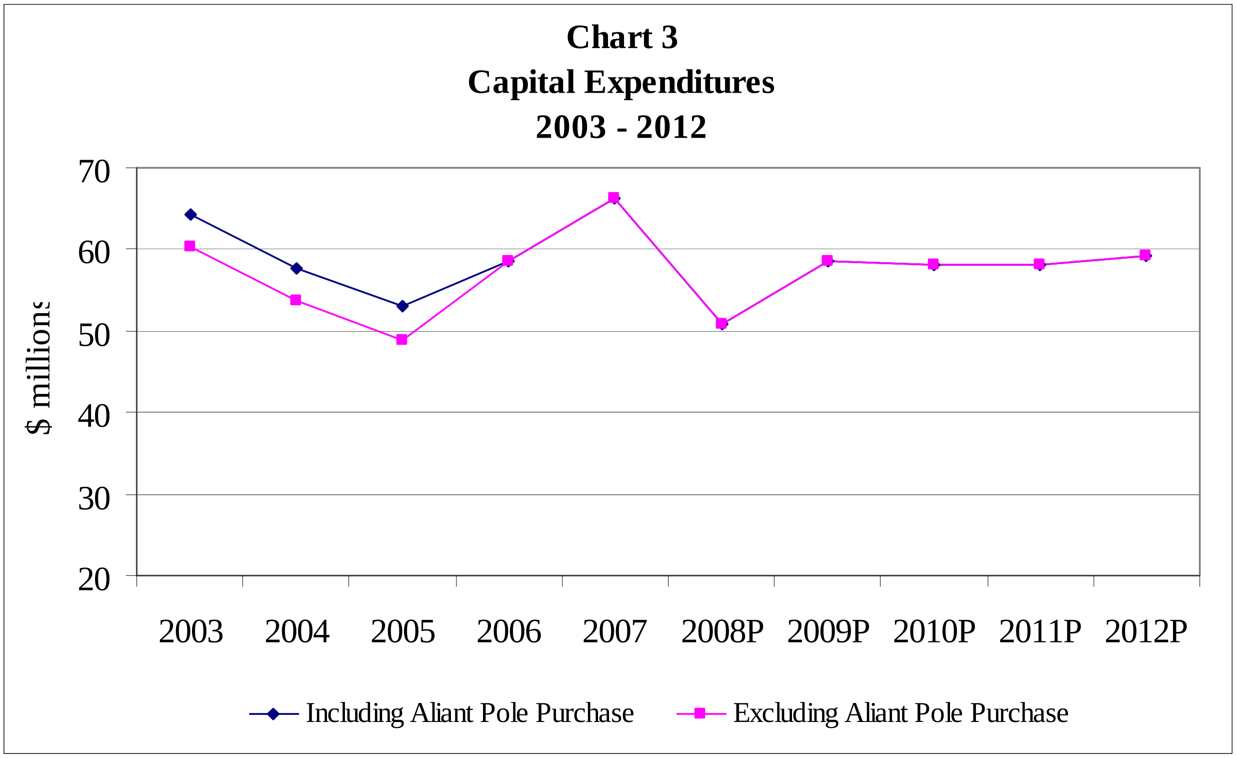
Newfoundland Power's 5-year capital outlook for 2008 through 2012 is broadly consistent with capital expenditures over the period 2003 through 2007, with the exception of the 2007 Rattling Brook Hydro Plant Refurbishment project. Planned capital expenditures are forecast to be stable on a year-to-year basis through 2012.

4.1 Capital Expenditures: 2003 - 2012

The Company plans to invest $288 million in plant and equipment during the 2008 through 2012 period. On an annual basis, capital expenditures are expected to average approximately $57.0 million and range from a low of $50.8 million in 2008[6] to a high of $59.3 million in 2012.

Chart 3 shows actual and planned capital expenditures for the period 2003 through 2012 including and excluding the purchase of joint use support structures from Aliant Telecom Inc. over the period 2003 through 2005.

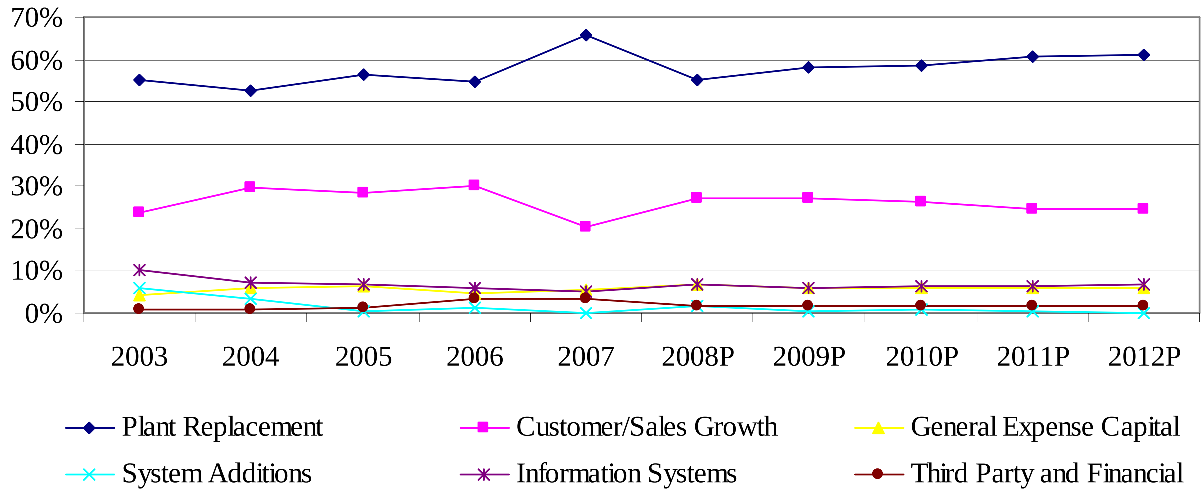
[6] Excludes $2.7M for the Rattling Brook Plant Dam Refurbishment project in 2008.



Overall planned capital expenditures over the 5-year period from 2008 through 2012 are expected to be broadly consistent with those in the 5-year period from 2003 through 2007 with the exception of the Rattling Brook Refurbishment project.

Chart 4 shows actual and planned capital expenditures for the period 2003 through 2012 by origin, or root cause. The Aliant Telecom Inc. joint use support structure purchase has been excluded from the analysis.

Chart 4
Capital Expenditures By Origin (excluding Aliant)
2003 - 2012



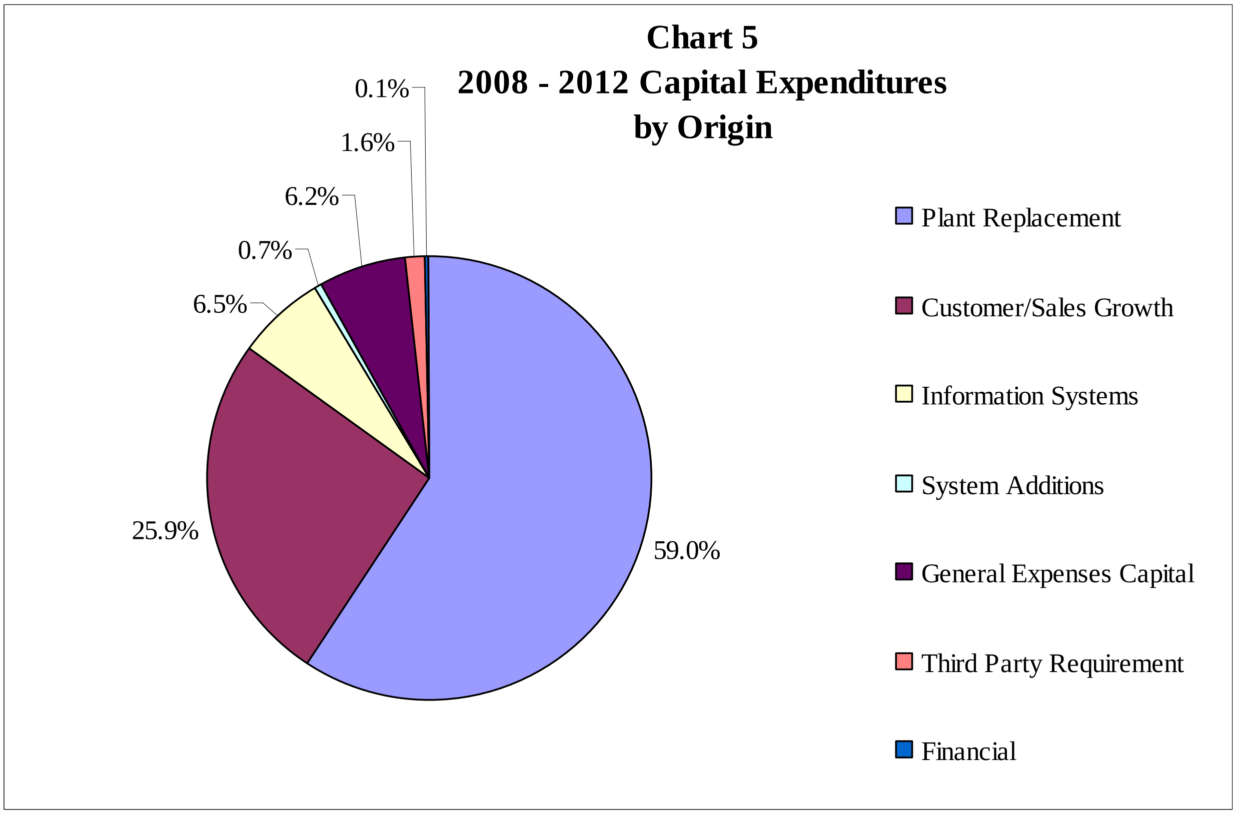
For the entire 2003 through 2012 period, the replacement of plant has been, and will continue to be, the dominant driver of Newfoundland Power's capital budget, accounting for approximately 58% of total expenditures.

Capital expenditures to meet increases in customer connections and sales will continue to account for approximately 26% of total expenditures.

4.2 2008 – 2012 Capital Expenditures

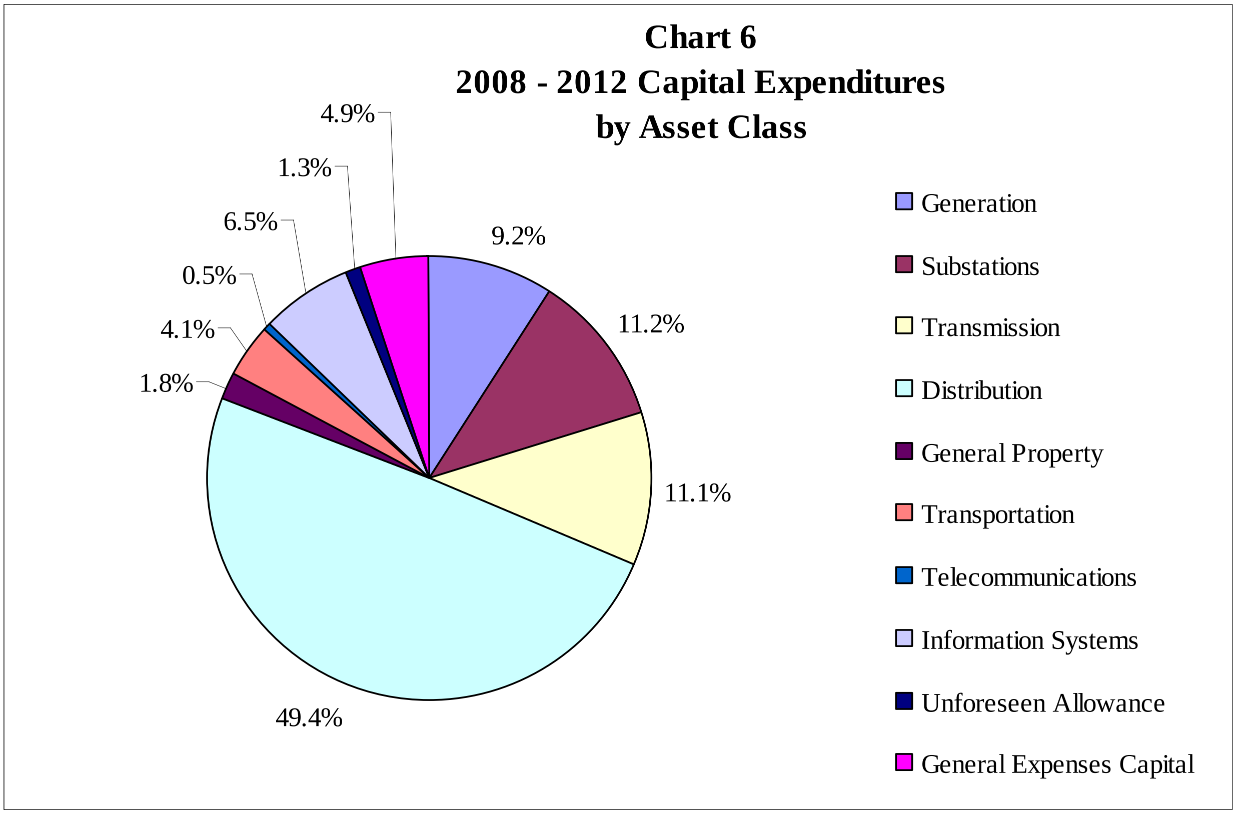
4.2.1 Overview

The origin of expenditures through the 2008 to 2012 period is consistent with the 2003 through 2007 period. The pattern of expenditures by origin for the 2008 to 2012 period is shown in Chart 5.



Plant replacement accounts for 59% of all planned expenditures over the next five years, followed by customer and sales growth at 26%. The remaining 5 origins account for a combined 15% of total capital expenditures for the 2008 through 2012 period

Chart 6 shows planned capital expenditures for the period 2008 through 2012 by asset class. Distribution accounts for 49% of all planned expenditures over the next five years, followed by Substations (11%), Transmission (11%) and Generation (9%). The remaining six asset classes account for 20% of total capital expenditures for the 2008 through 2012 period.



A summary of planned capital expenditures for the period 2008 through 2012 by asset class along with a breakdown by project is contained in Appendix A. Overall, planned expenditures are expected to remain stable in all asset classes with the exception of generation and transmission.

4.2.2 Generation

Generation capital expenditures will average approximately $5.2 million per year from 2008 to 2012, which is lower than the average of $6.7 million spent between 2003 through 2006.[7]

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 program; and
- Capital project initiatives.

The Company has an industry best practice 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.

7 2007 was not included in the calculation of the average as it included the Rattling Brook Refurbishment project.

Due to the age of the Company's fleet of generating plants, significant refurbishment will be required over the planning period. Over the next five years, the Company plans to continue the practice adopted in recent years of undertaking a major initiative in approximately one generation plant per year. Specifically, the following major capital project initiatives are planned:

- In 2008, the Company plans to refurbish the Rattling Brook spillway and associated dam structures at an estimated cost of $2.7 million. At this time the Company is working with government officials for the appropriate approvals for this project. As a result, the project is not included in the 2008 Capital Budget Application. The Company will bring this project forward when all necessary approvals have been received.

- In 2009, the Company plans to replace the Rocky Pond hydroelectric plant penstock and main valve at an estimated cost of $4.0 million.

- In 2010, a refurbishment of the Victoria hydroelectric plant is planned at an estimated cost of $3.0 million.

- In 2011, the Company plans to upgrade the governors and protection and control systems at the Lookout Brook hydroelectric plant at an estimated cost of $1.0 million.

- In 2011, the runners and wicket gates are planned for replacement on two units at the Tors Cove hydroelectric plant at an estimated cost of $1.1 million.

- In 2012, the Company plans to replace the Hearts Content hydroelectric plant penstock and main valve at an estimated cost of $3.0 million.

The Company will bring forward, as part of its Capital Budget Application to the Board, engineering reports regarding each of these initiatives as well as analysis of the long term economic viability of each generating plant.

4.2.3 Substations

Substations capital expenditures are expected to average $6.4 million annually over the 2008 through 2012 period which is greater than the average of $5.1 million spent annually between 2003 and 2007.

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

- Breakdown capital maintenance;
- Substation preventive capital maintenance program; and
- System load growth.

The level of breakdown capital maintenance is expected to remain consistent over the forecast period. The Company expects its efforts in preventive maintenance will counter the continuous aging of the substation assets such that the level of failures and overall reliability of substation assets remains stable.

In the 2007 Capital Budget Application, the Company submitted its 10-year substation strategy in a report titled *Substation Strategic Plan*. The Company intends to follow this approach to preventive capital maintenance that involves the refurbishment and modernization of substation plant and equipment. An update of the strategic plan is included in report ***2.1*** *2008 Substation Refurbishment and Modernization*.

The Company forecasts two significant projects will be required due to system load growth over the planning period.

In 2009, a new substation is forecast for construction near the community of Little Rapids in the Humber Valley area. To provide a power transformer for the new Little Rapids substation a series of transformer transfers will be required. These transfers involve substations in the communities of Deer Lake, Bonavista, Grand Bank and St. John's. These transfers are designed to address load growth issues in these communities. The transfers negate the need to purchase a new power transformer for Little Rapids substation.

A second load growth issue is developing at Lethbridge on the Bonavista Peninsula. At present the problem is being addressed through customer load transfers with adjacent substations. In 2010, a larger power transformer will be required for Lethbridge substation, necessitating a rebuild of the entire substation.

4.2.4 Transmission

Transmission capital expenditures are expected to average $6.3 million annually over the 2008 through 2012 period. This is higher than the average $5.1 annual expenditure over the 2003 to 2007 period.

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

- Breakdown capital maintenance;
- Transmission preventive capital maintenance program; and
- Third party requests.

The Company has an industry best practice maintenance program in place for its transmission assets. However, in-service failures of transmission assets are unavoidable and therefore a level of capital expenditure will be required for breakdown maintenance. The Company expects its efforts in preventive maintenance will counter the continuous aging of the transmission assets such that the capital expenditure due to transmission plant and equipment failures will approximate the historical average cost and remain stable over the next five years.

In the 2006 Capital Budget Application, the Company submitted its 10-year transmission strategy in a report titled *Transmission Line Rebuild Strategy*. The report outlined the need to completely rebuild certain sections of aging transmission lines throughout the Company's service territory that are either deteriorated or of non-standard construction. This proactive approach to managing transmission assets is expected to reduce failures over the long term and is the principal reason for the increase in capital expenditures in transmission over the next five years as compared to the past five years. An update of the plan is included in report ***3.1*** *Transmission Line Rebuild*.

Transmission capital expenditures for third party requests by governments, telecommunications companies and individual customers to relocate or replace transmission lines are forecast to approximate the historical average cost and remain stable over the next five years.

4.2.5 Distribution

Distribution capital expenditures are expected to remain relatively stable at an average of approximately $28.1 million for the period 2008 to 2012 compared to an average of $28.1 million for the period 2003 to 2007.

The Company operates approximately 8,000 km of distribution lines serving over 230,000 customers. Distribution capital expenditures are primarily driven by:

- New customers;
- Third party requests;
- Breakdown capital maintenance;
- Distribution preventive capital maintenance program;
- System load growth; and
- Capital project initiatives.

Capital expenditures associated with new customer connections are forecast to remain relatively constant over the planning period. This is primarily due to an anticipated decline in the number of new customer connections offset by normal 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 7 shows the total capital expenditures associated with the connection of new customers to the system over the next five years.

Table 7
New Customer Connection Cost

	2008	**2009**	**2010**	**2011**	**2012**
Capital Expenditure ($000s)	$13,381	$13,584	$13,736	$13,940	$14,195
New Customer Connections	3,451	3,332	3,285	3,251	3,225
Average Cost/Connection	$3.877	$4,077	$4,181	$4,288	$4,402

Distribution capital expenditures for third party requests by governments, telecommunications companies and individual customers to relocate or replace distribution lines are forecast to approximate the historical average cost and remain stable over the next five years.

The Company has an industry best practice 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 the distribution assets such that the capital expenditure due to distribution plant and equipment failures will approximate the historical average cost and remain 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 project, *Rebuild Distribution Lines*. The Company plans to perform preventive capital maintenance on approximately 45 distribution feeders per year over the planning period.

The amount of Distribution capital expenditure for system load growth is expected to be less than the historical average due to a forecast reduction in load growth over the next five years compared 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*. This capital project was suspended in 2007 to balance overall capital expenditures due to the upward pressure of the Rattling Brook project.

In 2008, the Company will resume the *Distribution Reliability Initiative* project. The projects planned for 2008 involve three feeders where work commenced in 2006 but was suspended in 2007.

4.2.6 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 in the day-to-day operation of the Company, as well as the replacement or addition of office furniture and equipment. This asset class includes additions to real property necessary to maintain buildings and facilities and to operate them in an efficient manner. Also included in this asset class are investments to provide backup diesel generation and implement demand/load control at Company buildings.

General Property capital expenditures are expected to average $1.0 million annually over the 2008 through 2012 period which is less than the $1.5 million spent over the 2003 through 2007 period.

4.2.7 Transportation

The Transportation asset class includes the replacement of existing heavy 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 average $2.3 million annually over the 2008 through 2012 period which is slightly less than the $2.8 million spent over the 2003 through 2007 period.

4.2.8 Telecommunications

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

Telecommunications capital expenditures are expected to average $0.3 million annually over the 2008 through 2012 period which is slightly more than the $0.2 million spent over the 2003 through 2007 period. This is a result of plans to replace rented fibre optic circuits with new fibre optic cables owned by Newfoundland Power.

4.2.9 Information Systems

The Information Systems asset class includes: the replacement of 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 new developments and product improvements.

Information Systems capital expenditures are expected to average $3.7 million annually over the 2008 through 2012 period which is lower than the $4.1 million spent over the 2003 through 2007 period. Capital expenditure in Information Systems in the 2008 and 2012 period do not include expenditure for the anticipated replacement of the Company's Customer Service System.

4.2.10 Unforeseen Allowance & General Expenses Capitalized

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 the approval of the Board.

The Unforeseen Allowance constitutes $750,000 in each year's capital budget from 2008 through 2012.

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

General Expenses Capitalized of $2.8 million is reflected in each year's capital budget from 2008 through 2012.

4.3 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 Plan has identified some risks to such stability in the period 2008 through 2012.

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 potential mine sites within the Company's service area. Should one of these sites be developed, it may require additional capital expenditures in the order of $5 million. Due to the speculative nature of these developments, the projects have not been included in the Plan.

An example of a potential large project is the impending replacement of the Company's Customer Service System ("CSS"), which is over 15 years old. As the replacement cost of a CSS system could be as high as $15 million, the Company is taking steps to extend the life of CSS through 2012. The current plan is to replace CSS over a number of years beginning in 2013. However, changing technology and vendor support could conceivably dictate otherwise.

Another area that may impact capital expenditures is metering technology. In this plan, the Company intends to continue with its metering strategy as outlined in *Metering Strategy*, filed with the 2006 Capital Budget Application. However, the Company will continually assess technological and business developments in metering and explore opportunities to reduce costs to customers with the implementation of metering technology. This may manifest itself in revisions to the *Metering Strategy* and increased capital expenditures in the future.

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. In 2003, Hurricane Juan hit Nova Scotia, resulting in severe damage to that province's transmission and distribution systems and the loss of power to over 300,000 customers. The occurrence and costs of natural disasters are not predictable.

Overall, planned capital expenditures are forecast to be relatively stable during the 2008 through 2012 period. However, circumstances can change and, as a result, so can priorities and the level of capital expenditures.

Assessment of maximum budget growth in this period necessarily involves a significant degree of conjecture. Given that the addition of a single large general service customer could conceivably add capital expenditures of $5 million, a maximum annual capital budget could approximate $60 - 65 million. In such a case, certain otherwise justifiable projects might be deferred in a way that minimizes the negative impact of deferral on the quality of service.

4.4 5-Year Plan: Summary

Over the next five years, the Company plans to invest approximately $288 million in plant and equipment. Overall, the planned expenditures are expected to remain relatively stable for all asset classes, and consistent with expenditures incurred during the 2003 through 2007 period.

Approximately 60% of planned expenditures focus on the replacement of deteriorated, defective or obsolete distribution, transmission, generation and substation electrical equipment. Capital expenditures related to customer and sales growth is forecast to remain relatively stable. The

Company does not anticipate any significant changes in the pattern of planned expenditures by origin.

While planned capital expenditures are forecast to be relatively stable during the 2008 through 2012 period, circumstances can change and, as a result the maximum capital budget could approximate $60 - 65 million.

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

Asset Class	2008	2009	2010	2011	2012
Generation[1]	$6,160	$6,790	$5,294	$5,200	$5,393
Substations	5,276	7,050	6,887	6,072	6,569
Transmission	4,890	6,216	6,563	6,920	7,045
Distribution	26,636	27,718	28,206	28,766	29,417
General Property	977	1,081	1,096	969	986
Transportation	2,214	2,264	2,361	2,501	2,303
Telecommunications	224	336	367	403	128
Information Systems	3,502	3,600	3,725	3,800	3,900
Unforeseen Allowance	750	750	750	750	750
General Expenses Capitalized	2,800	2,800	2,800	2,800	2,800
Total	**$53,429**	**$58,605**	**$58,049**	**$58,181**	**$59,291**

[1] The Rattling Brook Plant – Dam Refurbishment project is included here in the capital budget plan 5 year forecast, although it is not included in the 2008 Capital Budget Application Schedule A. Newfoundland Power intends to bring this project forward in a supplemental application when the necessary government approvals have been established.

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

GENERATION

Project	2008	2009	2010	2011	2012
Facility Rehabilitation – Hydro	$3,260	$2,410	$2,125	$2,950	$2,243
Facility Rehabilitation - Thermal	100	350	125	150	150
Rattling Brook Plant – Dam Refurbishment[2]	2,675	-	-	-	-
Engineering to Increase Production	125	-	-	-	-
Rocky Pond Penstock and Main Valve	-	4,030	75	-	-
Victoria Hydro Plant Refurbishment	-	-	2,953	-	-
Tors Cove Runners and Wicket Gates	-	-	16	1,100	-
Lookout Brook Governors P&C	-	-	-	1,000	-
Hearts Content Penstock	-	-	-	-	3,000
Total - Generation	**$6,160**	**$6,790**	**$5,294**	**$5,200**	**$5,393**

[2] The Rattling Brook Plant – Dam Refurbishment project is included here in the capital budget plan 5 year forecast, although it is not included in the 2008 Capital Budget Application Schedule A. Newfoundland Power intends to bring this project forward in a supplemental application when the necessary government approvals have been established.

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

SUBSTATIONS

Project	**2008**	**2009**	**2010**	**2011**	**2012**
Substations Refurbishment & Modernization	$3,703	$3,680	$4,289	$4,646	$5,112
Replacements Due to In-Service Failure	1,340	1,370	1,398	1,426	1,457
Additions Due to Load Growth	-	2,000	1,200	-	-
Convert 403L to 66 KV	233	-	-	-	-
Total – Substations	**$5,276**	**$7,050**	**$6,887**	**$6,072**	**$6,569**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

TRANSMISSION

Project	**2008**	**2009**	**2010**	**2011**	**2012**
Transmission Line Rebuild	$4,890	$6,216	$6,563	$6,920	$7,045
Total – Transmission	**$4,890**	**$6,216**	**$6,563**	**$6,920**	**$7,045**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

DISTRIBUTION

Project	2008	2009	2010	2011	2012
Extensions	$7,791	$8,014	8,098	$8,215	$8,359
Meters	986	1,023	1,078	1,155	1,259
Services	2,004	1,997	2,025	2,060	2,102
Street Lighting	1,361	1,315	1,313	1,314	1,319
Transformers	5,811	5,916	6,011	6,107	6,217
Reconstruction	3,129	3,213	3,297	3,384	3,474
Rebuild Distribution Lines	3,385	3,670	3,753	3,838	3,930
Relocate/Replace Distribution Lines For Third Parties	606	622	638	655	672
Distribution Reliability Initiative	1,286	1,489	1,523	1,557	1,593
Feeder Additions and Upgrades to Accommodate Growth	-	381	390	400	410
Install Capacitors to Reduce Losses	200	-	-	-	-
Interest During Construction	77	78	80	81	82
Total – Distribution	**$26,636**	**$27,718**	**$28,206**	**$28,766**	**$29,417**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

GENERAL PROPERTY

Project	**2008**	**2009**	**2010**	**2011**	**2012**
Tools and Equipment	$690	$703	$714	$725	$738
Additions to Real Property	122	236	240	244	248
Stand-By Diesel Generators – Company Buildings	165	142	142	-	-
Total – General Property	**$977**	**$1,081**	**$1,096**	**$969**	**$986**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

TRANSPORTATION

Project	2008	2009	2010	2011	2012
Purchase Vehicles and Aerial Devices	$2,214	$2,264	$2,361	$2,501	$2,303
Total – Transportation	**$2,214**	**$2,264**	**$2,361**	**$2,501**	**$2,303**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

TELECOMMUNICATIONS

Project	**2008**	**2009**	**2010**	**2011**	**2012**
Replace/Upgrade Communications Equipment	$104	$121	$123	$125	$128
Fibre Optic Cable	120	215	244	278	-
Total – Telecommunications	**$224**	**$336**	**$367**	**$403**	**$128**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

INFORMATION SYSTEMS

Project	**2008**	**2009**	**2010**	**2011**	**2012**
Application Enhancements	$1,389	$1,325	$1,375	$1,400	$1,445
System Upgrades	697[3]	850	875	890	905
Personal Computer Infrastructure	408	425	440	445	450
Shared Server Infrastructure	889	850	875	900	925
Network Infrastructure	119	150	160	165	175
Total – Information Systems	**$3,502**	**$3,600**	**$3,725**	**$3,800**	**$3,900**

[3] Includes Microsoft Enterprise Agreement ($210,000) approved with the 2006 Capital Budget Application for 2006 to 2008.

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

UNFORESEEN ALLOWANCE

Project	2008	2009	2010	2011	2012
Allowance for Unforeseen	$750	$750	$750	$750	$750
Total – Unforeseen Allowance	**$750**	**$750**	**$750**	**$750**	**$750**

Newfoundland Power Inc.
2008-2012 Capital Budget Plan
(000s)

GENERAL EXPENSES CAPITALIZED

Project	2008	2009	2010	2011	2012
General Expenses Capitalized	$2,800	$2,800	$2,800	$2,800	$2,800
Total – General Expenses Capitalized	**$2,800**	**$2,800**	**$2,800**	**$2,800**	**$2,800**

2007 Capital Expenditure Status Report

June 2007

NEWFOUNDLAND POWER INC.

2007 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 4 of Order No. P.U. 35 (2003).

Page 1 of the 2007 Capital Expenditure Status Report outlines the forecast variances from budget of the capital expenditures approved by the Board in Order Nos. P.U. 30 (2006) and P.U. 34 (2006). The detailed tables on pages 2 to 12 provide additional detail on capital expenditures in 2007, and also include information on those capital projects approved for 2006 that were not completed prior to 2007.

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 2007 Capital Expenditure Status Report. While forecast expenditure is below budget and within the above guidelines, an explanation is also provided on the Plant Rehabilitation at Rattling Brook.

Newfoundland Power Inc.

2007 Capital Budget Variances
(000s)

	Approved by Order Nos. P.U. 30 (2006) P.U. 34 (2006)	Forecast	Variance
Generation - Hydro	$19,188	$18,932	($256)
Generation - Thermal	0	0	0
Substations[1]	3,968	4,318	350
Transmission	4,283	4,283	0
Distribution[2]	24,103	27,090	2,987
General Property[3]	1,995	2,095	100
Transportation	2,206	2,206	0
Telecommunications	101	101	0
Information Systems	3,457	3,457	0
Unforeseen Items	750	750	0
General Expenses Capitalized	2,800	2,800	0
Total	$62,851	$66,032	$3,181
Projects carried forward from 2006		$277	

[1] Substations variance is attributed to the failure of two power transformers at Lockston and Broad Cove substations. Reference page 4 of 12 and Appendix A page 2 of 4.

[2] Distribution variance largely attributed to growth in cottage areas and higher than normal activity by telecommunications companies requiring third party relocation and replacements. Of the $2,685,000 variance attributed to two Distribution projects, Extensions and Relocate/Replace Distribution Lines for Third Parties, approximately $1,811,000 will be recovered through Contributions in Aid of Construction. Reference page 6 of 12 and Appendix A page 3 of 4.

[3] Budget includes $685,000 for Maple Valley Service Building approved in P.U. 34 (2006).

2007 Capital Expenditure Status Report
(000s)

	Capital Budget			Actual Expenditures			Forecast			
	2006	2007	Total	2006	2007	Total To Date	Remainder 2007	Total 2007	Overall Total	Variance
	A	B	C	D	E	F	G	H	I	J
2007 Projects	$ -	$ 62,851	$ 62,851	$ -	$ 22,999	$ 22,999	$ 43,033	$ 66,032	$ 66,032	$ 3,181
2006 Projects	1,455	-	1,455	1,471	265	1,736	12	277	1,748	293
Grand Total	**$ 1,455**	**$ 62,851**	**$ 64,306**	**$ 1,471**	**$ 23,264**	**$ 24,735**	**$ 43,045**	**$ 66,309**	**$ 67,780**	**$ 3,474**

Column A	Approved Capital Budget for 2006
Column B	Approved Capital Budget for 2007
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2006
Column E	Actual Capital Expenditures for 2007
Column F	Total of Columns D and E
Column G	Forecast for Remainder of 2007
Column H	Total of Columns E and G
Column I	Total of Columns D and H
Column J	Column I less Column C

2007 Capital Expenditure Status Report
(000s)

Category: Generation - Hydro

Project	Capital Budget 2007 A	Capital Budget Total B	Actual Expenditures 2007 C	Actual Expenditures To Date D	Forecast Total 2007 E	Forecast Remainder 2007 F	Forecast Total Total G	Forecast Overall Variance H	Notes*
2007 Projects									
Hydro Plants - Facility Rehabilitation	$ 946	$ 946	$ 110	$ 110	$ 836	$ 946	$ 946	$ -	
Plant Refurbishment - Rattling Brook	18,242	18,242	4,450	4,450	13,536	17,986	17,986	(256)	1
Total - 2007 Projects	$ 19,188	$ 19,188	$ 4,560	$ 4,560	$ 14,372	$ 18,932	$ 18,932	$ (256)	
Total - Generation Hydro	**$ 19,188**	**$ 19,188**	**$ 4,560**	**$ 4,560**	**$ 14,372**	**$ 18,932**	**$ 18,932**	**$ (256)**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2007
Column D	Total of Column C
Column E	Forecast for Remainder of 2007
Column F	Total of Columns C and E
Column G	Total of Column F
Column H	Column G less Column B

2007 Capital Expenditure Status Report
(000s)

Category: Substations

	Capital Budget		Actual Expenditures		Forecast				
Project	**2007**	**Total**	**2007**	**Total To Date**	**Remainder 2007**	**Total 2007**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2007 Projects									
Substation Refurbishment and Modernization	$ 2,190	$ 2,190	$ 647	$ 647	$ 1,543	$ 2,190	$ 2,190	$ -	
Replacement Due to In-Service Failures	1,200	1,200	1,133	1,133	417	1,550	1,550	350	2
Rattling Brook Substation Refurbishment	578	578	132	132	446	578	578	-	
Total - Substations	**$ 3,968**	**$ 3,968**	**$ 1,912**	**$ 1,912**	**$ 2,406**	**$ 4,318**	**$ 4,318**	**$ 350**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2007
Column D	Total of Column C
Column E	Forecast for Remainder of 2007
Column F	Total of Columns C and E
Column G	Total of Columns D and E
Column H	Column G less Column B

2007 Capital Expenditure Status Report
(000s)

Category: Transmission

	Capital Budget		Actual Expenditures		Forecast				
Project	**2007**	**Total**	**2007**	**Total To Date**	**Remainder 2007**	**Total 2007**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2007 Projects									
Transmission Line Rebuild	$ 4,283	$ 4,283	$ 567	$ 567	$ 3,716	$ 4,283	$ 4,283	$ -	
Total - Transmission	**$ 4,283**	**$ 4,283**	**$ 567**	**$ 567**	**$ 3,716**	**$ 4,283**	**$ 4,283**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2007
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Column E	Forecast for Remainder of 2007
Column F	Total of Columns C and E
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2007 Capital Expenditure Status Report
(000s)

Category: Distribution

Project	Capital Budget 2007 (A)	Capital Budget Total (B)	Actual Expenditures 2007 (C)	Actual Expenditures Total To Date (D)	Forecast Remainder 2007 (E)	Forecast Total 2007 (F)	Forecast Overall Total (G)	Variance (H)	Notes*
2007 Projects									
Extensions	$ 6,815	$ 6,815	$ 2,941	$ 2,941	$ 4,990	$ 7,931	$ 7,931	$ 1,116	3
Meters	1,100	1,100	456	$ 456	635	$ 1,091	1,091	(9)	
Services	1,848	1,848	815	$ 815	1,206	$ 2,021	2,021	173	
Street Lighting	1,288	1,288	589	$ 589	675	$ 1,264	1,264	(24)	
Transformers	5,728	5,728	3,916	$ 3,916	1,812	$ 5,728	5,728	-	
Reconstruction	3,077	3,077	1,323	$ 1,323	1,916	$ 3,239	3,239	162	
Trunk Feeders									
Rebuild Distribution Lines	3,625	3,625	1,446	$ 1,446	2,179	$ 3,625	3,625	-	
Relocate/Replace Distribution Lines For Third Parties	541	541	716	$ 716	1,394	$ 2,110	2,110	1,569	4
Interest During Construction	81	81	21	$ 21	60	$ 81	81	-	
Total - Distribution	**$ 24,103**	**$ 24,103**	**$ 12,223**	**$ 12,223**	**$ 14,867**	**$ 27,090**	**$ 27,090**	**$ 2,987**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2007
Column D	Total of Column C
Column E	Forecast for Remainder of 2007
Column F	Total of Columns C and E
Column G	Total of Columns D and E
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2007 Capital Expenditure Status Report
(000s)

Category: General Property

Project	Capital Budget 2006 A	Capital Budget 2007 B	Capital Budget Total C	Actual Expenditures 2006 D	Actual Expenditures 2007 E	Actual Expenditures Total To Date F	Forecast Remainder 2007 G	Forecast Total 2007 H	Forecast Overall Total I	Variance J	Notes*
2007 Projects											
Tools and Equipment	$ -	$ 600	$ 600	$ -	$ 82	$ 82	$ 518	$ 600	$ 600	$ -	
Additions to Real Property	-	100	100	-	96	96	29	125	125	25	
Energy Efficient HVAC System	-	610	610	-	7	7	603	610	610	-	
Maple Valley Building Renovations	-	685	685	-	204	204	556	760	760	75	
Total 2006 General Property	-	1,995	1,995	-	389	389	1,706	2,095	2,095	100	
2006 Projects											
Grand Falls Windsor Building Renovations	$ 705	$ -	$ 705	$ 647	$ 137	$ 784	$ 10	$ 147	$ 794	$ 89	
Total - General Property	**$ 705**	**$ 1,995**	**$ 2,700**	**$ 647**	**$ 526**	**$ 1,173**	**$ 1,716**	**$ 2,242**	**$ 2,889**	**$ 189**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
Column B	Approved Capital Budget for 2007
Column C	Total of Columns A and B
Column D	Actual Capital Expenditures for 2006
Column E	Actual Capital Expenditures for 2007
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Column I	Total of Columns F and G
Column J	Column I less Column C

2007 Capital Expenditure Status Report
(000s)

Category: Transportation

	Capital Budget		Actual Expenditures		Forecast				
Project	**2007**	**Total**	**2007**	**Total To Date**	**Remainder 2007**	**Total 2007**	**Overall Total**	**Variance**	**Notes***
	A	B	C	D	E	F	G	H	
2007 Projects									
Purchase Vehicles and Aerial Devices	$ 2,206	$ 2,206	$ 73	$ 73	$ 2,133	$ 2,206	$ 2,206	$ -	
Total - Transportation	**$ 2,206**	**$ 2,206**	**$ 73**	**$ 73**	**$ 2,133**	**$ 2,206**	**$ 2,206**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2007
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Column E	Forecast for Remainder of 2007
Column F	Total of Columns C and E
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2007 Capital Expenditure Status Report
(000s)

Category: Telecommunications

Project	Capital Budget 2007 A	Capital Budget Total B	Actual Expenditures 2007 C	Actual Expenditures Total To Date D	Forecast Remainder 2007 E	Forecast Total 2007 F	Forecast Overall Total G	Variance H	Notes*
2007 Projects									
Replace/Upgrade Communications Equipment	$ 101	$ 101	$ 2	$ 2	$ 99	$ 101	$ 101	$ -	
Total - Telecommunications	**$ 101**	**$ 101**	**$ 2**	**$ 2**	**$ 99**	**$ 101**	**$ 101**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
Column B	Total of Column A
Column C	Actual Capital Expenditures for 2007
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Column E	Forecast for Remainder of 2007
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2007 Capital Expenditure Status Report
(000s)

Category: Information Systems

Project	Capital Budget 2007	Capital Budget Total	Actual Expenditures 2007	Actual Expenditures Total To Date	Forecast Remainder 2007	Forecast Total 2007	Forecast Overall Total	Variance	Notes*
	A	B	C	D	E	F	G	H	
2007 Projects									
Application Enhancements	$ 1,281	$ 1,281	$ 792	$ 792	$ 489	$ 1,281	$ 1,281	$ -	
System Upgrades	689	689	92	92	597	689	689	-	
Personal Computer Infrastructure	400	400	197	197	203	400	400	-	
Shared Server Infrastructure	877	877	553	553	324	877	877	-	
Microsoft Enterprise Agreement	210	210	197	197	13	210	210	-	
Total - Information Systems	**$ 3,457**	**$ 3,457**	**$ 1,831**	**$ 1,831**	**$ 1,626**	**$ 3,457**	**$ 3,457**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
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2007 Capital Expenditure Status Report
(000s)

Category: Unforeseen Items

Project	Capital Budget 2006 (A)	Capital Budget 2007 (B)	Capital Budget Total (C)	Actual Expenditures 2006 (D)	Actual Expenditures 2007 (E)	Actual Expenditures Total To Date (F)	Forecast Remainder 2007 (G)	Forecast Total 2007 (H)	Forecast Overall Total (I)	Variance (J)	Notes*
2007 Projects											
Allowance for Unforeseen Items	$ -	$ 750	$ 750		$ -	$ -	$ 750	$ 750	$ 750	$ -	
2006 Projects											
Allowance for Unforeseen Items	$ 750	$ -	$ 750	$ 824	$ 128	$ 952	$ 2	$ 130	$ 954	$ 204	5
Total - Unforeseen Items	**$ 750**	**$ 750**	**$ 1,500**	**$ 824**	**$ 128**	**$ 952**	**$ 752**	**$ 880**	**$ 1,704**	**$ 204**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2006
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2007 Capital Expenditure Status Report
(000s)

Category: General Expenses Capitalized

	Capital Budget		Actual Expenditures		Forecast				
Project	**2007**	**Total**	**2007**	**Total To Date**	**Remainder 2007**	**Total 2007**	**Overall Total**	**Variance**	**Notes***
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	
2007 Projects									
Allowance for General Expenses Capitalized	$ 2,800	$ 2,800	$ 1,442	$ 1,442	$ 1,358	$ 2,800	$ 2,800	$ -	
Total - General Expenses Capitalized	**$ 2,800**	**$ 2,800**	**$ 1,442**	**$ 1,442**	**$ 1,358**	**$ 2,800**	**$ 2,800**	**$ -**	

* See Appendix A for notes containing variance explanations.

Column A	Approved Capital Budget for 2007
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2007 Capital Expenditure Status Report
Notes

Generation Hydro

1. *Plant Refurbishment – Rattling Brook:*
   Budget: $18,242,000 Actual: $17,986,000 Variance: ($256,000)

   The $256,000 reduction in forecast expenditure is associated with a lower estimated cost for the Rattling Brook penstock. The tender price for the supply of the steel penstock was consistent with the original budget estimate. However, the tender price for the field installation and welding of the steel penstock sections was $256,000 lower than budget.

2007 Capital Expenditure Status Report
Notes

Substations

2. *Replacement Due to In-Service Failures:*
Budget: $1,200,000 Actual: $1,550,000 Variance: $350,000

The increased expenditure is due to the in-service failure of the power transformers at Lockston and Broad Cove substations.

In January, power transformer T3 at the Lockston substation failed when a crack developed in the transformer tank. The transformer was removed from service and repaired at a cost of $225,000.

In May, a gas analysis indicated a problem with the tap changer on power transformer T1 at Broad Cove substation. The transformer was removed from service and repaired at a cost of $125,000.

2007 Capital Expenditure Status Report
Notes

Distribution

3. *Extensions :*
Budget: $6,815,000 Actual: $7,931,000 Variance: $1,116,000

The capital expenditure variance for Extensions is largely the result of the expansion required to serve the Humber Valley Resort $267,000 and five cottage areas. To date, in 2007, extensions are being constructed to service five cottage areas; Nine Mile Road $262,000 (Order No. P.U. 37 (2006)), The Pond that Feeds the Brook $138,000 (Order No. P.U. 33 (2006)), Nine Island Pond $131,000 (Order No. P.U. 2 (2007)), Witless Bay Line $65,000 (Order No. P.U. 6 (2007)) and Placentia Junction $192,000 (Order No. P.U. 8 (2006)). Contributions in Aid of Construction will recover a minimum of $411,000, or 52% of the total capital cost of the cottage area projects.

4. *Relocate/Replace Distribution Lines for Third Parties :*
Budget: $541,000 Actual: $2,110,000 Variance: $1,569,000

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 expenditure in 2007 is driven by higher than normal activity associated with upgrades to their systems by the various telecommunications companies. The total cost is now estimated to be $2,110,000. Contributions in Aid of Construction will recover approximately $1,400,000 or 66% of the total capital cost of this project.

2007 Capital Expenditure Status Report
Notes

Unforeseen

5. *Unforeseen (2006 Project):*
Budget: $750,000 Actual: $954,000 Variance: $204,000

The unforeseen expenditure was required to rehabilitate Cape Broyle tunnel. In early June 2006, plant operators reported excessive leakage at the downstream toe of the main dam at the Cape Broyle hydro plant. Upon investigation, it was observed that there was extensive damage to the furthest downstream 10-metre long section of the Tunnel. Based on the inspection it was determined that it was not safe to operate the Plant, and that the Tunnel would require rehabilitation before the Plant could be safely returned to service.

2008 Facility Rehabilitation

June 2007

Prepared by:

Jennifer Williams, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
JENNIFER M. WILLIAMS
SIGNATURE
June 28/07
DATE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

The 2008 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 to improve the efficiency and reliability of various hydro plants or to replace plant due to in-service failures.

The Company operates 23 hydroelectric plants that provide energy to the Island interconnected electrical 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 to 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[1] of 419.6 GWh. The alternative to maintaining these facilities would be to retire them.

The 2008 Facility Rehabilitation project totalling $3,260,000 is comprised of the following items:

- Hydro Dam Rehabilitation;
- Cape Broyle Protection and Control;
- Heart's Content Runner and Wicket Gate Replacement;
- Equipment Replacements Due to In-Service Failures;
- Pierre's Brook Governor Replacement;
- Mobile Wicket Gate Bushings Replacement; and
- Engineering for Rocky Pond Plant.

2.0 Hydro Dam Rehabilitation

Cost: $885,000

This item involves the refurbishment of deteriorated components at various dam structures. This work primarily includes upstream slope improvements at embankment dams and outlet structure concrete repairs.

Specific work to be completed in 2008 includes:

1. Port Union: Whirl Pond Dam ($175,000)
   This item involves replacement of the rock filled timber crib dam at Whirl Pond. Specific observations arising from inspection reports include separation of structural timbers from the upstream timber face, rotted structural timbers in the crib sections and rotted upstream timber planking with holes observed in the face.

[1] Normal annual production was established in the Water Management Study – Hydrology Update prepared by SGE Acres dated August 1, 2005.

2. Port Union: Whirl Pond Outlet Structure ($100,000)
   This item involves replacement of the rock filled timber crib outlet structure at Whirl Pond. Inspection reports indicate the top portion of the timber gate and structural timbers of the crib section are rotted. Leakage through the timber crib section has been observed.

3. Fall Pond Plant: Main Dam ($110,000)
   This concrete dam requires rehabilitation of buttresses, decking, and the concrete faces of the dam. Recent inspections have shown increased deterioration and rehabilitation is required to maintain safety of the structure. Leakage has been observed through the concrete dam.

4. Seal Cove Plant: Soldiers Pond Dam and Spillway ($250,000)
   This item involves the replacement of a rock filled timber crib dam and timber crib overflow spillway. The existing structure has rotted structural timbers throughout and separation of the timber facing from the timber cribbing. Significant voids are evident in the dam and spillways cribbing due to loss of rock fill.

5. Horsechops and Cape Broyle Plant: Mount Carmel Pond Dam ($200,000)
   Mount Carmel Pond Dam is the main dam in the Horsechops and Cape Broyle system. The rip rap in the main dam is sparse in several areas and requires additional rip rap to protect the dam filters and core. The downstream face is heavily vegetated and requires grubbing to remove the root mat from the dam and rock fill placed over the downstream face to prevent erosion and vegetation growth. Deteriorated gabions and concrete headwall at the outlet structure requirement replacement.

6. Petty Harbour Plant: Cochrane Pond Dam ($50,000)
   This item involves the installation of rip rap on the upstream face of the dam near the spillway. There is evidence of embankment erosion near the spillway channel due to the lack of rip rap protection. In addition, the spillway channel is narrow and currently will not allow the design flood to pass. Channel improvements are required to allow the design flood to pass.

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

Newfoundland Power has over 150 dam structures throughout its 23 hydroelectric facilities. Based on the average age of structures in the Newfoundland Power system, deterioration of embankment and concrete dams is to be expected. Refurbishment is required to ensure integrity of the structures is maintained to an appropriate level of dam safety as per the guidelines established by the Canadian Dam Association. The cost of the items 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.

3.0 Cape Broyle Protection and Control

Cost: $750,000

The Cape Broyle generating plant was commissioned in 1953 and has a nameplate rating of 6.3 MW. The normal annual production from the plant is 32.8 GWh or approximately 7.8% of Newfoundland Power's annual hydroelectric production.

The plant contains a vertical Francis turbine manufactured by Canadian Vickers and a Westinghouse generator. The unit is automated and controlled remotely through the SCADA system. The plant is connected to the Island interconnected electrical system at Mobile substation via Newfoundland Power's transmission line 20L.

Major work completed at this facility in recent years includes a generator stator rewind, steel penstock and intake structure, programmable logic controller, new main inlet valve and turbine rebuild including installation of greaseless bushings. The existing protection and control schemes, including the governor, generator protection, voltage regulation, switchgear, and plant control system are obsolete and are in need of modernization.

3.1 Governor Control System ($105,000)

The existing Woodward Model HR gate shaft governor is the original equipment installed in 1953.[2] The governor is obsolete and the manufacturer no longer supplies replacement parts or offers maintenance support.

This item involves the removal of the hydraulic control portion of the governor and installation of a digital control system to provide enhanced performance and control. The existing power piston is in good condition and will not be replaced. The new governor control makes possible the implementation of a water management algorithm in the plant control system to optimize energy production from the available water in the development.

3.2 Generator Protection ($110,000)

The existing protection system at Cape Broyle lacks four elements[3] of the minimum protection set.[4] In addition to not meeting the minimum recommended protection level, the existing electromechanical relays have experienced trouble related to age and environmental conditions. The generator ground fault protection requires upgrading. Currently, the generator neutral is

2 US Army Core of Engineers indicate typical service life of governor control system to be 15 to 40 years. The Cape Broyle governor control system is 54 years old.

3 The existing generator protection does not include unit differential 87G, sensitive ground fault 87GN, rotor ground fault 64F and over/under frequency 81 elements which are recommended for this generator.

4 Protective relaying systems provide protection to equipment and personnel during abnormal loading or fault conditions. The selection of protection elements for a particular generator will depend upon the equipment design and system configuration.

solidly bonded to ground exposing the generator winding to high fault current levels. Modern protection designs involve high impedance grounding to minimize the exposure of the generator windings to large fault currents. Continuous conditional monitoring of stator insulation is required to ensure the unit is not remotely started when the windings have high moisture levels.

This item involves the installation of a new protection panel containing digital protection relays and new current transformers. A neutral grounding transformer with secondary resistor will be installed to improve ground fault protection. A neutral contactor will be installed to allow the installation of continuous online monitoring of the stator insulation.

3.3 Voltage Regulation ($60,000)

The existing voltage regulator unit contains a mechanical operating mechanism that has been manufacturer discontinued. The voltage regulator has corrosion damage making its operation unreliable.

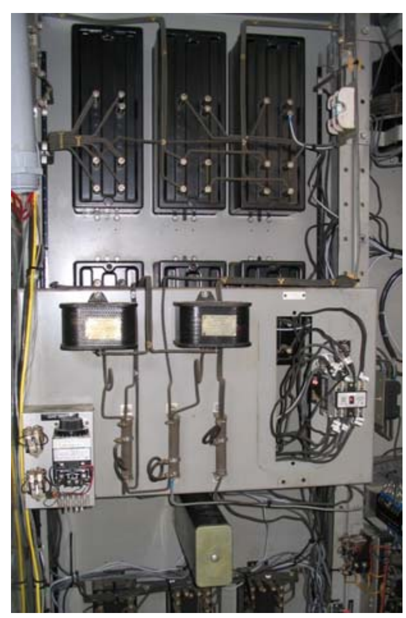
This item involves the replacement of the existing voltage regulator with a digital voltage regulator integrated with the plant control system panel.

3.4 Switchgear ($100,000)

The switchgear has been upgraded in recent years with the installation of a new breaker. However, the meters, instruments, wiring and other electrical components are original. The original equipment lacks the accuracy required for metering of the plant, and is vulnerable to insulation breakdown as it continues to age.

This item involves the replacement of the original potential and current transformers with more reliable, accurate units. The control switches, meters and associated wiring will also be replaced with new equipment in the generating unit control panel.

3.5 Plant Control System ($375,000)



The Cape Broyle system is controlled through various electromagnetic relays and switches from the original plant installation. This type of control does not allow for modernization of the plant, including the implementation of automated water management routines. Water management is an intelligent system of online monitoring of water levels and subsequent operation of the plant in response to changing water levels. The water management system will optimize the efficiency of the plant by controlling unit loading based upon water level, inflow and wicket gate position.

This item involves the installation of a programmable logic controller ("PLC") to provide full local and remote plant control. As well, resulting control functionality will make possible the implementation of a variety of control modes, including water management and the capability to remotely black start the plant. A gateway data concentrator will provide communications to the SCADA system and access to data from the digital relays and PLC.

4.0 Heart's Content Runner and Wicket Gate Replacement

Cost $700,000

The original Heart's Content generating plant was commissioned in 1918. The plant has been modified since that time and now has a single turbine unit of 1960 vintage with a nameplate capacity of 2.7 MW. The output of the plant is approximately 2% of Newfoundland Power's annual normal hydroelectric production. Recent engineering reviews revealed severe deterioration of essential components of the turbine system. The deterioration results in inefficient operation of the turbine thereby reducing energy output at the plant.

Newfoundland Power conducted an inspection of the major components of the turbine in March 2007. The inspection revealed severe deterioration of the turbine runner[5], which is of mild steel construction, at the low pressure zones and trailing edge of each runner blade. Figure 1 shows a large hole at the low pressure zone of one runner blade. Figure 2 shows corrosion damage to the trailing edge of another runner blade. The extent of damage to the runner blades is such that the runner is no longer able to operate efficiently.

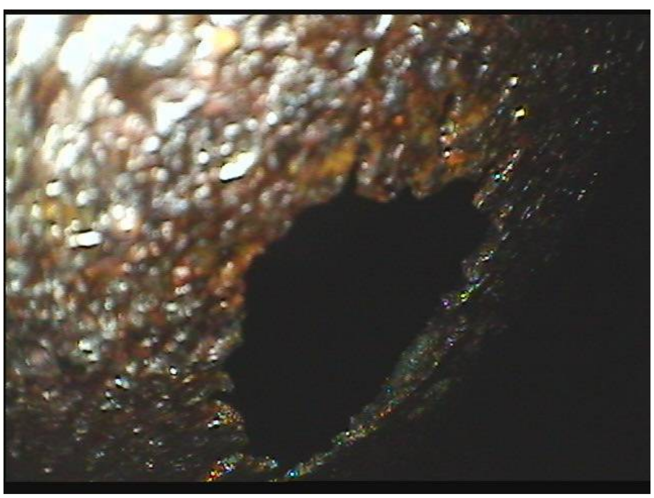


Figure 1
Hole (117mm x 63mm)

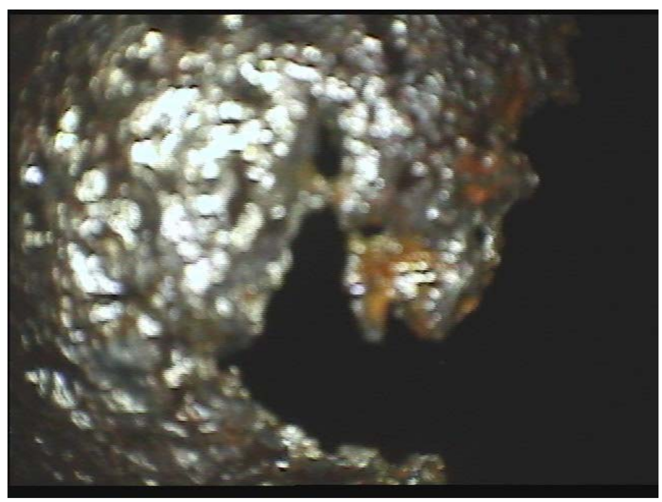


Figure 2
Trailing Edge Corrosion

Previous deterioration of the runner was repaired in 1983 using a molecular steel compound most of which has since eroded. The runner has now deteriorated through cavitation to the extent that

[5] The runner is the rotating part of the turbine that converts the energy of falling water into mechanical energy. The 'blades' on the runner are what the water pushes against to turn the runner and generate electricity.

there are large holes in the runner blades. This results in inefficient plant operation and increases the risk of an in-service failure.

The turbine wicket gates[6] are also of mild steel construction and have extensive corrosion such that the gates do not operate efficiently through their full range of motion.

This item involves the replacement of the deteriorated runner with a stainless steel runner and replacement of the wicket gates with stainless steel wicket gates. This also involves the replacement of the wicket gate bushings with self-lubricating bushings.

Table 1 shows the cost estimate for the runner and wicket gate replacement.

Table 1
Heart's Content
Runner and Wicket Gate Replacement

Item	Amount
Material	$550,000
Internal Labour	120,000
Engineering	20,000
Other	10,000
Total	**$700,000**

This item will ensure efficient plant operations at Heart's Content and prevent further deterioration of the plant's assets. It will also address the risk of an extended plant shutdown as the result of an in-service turbine failure resulting in damage to bearing surfaces and other internal components. An extended plant shutdown would result in lost energy to the system, resulting in larger dependence on more expensive sources of energy.

5.0 Equipment Replacements Due to In-Service Failures

Cost: $425,000

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

This item involves the refurbishment or replacement of structures and equipment due to damage, deterioration, corrosion, technical obsolescence and imminent or in-service failure. This equipment is critical to the safe and reliable operation of generating facilities and must be

[6] The wicket gates are adjustable gate blades that control the flow of water to the turbine passage.

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 required for one of the following 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 2 shows the expenditures for replacements due to in-service failures since 2003.

Table 2
Expenditures Due to In-Service Failures
(000s)

Year	**2003**	**2004**	**2005**	**2006**	**2007F**
Total	**$365**	**$385**	**$570**[1]	**$591**[1]	**$425**

[1] Excludes Rocky Pond rebuild.

Based upon this recent historical information and engineering judgement, $425,000 is estimated to be required in 2008 for replacement 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.

6.0 Pierre's Brook Governor Component Replacement

Cost: $225,000

The Pierre's Brook Hydro Plant was commissioned in 1931. The governor system at Pierre's Brook is essential to the operation of the plant. The primary purpose of a governor is to control the speed and loading of the unit. It accomplishes this by controlling the flow of water through the turbine. Operator's reports, inspections and plant data from recent years indicate issues exist with the operation of the governor.

Issues with the existing Pierre's Brook governor include an oil leak at the power piston, the problematic operation of the external shutdown solenoid and overheating of various components in the control panel circuit boards. The results of these issues are forced outages, increased maintenance, and decreased reliability of the generating unit.

To address these issues, existing governor controls will be replaced with digital controls that will be integrated into the existing plant protection and control system. The leaking power piston will be replaced with a new unit.

Reliable operation of the governor is essential to the efficient operation of the Pierre's Brook plant. This item will provide reliable control of the generating unit.

7.0 Mobile Wicket Gate Bushings Replacement

Cost: $200,000

The Mobile generating plant is comprised of the largest single generating unit in the Newfoundland Power group of plants. The turbine unit at Mobile generating station was last overhauled in 1990. The runner, upper stationary seal, lower stationary seal and wicket gates were replaced at that time and remain in good condition. The thrust bearing was replaced in 2000.

The installed capacity of this unit is 12.0 MW but is currently de-rated to a capacity of 10.5 MW due a mechanical limitation in the turbine. An inspection recently completed on major mechanical components of the turbine revealed components that require replacement to maintain good operating condition of this generating plant.

The inspection of the Mobile turbine revealed that the bushings for the lower wicket gates require replacement. The clearance between the gate stems and bushings has increased due to friction and subsequent wear of the materials in the bushings and gate stems. The excessive clearance has resulted in scoring of the adjacent runner seals and also contributes to the inability to fully close the wicket gates. Scoring of the runner seals and improper closing of the wicket gates leads to deterioration of associated turbine components.

This item involves the replacement of the bushings to improve the clearance with the gate stems such that the clearance ensures safe and efficient operation of the wicket gates. The mechanical overhaul of the wicket gate bushings will lead to the recovery of some or all of the 1.5 MW derating on the generator. The new bushings will be of a self-lubricating material. Self-lubricating bushings involve no maintenance program of greasing and removes the risk associated with the release of petroleum based grease into the environment.

This equipment is critical to the reliable and efficient operation of the Mobile plant. This item will help maintain the existing turbine components in good condition and prevent deterioration of critical turbine components.

8.0 Engineering for Rocky Pond Plant

Cost $75,000

Newfoundland Power's Rocky Pond Hydroelectric generating plant is located approximately 40 kilometres south of the City of St. John's. The plant was commissioned in 1943 and has a capacity of 3.25 MW. The normal annual production at Rocky Pond is approximately 14.1 GWh or 3.3% of the total hydroelectric production of Newfoundland Power.

Rocky Pond is serviced by one generating unit supplied by a woodstave penstock and concrete intake. Few upgrades or modifications were necessary from the time the plant was commissioned in 1943 until 2005. In 2005 an electrical fire occurred in the switchgear, destroying the switchgear cubicle including all protection and control equipment in the plant. As a result, the switchgear and protection and control systems were replaced in 2005 and 2006.

The woodstave penstock is 65 years old and is in poor condition with excessive deterioration and significant leakage along its entire length. The 2.3m diameter, 765m long penstock follows the topography of the land without the use of anchor blocks or movement joints. The penstock bedding is firm but wet, attributable to both leakages from the pipe as well as the existence of a bog along the upper half of the penstock route. The penstock is sagging in some areas due to settlement of the support cradles into the soil bed. Cradle assemblies exhibit some cracks, and some have been undercut by the heavy water flows along either side. The steel bands are heavily corroded and several bands have failed in recent years due to corrosion. The staves are significantly deteriorated in several areas due to lack of ventilation. Because of its current condition, dewatering of the penstock is avoided due to leakage concerns when returning it to service. Leakage is expected to worsen causing operational difficulties, increasing maintenance costs and lost energy.

Figure 3
Rocky Pond Penstock

Newfoundland Power currently plans to bring forward a capital budget project proposal for the replacement of Rocky Pond penstock and the refurbishment of the plant systems with its 2009 Capital Budget Application. This capital project proposal will require detailed engineering design work to finalize the necessary budget estimates and schedules. Also the detailed engineering design work will allow Newfoundland Power to prepare engineering specifications and tender documents in advance to ensure the project can be completed during the 2009 construction season.

9.0 Concluding

The Facilities Rehabilitation project, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable plant operations. A breakdown of the 2008 budget of $3,260,000 for Facility Rehabilitation is shown in Table 3.

Table 3
2008 Facilities Rehabilitation Project

Item	Budget
Hydro Dam Rehabilitation	$885,000
Cape Broyle Protection and Control	$750,000
Heart's Content Runner and Wicket Gate Replacement	$700,000
Equipment Replacements Due to In-Service Failures	$425,000
Pierre's Brook Governor Replacement	$225,000
Mobile Wicket Gate Bushings Replacement	$200,000
Engineering for Rocky Pond	$75,000
Total	**$3,260,000**

2008 Substation Refurbishment and Modernization

June 2007

Prepared by:

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1.0 Substation Modernization and Refurbishment Strategy

Newfoundland Power's (the "Company") substations serve a critical role in providing service to its customers. The Company's substation maintenance program and the Substation Modernization and Refurbishment project ensures reliable, least cost power is provided to customers in a safe and environmentally responsible manner.

In the 2007 Capital Budget Application, the Company submitted its *Substation Strategic Plan*. This plan outlined a structured approach for the overall refurbishment and modernization of its substations that will be coordinated with ongoing major equipment maintenance and replacement activities. The substation plan follows a 10-year cycle, coinciding with the maintenance cycle for major substation equipment. This coordination minimizes customer service interruptions and improves productivity.

In preparation of annual capital budgets, substations are assessed with particular consideration given to the physical condition of core infrastructure and equipment. Due to changing priorities, recent reliability performance and inspection and asset condition data, the scheduling of work in a particular substation may be altered within the 10-year cycle.

The current five-year forecast for the Ten-Year Refurbishment and Modernization Capital Plan is shown in Appendix A.

2.0 Substation Modernization and Refurbishment 2008 Projects

Table 1 is a summary of the Substation Refurbishment and Modernization projects planned in 2008 for ten substations.

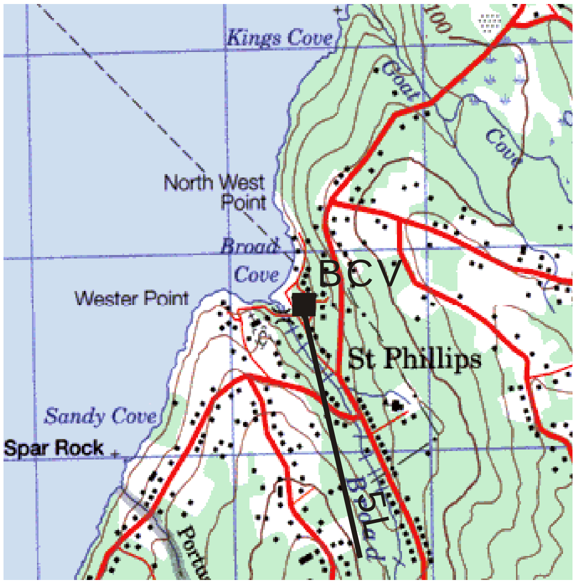
Table 1
2008 Substation Projects
(000s)

Substation	Budget
Broad Cove (BCV)	$ 71
Botwood (BOT)	500
Clarenville (CLV)	547
Fermuse (FER)	64
Gander (GAN)	678
Kings Bridge (KBR)	1,126
Kelligrews (KEL)	145
Lewisporte (LEW)	48
Mobile (MOB)	327
Oxen Pond (OXP)	197
Total	**$ 3,703**

The following pages outline the capital work required in each substation. Power transformers and switch maintenance overhauls required to be performed in 2008 in these same substations will be completed at the same time as the capital work in order to minimize interruption of service to customers.

2.1 Broad Cove Substation ($71,000)

Broad Cove substation was built prior to 1960 as a distribution substation. It contains a 66 kV to 12.5 kV, 25 MVA transformer (T1). The 66 kV bus is energized via a radial 66 kV transmission line 5L from Hardwoods substation. The substation serves approximately 4,350 customers in the St. Phillips and Bell Island areas through four 12.5 kV feeders.



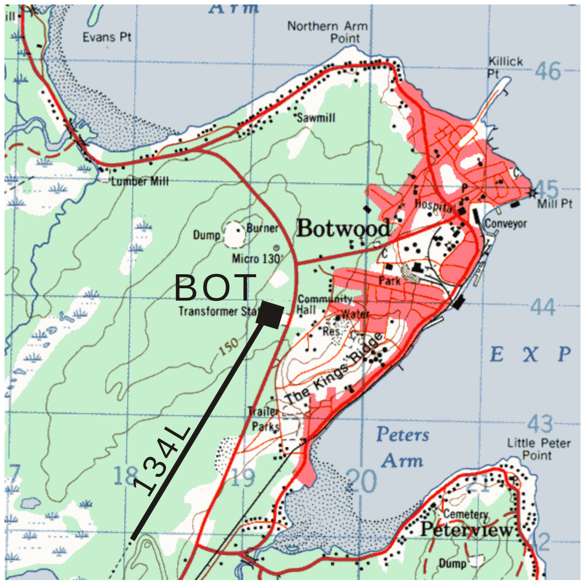
Broad Cove Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV and 12.5 kV wood pole structures and concrete foundations are in good condition with no signs of deterioration. The 66 kV and 12.5 kV bus and insulators are also in good condition with no signs of deterioration.

The metering tank has failed in service and requires replacement. In 2008 metering and under-frequency load shedding will be re-established and tied in to the SCADA system.

2.2 Botwood Substation ($500,000)

Botwood substation was built in 1977 as a distribution substation. It contains one 138 kV to 25 kV power transformer (T1). The power transformer is rated for 20 MVA. The 138 kV bus is energized via a radial 138 kV transmission line 134L from Bishop's Falls substation. The substation serves approximately 3,350 customers in the Botwood area through three 25 kV feeders.



Botwood Substation Location

Maintenance records and on-site engineering assessments show that the 138 kV and 25 kV steel structures are in good condition with no sign of deterioration.

Inspections of the concrete foundations show that there is one 25 kV concrete structure foundation that is crumbling and requires refurbishment.


25 kV Structure Foundation

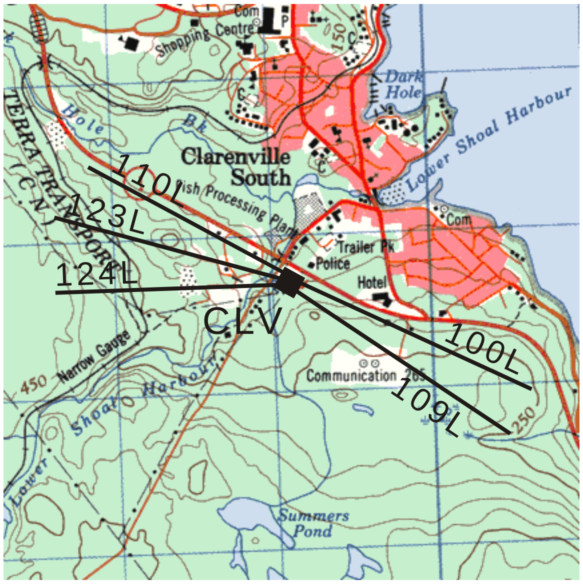
The power transformer is in good condition with no obvious signs of deterioration.

The lightning arrestors on the transformer are silicon carbide and require replacement with metal oxide arrestors. The power transformer does not have protection installed. Therefore, protection for the power transformer will be installed to adequately protect the unit. The installation of transformer protection will require that a high speed ground switch be installed. This will be installed on a new transformer airbreak switch. The tap changer controller is thirty years old and requires replacement. Small animal protection will be installed on the 25 kV equipment and bus.

Three Nulec reclosers will be installed automating the three feeders to allow remote control from the System Control Centre.

2.3 Clarenville Substation ($547,000)

Clarenville substation was built in 1966 as a transmission switching station for the Bonavista Peninsula and also as a 12.5 kV distribution substation for the Clarenville area. The substation contains two power transformers T1 & T2. Transformer T1 is a 138 kV to 66 kV, 25 MVA transformer serving the Bonavista Peninsula. T2 is a 138 to 12.5 kV, 20 MVA power transformer serving approximately 2,000 customers in the Clarenville area through three 12.5 kV feeders.



Clarenville Substation Location

There are four 138 kV transmission lines and one 66 kV transmission line terminated in the substation. The 138 kV transmission lines are 100L to Sunnyside substation, 109L to Northwest Brook substation, 124L to Port Blandford substation and 123L to Catalina substation. The 66 kV transmission line is 110L to Milton substation.

Maintenance records and on-site engineering assessments show that the 138 kV and 12.5 kV steel structures and concrete foundations are in good condition with no sign of deterioration. The

66 kV wood pole structure is also in good condition. The power transformers are in good condition with no signs of deterioration.

Clarenville Substation

The lightning arrestors on the transformers are silicon carbide and require replacement with metal oxide arrestors. Small animal protection will be installed on the 12.5 kV equipment and bus.

The three 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. The transmission line relaying on 100L and 109L will be replaced as this relaying is in excess of 40 years old. The transmission line relaying on 123L and 124L will be replaced and consolidated on one panel to provide space in the control room for the feeder panels and the communications equipment. To facilitate continuity of service, a by-pass switch will be installed across the breaker on line 110L. Installation of the bypass switch will enable the breaker to be taken out of service for maintenance without disruption of service to customers.

66 kV Breaker By-pass Switch To Be Installed On 110L

2.4 Fermeuse Substation ($64,000)

Fermeuse substation was built in 1976 as a distribution substation. It contains one 66 kV to 12.5 kV power transformer (T1). The power transformer is rated for 4 MVA. The 66 kV bus is energized via a radial 66 kV transmission line 66L from Cape Broyle substation. The substation serves approximately 630 customers in the Fermeuse area through one 12.5 kV feeder.

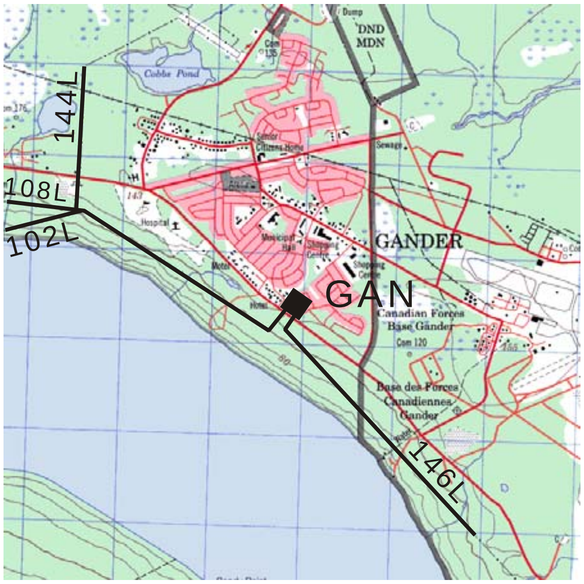
Fermeuse Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV and 12.5 kV wood pole structures are in good condition with no signs of deterioration. The concrete foundations are in good condition with no signs of deterioration. The 66 kV and 12.5 kV bus and insulators are also in good condition with no signs of deterioration.

The air-break switch for the distribution transformer T1 has been in service in excess of thirty years and will be replaced. Small animal protection will be installed on the 12.5 kV equipment and bus.

2.5 Gander Substation ($678,000)

Gander substation was built in 1959 as a distribution substation and over the years has developed into a major transmission and distribution substation. The substation contains one 138 kV to 66 kV, 27 MVA (T2) power transformer, one 138 kV to 12.5 kV, 20 MVA (T1) power transformer and three single phase 66 kV to 6.9 kV, 1.6 MVA (T3) power transformers for providing a ground reference for the 66 kV transmission system. The substation directly serves approximately 1,600 customers in the Gander area through four 12.5 kV feeders.



Gander Substation Location

There are two 138 kV transmission lines terminated in the substation, transmission lines 144L to Cobb's Pond substation and 146L to Gambo substation. There are also two 66 kV transmission lines terminated in the substation, transmission lines 102L to Roycefield substation and 108L to Gander Bay substation.

Maintenance records and on-site engineering assessments show that the 138 kV and 12.5 kV steel structures and 66 kV wood pole structures are in good condition with no signs of deterioration.

Most concrete foundations are in good condition with no signs of deterioration. However, four of the 138 kV structure foundations, one breaker foundation and transformer T3's foundation will require refurbishment.


138 kV Structure Foundation

Transformer T3 Foundation

Power transformers T1 and T2 are in good condition with no obvious signs of deterioration.

Tap changer controllers have a service life of approximately 25 years. Transformer T1 will have the tap changer controls replaced. The lightning arrestors on the high side of transformer T2 are silicon carbide and require replacement with metal oxide arrestors. The grounding transformer T3 (three single phase units) is over 40 years old. Radiators have been cut off and capped due to leaking and there are leaks around the gauge wells of the transformers. These transformers will be replaced with a new three phase unit.

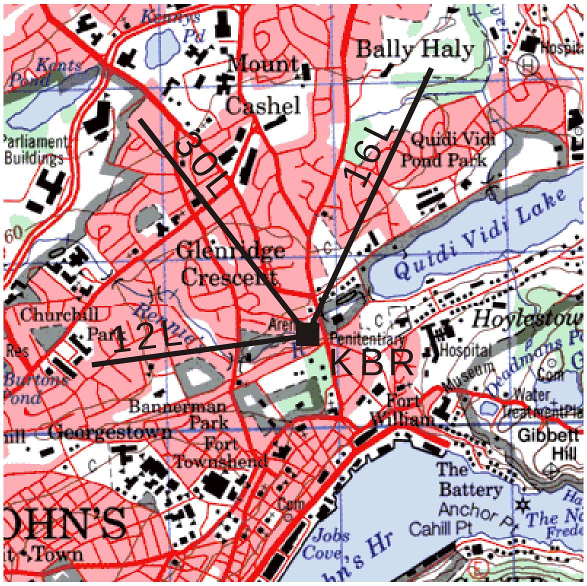
The switches in the substation are in good condition with the exception of one 138 kV bus tie switch which is inoperable. This switch will be replaced.

The four 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. The relaying on 146L is over 40 years of age and will be replaced.

2.6 King's Bridge Substation ($1,126,000)

King's Bridge substation was built in the 1940's as a 33 kV substation. Today it is a 66 kV transmission substation as well as a 4.16 kV and 12.5 kV distribution substation. The substation contains three distribution power transformers (T1, T2 and T3) with a combined capacity of 20 MVA at 4.16 kV and 25 MVA at 12.5 kV.

The substation directly serves approximately 5,500 customers in the King's Bridge Road and Empire Avenue East area of St. John's through eight 4.16 kV metal clad switchgear feeders and four 12.5 kV metal clad switchgear feeders. In the substation there are three 66 kV transmission lines terminated in the high voltage bus. These are transmission lines 12L to Memorial substation, 16L to Pepperrell substation and 30L to Ridge Road substation.



King's Bridge Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures are in good condition with no signs of deterioration.

The concrete foundations are in good condition with no signs of deterioration, with the exception of the 66 kV structure foundation and transformer T2 foundation which will be refurbished.

Concrete Structure Foundation

Kings Bridge substation currently has two buildings, a 12.5 kV switchgear building in the upper yard and a 4.16 kV switchgear building in the lower yard. The 12.5 kV switchgear building installed in 1977 is of steel construction and is showing significant signs of deterioration. This building houses the 12.5 kV equipment for the four 12.5 kV feeders from the substation. This building requires replacement in 2008.

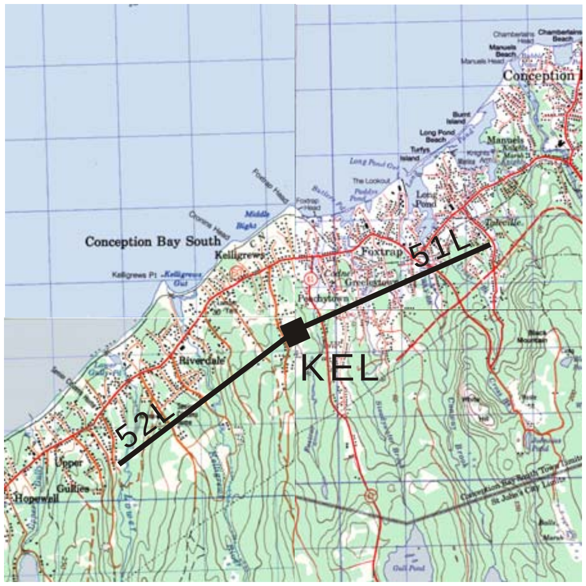
12.5 kV Switchgear Building

The 4.16 kV switchgear building houses the eight 4.16 kV feeders and the transmission line protection panels. These eight feeders and the four 12.5 kV feeders will have relaying replaced and be automated to allow remote control from the System Control Centre. The new control panels for feeder remote control must be housed in the lower yard. However, there is no space in the existing lower yard building to accommodate the new control panels. Therefore, a control building will be built to accommodate these panels.

The three power transformers are in good condition with no signs of deterioration. The power cables on the two 4.16 kV transformers are 35 years old and require replacement in 2008.

2.7 Kelligrews Substation ($145,000)

Kelligrews substation was built in 1977 as a 12.5 kV distribution substation. The distribution substation contains one power transformer T1 with a capacity of 15 MVA. The substation directly serves approximately 2,600 customers in the Kelligrews and Upper Gullies areas through two 12.5 kV feeders. There are two 66 kV transmission lines terminated in the substation, transmission lines 51L to Chamberlains substation and 52L to Seal Cove substation.



Kelligrews Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV and 12.5 kV steel structures are in good condition with no signs of deterioration. The concrete structure and equipment foundations are in good condition with no signs of deterioration. The 66 kV and 12.5 kV bus and insulators are also in good condition with no signs of deterioration.

The 25 kV potential transformer shows significant deterioration due to rusting and will be replaced.

25 kV Potential Transformer

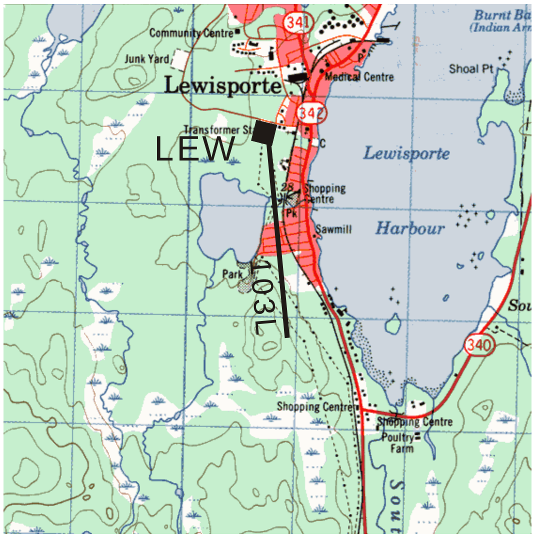
The control building is in good condition but the roof shows significant signs of deterioration due to rusting and will be replaced.

Control Building Roof Deterioration

The power transformer is in good condition with no signs of deterioration. The lightning arrestors on the transformer are silicon carbide and require replacement with metal oxide arrestors. The 30 year old power cables connecting the transformer to the low voltage bus will be replaced with overhead conductor.

2.8 Lewisporte Substation ($48,000)

Lewisporte substation was built in 1974 as a 25 kV distribution substation. The distribution substation contains one power transformer T1 with a capacity of 25 MVA. The substation directly serves approximately 3,900 customers in the Lewisporte area through four 25 kV feeders. There is one 66 kV transmission line, 103L to Notre Dame Junction substation terminated in the substation.

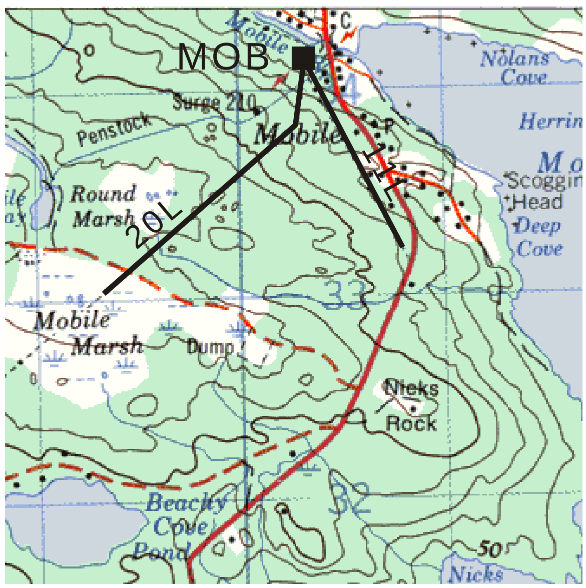


Lewisporte Substation Location

The power transformer is in good condition with no signs of deterioration. The lightning arrestors on the transformer are silicon carbide and require replacement with metal oxide arrestors.

2.9 Mobile Substation ($327,000)

Mobile substation was built in 1954 as a generation substation. Today it is a 66 kV transmission infeed substation through which the generation from seven Southern Shore hydro plants flow. As well it is a 12.5 kV distribution substation with a 66 kV to 12.5 kV, 6.7 MVA power transformer. The substation directly serves approximately 1,600 customers in the Mobile area through two 12.5 kV feeders. The station contains one power transformer T3 for generation, a 66 kV to 33 kV, 4.6 MVA unit for the Pierre's Brook generation. There are three 66 kV and one 33 kV transmission lines terminated in the substation. These are 66 kV transmission lines 24L to Big Pond substation, 11L to Tors Cove substation, 20L to Cape Broyle substation and 33 kV transmission line 23L to Pierres Brook substation.



Mobile Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV, 33 kV and 12.5 kV wood pole structures are in generally good condition with the only sign of deterioration being some cross-arms on the 66 kV and 12.5 kV structures. These cross-arms will be replaced. The concrete equipment foundations are in good condition with no signs of deterioration except for the 23L breaker foundation which will be refurbished. The 66 kV and 12.5 kV bus and insulators are also in good condition with no signs of deterioration.

The air-break switch for the distribution transformer T2 is a 1965 vintage and will be replaced as well as the 66 kV power fuses which are in excess of 35 years old. The 66 kV potential transformers were installed in 1958. These potential transformers will be replaced. To facilitate continuity of service, a by-pass switch will be installed across the breaker on line 24L. This will allow maintenance to be undertaken on the breaker without causing outages to customers or lowering system integrity.

The three 66 kV transmission lines 11L, 20L and 24L all have original electro-mechanical impedance relaying installed for protection which are over 50 years old. The protection for these three lines will be replaced utilizing digital relaying.

Deteriorated Crossarms 66 kV Structure

23L Breaker Foundation

66 kV Potential Transformers

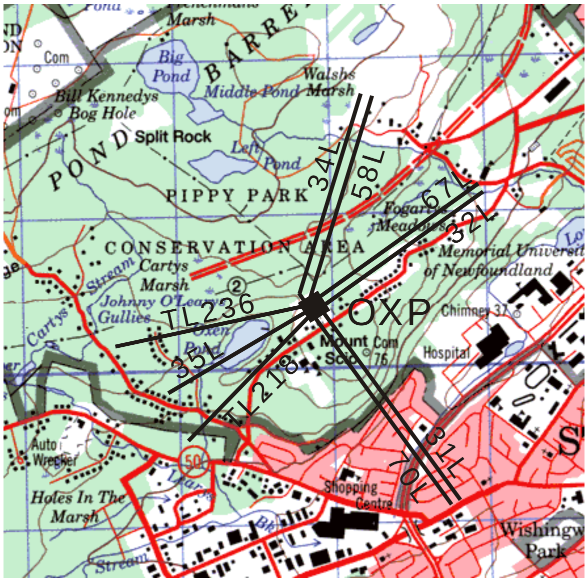
Power transformer T3 is in good condition with no signs of deterioration.

Power transformer T2 is showing some significant signs of deterioration and will require some refurbishment. The lightning arrestors on the two transformers are silicon carbide and require replacement with metal oxide arrestors.

Transformer T2

2.10 Oxen Pond Substation ($197,000)

Oxen Pond substation was built in 1966 as an infeed substation to the City of St. Johns. Today it is one of two major 230 kV in-feed substations serving the City of St. John's and surrounding communities. Newfoundland Power's section of Oxen Pond substation contains one distribution power transformer and seven 66 kV transmission lines.[1] The distribution transformer T1 has a capacity of 13.3 MVA at 12.5 kV. The substation directly serves approximately 1,150 customers in the Thorburn Road and Mount Scio Road area of St. John's through one 12.5 kV feeder. The seven 66 kV transmission lines terminated in the high voltage bus are 31L and 70L to Stamps Lane substation, 32L and 67L to Ridge Road substation, 34L and 58L to Virginia Waters substation, and 35L to Kenmount substation.



Oxen Pond Substation Location

Maintenance records and on-site engineering assessments show that the 66 kV steel structures are in good condition with no signs of deterioration. The majority of the concrete foundations are in good condition with no signs of deterioration except the foundation on 34L breaker which is deteriorated and requires replacement and one of the foundations for the 12.5 kV steel columns which has some of the anchor bolts rusted off. These will be replaced. Replacement of the structure foundation will require the dismantling and re-assembly of the 12.5 kV structure.

[1] Oxen Pond substation is owned by Newfoundland and Labrador Hydro.

34L Breaker Foundation

12.5 kV Structure Foundation

The 12.5 kV feeder will have relaying replaced and be automated to allow remote control from the System Control Centre.

Power transformer T1 is in good condition with no obvious signs of deterioration. The lightning arrestors on the transformers are silicon carbide and require replacement with metal oxide arrestors.

Appendix A

Substation Refurbishment and Modernization Plan
Five-Year Forecast 2008 to 2012

Substation Refurbishment and Modernization Plan
Five-Year Forecast
2008 to 2012
(000s)

2008		2009		2010		2011		2012	
SUB	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**	**SUB**	**Cost**
BCV	$ 71	ABC	$ 99	CAR	$ 464	BRB	$ 770	GBE	$ 71
BOT	500	BHD	228	GAL	396	BON	620	BLA	161
CLV	547	BOY	26	FRN	436	GIL	145	BVS	567
FER	64	GFS	754	GLN	183	MAS	367	BIG	295
GAN	678	HCT	187	HGR	1,276	MKS	428	GAM	697
KBR	1,126	NCH	428	HAR	159	NHR	423	HBS	165
KEL	145	P335	287	JON	13	SCR	516	ISL	114
LEW	48	P435	287	SPR	222	TWG	165	P135	377
MOB	327	STV	239	STX	123	WAL	345	SCT	81
OXP	197	SUN	318	VIR	223	GBS	629	TBS	712
		FPD	7	WAV	154	SPF	57	TRP	880
		PJN	7	BLA	17	DLK	57	TRN	154
		PAB	182	ISL	53	PAS	17	WBC	235
		SPO	221	PEP	48	PBK	8	BFS	603
		WBK	7	SCV	7	ICV	55		
		ROP	403	SUM	16	LAU	17		
				MMT	53	MRP	11		
				VIC	446	MGT	8		
						WES	8		
Total	**$3,703**		**$3,680**		**$4,289**		**$4,646**		**$5,112**

Note: SUB: Substation - Refer to the Electrical System handbook included with the 2006 Capital Budget Application for three letter substation designations.
P135, P335 and P435 are the designations for the portable substations.

Convert 403L to 66kV to Reduce Losses

June 2007

Prepared by:

Geoff Emberley, P.Eng., MBA

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1.0 Introduction

The energy efficiency of transmission line 403L between Lookout Brook plant and St. George's and Robinson's substations can be improved by increasing the transmission line voltage from 33,000 volts to 66,000 volts. Operating at the higher voltage will reduce line losses, thereby making more of the energy produced at the Lookout Brook plant available to the Island interconnected system. This study examines the feasibility of converting the St. George's 33 kV system to 66 kV.

When substations and their connecting transmission lines were constructed during the electrification of Newfoundland, 33 kV was an economic transmission voltage level. At that time, loads were smaller consisting of mostly lighting, some heating, and small appliances. The capital construction costs associated with 33 kV facilities were favoured over more expensive higher voltage systems for smaller loads.

As energy costs increase, so does the cost of losses associated with the St. George's 33 kV transmission system.

Operating transmission lines at higher voltage requires less current, thereby reducing line losses and reducing operating costs.

2.0 Description of Existing System

Figure 1 shows Newfoundland Power transmission lines 407L and 403L.

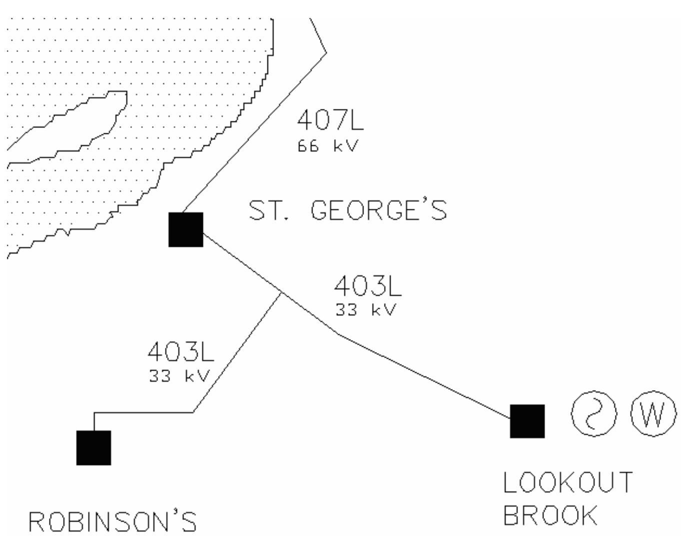

Figure 1

Transmission line 407L operates at 66 kV and supplies St. George's Substation. At St. George's, a power transformer steps the voltage down from 66 kV to 33 kV. Transmission line 403L then extends from St. George's Substation to Robinson's Substation[1] and Lookout Brook Plant[2] at 33 kV.

Transmission line 403L has been rebuilt over time as the original 33 kV structures reached the end of their useful life. The rebuilt sections were constructed to the 66 kV standard, with the last section rebuilt in 2004.

3.0 Description of Proposed Modifications

To achieve the energy savings, it is proposed to convert the 33 kV system to 66 kV. Modifications are required at all three substation locations to upgrade to 66 kV. At St. George's, the 66 to33 kV step down transformer will be removed. At Robinson's and Lookout Brook, the existing transformers are dual wound for 33 or 66 kV use and are therefore not to be replaced. At all locations, any 33 kV bus structures and equipment such as switches, fuses, and lightning arresters must be replaced with equivalent 66 kV components. Depending on the ability to coordinate work at these locations, the installation of a portable substation may be necessary to reduce the duration of outages as the modifications are being completed.

4.0 Technical Analysis

A review of the 33 kV system shows that there are no technical problems associated with conversion of the system to 66 kV.

Load flow analysis indicates that after conversion from 33 kV to 66 kV, the voltages throughout the system will remain within established criteria.

5.0 Economic Analysis

Table 1 shows the cost breakdown for the project.

Table 1
Convert 403L to 66KV
(000s)

Substation	Budget
St. George's (STG)	$ 104
Robinson's (ROB)	68
Lookout Brook (LBK)	61
Total	**$ 233**

1 Robinson's Substation load peaked at 4.0 MVA in January of 2007.
2 Lookout Brook Plant has a rated generating capacity of 5.8 MW.

To evaluate the economic impact of the proposed modifications, the cumulative present worth revenue requirement of the $233,000 conversion cost was calculated using a weighted average incremental cost of capital at 7.64%.

With this cumulative present worth, the levelized unit cost of the annual energy savings of 529,870 kWh, given an investment of $233,000, is 3.81¢/kWh. Appendix A contains the economic analysis.

The 3.81¢/kWh is significantly less than the levelized cost of electricity supplied from the Holyrood thermal generating plant at 11.06¢/kWh.

The economic analysis shows that the project is economic when compared to the levelized cost of oil used at Holyrood.

6.0 Concluding

Converting the St. George's 33 kV system interconnecting St. George's, Robinson's and Lookout Brook substations to operate at 66 kV is technically and economically feasible.

This feasibility study indicates that a conversion to 66 kV is technically viable and economically justifiable. The levelized unit cost of 529,870 kWh of energy saving, based on a capital cost of $233,000 is 3.81¢/kWh compared to a levelized cost of energy from the Holyrood thermal generating plant of 11.06¢/kWh.

It is recommended the St. George's area 33 kV system be converted to operate at 66 kV.

Appendix A

Levelized Unit Cost of Energy Savings

Weighted Average Incremental Cost of Capital **7.64%**
Present Worth Year **2007**

YEAR	Substation 46.2 yrs 8% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr)
1	233,000	22,651	0	0	-22,651	-21,043	-21,043	4.275	3.809
2	0	21,972	0	0	-21,972	-18,964	-40,007	4.147	3.809
3	0	22,169	0	0	-22,169	-17,776	-57,783	4.184	3.809
4	0	22,263	0	0	-22,263	-16,584	-74,367	4.202	3.809
5	0	22,300	0	0	-22,300	-15,432	-89,799	4.209	3.809
6	0	22,289	0	0	-22,289	-14,330	-104,130	4.207	3.809
7	0	22,236	0	0	-22,236	-13,281	-117,411	4.197	3.809
8	0	22,143	0	0	-22,143	-12,287	-129,698	4.179	3.809
9	0	22,014	0	0	-22,014	-11,348	-141,047	4.155	3.809
10	0	21,851	0	0	-21,851	-10,465	-151,512	4.124	3.809
11	0	21,658	0	0	-21,658	-9,636	-161,148	4.087	3.809
12	0	21,436	0	0	-21,436	-8,861	-170,009	4.046	3.809
13	0	21,189	0	0	-21,189	-8,137	-178,145	3.999	3.809
14	0	20,917	0	0	-20,917	-7,462	-185,608	3.948	3.809
15	0	20,623	0	0	-20,623	-6,835	-192,443	3.892	3.809
16	0	20,309	0	0	-20,309	-6,253	-198,696	3.833	3.809
17	0	19,977	0	0	-19,977	-5,714	-204,411	3.770	3.809
18	0	19,627	0	0	-19,627	-5,216	-209,627	3.704	3.809
19	0	19,261	0	0	-19,261	-4,755	-214,382	3.635	3.809
20	0	18,881	0	0	-18,881	-4,331	-218,713	3.563	3.809
21	0	18,488	0	0	-18,488	-3,940	-222,652	3.489	3.809
22	0	18,082	0	0	-18,082	-3,580	-226,232	3.413	3.809
23	0	17,665	0	0	-17,665	-3,249	-229,481	3.334	3.809
24	0	17,238	0	0	-17,238	-2,945	-232,426	3.253	3.809
25	0	16,801	0	0	-16,801	-2,667	-235,093	3.171	3.809
26	0	16,355	0	0	-16,355	-2,412	-237,504	3.087	3.809
27	0	15,901	0	0	-15,901	-2,178	-239,683	3.001	3.809
28	0	15,440	0	0	-15,440	-1,965	-241,648	2.914	3.809
29	0	14,971	0	0	-14,971	-1,770	-243,418	2.825	3.809
30	0	14,497	0	0	-14,497	-1,592	-245,011	2.736	3.809
31	0	14,016	0	0	-14,016	-1,430	-246,441	2.645	3.809
32	0	13,531	0	0	-13,531	-1,283	-247,724	2.554	3.809
33	0	13,040	0	0	-13,040	-1,149	-248,872	2.461	3.809
34	0	12,545	0	0	-12,545	-1,027	-249,899	2.368	3.809
35	0	12,046	0	0	-12,046	-916	-250,814	2.273	3.809
36	0	11,543	0	0	-11,543	-815	-251,630	2.178	3.809
37	0	11,036	0	0	-11,036	-724	-252,354	2.083	3.809
38	0	10,526	0	0	-10,526	-642	-252,995	1.987	3.809
39	0	10,013	0	0	-10,013	-567	-253,562	1.890	3.809
40	0	9,498	0	0	-9,498	-500	-254,062	1.792	3.809
41	0	8,979	0	0	-8,979	-439	-254,501	1.695	3.809
42	0	8,459	0	0	-8,459	-384	-254,885	1.596	3.809
43	0	7,936	0	0	-7,936	-335	-255,220	1.498	3.809
44	0	7,412	0	0	-7,412	-290	-255,510	1.399	3.809
45	0	6,886	0	0	-6,886	-251	-255,761	1.299	3.809
46	0	6,358	0	0	-6,358	-215	-255,976	1.200	3.809
47	0	-2,771	0	0	2,771	87	-255,889	-0.523	3.809

Transmission Line Rebuild

June 2007

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1.0 Transmission Line Rebuild Strategy

Transmission lines play a critical role in providing reliable service to a large number of customers. The Company is proactive in ensuring that transmission lines are maintained so as to avoid significant failure.

As part of its 2006 Capital Budget Application, the Company submitted its *Transmission Line Rebuild Strategy* outlining a 10-year plan to rebuild aging transmission lines. The strategy outlined a structured approach to maintaining the Company's transmission line system and prioritized the rebuild of transmission lines based on physical condition, risk of failure, and potential customer impact in the event of a failure.

The *Transmission Line Rebuild Strategy* is reviewed and revised on an ongoing basis to ensure that it accurately reflects the latest reliability data, inspection information, condition assessments, as well as the capital requirements within other asset classes. The strategy will continue to change with time to ensure targeted spending on the highest priority transmission lines based on physical condition, risk of failure, and potential impact upon customers in the event of a failure, and alignment with corporate goals and objectives.

Appendix A contains the updated Transmission Line Rebuild Strategy Schedule. The cost estimates in this revision have been adjusted to reflect the inflationary increases that have affected both labour and non-labour costs since the original strategy was prepared in 2005. As well, the costs presented in the table now utilize escalation factors to more accurately indicate the estimated cost of the project in the year in which it will take place.

2.0 Transmission Line Rebuild Projects Planned for 2008

In 2008, the Company plans to continue the rebuild of transmission line 20L and to rebuild a section of transmission line 111L. Major sections of these lines are within several kilometres of the coastline and subject to extreme salt contamination, high winds and icing.

Appendix B contains topographic views of each of the lines to be rebuilt. Appendix C contains photographs of the existing lines.

The poles, crossarms, hardware, and conductor on these lines are generally in a poor and weakened condition increasing the risk of power outages and making the lines vulnerable to large scale damage when they are exposed to heavy wind, ice and snow loading.

These lines are more than 50 years old and many of the original poles are deteriorated. Inspections have identified substantial evidence of external and/or internal rotting, insect and woodpecker damage, and cracks and splits in poles, crossarms, cross braces, and other hardware.

The existing conductors are small by today's standards and the steel core of each conductor shows evidence of corrosion which reduces the physical strength and current carrying capacity of the conductor.

2.1 Transmission Line 20L

20L is a 66kV transmission line built in 1951. The line runs between Mobile Substation and Cape Broyle Substation on the Southern Shore of the Avalon Peninsula. It is a radial line 20.1 kilometres in length and is of H-frame wood pole construction. The local load includes over 1,700 customers serviced through Cape Broyle Substation and Fermeuse Substation in the south. The line also serves as the connection to the main electrical grid for the Company's Morris, Rocky Pond, Horsechops, and Cape Broyle hydroelectric plants.

Because of the age, design, and location of this line, it is prone to cascading failure. If one structure fails, there is risk that the additional loading placed on adjacent structures will cause a chain reaction of multiple structure failures. Many of the insulators on this line are original equipment and are at the end of their service lives.

Some repairs have been made over the years to return the line to service after a failure. Due to the temporary nature of most of these repairs, there has not been any substantial improvement to the overall integrity of the line.

A 7.5 kilometre section of this line was approved for reconstruction in the 2007 Capital Budget Application. Based on the overall deteriorated condition of the line, it is recommended that the remainder of the line be rebuilt in 2008. The estimated cost of this work is $1,563,000. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

2.2 Transmission Line 111L

111L is a 66 kV transmission line built in 1956. The line runs between Lockston Substation and Catalina Substation, via Port Union Substation, on the Bonavista Peninsula. The line is 31 kilometres in length and is of single wood pole construction. The line serves approximately 1,058 customers on the Bonavista Peninsula. This line also connects the Company's Port Union hydroelectric and diesel plants to the main electrical grid.

Many of the poles on this line are deteriorated and some are severely decayed. The guy wires are generally corroded and are nearing the point of failure.

The non-standard conductor on this line is damaged and deteriorated in many places and its strands are actually broken in some locations. Over the years, many inline splices (sleeves) have been installed along the length of the conductor. These are evidence of repairs made after the conductor failed during various sleet storms in the area.

Based on the overall deteriorated condition of this line, it is recommended that entire line be rebuilt over a three-year period at a total cost of $3.6 million. It is recommended that the most deteriorated 13 kilometre section be rebuilt in 2008 at an estimated cost of $1,482,000.
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 111L, as recommended in this report, is the most cost-effective alternative to ensure the continued provision of safe, reliable electrical service.

Appendix A

Transmission Line Rebuild Strategy Schedule

Transmission Line Rebuilds
2008-2012
($000)

Line	Year	2008	2009	2010	2011	2012
012L KBR-MUN	1950			272		
014L SLA-MUN	1950				89	
015L SLA-MOL	1958				58	
016L PEP-KBR	1950		677			
020L MOB-CAB	1951	1,563				
021L 20L-HCP	1952					791
023L MOB-PBK	1942			685		
024L MOB-BIG	1964		927			
025L GOU-SJM	1954			1,158		
030L RRD-KBR	1959		349			
041L CAR-HCT	1958				2,463	
049L HWD-CHA	1966				356	
057L BRB-HGR	1958					2,453
069L KEN-SLA	1951					378
110L CLV-LOK	1958			2,218	1,962	
111L LOK-CAT	1956	1,482	1,766	376		
124L CLV-GAM	1964		599			1,380
	Total	**$3,045**	**$4,318**	**$4,619**	**$4,927**	**$5,002**
	Total (km)	**26.5**	**32.4**	**36.9**	**37.7**	**36.3**

Transmission Line Rebuilds
2013-2020
($000)

Line	Year	2013	2014	2015	2016	2017	2018	2019	2020
013L SJM-SLA	1962					334			
018L GOU-GDL	1952	673							
032L OXP-RRD	1963	447							
035L OXP-KEN	1959	791							
053L 38L-GEA	1961						1,145		
068L HGR-CAR	1958	750							
100L SUN-CLV	1964			2,113	3,265				
101L GFS-RBK	1957					3,635	1,828		
102L GAN-RBK	1958					3,090	2,694	3,260	3,022
105L GFS-SBK	1963								2,731
124L CLV-GAM	1964	2,767	3,538	1,625					
146L GAN-GAM	1964		2,000	1,625	3,093				
301L SPO-GRH	1959		169						
302L SPO-LAU	1959						1,924	3,362	
400L BBK-WHE	1967							1,630	3,022
403L TAP-ROB	1960			652					
	Total	**$5,428**	**$5,707**	**$6,015**	**$6,358**	**$7,059**	**$7,591**	**$8,252**	**$8,775**
	Total (km)	**37.3**	**37.1**	**37.0**	**37.0**	**38.8**	**39.5**	**40.5**	**40.7**

Appendix B

Topographic Maps of Transmission Lines 20L and 111L

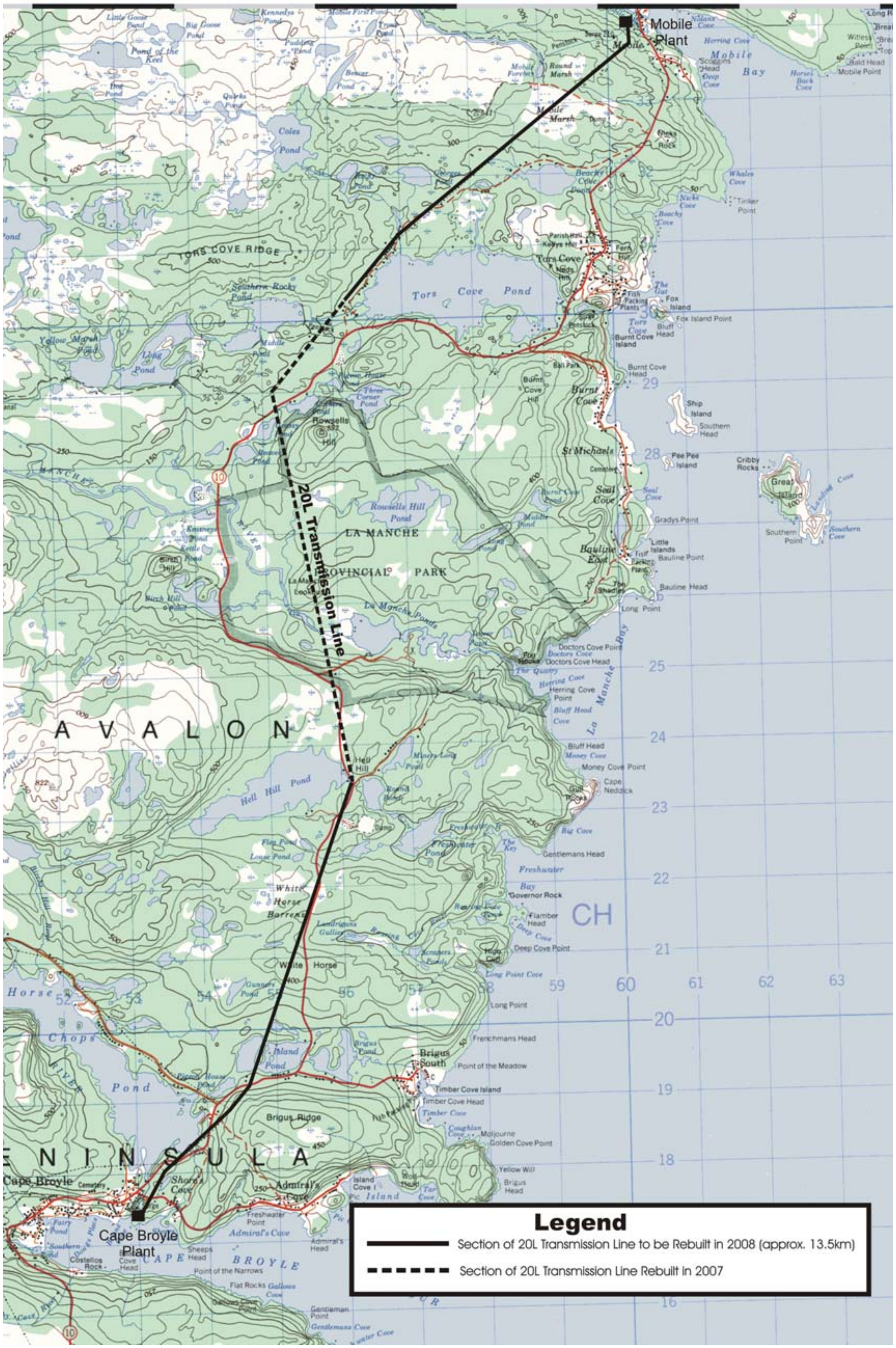

Figure 1 – Topographic Map 20L

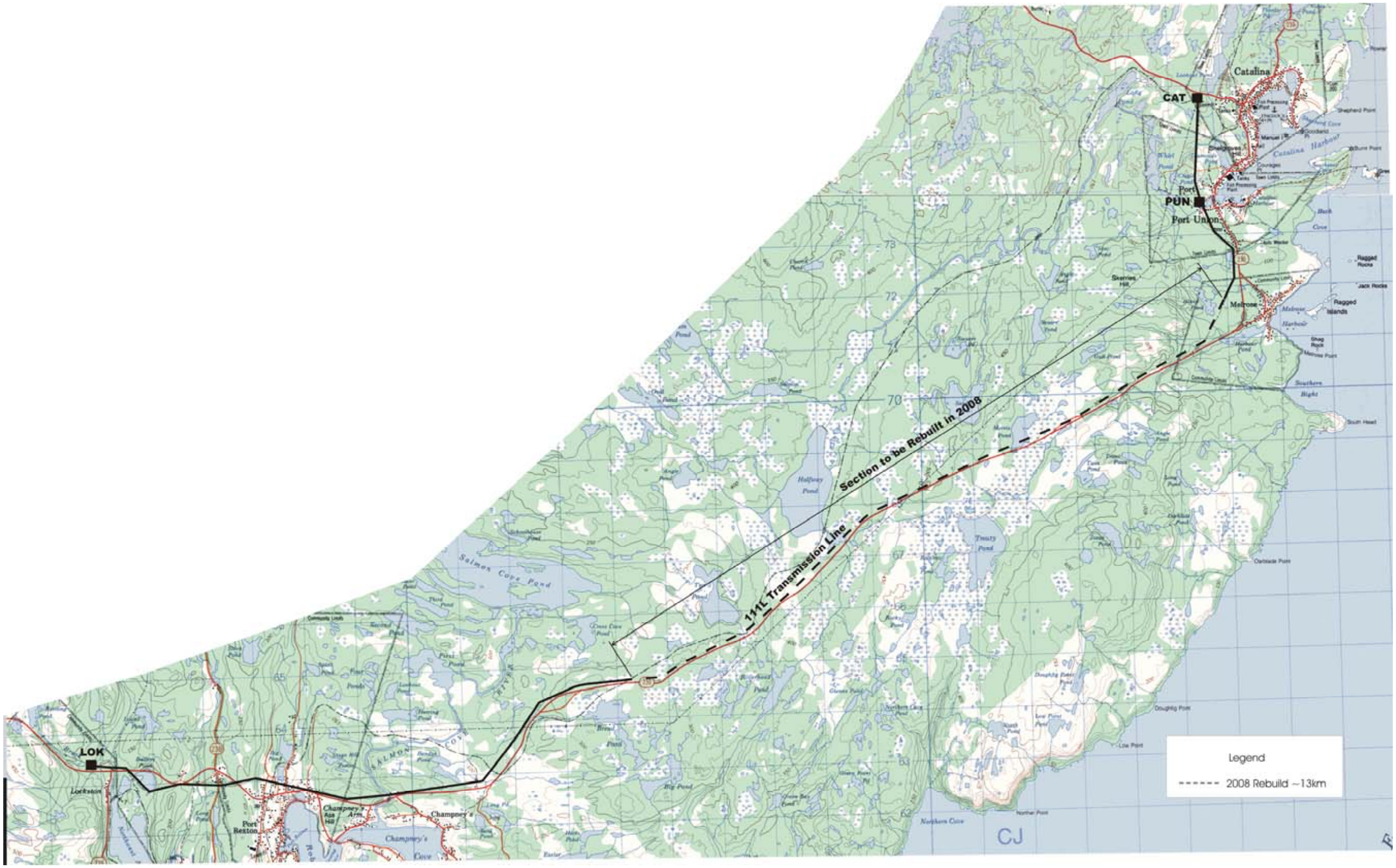

Figure 2 – Topographic Map 111L

Appendix C

Photographs of
Transmission Lines 20L and 111L

Figure 1 - Temporary Repair 20L

Figure 2 - Erosion 20L

Figure 3 - Old Insulators 20L

Figure 4 - Deteriorated Poles (top split) 20L

Figure 5 - Deteriorated Pole 111L

Figure 6 - Deteriorated Pole 111L

Figure 7 – Deteriorated Pole (Top Split) 111L

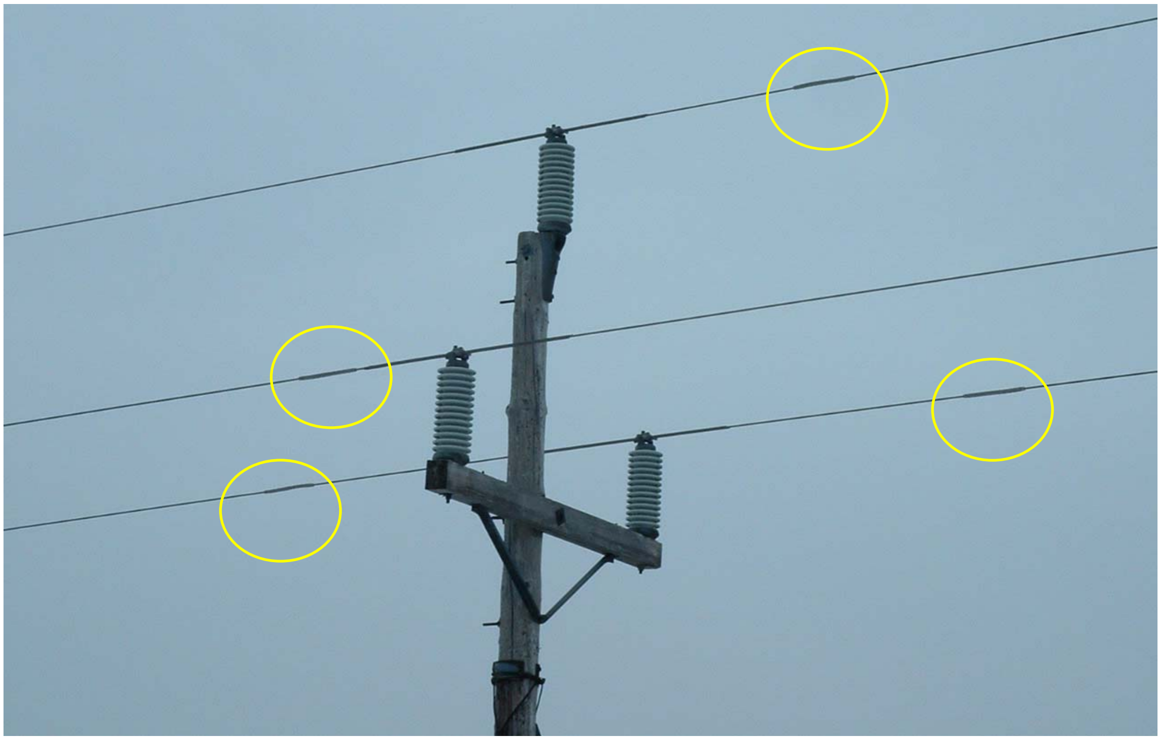

Figure 8 – Inline Splices Installed to Repair Conductor 111L

Figure 9 – Failed Guy Wire and Ice Loading on 111L

Distribution Reliability Initiative

June 2007

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1.0 Distribution Reliability Initiative

The Distribution Reliability Initiative is a capital project that focuses 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. Newfoundland Power examines its actual distribution reliability performance to assess whether 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 distribution reliability five-year average data of the 15 worst performing feeders.

2.0 Distribution Reliability Initiative Projects: 2006

As part of its 2006 Capital Budget Application, the Company submitted its *2005 Corporate Distribution Reliability Review*. As a result of this review, capital projects were proposed on seven feeders as part of the 2006 Capital Budget Application. The 2006 Distribution Reliability Initiative involved three feeders where work would be completed over multiple years and four feeders where work would be complete in 2006. The three feeders where work would continue into future years were BOT-01, LEW-02 and GLV-02. The 2006 projects were completed as per the original budget.

Table 1 identifies the cost estimates for the seven feeders included in the 2006 Distribution Reliability Initiative, including the cost estimates for 2007 and 2008.

Table 1

Distribution Reliability Initiative
Filed with 2006 Capital Budget Application
($000s)

Feeder	2006	2007	2008
BCV – 02	440		
BOT – 01	1,038	830	717
GBY – 02	398		
GLV – 02	465	361	419
GPD – 01	102		
SMV – 01	239		
LEW – 02	432	456	
Total	**3,114**	**1,647**	**1,136**

3.0 Distribution Reliability Initiative Projects: 2007

The 2007 Capital Budget Application included the Rattling Brook Refurbishment project. As a result the Distribution Reliability Initiative was suspended for 2007.

4.0 Distribution Reliability Initiative Projects: 2008

In 2008, the Company plans to resume the Distribution Reliability Initiative. Work will resume on BOT-01, LEW-02 and GLV-02 feeders. Appendix B contains maps of the feeder sections that will be rebuilt in 2008.

The Company intends to propose the completion of work on BOT-01 and GLV-02 in the 2009 Capital Budget Application. Table 2 summarizes the estimated cost to complete the required work.

Table 2
Distribution Reliability Initiative
2008 and 2009
($000s)

Feeder	2008	2009
BOT–01	820	717
LEW – 02	260	
GLV–02	206	419
Total	**1,286** [1]	**1,136**

4.1 BOT-01

The BOT-01 feeder is located in the Grand Falls-Windsor operating area of the Western Region. The feeder is a 25kV line that was originally constructed in 1959 to serve customers in the Botwood area. Sections extending to Leading Tickles and Fortune Harbour were subsequently constructed in 1965. The feeder serves approximately 1,607 customers.

The report *BOT-01 Feeder Study* filed with the 2006 Capital Budget Application recommended work be carried out in 2007 on the following sections of line:

- End of Charles Brook to Beginning of Cottrell's Cove
- Cottrell's Cove to Moore's Cove tap
- Moore's Cove tap
- Fortune Harbour (from Moore's Cove tap)

[1] The 2008 estimates for GLV-02 and LEW-02 have been revised from original estimates due to upgrades which have or will be carried out on the feeders to accommodate third party attachments.

Table 3 is a summary of the current outage statistics for the BOT-01 feeder.

Table 3

Unscheduled Distribution Related Outages
Annual Five-Year Average: 2002 – 2006

	Customer Interruptions	Customer Minutes of Interruption	Distribution SAIFI[2]	Distribution SAIDI[3]
BOT-01	5,052	688,459	3.11	7.07
Company Average	**1,028**	**86,539**	**1.45**	**2.03**

4.2 LEW-02

The LEW-02 feeder is located in the Grand Falls-Windsor operating area of the Western Region. The feeder is a 25 kV line that originates at the Lewisporte Substation located in Lewisporte and serves approximately 1,550 customers.

The report *LEW-02 Feeder Study* filed with the 2006 Capital Budget Application recommended work be carried out in 2007 on the following sections of line:

- End of existing 3 phase to Baytona tap
- Baytona tap
- Baytona tap to Birchy Bay
- Birchy Bay tap
- Loon Bay North tap
- Cambellton North tap

Table 4 is a summary of the current outage statistics for the LEW-02 feeder.

Table 4

Unscheduled Distribution Related Outages
Annual Five-Year Average: 2002 - 2006

	Customer Interruptions	Customer Minutes of Interruption	Distribution SAIFI	Distribution SAIDI
LEW-02	5,282	808,239	3.82	9.74
Company Average	**1,028**	**86,539**	**1.45**	**2.03**

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

3 System Average Interruption Duration Index ("SAIDI") is calculated by dividing the number of unscheduled customer-outage-hours (i.e. a 2-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area. Distribution SAIDI records the average hours of unscheduled outage related to distribution system failure.

4.3 GLV-02

The GLV-02 feeder is located in the Gander operating area of the Western Region. The feeder is a 25kV line that originates at the Glovertown Substation in Glovertown and serves approximately 1,222 customers.

The report *GLV-02 Feeder Study* filed with the 2006 Capital Budget Application recommended work be carried out in 2007 on the following sections of line:

- Tap to Happy Adventure
- Sandy Cove
- Tap to Burnside
- End of 3-phase to beginning of St. Chad's
- St. Chad's
- St. Chad's up to and including Burnside

Table 5 is a summary of the current outage statistics for the GLV-02 feeder.

Table 5

Unscheduled Distribution Related Outages
Annual Five-Year Average: 2002 – 2006

	Customer Interruptions	Customer Minutes of Interruption	Distribution SAIFI	Distribution SAIDI
GLV-02	3,988	552,441	3.19	7.36
Company Average	**1,028**	**86,539**	**1.45**	**2.03**

Appendix A

Distribution Reliability Data

Unscheduled Distribution Related Outages Five-Year Average 2002-2006 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
LEW-02	5,282	808,239	3.82	9.74
BOT-01	5,052	688,459	3.11	7.07
GLV-02	3,988	552,441	3.19	7.36
BCV-02	5,469	550,965	3.58	6.02
GFS-06	4,025	481,417	2.46	4.91
PUL-01	3,963	439,255	2.43	4.50
NWB-02	3,261	430,312	3.14	6.92
ROB-01	3,526	387,282	3.29	6.03
PUL-02	4,210	373,000	3.12	4.61
MIL-02	3,570	349,285	2.65	4.32
GBY-03	1,572	337,500	2.06	7.36
HWD-02	3,518	330,771	2.59	4.07
DUN-01	2,535	329,221	2.69	5.81
WES-02	2,887	322,876	3.82	7.13
SMV-01	1,892	319,628	1.84	5.18
Company Average	**1,028**	**86,539**	**1.45**	**2.03**

Unscheduled Distribution Related Outages

Five-Year Average
2002-2006
Sorted By Distribution SAIFI

Feeder	Annual Customer Interruptions	Annual Customer Minutes of Interruption	Annual Distribution SAIFI	Annual Distribution SAIDI
GBS-02	2,240	139,396	5.08	5.27
GRH-02	3,033	243,362	3.83	5.12
WES-02	2,887	322,876	3.82	7.13
LEW-02	5,282	808,239	3.82	9.74
BCV-02	5,469	550,965	3.58	6.02
LOK-01	3,631	226,198	3.55	3.69
WES-01	1,292	143,223	3.32	6.14
ROB-01	3,526	387,282	3.29	6.03
GLV-02	3,988	552,441	3.19	7.36
NWB-02	3,261	430,312	3.14	6.92
PUL-02	4,210	373,000	3.12	4.61
BOT-01	5,052	688,459	3.11	7.07
GLN-01	2,067	139,156	3.06	3.44
KEL-02	3,087	154,795	3.04	2.54
BHD-01	2,505	196,837	2.90	3.82
Company Average	**1,028**	**86,539**	**1.45**	**2.03**

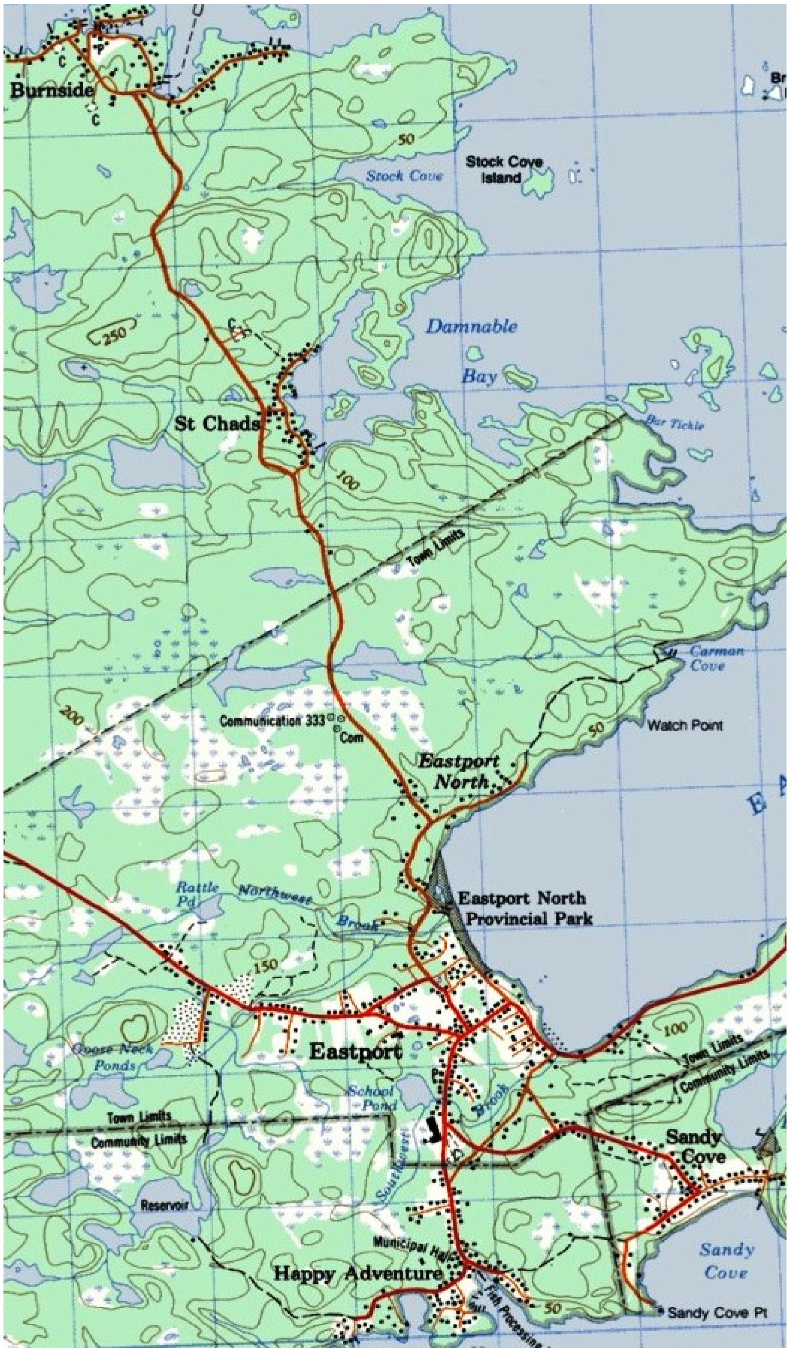
Unscheduled Distribution Related Outages Five-Year Average 2002-2006 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI**	**Annual Distribution SAIDI**
GPD-01	367	165,992	1.56	11.72
LEW-02	5,282	808,239	3.82	9.74
WES-03	1,415	267,222	2.73	8.60
GBY-03	1,572	337,500	2.06	7.36
GLV-02	3,988	552,441	3.19	7.36
WES-02	2,887	322,876	3.82	7.13
BOT-01	5,052	688,459	3.11	7.07
NWB-02	3,261	430,312	3.14	6.92
WES-01	1,292	143,223	3.32	6.14
ROB-01	3,526	387,282	3.29	6.03
BCV-02	5,469	550,965	3.58	6.02
DUN-01	2,535	329,221	2.69	5.81
GBY-02	1,638	302,500	1.86	5.74
GBS-02	2,240	139,396	5.08	5.27
SUM-02	974	182,938	1.67	5.21
Company Average	**1,028**	**86,539**	**1.45**	**2.03**

Appendix B

Maps

Section of BOT-01

Section of LEW-02



Section of GLV-02

Install Capacitors
to
Reduce Distribution Losses

June 2007

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1.0 Introduction

Line losses are an inherent characteristic of electricity transmission and distribution systems. The main contributor of line loss is heat dissipation that results from current passing through copper, steel and aluminium conductors. The amount of current flowing through a distribution system is a function of the size and type of loads connected to it.

The Company has 303 urban and rural feeders that comprise the distribution system that serves customers across the province. The use of capacitors on the distribution system can reduce the demand and energy on feeders through the reduction of line losses.[1]

The Company currently uses capacitors on the system to improve voltage regulation at substations located at the end of long radial transmission lines.

In 2008, this project will focus on installing capacitors to reduce line losses on 19 of the Company's feeders.

2.0 Reducing Distribution Line Losses with Capacitors

Capacitors reduce losses by correcting for the power factor[2] of the load and thus reducing the current required to supply the power and energy requirements of the load. This, in turn, reduces the energy that is lost in the form of heat in delivering electricity over distribution feeders.

Feeders that have the greatest potential for loss reduction through the installation of capacitors are those that travel long distances with few large branch lines, are constructed with small diameter conductors, have poor power factor loads and/or have a dense load centre located far from the source of energy.

Based on the profile above, simulated results from the Company's feeder modelling program and historical load data, the Company has identified 19 feeders that will provide both technical and economic benefits with the installation of capacitors in 2008.

Capital expenditure of $200,000 will provide for capacitor installations to reduce distribution losses on the 19 identified feeders in 2008.

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1 Line loss is the difference between the amount of energy delivered to the distribution system and the amount of energy consumed by customers.

2 Power factor is the ratio of real power to reactive power. Real power is the power that is converted into useful work for creating heat, light and motion. Reactive power is the power used to create electromagnetic fields in equipment such as motors and welding machines. Poor power factor loads increase losses in a distribution system by requiring additional reactive power resulting in increased current requirements.

3.0 Technical Analysis

Table 1 shows the 19 feeders and the anticipated annual energy savings and peak load reduction expected.

Table 1
Distribution Feeder Analysis

Feeder Selection			Analysis Results		
Feeder	**Voltage (kV)**	**2006 Peak (kVA)**	**Capacitor Size**	**kWh Saved**	**Peak Load Loss Reduction (kW)**
WES-02	12.47	3,613	450kVAR	33,540	12.98
WES-03	12.47	3,809	600kVAR	41,157	10.18
ABC-01	12.47	2,326	300kVAR	62,875	14.70
ABC-02	12.47	3,087	300kVAR	31,379	11.56
GAM-01	24.94	5,198	450kVAR	12,910	3.88
GBY-02	24.94	2,650	300kVAR	33,660	9.39
ROB-01	24.94	2,995	450kVAR	75,949	15.58
HBS-02	24.94	2,614	450kVAR	27,893	3.70
CLV-01	12.47	5,328	300kVAR	11,355	3.02
SPO-01	12.47	2,808	300kVAR	17,480	4.33
GIL-01	12.47	4,687	300kVAR	20,685	9.30
FRN-01	12.47	3,074	450kVAR	20,382	4.07
BOT-01	24.94	4,838	600kVAR	22,948	5.84
LEW-02	24.94	4,810	600kVAR	31,149	8.46
DLK-03	12.47	6,508	600kVAR	173,087	7.74
LET-01	24.94	7,920	900kVAR	28,138	7.95
DUN-01	24.94	4,162	600kVAR	31,996	9.10
VIC-02	12.47	4,637	300kVAR	42,377	8.56
WAL-02	12.47	5,526	450kVAR	13,352	1.64
			Total	**732,312**	**151.98**

Approximately, 732,000 kWh per year of energy savings and a 152 kW reduction in demand is expected.

4.0 Economic Analysis

Table 2 shows the economic analysis of installing the proposed capacitor banks on the 19 feeders proposed in the 2008 capital budget.

Table 2
Economic Evaluation of Capacitor Installation

Feeder	Capacitor Installation Cost	Levelized Cost[3] of Energy Savings ¢/kWh
WES-02	$9,700	2.52
WES-03	$9,700	2.06
ABC-01	$9,200	1.28
ABC-02	$9,200	2.56
GAM-01	$9,700	6.56
GBY-02	$9,200	2.38
ROB-01	$9,700	1.11
HBS-02	$9,700	3.03
CLV-01	$9,200	7.07
SPO-01	$9,200	4.59
GIL-01	$9,200	3.88
FRN-01	$9,700	4.15
BOT-01	$19,000	7.22
LEW-02	$9,700	2.72
DLK-03	$9,700	0.49
LET-01	$19,500	6.05
DUN-01	$9,700	2.65
VIC-02	$9,200	1.89
WAL-02	$9,800	6.40
Total	**$200,000**	**2.38**

Overall, the results of the economic evaluation shows that approximately 732,000 kWh per year of energy loss can be eliminated at a levelized cost of 2.38¢/kWh over the life of the capacitor installations. Appendix A contains the economic analysis.

[3] The cost per kWh is a levelized estimate based on the initial capital investment and annual energy savings.

The 2.38¢/kWh is significantly less than the levelized cost of electricity supplied from the Holyrood thermal generating plant at 11.06¢/kWh.

The economic analysis shows that the project is economic when compared to the levelized cost of oil used at Holyrood.

5.0 Concluding

Installing capacitors on distribution lines to reduce losses is both technically and economically feasible. The levelized unit cost of the annual energy savings of 732,000 kWh through the reduction of losses, given an investment of $200,000, is 2.38¢/kWh.

In 2008, a capital budget allocation of $200,000 would provide for capacitor installations on 19 distribution feeders.

Appendix A

Levelized Unit Cost of Energy Savings

APPENDIX A

Weighted Average Incremental Cost of Capital **7.64%**
PW Year **2007**

YEAR	Distribution 45.1 yrs 8% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Rev Rqmt (¢/kWhr)
2008	200,000	19,696	0	0	-19,696	-18,298	-18,298	2.69	2.38
2009	0	19,344	0	0	-19,344	-16,696	-34,994	2.64	2.38
2010	0	19,472	0	0	-19,472	-15,613	-50,607	2.66	2.38
2011	0	19,516	0	0	-19,516	-14,538	-65,145	2.67	2.38
2012	0	19,514	0	0	-19,514	-13,504	-78,649	2.66	2.38
2013	0	19,471	0	0	-19,471	-12,518	-91,167	2.66	2.38
2014	0	19,391	0	0	-19,391	-11,582	-102,749	2.65	2.38
2015	0	19,278	0	0	-19,278	-10,697	-113,447	2.63	2.38
2016	0	19,133	0	0	-19,133	-9,863	-123,310	2.61	2.38
2017	0	18,960	0	0	-18,960	-9,080	-132,390	2.59	2.38
2018	0	18,760	0	0	-18,760	-8,347	-140,737	2.56	2.38
2019	0	18,536	0	0	-18,536	-7,662	-148,399	2.53	2.38
2020	0	18,290	0	0	-18,290	-7,023	-155,422	2.50	2.38
2021	0	18,023	0	0	-18,023	-6,430	-161,852	2.46	2.38
2022	0	17,737	0	0	-17,737	-5,879	-167,731	2.42	2.38
2023	0	17,434	0	0	-17,434	-5,368	-173,099	2.38	2.38
2024	0	17,114	0	0	-17,114	-4,896	-177,994	2.34	2.38
2025	0	16,780	0	0	-16,780	-4,459	-182,454	2.29	2.38
2026	0	16,433	0	0	-16,433	-4,057	-186,511	2.24	2.38
2027	0	16,073	0	0	-16,073	-3,687	-190,197	2.19	2.38
2028	0	15,701	0	0	-15,701	-3,346	-193,543	2.14	2.38
2029	0	15,319	0	0	-15,319	-3,033	-196,576	2.09	2.38
2030	0	14,928	0	0	-14,928	-2,745	-199,321	2.04	2.38
2031	0	14,527	0	0	-14,527	-2,482	-201,803	1.98	2.38
2032	0	14,118	0	0	-14,118	-2,241	-204,044	1.93	2.38
2033	0	13,702	0	0	-13,702	-2,020	-206,065	1.87	2.38
2034	0	13,278	0	0	-13,278	-1,819	-207,884	1.81	2.38
2035	0	12,848	0	0	-12,848	-1,635	-209,519	1.75	2.38
2036	0	12,413	0	0	-12,413	-1,468	-210,987	1.70	2.38
2037	0	11,972	0	0	-11,972	-1,315	-212,302	1.63	2.38
2038	0	11,526	0	0	-11,526	-1,176	-213,478	1.57	2.38
2039	0	11,075	0	0	-11,075	-1,050	-214,528	1.51	2.38
2040	0	10,620	0	0	-10,620	-935	-215,463	1.45	2.38
2041	0	10,161	0	0	-10,161	-831	-216,295	1.39	2.38
2042	0	9,699	0	0	-9,699	-737	-217,032	1.32	2.38
2043	0	9,233	0	0	-9,233	-652	-217,684	1.26	2.38
2044	0	8,765	0	0	-8,765	-575	-218,259	1.20	2.38
2045	0	8,293	0	0	-8,293	-506	-218,765	1.13	2.38
2046	0	7,819	0	0	-7,819	-443	-219,208	1.07	2.38
2047	0	7,343	0	0	-7,343	-386	-219,594	1.00	2.38
2048	0	6,864	0	0	-6,864	-335	-219,929	0.94	2.38
2049	0	6,384	0	0	-6,384	-290	-220,219	0.87	2.38
2050	0	5,902	0	0	-5,902	-249	-220,468	0.81	2.38
2051	0	5,418	0	0	-5,418	-212	-220,680	0.74	2.38
2052	0	4,932	0	0	-4,932	-180	-220,860	0.67	2.38
2053	0	-6,103	0	0	6,103	206	-220,654	-0.83	2.38

Fibre Optic Circuit Replacement

June 2007

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1.0 Introduction

This report compares the cost of using leased and rented fibre optic circuits with the cost of Newfoundland Power ("the Company") owning the fibre optic circuits. Also, it details the capital expenditure plan from 2008 to 2011 required for fibre optic circuit construction.

2.0 Background

Newfoundland Power constructed its first fibre optic circuits in 1990. Since then, a network of 32 fibre circuits has been established; 16 circuits which were constructed by the Company, 15 which are leased and one which is rented. This network is used for corporate data, substation, voice and SCADA communications, protective relay communications as well as data communications between Newfoundland Power's and Newfoundland and Labrador Hydro's system control centres. These circuits are critical to Company operations as they provide reliable communications on a real-time basis between control centres and substations.

3.0 Future Lease Renewals

At present the Company has 15 fibre optic circuits leased and one fibre optic circuit rented from a third party service provider. Details of the leases and rental agreement are presented in Appendix A, Fibre Optic Circuit Leases. These leases will expire over the period of 2008 to 2011.

The existing service provider has offered to extend the existing lease terms for 10 more years. On six circuits, additional fibres are required to provide back-up communications circuits for the various applications to ensure continuous service. The projected costs to lease these additional fibres are based upon existing lease terms also shown in Appendix A.

For renewals starting in 2018 and 2028, the costs were projected to increase by the cumulative GDP Deflator from the previous renewal date.

The net present value analysis included in Appendix C estimates the cost of continuing with the lease and rental fibre alternative at $1,269,387 for the period 2008 to 2036.

4.0 Proposed Fibre Optic Circuit Construction Costs

Newfoundland Power is proposing to construct fibre optic circuits to coincide with the expiry of the associated leases. Table 1 shows the capital expenditure estimate for 2008 to 2011.

Table 1
Capital Expenditures to Replace Leased Circuits
($000s)

Year	Cost
2008	120
2009	215
2010	244
2011	278
Total	**857**

5.0 Operating and Maintenance Costs for Proposed Fibre Optic Circuits

Newfoundland Power's experience with its fibre optic circuits shows that maintenance is not required on a continuous basis. Only the failure of a circuit would require a maintenance response. Since 1990, the Company has had 2 failures on its fibre circuits. Due to the low rate of failures experienced with the existing circuits any prediction of future maintenance cost based upon historical failures might be artificially low. Therefore, a failure prediction model was used to estimate future maintenance cost.[1] This model predicts a failure rate of one per year applicable to the additional fibre proposed. Based upon the Company's experience, the response to this failure would cost approximately $1,600 for 2008. This cost was escalated by the annual GDP Deflator and included in annual operating cost.

6.0 Fibre Optic Plan

Newfoundland Power proposes to build two fibre optic circuits in 2008 at a cost of $120,000. The Company proposes to build the remaining 14 fibre optic circuits from 2009 to 2011. The total cost of building the 16 fibre optic circuits is $857,000. Appendix B contains the construction schedule.

The net present value analysis included in Appendix C estimates the cost of ownership at $1,029,600 for the period 2008 to 2036.

[1] IEEE Journal on Selected Areas in Communications, VOL. SAC-1, No. 3, April 1983, Field Experience with Fiber-Optic Installation, Splicing, Reliability, and Maintenance.

7.0 Analysis

Appendix C, Net Present Value Analysis shows that replacing leased fibre optic circuits with Company-owned fibre optic circuits is the least cost alternative for customers. Over the life of the cables, from 2008 to 2036, the total benefit is estimated at $239,787.

Appendix A

Fibre Optic Circuit Leases

Fibre Optic Circuit Leases

Link	Duration (Years)	Expiry Date	Current Fibres	Current Monthly Rate	Projected[2] Fibres	Projected[2] Monthly Rate
Virginia Waters Substation to Ridge Road Substation	10	2008	6	$ 395.13	12	$ 592.70
55 Kenmount Road to Stamps Lane Substation	10	2009	12	$ 450.00	12	$ 450.00
Oxen Pond Substation to 50 Duffy Place	10	2009	12	$ 450.00	12	$ 450.00
System Control Centre to Hydro Place[1]	Rental	Rental	2	$ 400.00	2	$ 400.00
Hardwoods Substation to Chamberlains Substation	10	2009	6	$ 556.73	12	$ 835.10
Hardwoods Substation to System Control Centre	10	2009	12	$ 698.64	12	$ 698.64
Gander Substation to Cobbs Pond Substation	10	2010	6	$ 337.05	12	$ 505.58
Goulds Substation to Glendale Substation	10	2010	12	$ 450.00	12	$ 450.00
Memorial Substation to Kings Bridge Substation	10	2010	6	$ 300.00	12	$ 450.00
Glendale Substation to System Control Centre	10	2010	12	$ 450.00	12	$ 450.00
Ridge Road Substation to Kings Bridge Substation	10	2010	6	$ 365.54	12	$ 548.31
Virginia Waters Substation to Pepperell Substation	10	2011	6	$ 543.00	12	$ 814.50
Kings Bridge Substation to Pepperell Substation	10	2011	6	$ 476.00	12	$ 714.00
Molloys Lane Substation to System Control Centre	10	2011	12	$ 652.50	12	$ 652.50
Molloys Lane Substation to Stamps Lane Substation	10	2011	12	$ 501.00	12	$ 501.00
Molloys Lane Substation to St Johns Main Substation	10	2011	12	$ 456.00	12	$ 456.00
Total Monthly Costs				$ 7,481.59		$ 8,968.33
Total Annual Costs				$ 89,779.08		$ 107,619.96

1. Monthly rental arrangement not subject to lease agreement.
2. Projected Monthly Rates are for 12 fibres on all links except as noted. Rates are as previously quoted by existing service provider.

Appendix B

Construction Schedule

Construction Schedule 2008 to 2011		
Origin	**Termination**	**Construction Scheduled**
SCC Topsail Road	NLH – Hydro Place	2008
Virginia Waters Substation	Ridge Road Substation	2008
55 Kenmount Road	Stamps Lane Substation	2009
Oxen Pond Substation	50 Duffy Place	2009
Hardwoods Substation	Chamberlains Substation	2009
Hardwoods Substation	SCC Topsail Road	2009
Gander Substation	Cobb’s Pond Substation	2010
Goulds Substation	Glendale Substation	2010
Glendale Substation	SCC Topsail Road	2010
Memorial Substation	Kings Bridge Substation	2010
Ridge Road Substation	Kings Bridge Substation	2010
Virginia Waters Substation	Pepperell Substation	2011
Kings Bridge Substation	Pepperell Substation	2011
Molloy’s Lane Substation	SCC Topsail Road	2011
Molloy’s Lane Substation	Stamps Lane Substation	2011
Molloy’s Main Substation	St. John’s Main Substation	2011

Appendix C

Net Present Value Analysis

Net Present Value
Renew Leases on Expiry

Year	Capital Expenditure	Capital Revenue Requirement	Operating Costs	Net Benefit	Present Worth Benefit	Cumulative Present Worth
2008	0	0	90,569	-90,569	-84,141	-84,141
2009	0	0	92,707	-92,707	-80,013	-164,154
2010	0	0	98,155	-98,155	-78,703	-242,858
2011	0	0	105,072	-105,072	-78,270	-321,127
2012	0	0	107,620	-107,620	-74,477	-395,605
2013	0	0	107,620	-107,620	-69,191	-464,796
2014	0	0	107,620	-107,620	-64,280	-529,076
2015	0	0	107,620	-107,620	-59,718	-588,793
2016	0	0	107,620	-107,620	-55,479	-644,272
2017	0	0	107,620	-107,620	-51,541	-695,814
2018	0	0	108,055	-108,055	-48,077	-743,890
2019	0	0	110,848	-110,848	-45,819	-789,709
2020	0	0	116,457	-116,457	-44,721	-834,430
2021	0	0	123,872	-123,872	-44,192	-878,622
2022	0	0	126,863	-126,863	-42,046	-920,668
2023	0	0	126,863	-126,863	-39,062	-959,730
2024	0	0	126,863	-126,863	-36,290	-996,020
2025	0	0	126,863	-126,863	-33,714	-1,029,734
2026	0	0	126,863	-126,863	-31,321	-1,061,054
2027	0	0	126,863	-126,863	-29,098	-1,090,152
2028	0	0	127,441	-127,441	-27,156	-1,117,308
2029	0	0	131,162	-131,162	-25,965	-1,143,273
2030	0	0	138,606	-138,606	-25,491	-1,168,764
2031	0	0	148,263	-148,263	-25,332	-1,194,096
2032	0	0	152,132	-152,132	-24,148	-1,218,243
2033	0	0	147,148	-147,148	-21,699	-1,239,942
2034	0	0	122,223	-122,223	-16,744	-1,256,686
2035	0	0	78,839	-78,839	-10,034	-1,266,720
2036	0	0	22,549	-22,549	-2,666	-1,269,387

Net Present Value
Newfoundland Power to Build Fibre Optic Cables

Year	Capital Expenditure	Capital Revenue Requirement	Operating Costs	Net Benefits	Present Worth Benefit	Cumulative Present Worth
2008	120,221	12,213	88,199	-100,411	-93,284	-93,284
2009	215,307	34,414	71,954	-106,368	-91,805	-185,089
2010	243,849	60,119	47,098	-107,217	-85,969	-271,058
2011	277,720	89,801	14,824	-104,625	-77,937	-348,995
2012	0	91,677	1,712	-93,389	-64,629	-413,624
2013	0	93,013	1,739	-94,752	-60,918	-474,542
2014	0	93,584	1,769	-95,352	-56,953	-531,495
2015	0	93,604	1,799	-95,403	-52,939	-584,433
2016	0	93,176	1,829	-95,005	-48,976	-633,409
2017	0	92,353	1,860	-94,213	-45,121	-678,530
2018	0	91,182	1,894	-93,076	-41,412	-719,942
2019	0	89,706	1,928	-91,634	-37,877	-757,819
2020	0	87,960	1,964	-89,925	-34,532	-792,350
2021	0	85,978	2,002	-87,979	-31,387	-823,737
2022	0	83,787	2,040	-85,827	-28,446	-852,183
2023	0	81,412	2,079	-83,491	-25,708	-877,891
2024	0	78,877	2,118	-80,995	-23,169	-901,060
2025	0	76,199	2,158	-78,357	-20,823	-921,883
2026	0	73,396	2,199	-75,596	-18,664	-940,547
2027	0	70,484	2,241	-72,725	-16,681	-957,227
2028	0	67,474	2,284	-69,758	-14,864	-972,092
2029	0	64,380	2,327	-66,707	-13,205	-985,297
2030	0	61,210	2,371	-63,581	-11,693	-996,990
2031	0	57,975	2,416	-60,391	-10,318	-1,007,308
2032	0	53,682	2,462	-56,144	-8,912	-1,016,220
2033	0	43,200	2,509	-45,709	-6,740	-1,022,960
2034	0	28,691	2,557	-31,247	-4,281	-1,027,241
2035	0	13,464	2,605	-16,070	-2,045	-1,029,286
2036	0	0	2,655	-2,655	-314	-1,029,600

2008 Application Enhancements

June 2007

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1.0 Introduction

The Company operates and supports over 50 computer applications including software packages such as the Great Plains financial system and the asset management system as well as internally developed software such as the Customer Service System ("CSS") and the Outage Management System. These applications help employees work more effectively and efficiently in their daily duties including providing effective customer service.

The Company's computer applications are divided into categories including: 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.

Identifying opportunities to improve these applications either through vendor supplied functionality or internal software development ensures the Company is able to respond to changing business requirements.

The following sections describe the items budgeted for 2008.

2.0 Customer Service Systems Enhancements

2.1 Service Order Tracking Improvements ($158,000)

Description

This item involves improving the integration of customer service orders captured in CSS and the subsequent work orders created in the asset management system used to assign technical work to field personnel.

Operating Experience

The Company received over 3,000 customer requests for new service in 2006 that required technical field work. Currently these new service requests are manually entered into CSS by Contact Centre staff in order to ensure customer account and billing information is completed as required. As well, the new service request is manually entered into the asset management system by Contact Centre staff in order to ensure field work is effectively tracked and completed. Once the field work is completed, Contact Centre staff must update the work order in the asset management system and then update the corresponding service order in CSS.

This highly manual process results in twice the necessary data entry as well as potential reductions in customer service resulting from delays experienced in having to enter transactions into two systems.

Justification

This item is justified on operating efficiency and improved customer service. Improving the integration between CSS service orders and the asset management system will reduce the manual effort required to manage the work in two systems. Once complete, creating a new service order in CSS will automatically create a corresponding work order in the asset management system. This will enhance service to customers by allowing service requests to be completed more timely and accurately.

A financial analysis of the costs and benefits associated with this item results in a positive net present value over the next 5 years. The financial analysis is included in Appendix A.

2.2 Customer Call Recording ($152,000)

Description

The Customer Contact Centre receives over 500,000 customer calls annually, 65% of which are handled by the Contact Centre employees. This item involves the use of call recording technology to record all voice conversations between customers and Contact Centre employees.

Call recording technology is widely used in the Contact Centre industry as a training/coaching tool, as well as a means to ensure that customer calls are handled appropriately by Contact Centre employees.

For example, Contact Centre employees deal with emergency calls from customers. The ability to replay customer's emergency calls ensures that the correct information is passed along to crews or emergency responders.

Operating Experience

Currently, the Company's ability to record calls is limited to a single workstation at a given time. As such, Contact Centre management must schedule a specified time in order to use the technology. This situation does not allow the appropriate flexibility to address training and coaching opportunities or to get a complete understanding of customer calls in emergency situations or those that may lead to escalations.

Justification

This item is justified on improvements in customer service. Having a complete understanding of customer calls provides an objective means to identify training and coaching opportunities for employees. By reviewing customer calls, the Company can ensure emergency calls are handled appropriately and can identify changes in process or communications that would improve customer service.

3.0 Operations and Engineering Enhancements

3.1 Work Order Reporting Enhancements ($113,000)

Description

This item will improve the Company's ability to manage work orders initiated and tracked in the asset management system. Access to information used to manage these work orders will be enhanced, providing more effective reports to employees involved with managing work orders.

Operating Experience

The Company manages over 20,000 work orders annually, including inspections, asset maintenance and customer initiated technical work. Currently, reports used to support the management of work orders are developed by staff with specific programming skills and often require users of the reports to review highly detailed information in order to analyze work backlog and customer commitments.

Justification

Accessing work orders and related effort estimates more effectively will ensure field employees are assigned the appropriate work in a timely manner.

A financial analysis of the costs and benefits associated with this item results in a positive net present value over the next 5 years. The financial analysis is included in Appendix A.

3.2 Power Plant Maintenance Mobility ($166,000)

Description

This item involves enhancements to the asset management system to enable employees equipped with mobile devices to complete power plant maintenance work orders in the field. The mobile devices will electronically update the asset management system eliminating the need for manual data entry.

Operating Experience

The Company operates 23 hydroelectric and 6 thermal generation facilities throughout the Company's service territory. The Company performs over 2,800 inspection and maintenance work orders on these plants annually. These work orders ensure the effective operation of the plants. Examples of tasks performed in these work orders include oil analysis, dam safety inspections and equipment condition monitoring.

The recording of the inspection data and associated deficiencies, and the creation of work orders and tasks in the asset management system required to correct the deficiencies, currently contains manual processes. The effort to capture this information impedes the efficient scheduling and execution of the follow-up work.

Justification

Enhancing the asset management system will increase efficiency and improve data quality by utilizing mobile devices to capture power plant inspection data and equipment condition in the field. This reduces the amount of time spent manually recording information in the field and entering it into the asset management system.

A financial analysis of the costs and benefits associated with this item results in a positive net present value over the next 5 years. The financial analysis is included in Appendix A.

4.0 Intranet/Internet Enhancements

4.1 Customer Service Internet ($192,000)

Description

This item involves enhancements to customer self-service options on the Company's Internet website. For 2008, this item includes automatically updating CSS as a result of on-line customer requests initiated on the Company's website. These requests include eBill sign-up, basic account information updates and meter reading. As well, improvements will be undertaken to on-line customer information such as expanding billing history, premise location information and improving customer email processing.

Operating Experience

In 2006, the Company's Internet website received more than 354,000 visits and customers sent over 17,000 email inquiries. In most cases a corresponding email was sent from the Company to the customer in response to their inquiry.

Currently, on-line customer requests related to information updates are manually reviewed and processed in CSS by Contact Centre employees. In addition, return email such as the confirmation of completion of the customer request is performed manually at the Contact Centre.

Justification

This item is justified on productivity improvements and customer service improvements.

For the portion of the item related to automatically updating CSS from on-line customer requests, a financial analysis of the costs and benefits results in a positive net present value over the next 5 years. The financial analysis is included in Appendix A.

A portion of this item is justified on improved customer service by enhancing the information on the Company's Internet website in response to its increasing usage by customers.

5.0 Business Support Systems

5.1 Safety Management System Enhancements ($350,000)

Description

The purpose of this item is to enhance the Company's Safety Management System ("SMS") to meet the requirements of the Occupational Health and Safety Assessment Series ("OHSAS") 18001 management system. OHSAS 18001 is an internationally recognized specification for health and safety management systems.

Operating Experience

The safety of the general public, employees and contractors is a high priority for the Company. The Company continually evaluates the effectiveness of its policies, procedures and systems to ensure a safe and healthy workplace. While the Company's safety performance has been consistent over the past several years, further improvement can be achieved with enhancements to the current SMS.

The Company has identified approximately 700 hazards involving potential risk to employees, contractors and the general public. These hazards form the basis of the SMS and are put through a rigorous risk assessment process to determine relative risk associated with each hazard. Over 100 control procedures related to the identified hazards describe in detail how the hazard is to be managed. The identified hazards must be documented and maintained to reflect ongoing changes to regulation and associated procedures.

The risk assessment, control procedures and legal aspects must be monitored and updated on an annual basis in order to meet the requirements of the OHSAS 18001 standard. Employees and contractors must identify and assess new hazards as they occur and keep a complete record of the process including training and compliance records on a continual basis.

Justification

Enhancements to the SMS will reduce the effort associated with managing the requirements of the OHSAS 18001 information system. As well, improvements to the SMS are required in order to demonstrate conformance to the Company's Occupational Health and Safety policies related to the OHSAS 18001 standard.

A financial analysis of the costs and benefits associated with this item results in a positive net present value over the next 5 years. The financial analysis is included in Appendix A.

5.2 Time Reporting Improvements ($108,000)

Description

The purpose of this item is to improve the process of collecting and processing employee timesheet data.

Operating Experience

The collection and processing of employee labour is central to the Company's payroll system as well as financial and regulatory reporting. The Company currently collects and processes over 600 employee timesheets (or approximately 5,000 timesheet line items) on a weekly basis. Under the existing process, employees enter their timesheet data on a paper timesheet or electronic timesheet template and forward it to an area/department coordinator for entry into the Great Plains financial system. As well, any timesheet exceptions (e.g. overtime, vacation) require supervisor approval before manually entering the data into the Great Plains financial system.

This highly manual process often requires timesheet coordinators to contact individuals in order to ensure the correct information is ready for processing.

Justification

Providing a means for employees to enter time into the Great Plains financial system for validation and processing will reduce the amount of re-keying currently required to prepare the timesheet files. Automating the workflow process for the approval of timesheet exceptions will reduce the amount of time spent by timesheet coordinators ensuring the proper approvals are given prior to encoding.

A financial analysis of the costs and benefits associated with this item results in a positive net present value over the next 5 years. The financial analysis is included in Appendix A.

6.0 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 and employee identified enhancements designed to improve customer service or employee productivity.

Operating Experience

Examples of previous items under this budget item include enhancing collections processes in the Customer Service System to reduce bad debt expense and enhancing the Company's Outage Management System to improve communications to customers and employees.

Justification

Work completed as part of various minor enhancements is justified on the basis of improved customer service, operating efficiencies and regulatory and legislative requirements.

Appendix A

Net Present Value Analyses

Service Order Tracking Improvements

		Capital Impacts		Operating Cost Impacts						
		Additions	Tax Deductions	Cost Increases		Cost Benefits				
	YEAR	New Software	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C		D		E	F	G
0	2008	($158,000)	$79,000	$0	$0	$0	$0	$0	$27,255	($130,745)
1	2009		$79,000	$0	$0	$60,060	$0	$60,060	$6,440	$66,500
2	2010			$0	$0	$61,862	$0	$61,862	($20,414)	$41,447
3	2011			$0	$0	$63,718	$0	$63,718	($21,027)	$42,691
4	2012			$0	$0	$65,629	$0	$65,629	($21,658)	$43,972
	Present Value (See Note H)		**@**	**6.59%**						**$37,427**

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 to current year using GDP Deflator Index.
D is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost expenditures. 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 present value of column G. Column G is discounted using the weighted after-tax cost of capital.

Work Order Reporting Enhancements

		Capital Impacts		Operating Cost Impacts						
		Additions	Tax Deductions	Cost Increases		Cost Benefits				
	YEAR	New Software	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C		D		E	F	G
0	2008	($113,000)	$56,500	$0	$0	$0	$0	$0	$19,493	($93,508)
1	2009		$56,500	$0	$0	$46,800	$0	$46,800	$3,298	$50,098
2	2010			$0	$0	$48,204	$0	$48,204	($15,907)	$32,297
3	2011			$0	$0	$49,650	$0	$49,650	($16,385)	$33,266
4	2012			$0	$0	$51,140	$0	$51,140	($16,876)	$34,264
	Present Value (See Note H)	**@**		**6.59%**						**$35,922**

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 to current year using the GDP Deflator Index.
D is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost expenditures. 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 present value of column G. Column G is discounted using the weighted after-tax cost of capital.

Power Plant Maintenance Mobility

		Capital Impacts			Operating Cost Impacts						
		Additions		Tax Deductions	Cost Increases		Cost Benefits				
	YEAR	New Software	New Hardware	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C	D		E		F	G	H
0	2008	($166,000)	($28,000)	$83,000	$0	$0	$0	$0	$0	$30,809	($163,192)
1	2009			$83,000	$0	$0	$58,240	$0	$58,240	$11,739	$69,979
2	2010				$0	$0	$59,987	$0	$59,987	($18,023)	$41,964
3	2011				$0	$0	$61,787	$0	$61,787	($19,415)	$42,372
4	2012				$0	$0	$63,640	$0	$63,640	($19,894)	$43,747
	Present Value (See Note I)	**@**			**6.59%**						**$8,261**

NOTES: A is the sum of the software additions by year.
B is the sum of the computer network hardware additions by year.
C is the Capital Cost Allowance deduction. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.
D is any software maintenance fees and internal support costs associated with the project. The cost estimates are escalated to current year using the GDP Deflator Index.
E is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
F is the sum of columns D and E.
G is the impact on taxes from the CCA and operating cost expenditures. It is equal to column C less column F times the tax rate.
H is the after tax cash flow which is the sum of the capital expenditure (columns A and B) plus operating expenditures (column F) plus income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Customer Service Internet

		Capital Impacts		Operating Cost Impacts						
		Additions	Tax Deductions	Cost Increases		Cost Benefits				
YEAR		New Software	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C		D		E	F	G
0	2008	($90,000)	$45,000	$0	$0	$0	$0	$0	$15,525	($74,475)
1	2009		$45,000	$0	$0	$30,333	$0	$30,333	$4,987	$35,320
2	2010			$0	$0	$31,243	$0	$31,243	($10,310)	$20,933
3	2011			$0	$0	$32,180	$0	$32,180	($10,619)	$21,561
4	2012			$0	$0	$33,145	$0	$33,145	($10,938)	$22,207
Present Value (See Note H)		**@**		**6.59%**						**$12,086**

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 to current year using the GDP Deflator Index.
D is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost expenditures. 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 present value of column G. Column G is discounted using the weighted after-tax cost of capital.

Safety Management Enhancements

		Capital Impacts		Operating Cost Impacts						
		Additions	Tax Deductions	Cost Increases		Cost Benefits				
	YEAR	New Software	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C		D		E	F	G
0	2008	($350,000)	$175,000	$0	$0	$0	$0	$0	$60,375	($289,625)
1	2009		$175,000	$0	$0	$104,000	$0	$104,000	$24,140	$128,140
2	2010			$0	$0	$107,120	$0	$107,120	($35,350)	$71,770
3	2011			$0	$0	$110,334	$0	$110,334	($36,410)	$73,924
4	2012			$0	$0	$113,644	$0	$113,644	($37,502)	$76,141
	Present Value (See Note H)	**@**		**6.59%**						**$13,768**

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 to current year using the GDP Deflator Index.
D is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost expenditures. 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 present value of column G. Column G is discounted using the weighted after-tax cost of capital.

Time Reporting Improvements

		Capital Impacts		Operating Cost Impacts						
		Additions	Tax Deductions	Cost Increases		Cost Benefits				
	YEAR	New Software	Software	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B	C		D		E	F	G
0	2008	($108,000)	$54,000	$0	$0	$0	$0	$0	$18,630	($89,370)
1	2009		$54,000	$0	$0	$34,070	$0	$34,070	$6,776	$40,846
2	2010			$0	$0	$35,093	$0	$35,093	($11,581)	$23,512
3	2011			$0	$0	$36,145	$0	$36,145	($11,928)	$24,217
4	2012			$0	$0	$37,230	$0	$37,230	($12,286)	$24,944
	Present Value (See Note H)	**@**		**6.59%**						**$8,959**

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 to current year using the GDP Deflator Index.
D is the reduced operating costs. The cost estimate is escalated to current year using Newfoundland Power's Labour Escalation Rates.
E is the sum of columns C and D.
F is the impact on taxes from the CCA and operating cost expenditures. 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 present value of column G. Column G is discounted using the weighted after-tax cost of capital.

2008 System Upgrades

June 2007

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1.0 Introduction

The Company depends on the effective implementation and on-going operation of its business applications in order to continue to provide cost effective service to customers. Over time these applications need to be upgraded to address functional or vendor obsolescence, ensure continued vendor support, improve software compatibility, or to take advantage of newly developed functionality.

This project consists of upgrades to several of the Company's business applications and the information technology used to operate and support the Company's business applications.

2.0 Business Application Upgrades

2.1 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 which ones require upgrades. For 2008, upgrades include:

1) Great Plains - $110,000

   This item involves an upgrade to the Company's Great Plains financial management system to the most current version supported by the vendor, Microsoft. The upgrade is required to ensure the components used to operate the financial application are compatible with the Great Plains servers being replaced as part of the Shared Server Infrastructure project.

2) Substation Design Software - $59,000

   This item involves an upgrade to the Company's substation design software to EPlan Electric P8, the most current version supported by the vendor. This upgrade is required to address functional obsolescence, ensure continued vendor support, and ensure continued efficiency gains through the vendor's functional enhancements.

3) Intranet - $142,000

   This item involves upgrading the Company's SharePoint Server intranet software to the most current version supported by the vendor, Microsoft. This upgrade is required in order to improve the security and management of information and documents stored and maintained on the Company's intranet. Customer service, environment, safety, regulatory and financial policy and procedures documents are used by employees on a daily basis. The Intranet is an efficient method of accessing and sharing these documents throughout the Company.

2.2 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 an upgrade.

As well, upgrades are often completed in order to take advantage of functional or technical enhancements provided by the vendor in new versions of the software application.

2.3 Justification

Investment in Business Application Upgrades is necessary to replace outdated technology that is no longer supported by vendors and to take advantage of newly developed capabilities. Unstable and unsupported software applications can negatively impact operating efficiencies and customer service.

3.0 Information Technology Management

3.1 Description

Managing the information technology ("IT") used to operate and support the Company's business applications consists of a variety of interrelated technologies and processes. These technologies are used to develop, configure, test, implement, monitor and maintain applications throughout the Company. For 2008, this item includes:

1) IT Change Management and Configuration Management Improvements - $176,000

   This item involves improvements to the software and interrelated processes used to manage changes to the Company's IT. IT requires ongoing updates and modifications as part of normal operations. These changes are made as a result of application enhancements, software upgrades, security enhancements, as well as application and infrastructure failures that sometimes occur. Improvements to the Change Management and Configuration Management applications will ensure that changes to the Company's IT are properly tracked for troubleshooting and restoration purposes; that the configuration and setup of the various components of the Company's IT are sufficiently documented as changes occur; and that the risks associated with making changes to the Company's IT are minimized.

3.2 Operating Experience

The Company depends on the stable operation of its over 50 business applications such as CSS, Great Plains and Avantis in order to sustain an effective level of customer service and employee productivity. The Company's IT environment consists of over 2000 technology components used to operate and support these applications. These components include servers, network switches and routers, desktop and notebook computers, software applications and printers. Effective management of this IT configuration is required to ensure a sustainable level of application availability and performance.

In 2006, the Company performed over 750 changes to its IT configuration, a 20% increase over 2005. Examples of these changes include application code modifications, the addition of new hardware components, and software security updates. Managing these changes effectively is critical to ensuring that application reliability and data integrity is maintained.

In the event of an operational failure, the Company has to quickly assess the state of the Company's production IT configuration, including the determination as to whether any changes recently introduced has caused the failure to occur. The complexity of the Company's IT and the level of ongoing change it undergoes make it difficult for specific individuals to be continually involved in assessing and resolving issues as they arise.

3.3 Justification

Managing the information technology used to operate and support the Company's business applications is justified on the basis of maintaining customer service levels and existing operating efficiencies.

The ability to consistently demonstrate that changes being made to the IT environment are tested, approved and properly applied to production ensures that the Company's business continuity/disaster recovery plans and IT general controls related to corporate governance are effective, and that legal obligations related to software and hardware licensing are met.

2008 Shared Server Infrastructure

June 2007

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The Shared Server Infrastructure consists of over 100 shared servers that are used for production, testing, and disaster recovery for the Company's business applications. The Company relies on these shared servers to ensure the efficient operation and support of its customer service, engineering and business support systems. Each year an assessment is completed to determine the Company's shared server infrastructure requirements. This assessment involves identifying servers and peripherals to be replaced based on age and risk of failure, as well as determining any new computing requirements for corporate applications.

2.0 Description

This project involves the addition, upgrade and replacement of computer hardware components and related technology associated with the Company's shared server infrastructure. For 2008, this project includes:

1. The purchase and implementation of additional disk, memory and processor upgrades for servers which are currently used to run corporate applications. The budget for this item is $99,000.

2. The purchase of a centralized storage system to meet the Company's business application availability and data storage requirements. This storage system will provide enhanced disaster recovery capabilities, and capacity requirements for the Company's business applications. The budget for this item is $295,000.

3. The replacement of the servers used to operate the Company's financial application, Microsoft Great Plains. These servers have been installed since 2001 and will be in service for 7 years in 2008. The timely replacement of aging servers ensures the reliable and effective operation of Great Plains as well as supports future upgrade requirements. This item is interrelated with the Great Plains upgrade that is part of the 2008 System Upgrades project. The budget for this item is $236,000.

4. Enhancements to information technology security infrastructure to help manage and support the security of both employee and customer data. These enhancements will help ensure the availability and integrity of corporate and customer data. In addition, enhancements will be made to improve the security of the SCADA communications network to improve the security of the technology components that support the Company's electrical system. The budget for this item is $188,000

5. Enhancements to the physical security and monitoring capabilities used to provide protection to Company facilities that contain computing assets. This item involves the addition, upgrade and replacement of hardware components and related technology associated with the Company's physical security including cameras, intruder detection, and security monitoring. The budget for this item is $71,000.

3.0 Operating Experience

The Shared Server Infrastructure project includes the purchase, implementation and management of the hardware and software related to the operation of shared servers. Shared servers are computers that support applications used by multiple employees. Management of these shared servers and their components are critical to ensuring that these applications are available in order for the Company to provide service to customers and operate efficiently.

Technology components such as servers and disk storage require on-going investment to ensure that they continue to operate effectively. As data storage requirements continue to grow and to maintain the effectiveness of our systems, upgrades, monitoring and security investments are necessary.

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 criticality of the applications running on the shared server components; the ability of the components to meet future growth; the cost of maintaining and operating the components using internal staff ; the cost of replacing or upgrading the components versus operating the current components; and the business or customer impact if the component fails.

Gartner states that computer servers have a useful life of approximately 5 years[1]. By making appropriate investments in its shared server infrastructure, Newfoundland Power's experience is that the useful life of its corporate servers has exceeded Gartner's findings.

In order to ensure high availability of applications and 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 or destroy information.

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[1] Gartner Inc. is the leading provider of research and analysis on the global Information Technology industry. They help more than 10,000 companies make informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology. Founded in 1979, Gartner is headquartered in Stamford, Connecticut and consists of 3,800 associates, including 1,200 research analysts and consultants in 75 countries.

4.0 Justification

The shared server infrastructure is vital to maintaining the provision of low cost, efficient and reliable 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 or becomes obsolete. 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 overall customer service.

Investments in the shared server infrastructure are made by evaluating the alternatives of modernizing or replacing technology components and selecting the least cost alternative whenever possible.

Deferred Charges and Rate Base

June 2007

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1.0 Introduction

In Order No. P.U. 19 (2003), the Board of Commissioners of Public Utilities (the "Board") ordered Newfoundland Power (the "Company") to incorporate deferred charges in rate base commencing in 2003. In addition, the Board ordered that evidence relating to changes in deferred charges, including deferred pension costs, be filed annually with the Company's capital budget application.

This report provides evidence with respect to changes in deferred charges.

2.0 Deferred Charges

2.1 Summary

Table 1 outlines the forecast deferred charges at December 31, 2006 reported in the Company's 2007 Capital Budget Application, the actual deferred charges reported at December 31, 2006 and forecast deferred charges at December 31, 2007 and 2008.

Table 1
Deferred Charges: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Deferred Pension Cost	90,333	90,122	96,656	99,764
Weather Normalization Account	8,998	11,808	10,683	10,683
Unamortized Debt Discount & Issue Expense	3,035	3,035	3,433	3,245
Unamortized Capital Stock Issue Expense	199	199	137	75
Deferred Retiring Allowances	134	133	0	0
Deferred Credit Facility Issue Costs	116	117	58	0
Deferred Depreciation Expense	5,793	5,793	11,586	11,586
Deferred Replacement Energy Cost	0	0	1,147	1,147
Total Deferred Charges	108,608	111,207	123,700	126,500

The total deferred charges at December 31, 2006 were approximately $2.6 million higher than that forecast in the Company's 2007 Capital Budget Application. This was due primarily to the operation of the Weather Normalization Account. The 2006 forecast for the Weather Normalization Account included actual stream-flows and weather patterns to the end of January 2006 and assumed normal stream-flows and weather patterns for the remainder of 2006.

2.2 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* with regard to the Company's defined benefit pension plan is captured as a deferred pension cost on the Company's balance sheet in accordance with Order No. P.U. 17 (1987).

Table 2 sets out (i) forecast December 31, 2006 deferred pension cost per the Company's 2007 Capital Budget Application, (ii) actual deferred pension costs at December 31, 2006, and (iii) forecast deferred pension cost at December 31, 2007 and 2008.

Table 2
Forecast Deferred Pension Costs: 2006-2008F
($000s)

	2006F	**Actual 2006**	**2007F**	**2008F**
Deferred Pension Costs, January 1st	84,999	84,999	90,122	96,656
Pension Plan Funding				
- Current Service Funding	3,200	3,371	3,598	3,840
- Special Funding	7,391	7,540	7,308	1,578
Total Pension Plan Funding	10,591	10,911	10,906	5,418
Pension Plan Expense	(5,257)	(5,788)	(4,372)	(2,310)
Increase in Deferred Pension Costs	5,334	5,123	6,534	3,108
Deferred Pension Costs, December 31st	90,333	90,122	96,656	99,764

Pension plan funding is comprised of two components: current service funding which is determined by an independent actuary and is related to service rendered by active employees in the current year; and, special funding which reflects additional pension funding requirements to address increases in the unfunded liability in the pension plan since its inception. The status of the unfunded liability is determined each time an actuarial study is completed which, under pension legislation, has to occur at least every three years. The last valuation was completed as of December 31, 2005. Therefore, the next valuation is required to be completed as of December 31, 2008, at the latest.

The Company calculates annual pension expense in accordance with recommendations of the Canadian Institute of Chartered Accountants ("CICA") and relevant Board orders, the most recent of which is Order No. P.U. 49 (2004). In this order, the PUB approved a variation from generally accepted accounting principles with respect to the amortization of costs associated with the 2005 Early Retirement Program. These costs have been deferred and are being amortized on a straight line basis over 10 years commencing April 1, 2005.

The forecast pension expense for 2008 is subject to change based upon the following factors:

1. The final pension expense for 2008 cannot be determined until early in 2008 once actual pension plan asset balances for 2007 are known. This determination is made based on the December 31, 2007 market value of pension plan assets in accordance with CICA Handbook recommendations and Order No. P.U. 19 (2003).

2. In accordance with CICA Handbook recommendations the discount rate required to calculate 2008 pension expense is the actual market rate of interest at December 31, 2007. Pension expense for 2008 in Table 2 above is calculated assuming a 5.25% discount rate at December 31, 2007. If a change in discount rate is required based on December 31, 2007 market interest rates, 2008 pension expense will vary from the amount forecast for 2008 in Table 2.

While pension plan expense for 2008 is subject to change from the forecast provided above, it will be determined based on standards that have been consistently applied year over year, and these standards are in compliance with CICA recommendations, actuarial principles, and Board orders.

2.3 Weather Normalization Account

The Weather Normalization Account has historically been included in rate base. Its treatment is unchanged by the inclusion of additional deferred charges in rate base as ordered by the Board in Order No. P.U. 19 (2003).

The balance in the Weather Normalization Account is comprised of two reserve accounts as shown in Table 3. The forecast change in each reserve account is shown in Table 4 and Table 5.

Table 3
Weather Normalization Account: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Hydro Production Equalization Reserve	4,539	4,981	3,856	3,856
Degree Day Normalization Reserve	4,459	6,827	6,827	6,827
Total	8,998	11,808	10,683	10,683

The functioning of these reserves is governed by orders of the Board; Order No. P.U. 32 (1968) in the case of the Hydro Production Equalization Reserve, and Order No. P.U. 1 (1974) in the case of the Degree Day Normalization Reserve.

Table 4
Hydro Production Equalization Reserve: 2006-2008F
($000s)

	2006F	**Actual 2006**	**2007F**	**2008F**
Balance, January 1st	6,001	6,001	4,982	3,856
Reduction per P.U. 19 (2003)	(1,126)	(1,126)	(1,126)	0
Normal operation of the reserve	(336)	107	0	0
Balance, December 31st	4,539	4,982	3,856	3,856

In Order No. P.U. 19 (2003), the Board approved the Company's proposal to amortize the recovery of the $5.6 million non-reversing balance in the Hydro Production Equalization Reserve at a rate of $1.126 million per year over a period of five years commencing in 2003. The final annual reduction in the Hydro Production Equalization Reserve of $1.126 million is included in the forecast for 2007. The 2007 and 2008 forecasts assume normal stream-flows from January 2007 through December 2008.

Table 5
Degree Day Normalization Reserve: 2006-2008F
($000s)

	2006F	**Actual 2006**	**2007F**	**2008F**
Balance, January 1st	4,099	4,099	6,827	6,827
Normal operation of the reserve	360	2,728	0	0
Balance, December 31st	4,459	6,827	6,827	6,827

Both the Hydro Production Equalization Reserve and the Degree Day Normalization Reserve are affected by actual weather patterns as compared to normal weather patterns. The 2007 and 2008 forecasts assume normal weather conditions from January 2007 through December 2008. Newfoundland Power does not expect the $6.8 million balance in the Degree Day component to reverse with normal long-term weather patterns. In the 2008 GRA, the Company is proposing to amortize the recovery of the $6.8 million of the Degree Day component over 5 years beginning in 2008. This proposal is not reflected in the table above as it is subject to the approval of the Board.

In Order No. P.U. 12 (2007), the Board approved the balance in the Weather Normalization Accounts as at December 31, 2006.

2.4 Unamortized Debt Discount & Issue Expense

Change in Unamortized Debt Discount & Issue Expense is set out in Table 6.

Table 6
Unamortized Debt Discount & Issue Expense: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Balance, January 1st	3,228	3,228	3,035	3,433
Costs incurred during the year	0	0	600	0
Amortization during the year	(193)	(193)	(202)	(188)
Balance, December 31st	3,035	3,035	3,433	3,245

The Company is anticipating the issue of Series AL First Mortgage Sinking Fund Bonds in August of 2007. The issue expenses are estimated to be 1 percent of the face value of the bonds or $600,000. The amortization recorded includes the normal amortization of these costs over 360 months beginning August 1, 2007.

2.5 Unamortized Capital Stock Issue Expense

Change in Unamortized Capital Stock Issue Expense is set out in Table 7.

Table 7
Unamortized Capital Stock Issue Expense: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Balance, January 1st	261	261	199	137
Amortization during the year	(62)	(62)	(62)	(62)
Balance, December 31st	199	199	137	75

The decline in the Unamortized Capital Stock Issue Expense each year reflects the normal amortization of these costs over a 20-year period.

2.6 Deferred Retiring Allowances

The details of the changes are set out in Table 8.

Table 8
Deferred Retiring Allowances: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Balance, January 1st	672	671	133	0
Cost incurred during the year	0	0	0	0
Amortization during the year	(538)	(538)	(133)	0
Balance, December 31st	134	133	0	0

In Order No. P.U. 49 (2004), the Board ordered that retiring allowances related to the 2005 Early Retirement Program be amortized over twenty-four months. The year-over-year change in deferred retirement allowances reflects the amortization methodology approved by the Board.

2.7 Deferred Credit Facility Issue Costs

The details of the changes are set out in Table 9.

Table 9
Deferred Credit Facility Issue Costs: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Balance, January 1st	117	117	118	58
Cost incurred during the year	57	58	0	0
Amortization during the year	(58)	(57)	(60)	(58)
Balance, December 31st	116	118	58	0

In Order No. P.U. 4 (2006), the Board approved the extension of the maturity date of the Company's revolving term credit facility (the "Credit Facility") to January 20, 2009. The fees related to this amendment, along with the unamortized balance at the end of 2005 of the fees related to the initial establishment of the facility, are being amortized on a straight line basis over the term of the amended facility (thirty-six months).

2.8 Deferred Depreciation True-up

The details of the changes are set out in Table 10.

Table 10
Deferred Depreciation Expense: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Balance, January 1st	0	0	5,793	11,586
Cost deferred during the year	5,793	5,793	5,793	0
Amortization during the year	0	0	0	0
Balance, December 31st	5,793	5,793	11,586	11,586

In Order No. P.U. 40 (2005), the Board ordered the Company to defer the recovery of an increase in 2006 depreciation expense of $5,793,000 related to the amortization of depreciation true-up. In P.U. 39 (2006), the Board ordered the Company to defer recovery, until a further Order of the Board, of an additional amount of $5,793,000 in 2007 related to the conclusion of the depreciation true-up in 2005. In its 2008 GRA, the Company is proposing to amortize the deferred depreciation true-up recorded in 2006 and 2007 over five years beginning in 2008. This proposal is not reflected in the table above as it is subject to Board approval.

2.9 Deferred Replacement Energy Costs

The details of the deferred replacement energy costs, on an after-tax basis, are set out in Table 11.

Table 11
Deferred Replacement Energy Costs: 2006-2008F
($000s)

	2006F	Actual 2006	2007F	2008F
Balance, January 1st	0	0	0	1,147
Cost deferred during the year	0	0	1,147	0
Amortization during the year	0	0	0	0
Balance, December 31st	0	0	1,147	1,147

In P.U. 39 (2006), the Board ordered the Company to defer recovery, until a further Order of the Board, of an after-tax amount of $1,147,000 in 2007 related to the replacement of energy costs associated with the Rattling Brook Project. In its 2008 GRA, the Company is proposing to amortize the deferred replacement energy cost over five years beginning in 2008. This proposal is not reflected in the table above as it is subject to Board approval.