Newfoundland Power Inc.
2006 Capital Budget Application
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Generation

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2006 Hydro Plants Facility Rehabilitation

June 2005

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The 2006 Hydro Plants Facility Rehabilitation project totalling $996,000 is comprised of the following items. The items presented here, for which there are no other feasible alternatives, are required for the safe and reliable operation of these hydro plant facilities.

1.0 Morris Canal Embankment Rehabilitation

Cost: $105,000

Description: This item involves rehabilitation of the earthfill embankment to mitigate leakage through the dam.

Operating Experience: The physical condition of the dam has been assessed within the scope of regularly scheduled dam safety inspections by an independent engineering consultant, as well as Newfoundland Power. The results of these inspections have shown that there is a significant amount of leakage through the dam structure.

Justification: The leak should be corrected to ensure the structural integrity of the dam is restored to an appropriate level of dam safety. The cost of this item is justified based on the need to upgrade the structure to an appropriate level to minimize the risk of failure and the associated environmental damages. This will allow for future operation of the hydro system in a safe and reliable manner.

2.0 Tors Cove Forebay Dam Rehabilitation

Cost: $101,000

Description: This item involves the refurbishment of the upstream slope and dam crest at the Tors Cove Pond embankment structures.

Operating Experience: An inspection of the Tors Cove Pond dams was recently completed by an independent engineering consultant. The inspection was part of a regularly scheduled dam safety review. Results of the inspection have indicated widespread deterioration of the upstream slope and dam crest of both structures (east and west embankments). Specific observations include evidence of surface slides on steep upstream slopes, deterioration of riprap stones, lack of bedding transition, and a narrow earthfill crest.

The scope of the Rehabilitation works includes the following;

- engineering analyses (including slope stability assessment and freeboard assessment);
- refurbishment of the upstream slope (both riprap and filter zones); and freeboard improvements.

Justification: Completion of this item will ensure that the integrity of the embankment structures is restored to an appropriate level. The cost of this item is justified based on the need to refurbish the structure to improve performance under normal operating conditions and during extreme flood events. This will allow for future operation of the hydro system in a safe and reliable manner.

3.0 Victoria Blue Hill Pond Dam Overtopping Protection

Cost: $85,000

Description: Improvements to the dam are required to provide adequate structural protection and improve hydraulic performance during design flood conditions.

Operating Experience: The spill/discharge capacity of the structure has been assessed within the scope of recently completed hydrology studies carried out by independent engineering consultants. The results of these studies have identified the potential for dam crest overtopping and associated erosion/undermining during extreme flood events.

Various refurbishment activities are required, including:

- placement of anti-scour/erosion protection adjacent to the dam abutments,
- drilling pressure relief drain holes along the downstream concrete face, and
- improvement of spillway hydraulics through the removal of discharge channel obstructions.

These modifications will ensure the dam structure has adequate flood handling capacity during extreme flood events.

Justification: The cost of this item is justified based on the need to refurbish the structure to improve performance under design flood conditions. This will allow for future operation of the hydro system in a safe and reliable manner.

4.0 Victoria Rocky Pond Dam Overtopping Protection

Cost: $85,000

Description: Improvements to the dam are required to provide adequate structural protection during design flood conditions.

Operating Experience: The spill/discharge capacity of the structure has been assessed within the scope of recently completed hydrology studies carried out by independent engineering consultants. The results of these studies have identified the potential for dam crest overtopping and associated erosion/undermining during extreme flood events.

Rehabilitation works will primarily involve the placement of anti-scour/erosion protection adjacent to the dam abutments and along the downstream toe. These modifications will ensure the dam structure has adequate flood handling capacity during extreme flood events.

Justification: The cost of this item is justified based on the need to refurbish the structure to improve performance under design flood conditions. This will allow for future operation of the hydro system in a safe and reliable manner.

5.0 West Brook Spillway Rehabilitation

Cost: $81,000

Description: This item involves refurbishment of the concrete crest and timber stoplog system at the West Brook forebay spillway and the concrete foundation of the intake control shed.

Operating Experience: The crest of the spillway is deteriorated. In particular, cracking, spalling, weathered concrete, and exposed rebar is evident throughout. In addition, many sections of the stoplog anchoring system have failed, the result of excessive ice loading conditions. Remedial works are also required at the intake control shed to protect the structure from damage during extreme flood events.

The observed deterioration has been identified during the course of regularly scheduled dam safety inspections.

Justification: The cost of this item is justified based on the need to refurbish the structure to maintain an appropriate level of safety and reliability and to maximize hydroelectric production at the generating facility. Rehabilitation works are required to ensure the structural integrity of the spillway is maintained.

6.0 Heart's Content Seal Cove Pond Dam Rehabilitation

Cost: $108,000

Description: This item involves replacement of the spillway decking and refurbishment of the rockfilled timber cribs throughout the main dam structure at Seal Cove Pond in Heart's Content.

Operating Experience: Regularly scheduled dam safety inspections have identified that the dam and spillway are deteriorated. In particular, widespread rotting of crib timber members and spillway decking is evident. Movement/settlement of rockfill ballast has also been observed, and requires rehabilitation.

Justification: The cost of this item is justified based on the need to maintain reliable water flow regulation within the Heart's Content watershed. The rehabilitation and improvement activities are required to ensure structural integrity of the dam/spillway is restored to an appropriate level, and to minimize the potential risk of dam failure and associated environmental damages.

7.0 Refurbish/Replace Hydro Generating Plant Infrastructure and Equipment

Cost: $230,000

Description: This item involves the refurbishment/replacement of deteriorated or damaged structures and equipment identified through the normal inspection process that requires immediate attention. The budgeted amount is based on past experience.

Operating Experience: Newfoundland Power maintains a variety of generation equipment, buildings, intakes, dams and control structures forming part of its various hydro generating facilities. Newfoundland Power's hydro generating facilities range in age from 7 to 105 years. Equipment and infrastructure at the various facilities routinely requires upgrading or replacement of components to extend the life of the related asset.

Some components are replaced under planned capital projects while those included in this item are unanticipated replacements and upgrades due to component failure.

Justification: The generation equipment, buildings, intakes, dams and control structures are critical components in the safe and efficient operation of company hydro facilities. This item is needed to enable the immediate refurbishment or replacement of unanticipated failures of hydro plant components. This will allow for future operation of the hydro system in a safe and reliable manner.

8.0 Cooling Coil Replacements

Cost: $50,000

Description: Replace bearing cooling coils, and install bearing oil level controls and bearing cooling water flow meters and controls. In 2006 cooling coils will be replaced in the hydro plants at Lawn, Topsail, Rocky Pond, Horsechops and Rose Blanche.

Operating Experience: Since 1997 there have been over ten cooling coil failures which resulted in oil spills and lost production. The latest was in 2003.

Justification: Replacement of cooling coils prior to failure will reduce the risk of bearing failures in the hydroelectric facilities. These replacements will result in increased reliability and reduced risk of hydrocarbon spills into the environment.

9.0 Projects < $50,000

Total Cost: $151,000

Description: In this project there are four items of less than $50,000. They are (i) freeboard dyke riprap rehabilitation at the reservoir for the Cape Broyle hydroelectric facility, (ii) the rehabilitation of Three Arm Pond Dam associated with the Topsail hydro electric facility, (iii) vibration protection at the Pittman's Pond hydroelectric facility, and (iv) instrumentation upgrades at the Heart's Content, Lookout Brook and Pierre's Brook hydroelectric plants.

Petty Harbour Hydro Plant Refurbishment

June 2005

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1.0 Introduction

The Petty Harbour hydroelectric power plant is located on the east coast of the Avalon Peninsula in the community of Petty Harbour. Commissioned in 1900 the plant contains three generating units. The generating station has undergone a number of changes since it was originally commissioned. The current configuration includes three horizontal generating units with an installed capacity of 5,300 kW under a net head of approximately 57.9 m.

The most recent overhaul of the facility was completed in 1986. Work on unit 2 included replacements of the main valve, flywheel, generator, turbine and governor. Work on unit 3 included replacements of the main valve, turbine, shaft, wicket gates, and governor. The stator of unit 3 was rewound in 1994. Unit 1 operates with the original governor installed in 1910 and is operated infrequently; only as water is available. The existing control panels, switchgear, and protection systems were installed on all three units in 1978. Units 2 and 3 underwent automation upgrades between 1986 and 1988. The Petty Harbour plant was the first Newfoundland Power plant to be controlled using Programmable Logic Controller Technology (PLC). The Square D Sy/Max PLCs installed on Unit Nos. 2 and 3 are now obsolete.

The justification for the refurbishment project is based on the plants continued ability to provide low cost electricity to the island electrical system.

The requirement for the refurbishment project is based upon the deficiencies identified in the site assessments and the number of maintenance issues being experienced with the existing PLC control system, voltage regulation equipment and Voith electronic governors. In recent years the plant has had a number of forced outages related to these plant components.

The refurbishment will provide improved electrical and mechanical protection as well as standardization with other plants in the system.

2.0 Role in Power System

The normal annual production at Petty Harbour Hydro Plant is approximately 15.9 GWh of energy or 3.7 % of the total hydroelectric production of Newfoundland Power. It has a peak power output of 5.3 MW and can supply the communities of Petty Harbour and Maddox Cove when isolated from the Island Interconnected System.

3.0 Project Scope of Work

The scope of this project includes work recommended in the site assessment included as Appendix A of this report. The following is a summary of the work to be undertaken.

3.1 Electrical

Unit 1

- Replace voltage regulator
- Install grounding transformer
- Install partial discharge testing
- Install condensation protection

Unit 2 and 3

- Replace voltage regulator
- Replace unit control PLC
- Replace electronic governor
- Install automatic synchronizer
- Instrumentation upgrade
- Integrate cooling water monitoring and control
- Integrate plant heating and ventilation
- Upgrade generator protection
- Install grounding transformer unit 3
- Install partial discharge testing
- Install condensation protection
- Replace forebay elevation probe

3.2 Mechanical

- Overhaul turbine #2

3.3 Penstock

- Replace coating system

4.0 Project Assessment

4.1 Electrical

As outlined in the Site Assessment in Appendix A the 2 PLCs, electronic governor controls, voltage regulators and auto-synchronizer at the Petty Harbour Plant are obsolete and require replacement. The equipment has undergone a number of upgrades throughout its 105 year life, the most recent upgrade occurring 20 years ago when the facility was commissioned for remote operation through the Supervisory Control and Data Acquisition (SCADA) system. The three subsystems of most concern are the PLCs, the voltage regulators and the automatic synchronizer. These three systems are critical to the operation of the individual generators. A complete failure of either subsystem would force an outage on the associated generator. Depending upon the circumstance the loss of a generator could result in lost energy at times of high water elevations or the inability to supply customer load when operating the community of Petty Harbour isolated from the grid.

The Square D Sy/Max PLC's installed between 1986 and 1988 to monitor and control units 2 and 3 have been discontinued by the manufacturer for many years and supplies of replacement parts have been exhausted. There are ongoing problems with the units failing to pick up load, offloading and changing operating modes.

Voltage and power factor control is an ongoing issue at Petty Harbour causing power quality concerns when operating as an isolated system. The voltage regulators are unable to meet the current standards for maintaining system voltage. Replacing the voltage regulators on the units will ensure voltages in all operating modes meet the current CSA standard.

The existing Westinghouse electromechanical auto-synchronizer, installed in 1978, is also obsolete and will be replaced by a stand-alone digital model. The operation of the auto-synchronizer is critical when placing the generators on line remotely.

In addition, the generators must be properly protected in the event that electrical or mechanical problems develop. Detecting these problems and removing the generator from service as quickly as possible is essential to minimize potential damage and avoid costly repairs.

The electromechanical relays presently used to protect all three units lack many of the IEEE recommended minimum set of protection elements. With the installation of a digital multifunction generator protection relay and relay grade current and potential transformers in the switchgear, additional protection elements will be provided. Enhancing the electrical and mechanical protection of the generators will reduce the risk of failure of the generator windings by earlier detection of fault conditions. The result is a less costly minor repair as opposed to the cost of a complete generator rewind.

There is presently no vibration protection on either unit and, with the exception of temperature switches on unit 2, no bearing temperature protection. Instrumentation for these and other monitoring functions will be installed for early detection of conditions that could lead to mechanical failure of key components. Similarly, the benefit here is a lower cost repair as opposed to the cost of an unplanned repair due to failure.

4.2 Mechanical

Unit 2 requires a turbine overhaul to ensure its safe operation and to enable it to produce its rated power output. When the wicket gates were replaced in 1985, the head and bottom covers had to be bored to accept the new gate stems. Since 1985 the gate stems have worn and when the unit has been running at greater than 80% load, the gates have dropped down in the elongated holes and have become stuck. In these instances it has been necessary to use the main valve to shut the unit down. Using the main valve to stop a unit is unacceptable as it exposes it to an increased risk of damage. The time delays associated with closing the main valve results in the unit going into overspeed. As a result of this problem with the wicket gates the unit has been restricted to less than 80% opening at the gate with a corresponding full load reduction from 1350 kW to less than 1000 kW.

To correct this problem, the existing wicket gates and bushings will have to be removed and the head and bottom covers machined to ensure alignment and to accept new bushing. New bushings will also have to be fabricated and installed along with the gates and covers.

4.3 Penstock

The woodstave penstock at the Petty Harbour plant was replaced with a steel penstock in 1999. The steel penstock was supplied with a two coat mastic epoxy paint system. Since that time the paint system on the penstock has deteriorated to the point where the coating system requires replacement.

Operating experience of both Newfoundland Power and the industry at large has revealed that two coat mastic epoxy systems in marine environments are known to break down after only 3-5 years of service life. Originally the manufacturers promoted this type of coating system to have a normal life expectancy of 15 years in the marine environment. Based on the findings it is now an industry recommendation that a two coat epoxy system be top coated with polyurethane to provide added protection and extend the life of the paint system. Since 2004 new steel penstocks installed in the Newfoundland Power system are painted with one coat zinc rich epoxy primer, an epoxy intermediate coat, and polyurethane topcoat.

5.0 Plant Reliability

All three units and in particular unit 2, have recently experienced forced and maintenance outages due to governor, control system and instrumentation problems.

Over the past three years, unit 2 has experienced the greatest percentage of forced downtime of all of Newfoundland Power’s generators at 5.98% downtime. Unit 3 is the fifth worse generator in the fleet.

Replacing the manufacturer-discontinued equipment with commercially available equipment will reduce the duration of unscheduled downtime. This will improve customer reliability when the plant is required to supply local generation and plant reliability by increasing availability and maximizing output.

6.0 Recommendations

The following is a list of the major recommendations that will be addressed as part of this refurbishment project:

- Replace AC & DC distribution panels.
- Install continuous partial discharge monitoring equipment on all units.
- Replace condensation monitoring protection on all units.
- Install digital voltage regulation on all units.
- Install additional potential and current transformers in switchgear for protection and synchronizing.
- Install grounding transformers for units 1 and 3.
- Upgrade generator protection and relaying on units 2 and 3.
- Install new industrial computer Human Machine Interfaces (HMIs) to replace existing annunciators and provide improved indication and control functionality
- Replace the existing Voith electronic governor controller for units 2 and 3 with a PLC based algorithm in the unit control PLCs.
- Replace the existing Square D Sy/Max PLC control systems with Allan-Bradley ControlLogix models to provide improved protection, control and reliability.
- Replace existing auto-synchronizer.
- Install/upgrade generator instrumentation.
- Integrate bearing cooling water system into PLC control system.
- Upgrade the heating/ventilation controls and integrate into PLC control system.
- Replace existing forebay water level monitoring equipment.
- Overhaul unit #2 turbine to restore full power output.
- Recoat the penstock.

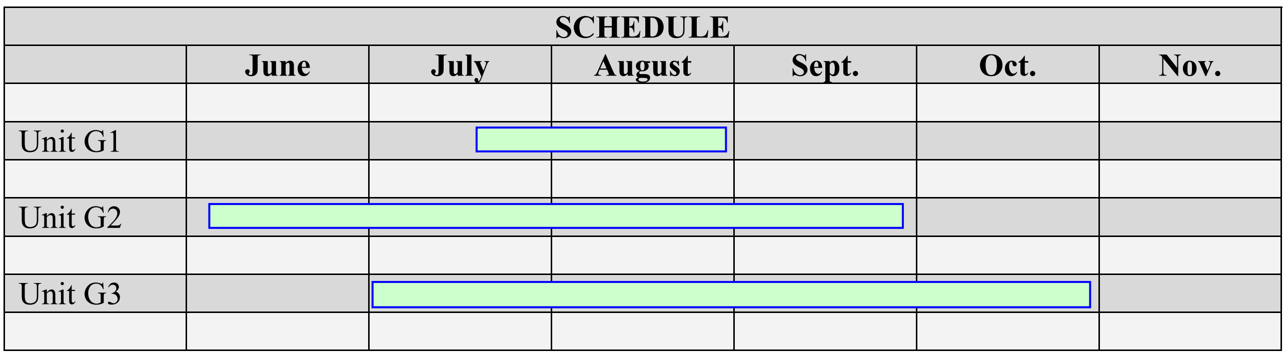
Obsolete, high-maintenance equipment places the reliability and availability of the plant at risk. In addition, inadequate electrical and mechanical protection could result in a sudden failure with subsequent repair costs and extended downtime. Loss of a PLC could result in a unit or plant being out of service until a new PLC is procured and installed. Therefore, action should be taken to mitigate this risk and ensure that the PLCs and other obsolete components are replaced in a planned manner. The replacement of the unit 2 and 3 PLCs, electronic governor controls, voltage regulators and auto-synchronizers should be completed in 2006.

There are no feasible alternatives to the refurbishment of existing hydroelectric facilities that continue to provide a low cost source of electricity. The poor reliability experienced cannot be effectively addressed through other means.

7.0 Implementation

The refurbishment project will involve the disassembly of the existing protection and control system and removal from site. There is turbine work required on unit 2 and the recoating of the penstock that requires the pipeline to be dewatered. The scheduling of the work can be accomplished such that there is at least one unit available to operate in late spring and early fall when there is water available to the plant. In addition, unit 1 will be available to generate electricity until the penstock is dewatered for painting. Since the plant would only be shut down for 8 to10 weeks in the summer period there would be an insignificant amount of spill, based on normal inflows, into the system during this time.

The high level schedule is as follows:



Appendix A

Site Assessment

General

The site assessment at the Petty Harbour generating station was completed in April 2004 and reviewed again in April 2005. This report documents the findings of these two site assessments. As part of this site assessment a review of the forced outage log was completed. Thirteen of the thirty eight forced outages recorded on unit 2 from February 2003 to May 2005 were directly related to voltage regulation problems. Five forced outages were related to electronic governor malfunctions while three were PLC related.

The electronic governors have suffered heat damage to the backplane and printed circuit boards. Replacement parts are not available, so, soldered "jumper" repairs have been made. These repairs will eventually fail and there will be no practical means to make another repair.

The Square D programming interface terminal has faulted so programming of the PLC is now done using laptop computers. As a result communication and compatibility problems have been experienced with the laptop computers and PLC software. This has extended repair and troubleshooting time and restricted upgrading of the sequencing and control functions. The annunciator display has a number of the light emitting diodes burnt out making the display unreadable. The PLC components are no longer supported by the manufacturer.

AC Distribution

The AC distribution system consists of multiple panels located throughout the plant. In addition to the original 120/208V 3-phase AC service panel, installed in 1978, there are three auxiliary panels at various other locations within the building. It is recommended that a new AC panel be installed with sufficient capacity to replace all existing panels and provide additional spare capacity. The AC distribution system does not currently meet CSA standards. The new system will be designed to CSA standards.

Station Service

The station service consists of two 37.5 KVA 2400-120/240V transformers located in the switchgear cabinet. These transformers are in good condition with spare units available. It is recommended that the station service not be replaced.

DC Distribution

The existing DC distribution panel was installed in 1978. Replacement breakers are no longer available. The panel has insufficient spare circuits to accommodate the refurbishment of the protection and control equipment. It is recommended that the DC distribution panel be replaced.

Battery Plant and Charger

A review of maintenance records for the battery bank indicates it has remaining service life. The battery charger was replaced in 2003. It is recommended that both the existing battery bank and charger remain in service.

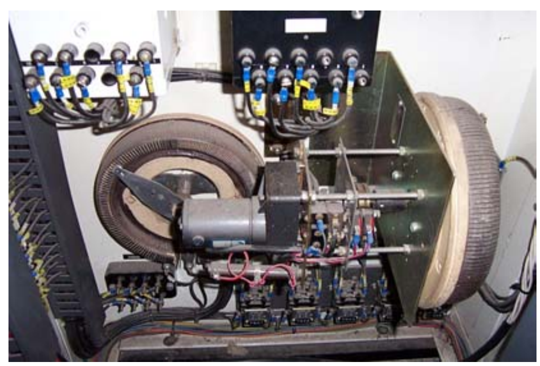
Generators

Unit 1 was rewound in 1970, unit 3 in 1994, and unit 2 in 1986. There are no indications that the generator windings have deteriorated. The addition of continuous partial discharge testing equipment on each generating unit is recommended to monitor the condition of the windings to facilitate scheduled replacement before failure. The integration of the MegAlert stator insulation resistance monitors with the unit control panels is recommended to ensure the units are not started with condensation on the windings which could result in failure.

Excitation Systems

The field breakers on unit 1 and unit 3 were replaced in 1993 and 1995 respectively. The excitation system on unit 2 was replaced in 1986 with a brushless exciter and is in good condition. The excitation systems on unit 1 and unit 3 are original equipment and with proper maintenance will remain serviceable. The excitation systems do not need to be replaced at this time.

Voltage Regulation



There is difficulty in regulating voltage on the units, particularly when operating an isolated system during outages to transmission line 3L. Also, the inability to match machine voltage to system voltage has created situations where the units have tripped while attempting to synchronize with the system. Units 1 and 3 have Brown-Boveri model AB2/1 voltage regulators and unit 2 has a Basler model SR-8 voltage regulator. It is recommended that the voltage regulators on all three units be replaced with digital technology to eliminate the voltage regulation problems.

Switchgear

The inspection of the switchgear identified that the bus work and breakers are in good condition and do not need to be replaced. It is recommended that revenue class current and potential transformers be added to the switchgear to provide accurate metering data from these units.

Power Cables

The power cables were installed in 1978 and remain in serviceable condition.

Generator Grounding

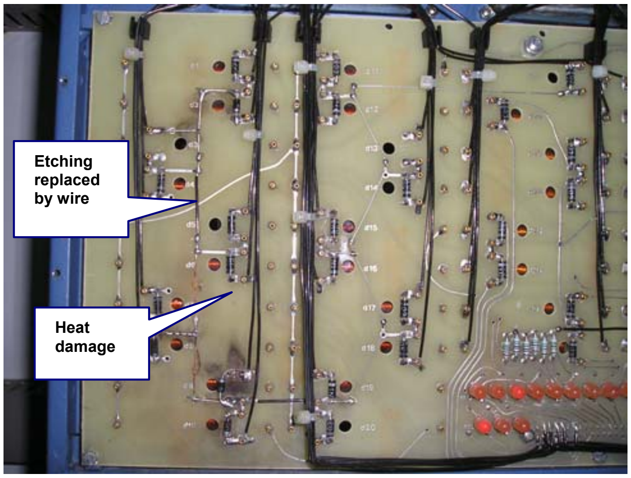
The grounding system for unit 2 includes a high impedance grounding transformer. Units 1 and 3 are solidly bonded to ground and as a result their windings would be exposed to high level fault currents should a ground fault occur. It is recommended that units 1 and 3 be equipped with grounding transformers to protect the windings from high level ground fault currents.

Protective Relays

All three generators are protected by electromechanical relays. The protection scheme of each unit utilizes different elements as outlined in the table below. It is recommended that the unit 2 and 3 protection be upgraded with digital, multifunction generator protection relays. A protection study will determine the protection elements to be implemented in the relays.

Generator	Protection Provided
Unit 1	51V Voltage restrained time delay overcurrent 87G Generator differential relay
Unit 2	40 Loss of field 46 Negative Phase Sequence (Stator unbalanced current) 51V Voltage restrained time delay overcurrent 64G Stator ground faults 87G Generator differential relay
Unit 3	40 Loss of field 46 Negative Phase Sequence (Stator unbalanced current) 51V Voltage restrained time delay overcurrent 87G Generator differential relay

Governors



Unit 1 is controlled by a belt-driven governor system. It is recommended that it continue to operate in this manner as unit 1 only runs infrequently, as water is available.

Units 2 and 3 have Voith EHR 530 electronic governors and associated high pressure hydraulic systems installed in 1986. The hydraulic systems are in good condition and continue to be serviceable. The manufacturer of the electronic governor that controls the hydraulic system has discontinued manufacturing replacement parts and no longer supports this equipment. Thus no spare parts are available to facilitate repairs. The copper etching on the circuit boards has cracked. Repairing the circuit boards is difficult as the heat from soldering tends to make the etchings even more brittle. The problems experienced in maintaining system frequency when operating as an isolated system can be attributed to the electronic governor no longer meeting original specifications. It is recommended that the hydraulic power units be maintained and the electronic governors be replaced with PLCs.

Plant Control

Unit 1 is controlled by discrete relays and is operated under manual control. The controls for units 2 and 3 were retrofitted with Square D SY/Max PLCs between 1986 and 1988. The PLCs provide alarm monitoring of generator and turbine instrumentation, sequencing and operator interfaces. These PLCs are no longer supported by the manufacturer. The programming interface terminal has failed and now a laptop computer provides limited programming capability. Programming expertise is limited and recent equipment failures have consumed the supply of spare parts. It is recommended that the PLC equipment on units 2 and 3 be replaced with current technology.

Instrumentation

Reliable monitoring and control of the generating units requires that the following instrumentation be installed on units 2 and 3:

- Speed switch
- Vibration sensors
- Bearing surface temperature sensors (thermocouples or resistive temperature devices)
- Bearing oil level sensors
- Stator temperature sensors
- Brush gear temperature sensors
- Scroll case pressure gauge
- Wicket gate position transducer and limit switches
- Pit flood sensors

Bearing Cooling Water Control

All three units presently have cooling water control valves and flow meters. The controls for the systems must be integrated with any new PLC control system.

Heating and Ventilation

The anti-condensation heaters and infrared heaters for each unit are controlled by hand operated humidistat and thermostats respectively. The ventilation system composed of fans and louvers installed in 1986 remain in serviceable condition. It is recommended the controls for the heating and ventilation equipment be integrated with the unit control PLCs.

Forebay Water Level Monitoring and Control

The forebay communications cable is in good condition. The water level probe and transducer are no longer supported by the manufacturer. Also, there have been unit trips resulting from loss of water level signal. It is recommended that the probe and transducer be replaced with a 4 to 20 milliamp water level probe and associated transmission equipment.

Penstock

The penstock was replaced in 1999. In 2002 the penstock paint system started to show signs of deterioration and over the last year the level of deterioration has increased. Most of the surface area has significant rust staining indicating that the surface is permeable and not protecting the steel as intended. Water and oxygen are able to penetrate the coating system and are causing the penstock to rust. The entire steel penstock should be recoated.

Mechanical

The G2 turbine was overhauled in 1985 replacing the runner, wicket gate and stationary seals. The top and bottom covers were machined to accept the new wicket gate bushings. Since 1985 the gate stems have worn and the seats are now elongated. When the unit has been running at greater than 80% load, the gates have dropped down in the elongated holes and have become stuck. This can create a situation where if the unit were to trip, the gate would not be able to close and the unit would go into overspeed. The unit needs to be dismantled to replace the bushings and allow the gates to operate through their full range. Presently the gates are restricted to less than 80% opening to prevent them from sticking.

Appendix B

Budget Estimates

2006 Capital Budget Estimate

Description	Cost Estimate
Upgrade Controls G1	$ 80,000
Replace Unit Control PLCs G2	372,000
Replace Electronic Governor G2	86,000
Upgrade Generator Protection and Control G2	184,000
Replace Unit Control PLCs G3	372,000
Replace Electronic Governor G3	86,000
Upgrade Generator Protection and Control G3	191,000
Upgrade Plant AC and DC Systems	79,000
Turbine Overhaul	153,000
Penstock Coating Replacement	226,000
Total	**$1,829,000**

Appendix C

Feasibility Analysis

Introduction

This feasibility analysis examines the future viability of the Petty Harbour hydro plant. In addition to the capital expenditures proposed for 2006, all capital and operating expenditures required to maintain the safe and reliable operation of the plant for the next 25 years are estimated. A present-worth analysis is used to determine the revenue requirement and levelized cost of energy from the Petty Harbour plant. To evaluate the financial feasibility of the project proposed for 2006 and the overall viability of the plant, the levelized cost of energy is compared with the cost of replacement energy from Newfoundland and Labrador Hydro's Holyrood Generating Facility.

Capital Costs

All significant capital costs foreseen for the Petty Harbour hydroelectric plant over the next 25 years have been identified. The majority of these expenditures are currently planned for 2006 and 2015, and the remaining expenditures are distributed throughout the 25 year period from 2006 to 2030. The capital expenditures, in 2005 dollars, required to maintain the safe and reliable operation of the facilities are summarized in the following table:

Petty Harbour Hydro Plant
Future Capital Costs

Year	Cost
2006	$ 1,829,000
2007	50,000
2010	20,000
2011	285,000
2012	175,000
2015	1,100,000
2020	300,000
2025	170,000
2026	770,000
Total	**$ 4,699,000**

Operating Costs

Operating costs for this hydroelectric system are estimated to be $127,000 per year. The operating costs represent both direct charges for operations and maintenance at this plant as well as indirect costs related to activities associated with managing the environment, safety, dam safety inspections and staff training.

The annual operating cost also includes a water power rental rate of $0.80 per MWh. This fee is paid annually to the Provincial Department of Environment and Conservation based on yearly hydro plant generation/output.

Financial Analysis

An overall financial analysis of combined costs and benefits has been completed using the levelized cost of energy approach. The levelized cost of energy is representative of the revenue requirement required to support the combined capital and operating costs associated with the project.

The estimated levelized cost of energy from the Petty Harbour plant is 2.8 cents per kWh. This figure includes all projected capital and operating costs necessary to operate and maintain the facility. Energy from Petty Harbour can be produced at a significantly lower price than the cost of replacement energy, that would come from Newfoundland and Labrador Hydro's Holyrood Generating Station. Based on information provided in Newfoundland Hydro's fuel price projection as of March 31, 2005 and Newfoundland Hydro's 2003 GRA, incremental energy is estimated to cost 5.8 cents per kWh in the short term (assuming $36.85 per barrel and 630 kWh/barrel, respectively), with an associated levelized cost of 6.9 cents per kWh assuming a 2% long-term escalation rate. Table A provides details of the financial analysis.

Recommendation

Newfoundland Power should proceed with this project in 2006 as planned. The results of this feasibility analysis show that that the continued operation of the Petty Harbour hydroelectric development is economically viable over the long term. Investing in the life extension of facilities at Petty Harbour guarantees the availability of low cost energy to customers. Otherwise the annual production of nearly 15.9 GWh would be replaced by more expensive energy sources such as new generation or additional production from the Holyrood Generating Station.

Table A
Present Worth Analysis – Petty Harbour Hydro Plant

Weighted Average Incremental Cost of Capital 8.29%

PW Year 2005

Year	Capital Expenditure In Year By Asset Type: Generation Hydro 49.26 yrs 4% CCA	Generation Hydro 49.26 yrs 50% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Revenue Requirement	Benefits	Net Benefit	Present Worth Benefit	Cumulative Present Worth Benefit	Rev Rqmt (¢/kWhr)	Levelized Cost (¢/kWhr)
2006	1,829,000	0	0	230,161	127,175	0	-357,336	-329,981	-329,981	2.247	2.777
2007	50,900	0	0	212,758	129,464	0	-342,222	-291,831	-621,812	2.152	2.777
2008	0	0	0	209,765	131,665	0	-341,429	-268,866	-890,678	2.147	2.777
2009	0	0	0	207,304	133,903	0	-341,207	-248,122	-1,138,799	2.146	2.777
2010	21,416	0	0	207,474	136,180	0	-343,654	-230,770	-1,369,569	2.161	2.777
2011	310,368	0	0	243,666	138,495	0	-382,161	-236,982	-1,606,552	2.404	2.777
2012	193,626	0	0	261,319	140,711	0	-402,030	-230,218	-1,836,770	2.528	2.777
2013	0	0	0	255,674	142,962	0	-398,636	-210,799	-2,047,570	2.507	2.777
2014	0	0	0	252,235	145,249	0	-397,485	-194,100	-2,241,669	2.500	2.777
2015	580,769	696,923	0	318,876	147,719	0	-466,595	-210,405	-2,452,075	2.935	2.777
2016	0	0	0	256,976	150,378	0	-407,353	-169,629	-2,621,703	2.562	2.777
2017	0	0	0	324,976	153,084	0	-478,060	-183,833	-2,805,536	3.007	2.777
2018	0	0	0	355,949	155,840	0	-511,789	-181,737	-2,987,273	3.219	2.777
2019	0	0	0	368,372	158,489	0	-526,861	-172,766	-3,160,039	3.314	2.777
2020	253,483	0	126,742	421,169	161,183	0	-582,352	-176,344	-3,336,383	3.663	2.777
2021	0	0	0	414,508	163,924	0	-578,432	-161,748	-3,498,131	3.638	2.777
2022	0	0	0	409,934	166,874	0	-576,808	-148,946	-3,647,077	3.628	2.777
2023	0	0	0	404,123	170,045	0	-574,168	-136,914	-3,783,991	3.611	2.777
2024	0	0	0	397,658	173,106	0	-570,764	-125,683	-3,909,674	3.590	2.777
2025	235,331	0	0	420,443	176,048	0	-596,492	-121,293	-4,030,968	3.752	2.777
2026	1,084,032	0	0	546,750	179,041	0	-725,791	-136,288	-4,167,255	4.565	2.777
2027	0	0	0	525,153	182,085	0	-707,238	-122,637	-4,289,892	4.448	2.777
2028	0	0	0	516,176	185,180	0	-701,356	-112,307	-4,402,199	4.411	2.777
2029	0	0	0	507,070	188,328	0	-695,398	-102,828	-4,505,028	4.374	2.777
2030	0	0	0	497,850	191,530	0	-689,380	-94,135	-4,599,162	4.336	2.777

Wesleyville Gas Turbine
Refurbishment Alternatives

June 2005

Prepared by:

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1.0 Introduction & Background

In Order No. P.U. 43 (2004) the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), approved the Newfoundland Power 2005 Capital Budget which included the Wesleyville Gas Turbine Overhaul project estimated at a cost of $1,124,000.

The Board further ordered that "Unless otherwise directed by the Board, NP shall file with the Board, no later than its Capital Budget Application for 2006, a report on the chosen alternative with respect to the Wesleyville Gas Turbine".

During the 2005 Capital Budget Proceeding, Newfoundland Power identified two alternatives to carry out this project: (i) overhaul the existing gas generator unit or (ii) replace the unit with one that has already been refurbished and use the existing gas generator unit as a credit toward the purchase price. These two options would provide flexibility to ensure that the project could be completed at the least cost to customers.

2.0 Request for Proposals

On February 25, 2005, Newfoundland Power issued a Request for Proposal (RFP) to six companies having expertise in the overhaul of Rolls Royce Avon gas generators. The intent was to identify a suitable contractor to provide all required expertise, labour, equipment, and materials to overhaul or replace the Company's unit and to obtain detailed information on the cost of each alternative.

Four proposals were received in response to the RFP. The proposals varied greatly in both scope and price, particularly with respect to the overhaul option. For the overhaul, each contractor compiled their cost estimate based on different assumptions about the internal condition of the unit. Some contractors assumed that minimal internal refurbishment and repairs would be required, while other contractors assumed that the majority of the components would require replacement or extensive refurbishment.

It was realized that with a unit overhaul, an accurate cost estimate cannot be completed until the unit is stripped, tested and inspected at an overhaul facility. Therefore, it is highly probable that the final cost of a unit overhaul will be significantly different than the price quoted in the proposal documents.

In the case of a unit replacement, there is a lesser risk of cost fluctuation from that quoted in the proposal documents.

3.0 Evaluation Process

The proposal evaluation process identified one contractor that was the low bidder on both the overhaul and the replacement options and met all the requirements of the RFP. As of the date of this report, Newfoundland Power is in final contract negotiations to have this contractor complete a comprehensive inspection of the Company's gas generator at the contractor's overhaul facility and provide a detailed fixed cost for a complete overhaul. If this cost is below the cost of the replacement unit, then Newfoundland Power will proceed with the overhaul. If the overhaul cost is above that for the replacement unit, then Newfoundland Power will exchange its existing unit for the replacement unit at the pre-negotiated fixed cost. This contract will allow Newfoundland Power the flexibility to pursue the alternative that provides the most reliable gas generator at the lowest life cycle cost.

4.0 Conclusion

Newfoundland Power continues to have two alternatives under active consideration to provide a reliable source of standby generation in the Wesleyville area. These two alternatives (i) overhaul the existing unit or (ii) replace the existing unit with a refurbished unit will be evaluated and the most cost effective alternative selected.

2006 Rebuild Substations

June 2005

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The Rebuild Substations project for 2006 focuses on five items, Site and Foundation Upgrades, Install Heating System in Transformer Spill Pans, Replace Gap Type Lightning Arrestors, Prevention of Damage by Animals and Non-PCB Environmental Initiatives. This report describes the need for these items.

1.0 Site & Foundation Upgrades

1.1 Description

This work is related to rectifying deteriorated concrete foundations in Bay Roberts and Laurentian Substations and inadequate drainage at Laurentian Substation (see Pictures #1 & #2). In addition, the deteriorated timber transformer pad (see Picture #3) at Topsail Substation will be replaced with a concrete pad. At Petty Harbour, civil work will be done to allow the set up of a portable substation at the site.

The costs associated with each individual substation are:

1. Bay Roberts	$21,000
2. Laurentian	$112,000
3. Topsail	$90,000
4. Petty Harbour	$14,000

1.2 Identified Deficiencies

1.2.1 Bay Roberts & Laurentian - Deteriorated Foundations

In 2002, a report prepared by SGE Acres detailing the concrete foundation replacement or refurbishment needed in our substations was filed with the PUB as part of Newfoundland Power's 2003 Capital Budget. The report inspected all substation concrete foundations and detailed the damage and type of remediation work required and produced a prioritized list of foundations for replacement or refurbishment.

In responding to the deficiencies noted in the report, the Company will replace one 25 kV structure foundation at Bay Roberts Substation and refurbish seven 138 kV structure foundations at Laurentian Substation.

1.2.2 Laurentian – Drainage

The drainage in the Laurentian Substation is inadequate resulting in frost action which has caused movement of the cable trench. In addition, during wet periods, movement around the yard by vehicles is difficult and damages the yard.

Picture #1: Laurentian Substation
Shifting of cable trench due to frost heaving.

Picture #2: Laurentian Substation
Damage to crushed stone and sub-grade.

1.2.3 Topsail – Foundation Replacement
The foundation for the Topsail T1 transformer is approximately fifteen years old, and because it is in close proximity to a water body, it was constructed of untreated timber. Wood rot and splitting of the timber has been identified. Failure of this foundation could lead to an oil spill and failure of the transformer. The timber foundation will be replaced with a concrete foundation.

Picture #3
Topsail T1, rotting timber foundation

1.2.4 Petty Harbour – Site Improvement
Presently portable substations cannot be moved into Petty Harbour substation readily due to the topography of the road. In addition, the substation does not have any area where the portable substation can be set up to respond to emergency situations or for maintenance in the substation. Civil work will be completed to accommodate the setup of a portable substation.

2.0 Install Heating System in Transformer Spill Pans

2.1 Description

This work is related to installing a heating system in the Clarke's Pond and Twillingate substations transformer spill pans.

The costs associated with each individual substation are:

1. Clarke's Pond $28,000
2. Twillingate $29,000

2.2 Identified Deficiencies

Both Clarke's Pond and Twillingate substation sites are located adjacent to public drinking water supplies. The transformers at these two substations have spill pans installed under the power transformers to capture any leaking oil from the transformers and to prevent release of the oil into the drinking water supplies. Spill pans are inspected and drained monthly. During cold weather, water in the pan freezes reducing the effectiveness of spill pans in the event of an oil spill. Should a transformer oil spill occur, damage to the environment could be extensive and clean-up costly.

3.0 Replace Gap Type Lightning Arrestors

3.1 Description

Replace gap type lightning arrestor in substations.

The cost associated with this project is $350,000.

An engineering report "Lightning Arrestors Replacement" outlining the rationale for this project is attached in Appendix A.

4.0 Prevention of Damage by Animals

4.1 Description

Install insulated conductors and animal bushing guards on the low voltage equipment bushings and leads at Marystown substation.

The cost associated with this project is $50,000.

4.2 Operating Experience

In 2004 there were 3,213,815 customer minutes of unscheduled outage due to failures in substations. Of this amount 643,868 customer minutes, or 20% of the total, was caused by animals such as crows and squirrels.

To date in 2005, there has been 2,330,001 customer minutes of unscheduled outage due to failures in substations. Of this amount 702,620 customer minutes, or 30% of the total, was caused by animals.

There are concerns that the installation of equipment to prevent outages due to animals may lead to premature corrosion of equipment and other operating difficulties. The experience with the installation at Marystown substation may lead to further installations in substations that have been prone to damage by animals.

5.0 Non-PCB Environmental Initiative

5.1 Description

This is a long-term program to replace equipment in substations that contain more than 50PPM of PCB. This project will replace equipment such as substation service transformers, metering tanks and potential transformers.

The cost associated with this project is $16,000.

5.2 Operating Experience

The Company has a large quantity of oil filled electrical equipment. Due to cross contamination, mineral oil in distribution transformers and other electrical equipment was inadvertently contaminated with PCB's at the manufacturing plant. Years ago transformer manufacturers used the same hoses and pumps to fill electrical equipment with PCB's and mineral oil. This resulted in some pieces of oil filled electrical equipment having 50 ppm PCB's or more. In other cases some equipment such as capacitors and ballasts were manufactured with pure PCB's.

The Company may experience spills from oil filled electrical equipment due to a number of reasons including rust, lightning, mechanical damage, storms, and human error. In the event of a spill, PCB's may be involved.

PCB spills can result in significant clean up costs. The general public and the environmental regulators also view PCB spills very negatively.

PCB's are synthetic chemical compounds consisting of chlorine, carbon and hydrogen. First synthesized in 1881, PCB's are relatively fire-resistant, very stable, do not conduct electricity and have low volatility at normal temperatures. PCB's were used for insulating fluid for electrical equipment, surface coatings for carbonless copy paper, as plasticizers in sealants, caulking, paints, waxes, asphalts, etc.

Unfortunately, one of the properties of PCB's which most contribute to their widespread use – their chemical stability – is also one of the properties which causes the greatest amount of environmental concern. This unusual persistence coupled with its tendency to accumulate in living organisms, means that PCB's are stored and concentrated in the environment. This bioaccumulation raises concern because of the wide dispersal of PCB's in the environment and the potential adverse effects they can have on various organisms. When PCB's are involved in fires the combustion of these materials can result in the production of highly toxic substances.

As a result of these concerns Government placed a ban on the manufacturing of PCB's in the late 1970's with further regulations established in the early 1980's. Under the regulations PCB's removed from equipment must be properly stored and disposed of in accordance with the regulations. There is also a requirement to report PCB spills, if one or more of the following conditions apply:

- The PCB concentration is 50 parts per million (ppm) or more by weight

- The quantity of PCB's released is 1 gram or more per day.

In the late 1980's the Company started to remove PCB's from its system and in the early 1990's a PCB phase out plan was implemented to ensure that the PCB level in equipment was below the permitted level of 50 ppm

6.0 Recommendations

The recommended work for which there are no feasible alternatives, is required in order to ensure the continued provision of safe, reliable electrical service.

I recommend that $710,000 be allocated in the 2006 budget as follows:

a) Site and Foundation Upgrades - $237,000
b) Install Heating System in Transformer Spill Pans - $57,000
c) Replace Gap Type Lightning Arrestors - $350,000
d) Prevention of Damage by Animals - $50,000
e) Non-PCB Environmental Initiatives - $16,000

Appendix A

Lightning Arrestors Replacement

Background

The most critical asset in a substation is the power transformer. It is expensive to purchase and requires a lead time of a minimum six to eight months. To avoid large expenditures or long outages, it is important that the transformer be adequately protected. One means of protecting the transformer is through the use of lightning arrestors connected to the transformer. Lightning arrestors protect transformers from lightning strikes and from switching surges associated with operating electrical system breakers and fuses.

Most of Newfoundland Power's transformers are protected by silicon carbide gap type lightning arrestors. This arrestor type is made up of a series of gaps inside a porcelain housing which flashes over when the voltage level reaches the rating of the arrestor, thereby protecting the power transformer. Newer technology in lightning arrestor design which became common during the 1980s replaced the gap type arrestor with an arrestor that utilized metal oxide disks in-series inside a porcelain housing. This design (metal oxide arrestors) provided a greater margin of protection for the equipment and has proved to be less prone to failure.

When gap type arrestors reach the end of their life, they are prone to high failure rates. The high failure rate of the gap type arrestor has been attributed to a failure in the seals on the ends of the arrestor. This seal failure then allows the ingress of moisture and subsequent failure. Failure of an arrestor can cause extensive power outages to customers. Several methods of testing have been tried over the years to identify those arrestors close to the end of their life. The two methods in use today are power factor testing and infrared scanning. Infrared has not proven to be effective and utilities are discontinuing using this method. Power factor testing, though proven to be an effective means of testing arrestors is not practical as it requires a transformer outage to test. The only practical time to perform this testing is when the transformer is out of service for major maintenance, usually on a ten year cycle. This testing cycle is not of adequate frequency to detect imminent failure of an arrestor and maintain a reliable electrical system.

The arrestors installed at Newfoundland Power, with a few exceptions, were installed when the transformers were originally installed. Newfoundland Power currently has 190 power transformers in service ranging in age of one year to sixty-four years. Approximately 160 of these transformers were installed prior to 1980. Based on these numbers and the few arrestor replacements that have occurred in recent years, it is estimated that approximately 60% of installations (115 transformers) still have the silicon carbide gap type arrestor in service.

Recent Failures

In 2004 there were 3,213,815 customer minutes of unscheduled outages due to failures in substations. Of this amount 594,218 customer minutes, or 18% of the total, was caused by the failure of gap type lightning arrestors.

To date in 2005, there have been 2,330,001 customer minutes of unscheduled outages due to failures in substations. Of this amount 967,414 customer minutes, or 42% of the total, was caused by gap type lightning arrestors.

North American Utility Experience

Feedback from other North American utilities involved with the Canadian Electrical Association Technologies Inc. (CEATI) group (comprised of approximately twenty-five Canadian and American utilities of which Newfoundland Power is a member), indicates that silicon carbide gap arrestors still in service are beyond their expected life span and prone to failures. Many utilities have completed replacement of all gap type arrestors on their system.

Plan

In order to confirm the numbers of silicon carbide gap type lightning arrestors at each installation, an inspection program will be completed in 2005. Following these inspections, cost estimates will be completed and a replacement schedule developed over a multi-year period. Replacing all of the remaining gap type arrestors in the system will involve an approximate expenditure between one million and two million dollars.

Recommendations

1. Allocate $350,000 in the 2006 Capital to do engineering and start replacement of the silicon carbide gap arrestors.

2. Develop a comprehensive multi-year plan for completion of all required substation lightning arrestor replacements.

2006 Replacement and Standby Substation Equipment

June 2005

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1.0 Background

Each year Newfoundland Power retires substation equipment because of vandalism, storm damage, lightning strikes, electrical or mechanical failure, corrosion damage, technical obsolescence, and failure during maintenance testing. This equipment is essential to the integrity and reliability of the electrical supply to our customers and must be replaced in a timely manner.

2.0 Corporate Standby Equipment

The most significant items related to replacement equipment include replacement circuit breakers, reclosers, potential transformers, voltage regulators, DC power systems and switches. The following provides details on these major components.

2.1 Circuit Breakers

Newfoundland Power has approximately 400 circuit breakers in service. Breakers are used to switch transmission lines, transformers, feeders, generators and other equipment on and off the electrical system. In conjunction with protective relaying, circuit breakers isolate electrical faults.

The majority of breakers are either transmission breakers (138 or 66 kV) or distribution breakers (typically 15 or 25 kV). The remainder are required in generation stations. The older breakers are often oil-filled and represent an environmental risk due to deterioration and unexpected failure. Approximately 25 circuit breakers have been retired since 2000 because of deterioration, electrical failure, or technological obsolescence.

Based on past experience, the Company maintains a pool of breakers to respond to failures. This pool normally contains one 138 kV, two 66 kV and two 25 kV breakers. The 25 kV units can be installed in either 15 or 25 kV installations, thereby reducing the number of spares required. New units have either galvanized or stainless steel exteriors to minimize corrosion related problems and are oil free, low maintenance units.

2.2 Electronic Reclosers

The Company has approximately 200 reclosers in service. Reclosers allow switching of rural feeders, which carry lighter loads and have smaller electrical fault levels than urban feeders. They have built-in control units that sense electrical faults and operate to de-energize the feeder in the event of a fault.

The newer reclosers have greater functionality and electrical isolating capabilities than the older hydraulic, relay and resistor types.

Reclosers are replaced due to failure, deterioration, and obsolescence. Since 2000, approximately 55 units have been retired. In order to respond to replacement requirements, the Company maintains a pool of spare reclosers. Each new unit will be oil free, low maintenance and digitally controlled so that it is capable of replacing any other recloser. They will also have either stainless steel or galvanized exteriors to minimize corrosion related problems.

2.3 Potential Transformers (PTs)

The Company has approximately 220 PTs in service. They measure voltage levels for input to protective relays, the SCADA system and metering circuitry. Failure of this equipment compromises the reliable operation of the electrical system and can endanger workers. Each year, PT replacements are required due to in-service failures. Since 2000, 18 PTs were retired due to rusting and oil leakage. New units will normally be of oil-free design, eliminating the environmental risk associated with the older oil-filled units.

2.4 Voltage Regulators

The Company has approximately 340 voltage regulators in service. These regulators are used to control voltages on long feeders.

Regulators are replaced due to failure deterioration and obsolescence. Since 2000, approximately 80 units have been retired. In order to respond to replacement requirements, the Company maintains a pool of spare voltage regulators. The new units can operate at 15 or 25 kV, minimizing the size of the pool. They also have stainless steel cases to minimize corrosion related failures.

2.5 Direct Current Electrical Supply Systems (Batteries and Battery Chargers)

The Company has approximately 120 battery banks. They provide electricity for protective relays, circuit breakers, reclosers and emergency substation lighting.

Battery chargers are low maintenance, long life devices. The Company maintains a pool of units to allow prompt replacement of failed units to ensure the security of its DC electrical supplies. Since 2000, approximately 20 battery systems have been replaced due to failure.

2.6 Switches

Newfoundland Power has approximately 2500 high voltage switches in service. Each year, some switches require replacement because of deterioration or failure. The Company maintains a pool of switches to allow for the prompt replacement of failed units.

2.7 2006 Expenditures

Each year, equipment is required to either replace equipment that fails in the field or to keep the pool of standby equipment at appropriate levels. The equipment to be purchased will depend on actual failures. However, based on past experience and engineering judgment, $660,000 will be required in 2006 for the following equipment:

1 – 25 kV Circuit Breaker
1 – 25 kV Electronic Recloser
3 – 25 kV Potential Transformers
3 – 66 kV Current Transformers
2 – High Voltage 3 phase bank of switches
6 – 25 kV 100 amp Voltage Regulators
6 – 25 kV 200 amp Voltage Regulators
1 – 25 kV 300 amp Voltage Regulator
10 – Universal Regulator Controls and Enclosures
2 – 48 Volt Battery Banks
3 – 120 Volt Battery Banks
5 – Battery Chargers

3.0 Emergency Replacements

When substation equipment, material and civil infrastructure fail, or deficiencies are identified, it may be necessary to proceed with immediate correction or replacement to maintain electrical system reliability and safety. Expenditures in this category provide for the installation of equipment from the standby pool. Also provided for in this category are the replacement of stolen ground grid conductor, the replacement of failed lightning arrestors, the replacement of failed high voltage switches and the replacement of other equipment acquired on an as-needed basis.

Information to estimate future expenditures in this category is only available from 2002 onwards. Based upon this recent historical information and engineering judgement, $363,000 is estimated to be required in 2006 for emergency replacements.

4.0 Known Deficiencies

4.1 Replace Two Breakers at Greenhill Substation

The existing circuit breakers on 301L and 305L at the Greenhill substation are 1975 vintage oil filled units. These circuit breakers are deteriorated to the extent that they need to be replaced. Picture 1 shows the valve on one unit which is held in place by a cable since one of its bolts has completely rusted off. Additionally, the bushings, which are located on top of these breakers, are deteriorated to the point that they are at risk of failing (see Picture 2). Failure of a bushing will result in failure of the breaker. It is more cost-effective to replace the entire breaker than to replace the bushings.

The existing Greenhill substation breakers (for 301L/305L) are bulk oil type units that contain in excess of 12,000 litres of insulating oil. As a result, they represent a significant environmental risk should the units fail and the oil be released. The replacement breakers will be galvanized steel oil-free breakers.

Picture 1
GRH-301L-B

Picture 2
Bushing Deterioration

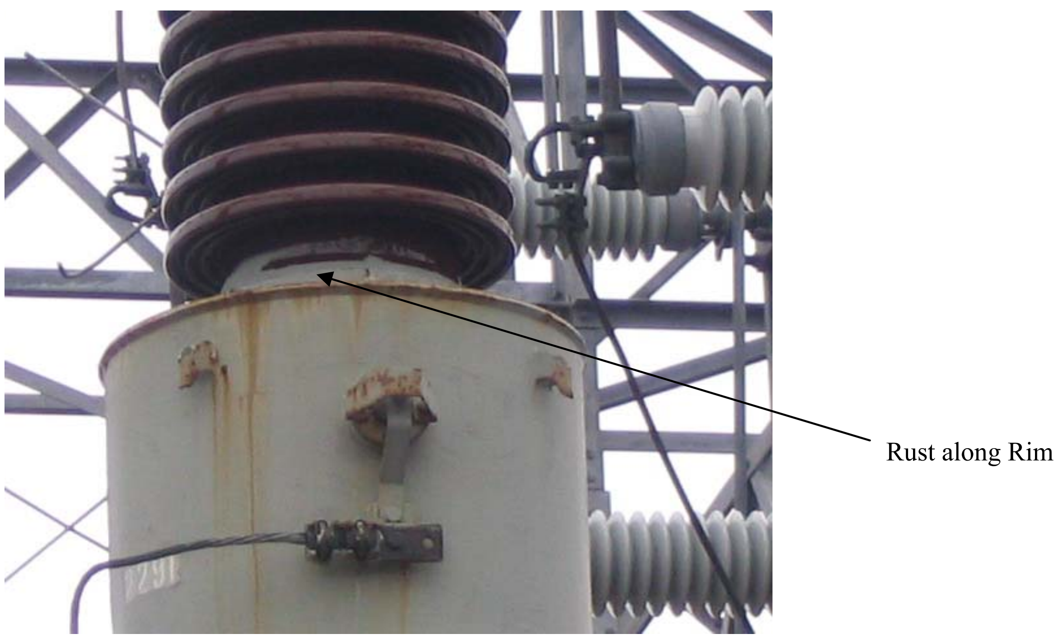
4.2 Replace Two Breakers at Virginia Waters Substation

At Virginia Waters Substation, the substation fault level is approximately 18.4 kA, which exceeds the maximum fault interrupting capacity of theVIR-04 and VIR-06 feeder breakers (12.5 kA).

To address this situation, both the VIR-04 and the VIR-06 breakers will be replaced in 2006 with breakers that have a fault interrupting capability that can accommodate the fault level at the Virginia Waters Substation.

4.3 Replace Three 66 kV PTs at Greenhill Substation

Three 66 kV PTs at the Greenhill Substation require replacement due to rusting and the resulting likelihood of failure of these units due to water ingress into the transformer. Failure of these units would affect the ability of protective relaying to perform properly. Also failure of a potential transformer would cause an outage to all the customers serviced from Greenhill Substation. Picture 3 shows the rusted case on one of the units. A similar PT failed at the Laurentian Substation due to rusting of its top cover which allowed water to enter the PT. A similar PT in the Greenhill Substation has also been replaced due to severe rusting.



Picture 3
Rusting Case of PT at Greenhill Substation

4.4 Transformer Cooling Refurbishment

The cooling radiators on two power transformers, one at Bayview Substation, and the other on portable substation P-335, require replacement in 2006 because of deterioration.

The original radiators, which are approaching 30 years of age, were coated with primer and enamel based paint for protection from the elements. Exposure to the environment causes the radiators to rust and blister. Eventually, the radiators begin to leak at the welded seams and through the thinner cooling panel surfaces. Failure of the radiators, besides releasing oil into the environment, will affect transformer operating capability. In the worst case, an oil leak from a radiator could lead to failure of the transformer.

The Bayview radiators will be replaced with galvanized units, which provide enhanced rust resistance. The new radiators have a life expectancy of 40 years. The portable substation radiator is of a chiller design (similar to a car radiator). It will be replaced with a similar type unit with an expected life of 30 years.

4.5 On Load Tap Changer Remote Control ("OLTC")

It is recommended that the Company replace 38 OLTC control modules that are approaching 25 years of age. Details are provided in *2.2.1 On Load Tap Changer Control Replacement.* Eight of these units are planned for replacement in 2006. The replacements are required to address control modules that are reaching the end of their useful life. The increased functionality of the new controllers will improve control and monitoring of system voltage levels. It will also provide the Company with the opportunity to exercise improved distribution bus voltage control and demand control.

5.0 Recommendation

The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service. Based on replacing the noted equipment, a 2006 budget of $1,918,000 for Replacement and Standby Substation Equipment is recommended as follows:

- $660,000 for Corporate Standby Equipment;
- $363,000 for Emergency Replacements;
- $261,000 for replacement of two Greenhill Substation breakers (301L & 305L);
- $171,000 for replacement of the two Virginia Waters breakers;
- $70,000 for replacement of three 66 kV PTs at the Greenhill Substation;
- $143,000 for transformer cooling refurbishment; and
- $250,000 for on load tap changer control replacements.

On Load Tap Changer Control Replacement

June 2005

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1.0 Background

Newfoundland Power has 64 on load tap changing power transformers ("OLTC"). OLTC maintain the voltage supplied to customers within the Canadian Standards Association ("CSA") standard – CAN3-C235-83 *Preferred Voltage Levels for AC Systems*. As the load on the electrical system varies, the voltage supplied to customers varies proportionately. To help offset these voltage variations, tap changers adjust substation voltages to maintain steady and acceptable levels to the customers. Operation of each OLTC is governed by the tap changer control module. Failure of these control modules may result in the OLTC not regulating or running to the upper or lower limits of their regulating ranges, causing high or low voltages to customers.

In substations with multiple tap changer equipped power transformers, a more sophisticated control method is required to ensure each tap changer produces the same output voltage. This is referred to as a "paralleling scheme". If parallel tap changers do not have the same output, electrical damage to the power transformers can occur. If the paralleling scheme should fail, the transformers have to be separated or the tap changer controllers turned off. Neither of these alternatives is desirable with respect to system operation and reliability. The Company currently has 9 substations with more than one OLTC serving the same bus voltages.

Appendix A shows a graph of the age distribution of the Company's installed OLTC. There are forty-seven units that are at least twenty years old. Many of the tap changer control modules are obsolete and there are no serviceable parts available to facilitate repairs. Engineering judgment indicates that the control module has a life expectancy of 25 years while the transformer itself has a life expectancy of 40 years. Therefore, replacing the control module after 25 years ensures the power transformers operates within the CSA guideline for its entire 40year asset life.

2.0 Recent Failures

In the three year period from January 2002 to December 2004, Newfoundland Power had to replace control modules on 12 of its OLTC because of in service module failure. Up to the end of May 2005, three additional units have failed and require replacement.

Besides causing unacceptable voltage, extended problems with control modules can cause excessive tap changer component wear because of unnecessary operation. This will lead to increased maintenance costs and, in the worst case, internal failure of the OLTC.

3.0 Newer Control Functionality

New tap changer control modules are capable of being monitored and controlled remotely. Increased remote monitoring and control of OLTC units will impact two main areas: power quality delivery and demand control.

Distribution bus power quality improvements will be from on line monitoring of OLTC health and immediate reporting of alarms to the System Control Centre for corrective action. This will result in quicker notification of problems which should lead to faster corrective actions.

Demand control can be obtained via remote control of the OLTC controllers which will allow Newfoundland Power to exercise conservation voltage reduction (“CVR”). CVR is a conservation method used by electric utilities to reduce electric load by lowering the bus voltages by small amounts within acceptable limits.

4.0 Conclusion

OLTC are a critical element in ensuring the voltage provided to customers is within CSA standards. OLTC control units approaching 25 years in service are reaching the end of their useful life. For many models there are no serviceable parts when the control units fail. Therefore, replacement is the only option. The new units will have many improvements over the old units, most notably improved monitoring and control. In addition to this, Newfoundland Power can take advantage of these upgrades to exercise improved distribution bus voltage control and demand control.

Consequentially, the Company needs to replace the controllers on the remaining 35 OLTC approaching 25 years old that have not had their controllers upgraded. Additionally, paralleling schemes will need to be upgraded as part of upgrading controllers.

5.0 Recommendation

As part of the work being done in 2005, design will be completed for new regulating controllers and for paralleling schemes. Therefore, the following is recommended:

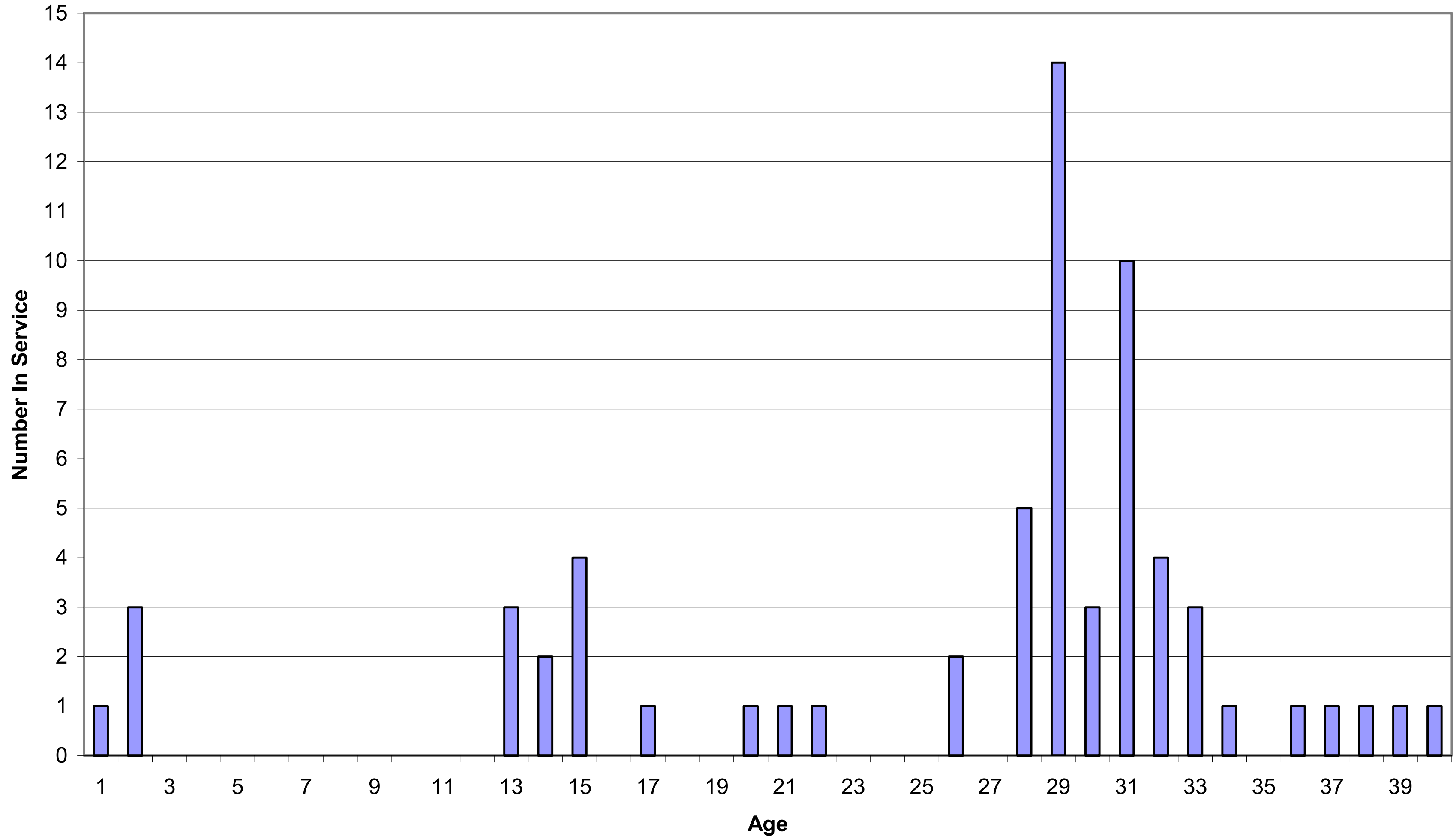
- Budget $250,000 in 2006 to replace controllers on 8 OLTC units.
- Replace the remaining units over the 2007 to 2008 timeframe.

The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

On Load Tap Changer Age Distribution

Appendix A
On Load Tap Changer Age Distribution



2006 Protection and Monitoring Equipment

June 2005

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1.0 Introduction

The Protection and Monitoring project consists of four items which are detailed in this Report. They include:

1. Installation of transformer power fuses in Trepassey and Riverhead Substations. The cost associated with this item is $77,000 and is detailed in Section 2.1 *Power Transformers*;

2. Installation of bus current differential protection schemes at Salt Pond and New Chelsea substations. The cost associated with this item is $196,000 and is detailed in Section 2.2 *Bus Protection*;

3. Engineering and installation of technology that automatically reports the real-time status of remote terminal units ("RTU"). The cost associated with this item is $109,000 and is detailed in Section 3.1 *RTU Communications*; and

4. Engineering and installation of an under voltage blocking scheme for remote blocking of TRN-116L-A3 air break switch from the System Control Centre. The cost associated with this item is $41,000, and is detailed in Section 3.2.

2.0 Substation Protection

2.1 Power Transformers

2.1.1 Power Transformers: Background

A substation is the point at which electrical power is taken off the transmission network and is transformed to distribution voltage. The most critical component in a substation is the power transformer. It is expensive to purchase, and replacement requires a minimum lead time of six to eight months. To ensure service continuity, it is important that the power transformer be adequately protected.

There are several methods in use to provide transformer protection. The most basic form of protection for transformers is provided by fuses. As the size and cost of transformers increase, so does the protection that is applied to the transformer. The more comprehensive protection can be provided by overcurrent protection, current differential protection, and individual transformer protection devices.

According to IEEE Standard C37.91-2000, *Guide for Protective Relay Applications to Power Transformers*, power fuses are an acceptable method to provide protection for power transformers rated less than 10 MVA. The standard also indicates that in protecting transformers, backup protection needs to be considered.

As part of its engineering practice, Newfoundland Power follows the above standard in applying fuse protection schemes to power transformers. Fuses are economical to install and require little maintenance. Newfoundland Power transformer protection is designed to have primary and backup protection schemes. Power fuses are used for either the primary protection or the backup protection on transformers rated less than 10 MVA.

2.1.2 Power Transformers: Need & Recommendation

Trepassey and Riverhead substations both have 5/6.7 MVA transformers. The transformer primary protection is provided by the transmission line protection at the remote end of the transmission line supplying these substations. There is no backup protection for these transformers as fuses were not installed on the high side of the units at the time of installation.

It is recommended that $77,000 be allocated in the 2006 Capital Budget for the engineering and installation of power fuses on the power transformers at Trepassey and Riverhead substations. 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 Bus Protection

2.2.1 Bus Protection: Background

The substation high voltage bus is a critical element of the substation, as it is the point of convergence of transmission, generation and/or distribution customer loads.

Bus faults, which occur in a substation containing more than one source of energy to supply current to the fault, involve higher energy levels than faults in other areas of the electrical power system. High-speed bus protection limits the damaging effects of bus faults on equipment and consequent negative impacts upon system stability and customer service.

According to ANSI/IEEE Standard C37.97-1979, *Guide for Protective Relay Applications to Power System Buses*, differential relaying is the preferred protection system for system buses.

As part of its engineering practice, Newfoundland Power has been applying bus current differential protection schemes to substation buses which are 66 kV or greater, and have two or more breaker controlled transmission lines.

To the date of this report, there has been at least one substation outage in each of 2003, 2004 and 2005 where the bus current differential protection has operated to successfully clear a bus fault, thus minimizing equipment damage.

Newfoundland Power uses almost exclusively, a basic single, high voltage main bus configuration. This configuration allows a simple and economical bus current differential scheme to be used.

2.2.2 Bus Protection: Need & Recommendation

There is currently no bus protection on the 66 kV bus at either of the New Chelsea or Salt Pond substations. Presently the transmission line and transformer overcurrent protection is relied on to remove 66 kV bus faults at these substations. This overcurrent protection is time delayed to coordinate with other system faults and will not operate to clear bus faults as quickly as bus differential protection. The increased length of exposure to fault current will increase equipment damage.

It is recommended a total of $196,000 be included in the 2006 Capital Budget for the engineering and installation of 66 kV bus current differential protection schemes at Salt Pond Substation ($110,000) and New Chelsea Substation ($86,000). The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

3.0 Substation Monitoring and Control

3.1 RTU Communications

3.1.1 RTU Communications: Background

The Supervisory Control and Data Acquisition (SCADA) system is the system used by Newfoundland Power's System Control Centre to remotely control and monitor the electric power system. The SCADA master computer system communicates with 77 remote terminal units that are located in the substations and generating plants. The RTU are connected to the substation's and generating plant's control systems and other equipment.

The RTU continuously monitors and communicates the status of equipment, like power circuit breakers, and alarms to the System Control Centre System (SCC). Operators at the SCC use this information to make decisions on how to operate the power system and how to dispatch crews.

3.1.2 RTU Communications: Need & Recommendation

Over the past 2 years, there have been incidents where some RTU have failed to alarm when field equipment has operated. It was subsequently determined that the RTU in question had stopped reporting status changes, with no advance indication that they had stopped operating. It was when equipment status changes were made in the field and the SCC operators notified by alternate means that the issue was identified.

In 2006, Newfoundland Power, proposes to install a "heart beat" indicator in 56 RTUs at a total cost of $109,000. If the SCADA system fails to receive the "heart beat" indication from an RTU, then the SCC will know that the RTU has stopped reporting. Staff can then be dispatched to correct the problem with the RTU.

The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

3.2 Trinity Substation Control

3.2.1 Trinity Substation Control: Background

Newfoundland Power serves the communities of Hare Bay, Trinity, Greenspond and New-Wes-Valley from Gambo substation by radial transmission lines 115L and 116L. This area experiences a high incidence of storms causing outages to the transmission lines.

To reduce outage time to customers, there is an automated control system on TRN-116L-A3 switch at Trinity substation, which allows the isolation of the failed transmission line.

The automated control system is used to operate TRN-116L-A3 switch in order to isolate the faults on 116L. This allows for earlier restoration of power to customers served from Hare Bay and Trinity substations.

The installation of the automated control system predates the installation of SCADA remote control to the Bonavista North area. The procedure to restore power to the Wesleyville and Greenspond substations, once TRN-116L-A3 has been opened, involves disabling the under voltage protection. Presently, staff have to travel to the substation to accomplish this task. This lengthens any outage to customers. In the past two and half years, there have been 8 instances where staff had to be dispatched to disable the scheme so the transmission system could be returned to normal. In one instance, 155,472 customer outage minutes were incurred due to this procedure.

3.2.2 Trinity Substation Control: Need & Recommendation

A modification of the control scheme at Trinity substation will allow the SCC to remotely disable the under voltage tripping circuit. With the modified control scheme in place the SCC will have full remote control to restore power to this area and not have to dispatch staff to manually block the under voltage scheme.

It is recommended that $41,000 be allocated in the 2006 Capital Budget to install the control scheme modification to remotely disable under voltage tripping on TRN-116L-A3 air break switch. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

2006 Additions Due to Load Growth

June 2005

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1.0 Background

Many areas of the Company's service territory continually experience load growth. With increasing use of electricity, at some point in time substation equipment becomes overloaded or not capable of supplying demand.

This report describes three substation capital budget items that are required in 2006 to address equipment loading concerns. All these items are justified on the basis of accommodating customer growth.

2.0 Pasadena Substation – Install Cooling Fan on PAS-T1 ($68,000)

Customer loads in the Humber Valley Area have increased significantly over the last few years. The load forecast indicates that at its existing load carrying capacity, PAS-T1 transformer will be overloaded in 2006. Projected load for Pasadena substation is 13.2 MVA in 2006 while PAS-T1 is capable of supplying 10 MVA. Addition of cooling fans on this unit will increase its capacity to 13.3 MVA. This will meet the power requirements in the area in the short term.

The cost of adding transformer capacity at Pasadena through installing cooling fans is $68,000. The deferral of the $1.5 million new substation at Little Rapids from 2006 to 2007, will save over $80,000.

The cost of installing cooling fans on PAS-T1 is the least cost way to accommodate short term future customer growth in the Humber Valley Area.

3.0 Little Rapids Substation – Land Survey/Grounding Study ($75,000)

Customer loads in the Humber Valley Area have increased significantly over the last few years. The load forecast indicates, even with proposed increases in load carrying capacity, PAS-T1 transformer will overload in 2007. To address this overload, a study was completed that recommends the least cost alternative is the construction of a new substation, Little Rapids (LTR), in 2007. The detailed study of the alternatives associated with meeting the electricity requirements in the Humber Valley Area is contained in 2.4.1 *Humber Valley Planning*.

This project will provide the land survey and grounding study necessary to proceed with substation construction planned for 2007.

4.0 Big Pond Substation – Increase Transformer Capacity ($67,000)

4.1 Background

Big Pond (BIG) substation is located on the outskirts of St. John's in the community of Gould's near the St. John's Regional Water Supply. This substation consists of a 66 kV to 12.5 kV power transformer (BIG-T1) presently rated for 8.4 MVA. The addition of cooling radiators on this unit will increase its capacity to 11.2 MVA.

The substation has two distribution feeders. BIG-01 feeder has only one customer, which is the St. John's Regional Water Supply pumping station. BIG-02 feeder extends both south and north. It extends north into the western portion of Gould's where BIG-02 can be connected if required to GOU-03 near Della Drive. It extends south along Route 10 but is limited to two phase and single phase as it approaches the outskirts of Bay Bulls which is supplied from Mobile substation.

The substation load forecast indicates that BIG-T1 existing load carrying capacity (8.4 MVA) will be exceeded in 2006. Projected load for BIG-T1 in 2006 is 9.2 MVA and will increase to 11.2 MVA at the end of the five year forecast in 2010.

4.2 Alternatives

To alleviate a transformer overload problem, there are two options:

1. A set of regulators can be installed on GOU-03 ($75,000); or
2. Cooling radiators can be installed on BIG-T1 to increase its capacity from 8.4 MVA to 11.2 MVA. ($67,000).

As part of option 1, it is possible to transfer load from BIG-02 to GOU-03. However, GOU-03 low voltage limits of 116 V will be violated if there is any significant load placed on the end of GOU-03. To make this a viable option a set of regulators would be installed on GOU-03.

The second option is to add cooling radiators to BIG-T1, increasing its capacity from 8.4 MVA to 11.2 MVA. A further benefit of increasing the capacity of BIG-T1 (2006) and upgrading a section of BIG-02 from single phase to three phase (2008), is that it will enable transfer of load from Mobile transformer to BIG-T1 in 2008. This will defer the forecast transformer overload at Mobile in 2008 thus deferring the Mobile transformer replacement for a number of years. The Mobile transformer replacement cost is approximately $1,000,000. Further, the Big Pond transformer upgrade and BIG-02 feeder upgrade will allow some backup to be provided for Mobile feeder (MOB-01) from Big Pond in 2008 and thereafter.

4.3 Conclusion

The option of installing cooling radiators on BIG-T1 is the lowest cost alternative to address a forecast overload of BIG-T1. Also, this option enables delaying the transformer replacement due to forecast overload in 2008 of the Mobile Substation transformer MOB-T1.

Humber Valley Planning

June 2005

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1.0 Executive Summary

The purpose of this report is to determine the least cost option to meet additional customer demand in the Humber Valley area. Customers in this area are currently served by the existing Pasadena (“PAS”) and Marble Mountain (“MMT”) substations. The substation forecast indicates the power transformer located at PAS substation will be loaded at 113% of capacity in 2007, after installation of additional cooling fans in 2006.

Humber Valley Resort is located near the community of Little Rapids. Estimated demand at the end of the construction phase for the Humber Valley Resort is 14.5 MVA, which is greater than the demand for the Town of Pasadena. The resort is located 8 km from the PAS substation and 10 km from the MMT substation. All power supplied through both substations is provided from Corner Brook Pulp & Paper Limited’s (CBPP) 66 kV Line #1.

This report establishes a 20-year load forecast for the area. To meet this forecast, three alternatives are developed. Each alternative includes an additional substation power transformer. The locations for each are PAS, MMT and Little Rapids (“LTR”). Each alternative estimates incremental costs, including transformers, substation equipment, distribution facilities and transmission facilities. A Net Present Value (“NPV”) calculation is provided for each alternative. A sensitivity analysis with respect to the load forecast provides further present worth calculations for each alternative.

Based on technical and economic analyses, to meet load growth in the Humber Valley area, it is recommended that Newfoundland Power install a new substation and associated equipment at Little Rapids in 2007. This alternative has the lowest NPV.

2.0 Introduction

This report provides a plan to supply power to the Humber Valley area currently served by PAS and MMT substations. The area is experiencing significant load growth mainly due to developments at the Humber Valley Resort complex. Due to the load growth in the area, the existing power system is becoming limited both from a distribution perspective and a substation transformer capacity perspective.

This study considers alternatives that are feasible from a technical perspective to accommodate the load growth in the Humber Valley area over the next 20 years. These alternatives are compared and evaluated from a present worth cost perspective. The least cost plan for power system expansion to meet the load growth is recommended.

3.0 Description of Existing System

As an aid in describing the existing system, Figure 1 is a map showing the general location of Pasadena, Marble Mountain and the Humber Valley Resort. Figure 2 is a schematic showing major components of the electrical system.

The PAS and MMT substations are supplied via a 66 kV CBPP line, extending from CBPP's generating station at Deer Lake to Newfoundland and Labrador Hydro's Massey Drive Substation.

The area serviced from these two existing substations extends from Steady Brook to Little Harbour. The Humber Valley Resort is located approximately halfway between the two existing substations.

PAS substation has two feeders installed, PAS-01 and PAS-02. PAS-01 feeder supplies power to the west side of the Town of Pasadena and further west to the beginning of Little Rapids. There is a three-phase tap that crosses the Humber River to feed the resort.

At the tie point between feeders PAS-01 and MMT-01, there are three voltage regulators for use when it is necessary to supply power to MMT-01 from PAS-01, or visa versa. This minimizes outages to customers in the area.

Transformer PAS-T1 is a 10 MVA rated unit with the ability to increase its capacity to 13.3 MVA with the addition of fans. It is also equipped with an on load tap-changer (OLTC).

MMT substation only has one feeder, MMT-01. This feeder supplies electricity to the communities of Steady Brook, Humber Village and Little Rapids along with Marble Mountain Ski Complex. Transformer MMT-T1 is a 4 MVA unit with fans and the transformer is not equipped with an OLTC.

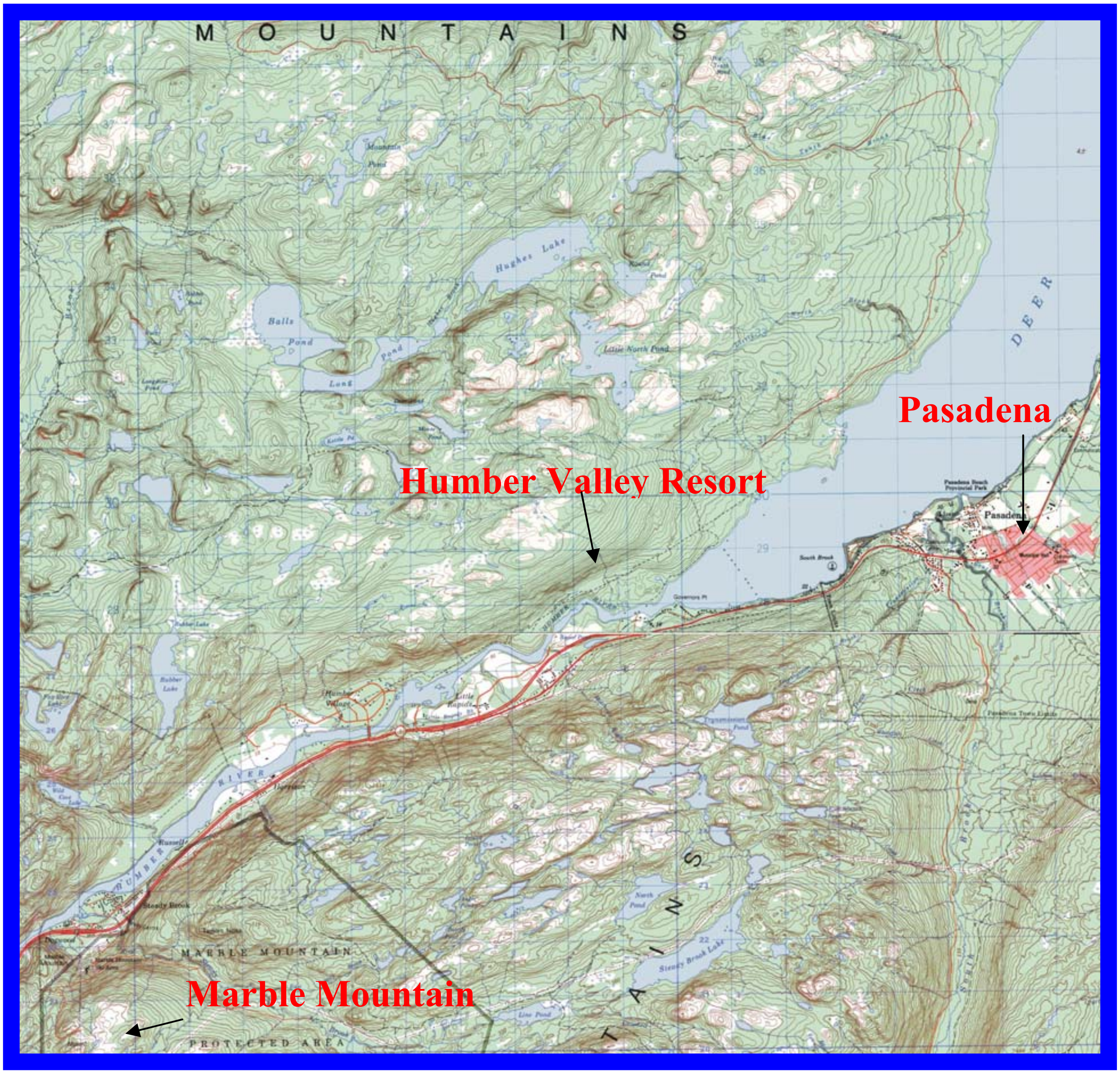

Figure 1: Topographic Map of Humber Valley Area

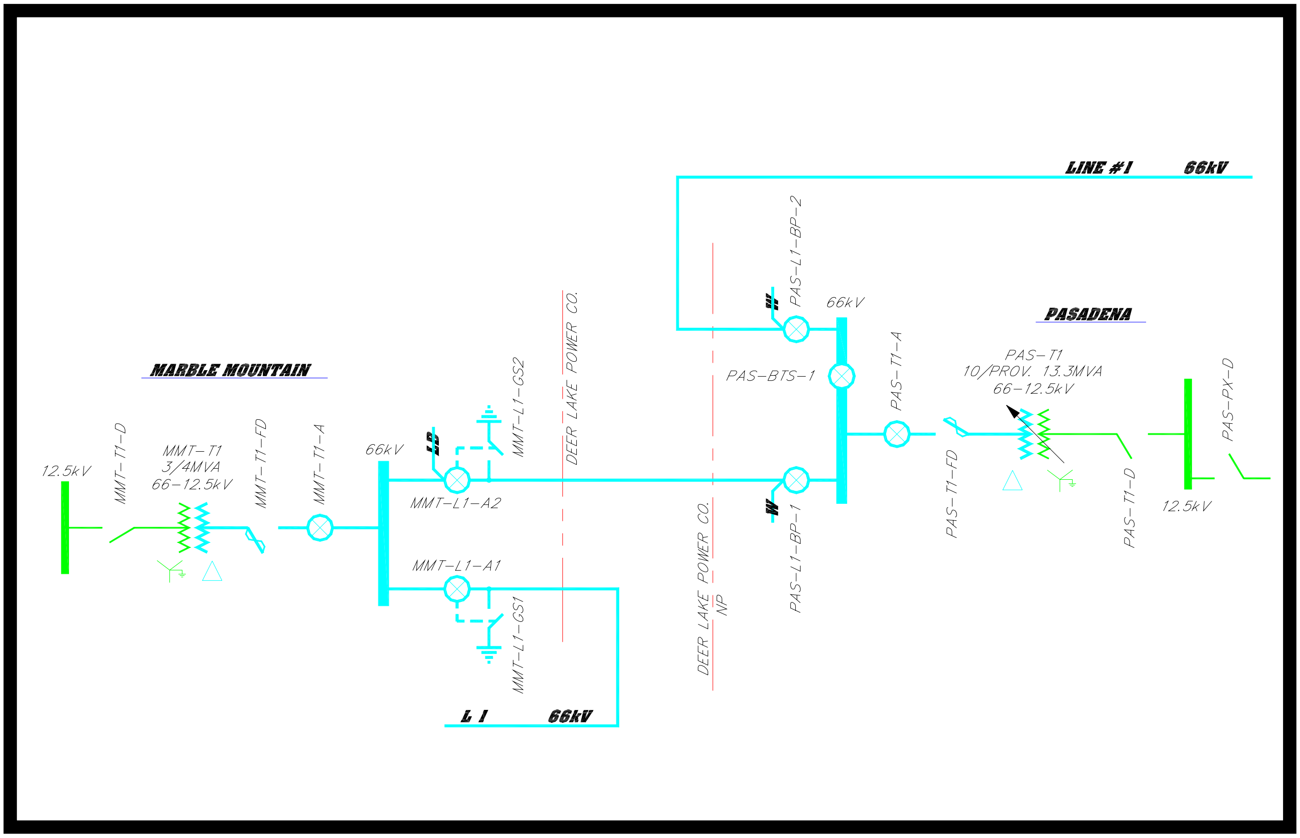

Figure 2: Humber Valley Area Electrical Infrastructure

4.0 Load Forecast and Capacity Limitations

The load forecast for the Humber Valley area is shown in the following table.

Year	PAS substation[1] Peak Demand (MVA)	MMT Substation Peak Demand (MVA)
2004 (Actual)	9.04	3.10
2005	11.16	3.29
2006	13.22	3.34
2007	14.97	3.40
2008	16.83	3.48
2009	19.07	3.52
2010	21.08	3.57
2011	23.05	3.61
2016	24.23	3.79
2021	25.46	3.98
2026	26.76	4.19

[1] Includes forecasted load of the Humber Valley Resort.

The load in the Humber Valley area, excluding the resort, is forecasted to grow between 1.26% to 2.15% annually over the next five years with a long-term growth rate of 1% annually.

The construction phase for the resort is forecasted to be completed in 2011. At that time, the resort is expected to contain

- 1000 Chalets
- 2 Clubhouses
- 3 - 8000 ft^2 Warehouses
- 1 - 8000 ft^2 Office Building
- 1 – 10,000 ft^2 Spa
- Restaurant / Boathouse

Total estimated peak demand for the resort in 2011 is 14.5 MVA.

The initial system capacity limit that will be exceeded, based on the forecast, is the overloading of the PAS substation transformer in 2007. Further details associated with this forecast are contained in Appendix A.

5.0 Development of Alternatives

5.1 Technical Criteria

The following technical criteria were established to evaluate the alternates:

1. The steady state primary voltage at any location along the feeder should not fall below 116 volts on a 120-volt base;

2. The steady state substation power transformer loading should not exceed the nameplate rating;

3. The recloser normal peak loading should be restricted to permit adequate cold load pickup;

4. The conductor loading should not exceed the ampacity rating established in the Company's Distribution Planning Guidelines.

5.2 Planning Methodology and Development of Alternatives

The planning methodology is the process whereby the forecasted electrical peak demands are serviced through developing alternatives that meet the technical criteria. Each alternative has a schedule of projects associated with it that extend over the period of the study. These projects are costed and are input to the economic analysis. Based on this analysis, a preferred alternative is recommended.

In reviewing the load forecast it is apparent that the Pasadena transformer is overloaded in 2007. The alternatives considered in this report are based on adding transformer capacity at three different locations: PAS substation; MMT substation; and a new LTR substation located near the river crossing to the Humber Valley Resort.

Effort is made to delay any power transformer replacement using a combination of load transfers, additional feeders and down line equipment such as regulators.

Due to the distance from PAS and MMT substations and the amount of load expected at the resort, care must be taken to ensure the voltage supplied to customers is within acceptable levels. Each scenario was checked to ensure that the voltage received by all customers on the feeder meet the Company's standards.

Costs and schedules associated with each alterative are noted in Appendix B.

5.3 Alternative 1 - Adding Capacity at PAS substation

This option uses PAS substation as the supply to the area for the next 20 years. Under this scenario, PAS-T1 is the only power transformer replaced. Feeder work is necessary to maintain voltage levels within acceptable limits and to prevent overload to distribution equipment.

This alternative requires PAS-T1 to be replaced in 2007. At the end of the 20-year study, two additional feeders, PAS-03 and PAS-04 are required to supply the area. Also load transfers are required between PAS-01, PAS-03 and PAS-04; and both PAS-03 and PAS-04 require 2 sets of 500 amp voltage regulators (12 regulators total).

5.4 Alternative 2 - Adding Capacity at MMT substation

This option uses MMT substation as the supply to the area for the next 20 years. With this alternative, MMT-T1 is the only power transformer replacement in the area. Feeder work is also required to maintain voltage levels within acceptable limits and to prevent overload to distribution equipment.

This alternative requires MMT-T1 to be replaced in 2007. At the end of the 20-year study, two additional feeders, MMT-02 and MMT-03 would be built. Also MMT-01, MMT-02 and MMT-03 would each require 2 sets of 500 amp voltage regulators (18 regulators total).

5.5 Alternative 3 - Installation of a new substation at Little Rapids

This option starts with the installation of a new substation in the vicinity of Little Rapids in 2007. The new 25 MVA unit would supply the Humber Valley Resort and surrounding area. This would be the only addition to the power transformer capacity in the Humber Valley area for the next 20 years. The new substation would be supplied by CBPP's 66 kV Line #1.

The building of LTR substation in 2007 includes a 25 MVA power transformer equipped with an OLTC and the installation of one feeder, LTR-01. Load from the Humber Valley resort would be transferred from PAS-01 to LTR-01. By the end of the 20 year study, two additional feeders, LTR-02 and LTR-03, would be installed.

6.0 Economic Analysis

In order to compare the economic impact of the alternatives, a net present value calculation of customer revenue requirement was completed for each alternative. Capital costs from 2006 to 2026 were converted to revenue requirement and the resulting customer revenue requirement from 2006 to 2026 was reduced to a net present value using the corporate weighted average incremental cost of capital. The result for each alternative is indicated in the following table. The details of the net present value calculations are shown in Appendix C.

In the comparing the three alternatives, alternative 3 is the lowest cost.

Alternative	Net Present Value Revenue Requirement ($)
1	$2,897,889
2	$2,745,512
3	$1,872,886

7.0 Sensitivity Analysis

In order to test the validity of selecting the lowest cost alternative, the sensitivity of the alternatives to varying load forecasts is calculated. These load forecasts are shown in Appendix D and are denoted as high and low forecasts. The low growth forecast results in delaying the time when the construction of various projects are required. Conversely, with a higher growth forecast the timing for the projects is advanced. Costing and schedules associated with each alternative as part of the sensitivity analysis is contained in Appendix E. Using these revised costs and schedules, the net present value of revenue requirements is calculated. The results of these calculations are shown in the following table and the details of the net present value calculations are shown in Appendix F.

In reviewing the table, alternative 3 is the least cost plan to supply power to the area currently served by the existing PAS and MMT substations across all load forecast scenarios analyzed.

Alternative	NPV RR Low Forecast Scenario ($)	NPV RR Base Forecast Scenario ($)	NPV RR High Forecast Scenario ($)
1	$2,034,213	$2,897,889	$3,802,698
2	$2,503,491	$2,745,512	$3,630,563
3	$1,555,634	$1,872,886	$2,008,309

8.0 Conclusions and Recommendations

A 20-year load forecast by feeder has projected the electrical demands for the Humber Valley area. The development of alternatives has established a preferred expansion plan to meet these needs. Further, a sensitivity analysis has confirmed the robustness of the recommended solution to varying load growth.

The lowest cost alternative that meets all the technical criteria is to install a new substation at Little Rapids in 2007.

Appendix A

Base Load Forecast

Pasadana (PAS)											
Feeders	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2016**	**2021**	**2026**
PAS-01	6.289	8.248	2.201	5.724	6.615	7.713	8.690	6.016	6.322	6.645	6.984
PAS-02	2.750	2.915	4.067	4.138	4.227	4.280	4.342	4.386	4.610	4.845	5.092
PAS-03	0.000	0.000	6.951	5.112	5.991	7.081	8.049	5.368	5.641	5.929	6.232
PAS-04								7.284	7.655	8.046	8.456
Sub Total*	**9.04**	**11.16**	**13.22**	**14.97**	**16.83**	**19.07**	**21.08**	**23.05**	**24.23**	**25.46**	**26.76**
PAS T1 Capacity	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00

Marble Mountain (MMT)											
Feeders	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2016**	**2021**	**2026**
MMT-01	3.1	3.3	3.3	3.4	3.5	3.5	3.6	3.6	3.8	4.0	4.2
Sub Total*	**3.10**	**3.29**	**3.34**	**3.40**	**3.48**	**3.52**	**3.57**	**3.61**	**3.79**	**3.98**	**4.19**
MMT T1 Capacity	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

* Forecasts assume that Humber Valley Resort is supplied by the PAS substation. Forecasts are given in MVA.

Appendix B

Alternative Costing and Schedules

Alternative # 1 - Expand PAS Substation	Cost	Year
Installation of fans on PAS-T1 - (Without the installation of fans, PAS-T1 would be overloaded)	68,000.00	2006
Install PAS-01-VR2 regulators (500 amp) - Required for Voltage Support to Humber Valley Resort / Boomsiding	75,000.00	2006
Replace PAS-01-VR1 regulators (500 amp) - Required for overload on existing equipment	60,000.00	2006
Transfer section PAS-01 to PAS-02 (1.1 MVA) - Required to correct overload condition on PAS-01 conductor	15,000.00	2007
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	30,000.00	2007
(All changes required to correct overload conditions on PAS-01 conductor and voltage support to Humber Valley resort)		
Replace PAS-T1 (25 MVA unit) - Required to correct overload condition on PAS-T1	1,200,000.00	2007
Install PAS-03-R / switches. Build PAS-03 to TCH along First Ave and on to South Brook Park.	495,000.00	2007
Install PAS-03-VR1 and PAS-03-VR2 regulators (500 amp)	160,000.00	2008
(All changes required to correct overload conditions on PAS-03 conductor and voltage support to Humber Valley resort)		
Extend PAS-03 from South Brook Park to Humber Valley Resort	303,000.00	2008
Transfer section of PAS-03 to PAS-01	15,000.00	2008
Install PAS-04-R, including switches, Steel Bus etc	190,000.00	2011
Extend PAS-04 to Humber Valley Resort	688,000.00	2011
Install PAS-04-VR1, PAS-04-VR2	160,000.00	2011
Total	**$3,459,000**	

Alternative # 2 - Expand MMT Substation	Cost	Year
Installation of fans on PAS-T1 - (Without the installation of fans, PAS-T1 would be overloaded)	68,000.00	2006
Install PAS-01-VR2 regulators (500 amp) - Required for Voltage Support to Humber Valley Resort / Boomsiding	75,000.00	2006
Replace PAS-01-VR1 regulators (500 amp) - Required for overload on existing equipment	60,000.00	2006
Replace MMT-T1 with 25 MVA	1,413,000.00	2007
Install MMT-02 recloser and Switches	100,000.00	2007
Install MMT-02 Feeder (4.6 km)/ MMT-02-VR1 and MMT-02-VR2	413,000.00	2007
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2007
Extend MMT-01 Feeder (4.6 km) / MMT-01-VR1 and MMT-01-VR2	413,000.00	2009
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2009
Install MMT-03 recloser and Switches	230,000.00	2011
Extend MMT-03 Feeder (4.6 km)	235,000.00	2011
Transfer load to MMT-03 from MMT-01 along with MMT-01 voltage regulators, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2011
Extend MMT-01 Feeder (4.6 km)/ MMT-01-VR1 and MMT-01-VR2	413,000.00	2020
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2020
Total	**$3,480,000**	

Alternative # 3 - Build LTR Substation	Cost	Year
Installation of fans on PAS-T1 - (Without the installation of fans, PAS-T1 would be overloaded)	68,000.00	2006
Install PAS-01-VR2 regulators (500 amp) - Required for Voltage Support to Humber Valley Resort / Boomsiding	75,000.00	2006
Replace PAS-01-VR1 regulators (500 amp) - Required for overload on existing equipment	60,000.00	2006
Site Preparation	75,000.00	2006
Install LTR Substation, 25 MVA LTR-01-R and Switches	1,413,000.00	2007
Install LTR-01 Feeder	87,000.00	2007
Transfer load from PAS-01 to LTR-01	15,000.00	2007
Install LTR-02 recloser and feeder	100,000.00	2008
Install LTR-02 Feeder	87,000.00	2008
Transfer load from LTR-01 to LTR-02	15,000.00	2008
Install LTR-03 recloser and feeder	100,000.00	2021
Install LTR-03 Feeder	140,000.00	2021
Transfer load from LTR-01 and LTR-02	15,000.00	2021
Total	**$2,250,000**	

Appendix C

Economic Analysis

Alternative #1 Base

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Distribution 30.4 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2006	0	68,000	135,000	0	26,408	0	0	-26,408	-24,387	-24,387
2007	0	1,725,510	45,810	0	240,141	0	0	-240,141	-204,781	-229,167
2008	0	0	494,876	0	264,499	0	0	-264,499	-208,286	-437,453
2009	0	0	0	0	253,674	0	0	-253,674	-184,469	-621,922
2010	0	0	0	0	254,321	0	0	-254,321	-170,781	-792,703
2011	0	206,912	923,480	0	403,174	0	0	-403,174	-250,013	-1,042,716
2012	0	0	0	0	375,268	0	0	-375,268	-214,893	-1,257,610
2013	0	0	0	0	374,270	0	0	-374,270	-197,915	-1,455,524
2014	0	0	0	0	372,460	0	0	-372,460	-181,880	-1,637,404
2015	0	0	0	0	369,905	0	0	-369,905	-166,804	-1,804,208
2016	0	0	0	0	366,663	0	0	-366,663	-152,684	-1,956,893
2017	0	0	0	0	362,789	0	0	-362,789	-139,506	-2,096,399
2018	0	0	0	0	358,334	0	0	-358,334	-127,245	-2,223,644
2019	0	0	0	0	353,345	0	0	-353,345	-115,867	-2,339,511
2020	0	0	0	0	347,863	0	0	-347,863	-105,338	-2,444,849
2021	0	0	0	0	341,930	0	0	-341,930	-95,614	-2,540,463
2022	0	0	0	0	335,580	0	0	-335,580	-86,655	-2,627,118
2023	0	0	0	0	328,847	0	0	-328,847	-78,416	-2,705,534
2024	0	0	0	0	321,761	0	0	-321,761	-70,852	-2,776,386
2025	0	0	0	0	314,352	0	0	-314,352	-63,922	-2,840,308
2026	0	0	0	0	306,644	0	0	-306,644	-57,581	-2,897,889

Alternative #2 Base

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year 2005

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
	Transmission	Substation	Distribution	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
	30.6 yrs 8% CCA	38.5 yrs 8% CCA	30.4 yrs 8% CCA	33 yrs 4% CCA						
YEAR										
2006	0	68,000	135,000	0	26,408	0	0	-26,408	-24,387	-24,387
2007	0	1,540,234	435,704	0	269,408	0	0	-269,408	-229,738	-254,125
2008	0	0	0	0	222,548	0	0	-222,548	-175,250	-429,375
2009	0	0	450,644	0	283,811	0	0	-283,811	-206,384	-635,759
2010	0	0	0	0	273,318	0	0	-273,318	-183,538	-819,297
2011	0	250,472	272,252	0	340,429	0	0	-340,429	-211,104	-1,030,401
2012	0	0	0	0	327,168	0	0	-327,168	-187,349	-1,217,750
2013	0	0	0	0	326,017	0	0	-326,017	-172,398	-1,390,149
2014	0	0	0	0	324,184	0	0	-324,184	-158,305	-1,548,454
2015	0	0	0	0	321,723	0	0	-321,723	-145,077	-1,693,531
2016	0	0	0	0	318,685	0	0	-318,685	-132,706	-1,826,237
2017	0	0	0	0	315,117	0	0	-315,117	-121,174	-1,947,411
2018	0	0	0	0	311,059	0	0	-311,059	-110,457	-2,057,869
2019	0	0	0	0	306,553	0	0	-306,553	-100,524	-2,158,392
2020	0	0	542,454	0	374,096	0	0	-374,096	-113,281	-2,271,674
2021	0	0	0	0	355,609	0	0	-355,609	-99,439	-2,371,113
2022	0	0	0	0	349,943	0	0	-349,943	-90,364	-2,461,477
2023	0	0	0	0	343,805	0	0	-343,805	-81,983	-2,543,460
2024	0	0	0	0	337,231	0	0	-337,231	-74,259	-2,617,719
2025	0	0	0	0	330,258	0	0	-330,258	-67,156	-2,684,875
2026	0	0	0	0	322,917	0	0	-322,917	-60,637	-2,745,512

Alternative #3 Base
($)

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**
PW Year 2005

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
	Transmission	Substation	Distribution	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth
	30.6 yrs	38.5 yrs	30.4 yrs	33 yrs						Benefit
	8% CCA	8% CCA	8% CCA	4% CCA						
YEAR										
2006	0	143,000	135,000	0	35,645	0	0	-35,645	-32,916	-32,916
2007	0	1,438,434	103,836	0	220,007	0	0	-220,007	-187,611	-220,527
2008	0	103,531	105,601	0	210,524	0	0	-210,524	-165,782	-386,309
2009	0	0	0	0	206,549	0	0	-206,549	-150,200	-536,509
2010	0	0	0	0	207,152	0	0	-207,152	-139,107	-675,616
2011	0	0	0	0	207,238	0	0	-207,238	-128,511	-804,126
2012	0	0	0	0	206,847	0	0	-206,847	-118,449	-922,575
2013	0	0	0	0	206,018	0	0	-206,018	-108,943	-1,031,518
2014	0	0	0	0	204,786	0	0	-204,786	-100,001	-1,131,519
2015	0	0	0	0	203,182	0	0	-203,182	-91,622	-1,223,141
2016	0	0	0	0	201,237	0	0	-201,237	-83,799	-1,306,940
2017	0	0	0	0	198,979	0	0	-198,979	-76,515	-1,383,455
2018	0	0	0	0	196,431	0	0	-196,431	-69,753	-1,453,208
2019	0	0	0	0	193,618	0	0	-193,618	-63,490	-1,516,698
2020	0	0	0	0	190,560	0	0	-190,560	-57,704	-1,574,402
2021	0	128,896	199,789	0	229,839	0	0	-229,839	-64,270	-1,638,672
2022	0	0	0	0	218,454	0	0	-218,454	-56,410	-1,695,083
2023	0	0	0	0	214,859	0	0	-214,859	-51,235	-1,746,317
2024	0	0	0	0	210,998	0	0	-210,998	-46,462	-1,792,779
2025	0	0	0	0	206,891	0	0	-206,891	-42,070	-1,834,850
2026	0	0	0	0	202,559	0	0	-202,559	-38,036	-1,872,886

Appendix D

Sensitivity Load Forecasts

Pasadena

Alternative #1			
Year	Low	Base	High
2004	9.04	9.04	9.04
2005	10.58	11.16	11.87
2006	12.05	13.22	14.64
2007	13.23	14.97	17.11
2008	14.50	16.83	19.68
2009	16.06	19.07	22.75
2010	17.39	21.08	25.59
2011	18.62	23.05	28.43
2012	18.69	23.28	28.86
2013	18.76	23.52	29.29
2014	18.84	23.75	29.73
2015	18.91	23.99	30.18
2016	18.98	24.23	30.63
2017	19.06	24.47	31.09
2018	19.13	24.72	31.56
2019	19.20	24.96	32.03
2020	19.28	25.21	32.51
2021	19.35	25.46	33.00
2022	19.43	25.72	33.49
2023	19.50	25.98	33.99
2024	19.58	26.24	34.50
2025	19.65	26.50	35.02
2026	19.73	26.76	35.55

Marble Mountain

Alternative #2			
Year	Low	Base	High
2004	3.10	3.10	3.10
2005	3.29	3.29	3.29
2006	7.53	3.34	10.12
2007	8.62	10.31	12.51
2008	9.80	12.07	14.98
2009	11.30	14.25	17.99
2010	12.56	16.19	20.76
2011	13.77	18.11	23.48
2012	13.84	18.29	23.83
2013	13.91	18.48	24.19
2014	13.98	18.66	24.55
2015	14.05	18.85	24.92
2016	14.12	19.04	25.29
2017	14.19	19.23	25.67
2018	14.26	19.42	26.06
2019	14.33	19.61	26.45
2020	14.40	18.81	26.84
2021	14.48	19.00	27.25
2022	14.55	19.19	27.65
2023	14.62	19.38	28.07
2024	14.69	19.57	28.49
2025	14.77	19.77	28.92
2026	14.84	19.97	29.35

Little Rapids

Alternative #3			
Year	Low	Base	High
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	5.22	6.97	9.10
2008	6.33	8.66	11.50
2009	7.78	10.79	14.47
2010	8.99	12.68	11.46
2011	10.20	14.57	13.27
2012	10.25	14.71	13.47
2013	10.30	14.86	13.67
2014	10.35	15.01	13.88
2015	10.41	15.16	14.08
2016	10.46	15.31	14.30
2017	10.51	15.46	14.51
2018	10.56	15.62	14.73
2019	10.62	15.77	14.95
2020	10.67	15.93	15.17
2021	10.72	16.09	23.10
2022	10.78	16.25	23.45
2023	10.83	16.42	23.80
2024	10.88	16.58	24.16
2025	10.94	16.75	24.52
2026	10.99	16.91	24.89

Appendix E

Sensitivity Costing and Schedules

Alternative # 1 - Expand PAS Substation	Cost	Low	Medium	High
Installation of fans on PAS-T1 - (Without the installation of fans, PAS-T1 would be overloaded)	68,000.00	2006	2006	2006
Install PAS-01-VR2 regulators (500 amp) - Required for Voltage Support to Humber Valley Resort / Boomsiding	75,000.00	2007	2006	2006
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2007	NA	NA
Replace PAS-01-VR1 regulators (500 amp) - Required for overload on existing equipment	60,000.00	2007	2006	2006
Transfer section PAS-01 to PAS-02 (1.1 MVA) - Required to correct overload condition on PAS-01 conductor	15,000.00	2007	2007	2007
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	30,000.00	NA	2007	2007
(All changes required to correct overload conditions on PAS-01 conductor and voltage support to HVR)				
Install PAS-T2 (25 MVA unit) - Required to correct overload condition on PAS-T1	1,413,000.00	NA	NA	2007
Replace PAS-T1 (25 MVA unit) - Required to correct overload condition on PAS-T1	1,200,000.00	2008	2007	NA
Install PAS-03-R / switches. Build PAS-03 to TCH along First Ave and on to South Brook Park.	495,000.00	2008	2007	2007
Transfer Boomsiding, First Ave (PAS-01) to PAS-03 (6.5 - 0.97 = 5.35 i.e. half of HVR Load)	15,000.00	2008	NA	NA
(All changes required to correct overload conditions on PAS-01 conductor and voltage support to HVR)				
Extend PAS-03 from South Brook Park to HV Resort	303,000.00	2009	2008	2008
Transfer section of PAS-03 to PAS-01	15,000.00	2009	2008	2008
Install PAS-03-VR1 and PAS-03-VR2 regulators (500 amp)	160,000.00	2009	2008	2008
(All changes required to correct overload conditions on PAS-01 conductor and voltage support to HVR)				
Install PAS-04-R, including switches, Steel Bus etc	190,000.00	NA	2011	2009
Extend PAS-04 to HV Resort	688,000.00	NA	2011	2009
Install PAS-04-VR1, PAS-04-VR2	160,000.00	NA	2011	2009
Install PAS-05-R, including switches, Steel Bus etc	190,000.00	NA	NA	2013
Extend PAS-05 to HV Resort	688,000.00	NA	NA	2013
Install PAS-05-VR1, PAS-05-VR2	160,000.00	NA	NA	2013
Total		**2,421,000**	**3,459,000**	**4,710,000**

Humber Valley Resort				
		Year of Expenditures		
Alternative # 2 - Expand MMT Substation	**Cost**	**Low**	**Medium**	**High**
Installation of fans on PAS-T1 - (Without the installation of fans, PAS-T1 would be overloaded)	68,000.00	2006	2006	2006
Install PAS-01-VR2 regulators (500 amp) - Required for Voltage Support to Humber Valley Resort / Boomsiding	75,000.00	NA	2006	2006
Replace PAS-01-VR1 regulators (500 amp) - Required for overload on existing equipment	60,000.00	NA	2006	2006
Replace MMT-T1 with 25 MVA	1,413,000.00	2007	2007	2007
Install MMT-02 recloser and Switches	100,000.00	2007	2007	2007
Install MMT-02 Feeder (4.6 km)/ MMT-02-VR1 and MMT-02-VR2	413,000.00	2007	2007	2007
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2007	2007	2007
Extend MMT-01 Feeder (4.6 km)/ MMT-01-VR1 and MMT-01-VR2	413,000.00	2009	2009	2008
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2009	2009	2008
Install MMT-03 recloser and Switches	230,000.00	2011	2011	2009
Extend MMT-03 Feeder (4.6 km)	235,000.00	2011	2011	2009
Transfer load to MMT-03 from MMT-01 along with MMT-01 voltage regulators, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	2011	2011	2009
Extend MMT-01 Feeder (4.6 km)/ MMT-01-VR1 and MMT-01-VR2	413,000.00	NA	2020	2010
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	NA	2020	2010
Install MMT-03 recloser and Switches	230,000.00	NA	NA	2012
Extend MMT-03 Feeder (4.6 km)	235,000.00	NA	NA	2012
Transfer load, Install Sectionalizing Cutouts, Feeder Balancing and Renumbering	15,000.00	NA	NA	2012
Install MMT-T2 (10 MVA) - Reconfigure Bus	750,000.00	NA	NA	2016
Total		**2,917,000**	**3,480,000**	**4,710,000**

Humber Valley Resort				
		Year of Expenditures		
Alternative # 3 - Build LTR Substation	**Cost**	**Low**	**Medium**	**High**
Installation of fans on PAS-T1 - (Without the installation of fans, PAS-T1 would be overloaded)	68,000.00	2006	2006	2006
Site Preparation	75,000.00	2006	2006	2006
Install PAS-01-VR2 regulators (500 amp) - Required for Voltage Support to Humber Valley Resort / Boomsiding	75,000.00	NA	2006	2006
Replace PAS-01-VR1 regulators (500 amp) - Required for overload on existing equipment	60,000.00	NA	2006	2006
Install LTR Substation, 13.3 MVA LTR-01-R and Switches	1,300,000.00	2007	NA	NA
Install LTR Substation, 25 MVA LTR-01-R and Switches	1,413,000.00	NA	2007	2007
Install LTR-01 Feeder	87,000.00	2007	2007	2007
Transfer load from PAS-01 to LTR-01	15,000.00	2007	2007	2007
Install LTR-02 recloser and feeder	100,000.00	2010	2008	2008
Install LTR-02 Feeder	87,000.00	2010	2008	2008
Transfer load from LTR-01 to LTR-02	15,000.00	2010	2008	2008
Install LTR-03 recloser and feeder	100,000.00	NA	2021	2010
Install LTR-03 Feeder	140,000.00	NA	2021	2010
Transfer load from LTR-01 and LTR-02	15,000.00	NA	2021	2010
Total		**1,747,000**	**2,250,000**	**2,250,000**

Appendix F

Sensitivity Economic Analysis

Alternative #1 Low

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
	Transmission	**Substation**	**Distribution**	**Buildings**	**Capital Revenue Requirement**	**Operating Costs**	**Operating Benefits**	**Net Benefit**	**Present Worth Benefit**	**Cumulative Present Worth Benefit**
	30.6 yrs 8% CCA	38.5 yrs 8% CCA	30.4 yrs 8% CCA	33 yrs 4% CCA						
YEAR										
2006	0	68,000	0	0	8,374	0	0	-8,374	-7,733	-7,733
2007	0	0	167,970	0	29,209	0	0	-29,209	-24,908	-32,642
2008	0	1,754,844	15,530	0	243,359	0	0	-243,359	-191,638	-224,280
2009	0	0	503,289	0	268,866	0	0	-268,866	-195,516	-419,796
2010	0	0	0	0	257,830	0	0	-257,830	-173,138	-592,934
2011	0	0	0	0	258,465	0	0	-258,465	-160,277	-753,211
2012	0	0	0	0	258,452	0	0	-258,452	-148,000	-901,211
2013	0	0	0	0	257,844	0	0	-257,844	-136,349	-1,037,559
2014	0	0	0	0	256,689	0	0	-256,689	-125,347	-1,162,906
2015	0	0	0	0	255,031	0	0	-255,031	-115,003	-1,277,909
2016	0	0	0	0	252,909	0	0	-252,909	-105,315	-1,383,224
2017	0	0	0	0	250,360	0	0	-250,360	-96,273	-1,479,498
2018	0	0	0	0	247,420	0	0	-247,420	-87,859	-1,567,357
2019	0	0	0	0	244,119	0	0	-244,119	-80,051	-1,647,407
2020	0	0	0	0	240,486	0	0	-240,486	-72,822	-1,720,229
2021	0	0	0	0	236,547	0	0	-236,547	-66,146	-1,786,375
2022	0	0	0	0	232,328	0	0	-232,328	-59,993	-1,846,368
2023	0	0	0	0	227,850	0	0	-227,850	-54,332	-1,900,700
2024	0	0	0	0	223,134	0	0	-223,134	-49,135	-1,949,835
2025	0	0	0	0	218,199	0	0	-218,199	-44,370	-1,994,204
2026	0	0	0	0	213,063	0	0	-213,063	-40,009	-2,034,213

Alternative #1 Base

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Distribution 30.4 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2006	0	68,000	135,000	0	26,408	0	0	-26,408	-24,387	-24,387
2007	0	1,725,510	45,810	0	240,141	0	0	-240,141	-204,781	-229,167
2008	0	0	494,876	0	264,499	0	0	-264,499	-208,286	-437,453
2009	0	0	0	0	253,674	0	0	-253,674	-184,469	-621,922
2010	0	0	0	0	254,321	0	0	-254,321	-170,781	-792,703
2011	0	206,912	923,480	0	403,174	0	0	-403,174	-250,013	-1,042,716
2012	0	0	0	0	375,268	0	0	-375,268	-214,893	-1,257,610
2013	0	0	0	0	374,270	0	0	-374,270	-197,915	-1,455,524
2014	0	0	0	0	372,460	0	0	-372,460	-181,880	-1,637,404
2015	0	0	0	0	369,905	0	0	-369,905	-166,804	-1,804,208
2016	0	0	0	0	366,663	0	0	-366,663	-152,684	-1,956,893
2017	0	0	0	0	362,789	0	0	-362,789	-139,506	-2,096,399
2018	0	0	0	0	358,334	0	0	-358,334	-127,245	-2,223,644
2019	0	0	0	0	353,345	0	0	-353,345	-115,867	-2,339,511
2020	0	0	0	0	347,863	0	0	-347,863	-105,338	-2,444,849
2021	0	0	0	0	341,930	0	0	-341,930	-95,614	-2,540,463
2022	0	0	0	0	335,580	0	0	-335,580	-86,655	-2,627,118
2023	0	0	0	0	328,847	0	0	-328,847	-78,416	-2,705,534
2024	0	0	0	0	321,761	0	0	-321,761	-70,852	-2,776,386
2025	0	0	0	0	314,352	0	0	-314,352	-63,922	-2,840,308
2026	0	0	0	0	306,644	0	0	-306,644	-57,581	-2,897,889

Alternative #1 High

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
	Transmission	Substation	Distribution	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
	30.6 yrs 8% CCA	38.5 yrs 8% CCA	30.4 yrs 8% CCA	33 yrs 4% CCA						
YEAR										
2006	0	68,000	135,000	0	26,408	0	0	-26,408	-24,387	-24,387
2007	0	1,942,344	45,810	0	266,844	0	0	-266,844	-227,552	-251,939
2008	0	0	494,876	0	286,091	0	0	-286,091	-225,288	-477,227
2009	0	200,052	892,864	0	419,328	0	0	-419,328	-304,930	-782,157
2010	0	0	0	0	393,646	0	0	-393,646	-264,341	-1,046,498
2011	0	0	0	0	393,809	0	0	-393,809	-244,205	-1,290,704
2012	0	0	0	0	393,029	0	0	-393,029	-225,064	-1,515,768
2013	0	213,586	953,268	0	545,029	0	0	-545,029	-288,212	-1,803,980
2014	0	0	0	0	514,376	0	0	-514,376	-251,180	-2,055,161
2015	0	0	0	0	511,324	0	0	-511,324	-230,575	-2,285,736
2016	0	0	0	0	507,272	0	0	-507,272	-211,236	-2,496,972
2017	0	0	0	0	502,301	0	0	-502,301	-193,154	-2,690,126
2018	0	0	0	0	496,485	0	0	-496,485	-176,302	-2,866,428
2019	0	0	0	0	489,890	0	0	-489,890	-160,643	-3,027,071
2020	0	0	0	0	482,580	0	0	-482,580	-146,132	-3,173,203
2021	0	0	0	0	474,612	0	0	-474,612	-132,716	-3,305,919
2022	0	0	0	0	466,037	0	0	-466,037	-120,342	-3,426,261
2023	0	0	0	0	456,905	0	0	-456,905	-108,952	-3,535,214
2024	0	0	0	0	447,261	0	0	-447,261	-98,488	-3,633,701
2025	0	0	0	0	437,145	0	0	-437,145	-88,891	-3,722,593
2026	0	0	0	0	426,595	0	0	-426,595	-80,105	-3,802,698

Alternative #2 Low

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
	Transmission	Substation	Distribution	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth
	30.6 yrs 8% CCA	38.5 yrs 8% CCA	30.4 yrs 8% CCA	33 yrs 4% CCA						Benefit
YEAR										
2006	0	68,000	0	0	8,374	0	0	-8,374	-7,733	-7,733
2007	0	1,540,234	435,704	0	254,656	0	0	-254,656	-217,158	-224,892
2008	0	0	0	0	207,800	0	0	-207,800	-163,636	-388,528
2009	0	0	450,644	0	269,104	0	0	-269,104	-195,689	-584,217
2010	0	0	0	0	258,687	0	0	-258,687	-173,713	-757,930
2011	0	250,472	272,252	0	325,906	0	0	-325,906	-202,098	-960,028
2012	0	0	0	0	312,781	0	0	-312,781	-179,111	-1,139,139
2013	0	0	0	0	311,794	0	0	-311,794	-164,877	-1,304,016
2014	0	0	0	0	310,149	0	0	-310,149	-151,452	-1,455,468
2015	0	0	0	0	307,900	0	0	-307,900	-138,843	-1,594,311
2016	0	0	0	0	305,094	0	0	-305,094	-127,046	-1,721,358
2017	0	0	0	0	301,777	0	0	-301,777	-116,045	-1,837,402
2018	0	0	0	0	297,989	0	0	-297,989	-105,816	-1,943,218
2019	0	0	0	0	293,767	0	0	-293,767	-96,331	-2,039,549
2020	0	0	0	0	289,148	0	0	-289,148	-87,558	-2,127,107
2021	0	0	0	0	284,161	0	0	-284,161	-79,461	-2,206,567
2022	0	0	0	0	278,838	0	0	-278,838	-72,003	-2,278,570
2023	0	0	0	0	273,204	0	0	-273,204	-65,147	-2,343,718
2024	0	0	0	0	267,285	0	0	-267,285	-58,857	-2,402,574
2025	0	0	0	0	261,103	0	0	-261,103	-53,094	-2,455,668
2026	0	0	0	0	254,679	0	0	-254,679	-47,823	-2,503,491

Alternative #2 Base

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Distribution 30.4 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2006	0	68,000	135,000	0	26,408	0	0	-26,408	-24,387	-24,387
2007	0	1,540,234	435,704	0	269,408	0	0	-269,408	-229,738	-254,125
2008	0	0	0	0	222,548	0	0	-222,548	-175,250	-429,375
2009	0	0	450,644	0	283,811	0	0	-283,811	-206,384	-635,759
2010	0	0	0	0	273,318	0	0	-273,318	-183,538	-819,297
2011	0	250,472	272,252	0	340,429	0	0	-340,429	-211,104	-1,030,401
2012	0	0	0	0	327,168	0	0	-327,168	-187,349	-1,217,750
2013	0	0	0	0	326,017	0	0	-326,017	-172,398	-1,390,149
2014	0	0	0	0	324,184	0	0	-324,184	-158,305	-1,548,454
2015	0	0	0	0	321,723	0	0	-321,723	-145,077	-1,693,531
2016	0	0	0	0	318,685	0	0	-318,685	-132,706	-1,826,237
2017	0	0	0	0	315,117	0	0	-315,117	-121,174	-1,947,411
2018	0	0	0	0	311,059	0	0	-311,059	-110,457	-2,057,869
2019	0	0	0	0	306,553	0	0	-306,553	-100,524	-2,158,392
2020	0	0	542,454	0	374,096	0	0	-374,096	-113,281	-2,271,674
2021	0	0	0	0	355,609	0	0	-355,609	-99,439	-2,371,113
2022	0	0	0	0	349,943	0	0	-349,943	-90,364	-2,461,477
2023	0	0	0	0	343,805	0	0	-343,805	-81,983	-2,543,460
2024	0	0	0	0	337,231	0	0	-337,231	-74,259	-2,617,719
2025	0	0	0	0	330,258	0	0	-330,258	-67,156	-2,684,875
2026	0	0	0	0	322,917	0	0	-322,917	-60,637	-2,745,512

Alternative #2 High

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year 2005

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Distribution 30.4 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
2006	0	68,000	135,000	0	26,408	0	0	-26,408	-24,387	-24,387
2007	0	1,540,234	435,704	0	269,408	0	0	-269,408	-229,738	-254,125
2008	0	0	443,111	0	281,741	0	0	-281,741	-221,863	-475,988
2009	0	242,168	263,227	0	337,019	0	0	-337,019	-245,076	-721,064
2010	0	0	458,305	0	386,583	0	0	-386,583	-259,598	-980,661
2011	0	0	0	0	375,379	0	0	-375,379	-232,777	-1,213,438
2012	0	254,480	276,608	0	442,831	0	0	-442,831	-253,582	-1,467,020
2013	0	0	0	0	428,440	0	0	-428,440	-226,560	-1,693,580
2014	0	0	0	0	426,182	0	0	-426,182	-208,113	-1,901,694
2015	0	0	0	0	423,075	0	0	-423,075	-190,781	-2,092,474
2016	0	886,835	0	0	528,402	0	0	-528,402	-220,035	-2,312,510
2017	0	0	0	0	502,887	0	0	-502,887	-193,380	-2,505,889
2018	0	0	0	0	498,246	0	0	-498,246	-176,927	-2,682,816
2019	0	0	0	0	492,750	0	0	-492,750	-161,581	-2,844,397
2020	0	0	0	0	486,467	0	0	-486,467	-147,309	-2,991,706
2021	0	0	0	0	479,461	0	0	-479,461	-134,072	-3,125,778
2022	0	0	0	0	471,789	0	0	-471,789	-121,828	-3,247,606
2023	0	0	0	0	463,504	0	0	-463,504	-110,526	-3,358,131
2024	0	0	0	0	454,657	0	0	-454,657	-100,116	-3,458,248
2025	0	0	0	0	445,291	0	0	-445,291	-90,548	-3,548,795
2026	0	0	0	0	435,448	0	0	-435,448	-81,768	-3,630,563

Alternative #3 Low

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year 2005

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Distribution 30.4 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2006	0	143,000	0	0	17,611	0	0	-17,611	-16,262	-16,262
2007	0	1,323,400	103,836	0	191,088	0	0	-191,088	-162,951	-179,213
2008	0	0	0	0	157,465	0	0	-157,465	-123,999	-303,212
2009	0	0	0	0	158,458	0	0	-158,458	-115,228	-418,441
2010	0	107,081	109,222	0	186,795	0	0	-186,795	-125,436	-543,877
2011	0	0	0	0	181,777	0	0	-181,777	-112,722	-656,599
2012	0	0	0	0	181,644	0	0	-181,644	-104,016	-760,615
2013	0	0	0	0	181,113	0	0	-181,113	-95,773	-856,388
2014	0	0	0	0	180,217	0	0	-180,217	-88,004	-944,392
2015	0	0	0	0	178,985	0	0	-178,985	-80,711	-1,025,103
2016	0	0	0	0	177,443	0	0	-177,443	-73,890	-1,098,994
2017	0	0	0	0	175,617	0	0	-175,617	-67,531	-1,166,525
2018	0	0	0	0	173,528	0	0	-173,528	-61,620	-1,228,145
2019	0	0	0	0	171,198	0	0	-171,198	-56,139	-1,284,284
2020	0	0	0	0	168,647	0	0	-168,647	-51,069	-1,335,352
2021	0	0	0	0	165,892	0	0	-165,892	-46,389	-1,381,741
2022	0	0	0	0	162,949	0	0	-162,949	-42,077	-1,423,818
2023	0	0	0	0	159,833	0	0	-159,833	-38,113	-1,461,931
2024	0	0	0	0	156,559	0	0	-156,559	-34,475	-1,496,406
2025	0	0	0	0	153,138	0	0	-153,138	-31,140	-1,527,546
2026	0	0	0	0	149,583	0	0	-149,583	-28,088	-1,555,634

Alternative #3 Base

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year **2005**

	CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE									
	Transmission	Substation	Distribution	Buildings	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
	30.6 yrs 8% CCA	38.5 yrs 8% CCA	30.4 yrs 8% CCA	33 yrs 4% CCA						
YEAR										
2006	0	143,000	135,000	0	35,645	0	0	-35,645	-32,916	-32,916
2007	0	1,438,434	103,836	0	220,007	0	0	-220,007	-187,611	-220,527
2008	0	103,531	105,601	0	210,524	0	0	-210,524	-165,782	-386,309
2009	0	0	0	0	206,549	0	0	-206,549	-150,200	-536,509
2010	0	0	0	0	207,152	0	0	-207,152	-139,107	-675,616
2011	0	0	0	0	207,238	0	0	-207,238	-128,511	-804,126
2012	0	0	0	0	206,847	0	0	-206,847	-118,449	-922,575
2013	0	0	0	0	206,018	0	0	-206,018	-108,943	-1,031,518
2014	0	0	0	0	204,786	0	0	-204,786	-100,001	-1,131,519
2015	0	0	0	0	203,182	0	0	-203,182	-91,622	-1,223,141
2016	0	0	0	0	201,237	0	0	-201,237	-83,799	-1,306,940
2017	0	0	0	0	198,979	0	0	-198,979	-76,515	-1,383,455
2018	0	0	0	0	196,431	0	0	-196,431	-69,753	-1,453,208
2019	0	0	0	0	193,618	0	0	-193,618	-63,490	-1,516,698
2020	0	0	0	0	190,560	0	0	-190,560	-57,704	-1,574,402
2021	0	128,896	199,789	0	229,839	0	0	-229,839	-64,270	-1,638,672
2022	0	0	0	0	218,454	0	0	-218,454	-56,410	-1,695,083
2023	0	0	0	0	214,859	0	0	-214,859	-51,235	-1,746,317
2024	0	0	0	0	210,998	0	0	-210,998	-46,462	-1,792,779
2025	0	0	0	0	206,891	0	0	-206,891	-42,070	-1,834,850
2026	0	0	0	0	202,559	0	0	-202,559	-38,036	-1,872,886

Alternative #3 High

Present Worth Analysis

Weighted Average Incremental Cost of Capital **8.29%**

PW Year 2005

CAPITAL EXPENDITURE IN YEAR BY ASSET TYPE

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Distribution 30.4 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue Requirement	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2006	0	143,000	135,000	0	35,645	0	0	-35,645	-32,916	-32,916
2007	0	1,438,434	103,836	0	220,007	0	0	-220,007	-187,611	-220,527
2008	0	103,531	105,601	0	210,524	0	0	-210,524	-165,782	-386,309
2009	0	0	0	0	206,549	0	0	-206,549	-150,200	-536,509
2010	0	107,081	165,975	0	242,511	0	0	-242,511	-162,851	-699,360
2011	0	0	0	0	236,037	0	0	-236,037	-146,370	-845,729
2012	0	0	0	0	235,718	0	0	-235,718	-134,981	-980,711
2013	0	0	0	0	234,883	0	0	-234,883	-124,207	-1,104,917
2014	0	0	0	0	233,576	0	0	-233,576	-114,060	-1,218,977
2015	0	0	0	0	231,834	0	0	-231,834	-104,543	-1,323,520
2016	0	0	0	0	229,691	0	0	-229,691	-95,647	-1,419,167
2017	0	0	0	0	227,180	0	0	-227,180	-87,359	-1,506,527
2018	0	0	0	0	224,330	0	0	-224,330	-79,660	-1,586,186
2019	0	0	0	0	221,168	0	0	-221,168	-72,525	-1,658,711
2020	0	0	0	0	217,719	0	0	-217,719	-65,928	-1,724,639
2021	0	0	0	0	214,007	0	0	-214,007	-59,843	-1,784,482
2022	0	0	0	0	210,051	0	0	-210,051	-54,240	-1,838,722
2023	0	0	0	0	205,872	0	0	-205,872	-49,092	-1,887,814
2024	0	0	0	0	201,488	0	0	-201,488	-44,368	-1,932,182
2025	0	0	0	0	196,915	0	0	-196,915	-40,042	-1,972,224
2026	0	0	0	0	192,168	0	0	-192,168	-36,085	-2,008,309

Transmission Line Rebuild Strategy

June 2005

Prepared by:

Keith Whiteway, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
G.R. SPURRELL
SIGNATURE
PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Executive Summary

This report outlines a 10 year plan to rebuild Newfoundland Power's aging transmission lines to ensure a safe and reliable supply of electricity to customers.

The important role transmission lines play in providing reliable service to large numbers of customers requires they be rebuilt before they deteriorate to the point that they fail in service. While the Company's approach to distribution reliability improvement includes rebuilding and upgrading those feeders that have the worst reliability performance on a targeted basis, that approach is not recommended for establishing priority for transmission line upgrading and rebuilding. Transmission lines serve more customers and therefore have a higher degree of overall electrical system criticality than distribution lines.

Assessment of current reliability performance statistics alone will not necessarily identify transmission lines that are at risk of failure. Field assessment of actual asset conditions are essential to establishing a sound capital maintenance strategy for transmission systems.

Newfoundland Power intends to redesign and rebuild its oldest and most deteriorated lines on a priority basis over the next 10 years at a total estimated cost of $43.5 million. Priority will be determined by the physical condition of the lines, the risk of line failure and the impact failure would have on customers.

Those transmission lines built in the late 1960s, the 1970s and beyond were designed and built to a higher standard than many of the older lines and are close to, or meet, present design and construction standards. These lines are expected to require only regular capital maintenance and component replacement to maintain their integrity through the 10 year transmission planning horizon.

2.0 Description of Newfoundland Power's Transmission Lines

Newfoundland Power has 104 transmission lines in service with a total length of 2,056 km. These lines range in length from 2 km to 94 km with an average length of 19 km.

2.1 Line Classification

Three different voltage classes exist within Newfoundland Power's electrical system, 33 kV, 66 kV, and 138 kV. The total length of lines in each of these voltages is set out in Table 1.

Table 1
Transmission Lines by Voltage

Voltage	Length (km)	%
33 kV	26	1
66 kV	1,410	69
138 kV	620	30

The total number of transmission poles in service is approximately 27,000, with the vast majority being pressure treated wood. A small number are specialty constructions of either steel or laminated wood. Lines are one of two structural configurations: H-frame or Single Pole, with 138 kV lines being of H-frame design and 66 kV lines being of either H-frame or Single Pole design. Table 2 summarizes the Company's transmission lines by structure configuration.

Table 2
Transmission Lines by Structure

Structure	Length (km)	%
H-Frame	1,186	58
Single Pole	870	42

2.2 Radial and Looped Lines

Many of Newfoundland Power's transmission lines are radial (i.e. there is only one transmission line path from the main supply point to the customer). These lines are predominately found in rural areas. When radial lines fail, customers are without power until the line is repaired.

Some of Newfoundland Power's radial lines have backup capability in the form of diesel generators, gas turbines or hydro generating plants. In the event of the failure of one of these radial lines the backup generation may be able to provide sufficient power to serve some or all of the customers depending on the time of year and how much generating capacity is available at the time of line failure.

When there is more than one transmission path from the customer to the main grid, these lines are categorized as looped lines. These are more common in urban areas. Failure of a looped line normally does not result in an outage to customers. Customers served by looped transmission lines receive a higher reliability of service than those served from radial transmission systems. As well, looped lines are more conveniently maintained as repair work can be completed on a de-energized line without the need for coordinating planned service interruptions with customers.

Table 3 summarizes the Company's transmission lines as radial or looped, identifying the proportion of radial lines with generation backup.

Table 3 Transmission Lines Radial or Looped		
Type	**Length (km)**	**%**
Radial	496	24
Radial (partial backup)	440	22
Looped	1,120	54

2.3 Age of Lines

Currently, the oldest original transmission line still in service was built in 1942 while the newest line was built in 1997. Several lines and parts of lines have been upgraded or completely rebuilt over the years. Table 4 shows the vintage of transmission lines in service and takes into account the sections of lines that have been rebuilt.

Table 4 Transmission Lines by Vintage	
Vintage	**km**
1940s	11
1950s	321
1960s	470
1970s	748
1980s	269
1990s	120
2000s	117
Total	**2,056**

3.0 Transmission Line Design

Newfoundland Power designs lines to meet Canadian Standard Association ("CSA") standards and guidelines. In keeping with CSA standards Newfoundland Power generally designs transmission lines to withstand 12.5 mm of radial ice on conductors with 90 km/hr wind or 25 mm of radial ice on conductor with no wind. On the Avalon and Bonavista Peninsulas, where ice loading is more severe, Newfoundland Power designs its lines to withstand 18.0 mm of radial ice on conductors with 90 km/hr wind.

Prior to the amalgamation of the three largest utilities in the province in 1966 (United Towns Electric, Newfoundland Light & Power, and Union Electric) there was limited transmission design expertise in any utility. There was little consistency in the design of transmission lines and, as a result, many lines built before 1960 were not designed to any standard (and do not meet present day standards).

During the 1960s a number of lines were designed by out of province engineering consultants. For example, Montreal Engineering Company designed many lines during the 1960s and early 1970s when the transmission system was expanding quickly with the drive to electrify the island following the formation of the Power Commission and development of the large Bay d'Espoir hydro generation station. In addition, by the 1970s, the amalgamated Newfoundland Light & Power had developed its own transmission line design and construction expertise. These developments largely explain why the majority of lines built in the 1970s and beyond were designed and constructed to meet present day standards.

4.0 Transmission Line Construction

A transmission line is only as strong as its weakest component or structure. Transmission lines are often built "across country", away from roads in long straight sections which results in the least cost construction to connect system supply points and substations. Along straight transmission line sections, the structures are more exposed to cascading failure (when one structure fails the additional loading placed on adjacent structures causes a chain reaction of multiple structure failures). Reducing the risk of cascading structure failures requires careful line inspection and replacement of components and structures before a single component failure occurs.

Two relatively recent examples of cascading failures occurred in 1992 and 1998. In 1992, a 4.3 km section of H-frame 138 kV line failed on 123L on the Bonavista Peninsula. In 1998, a 6.6 km section of H-frame 66 kV line failed on 305L on the Burin Peninsula.

Lines that are built away from the roadside or in remote locations are more difficult to patrol and locate problems and take a longer time to repair and restore to service. Often when sections of transmission lines fail (such as major ice storm damage) the requirement to restore power as soon as possible eliminates the opportunity to redesign and upgrade the line to a stronger standard.

Such was the case in the example of 123L noted above. In that case, because it was a radial line, the section that failed was temporarily rebuilt under emergency conditions to the same design standard prior to failure. The following year this newly constructed section of line was re-designed to a higher ice loading standard and rebuilt again.

5.0 Transmission Line Aging

Transmission lines can supply a single substation but generally supply several substations and multiple distribution feeders. They are a critical link in the electrical system in the transport of generated power to the distribution system. While feeders typically supply several hundred up to two thousand customers, transmission lines often supply a few thousand up to tens of thousands of customers. Therefore it is important that transmission lines be designed, constructed and maintained to provide a high degree of reliability. As transmission lines age and deteriorate they become subjected to increased risk of component failure. To ensure reliable performance: (i) older lines must be inspected regularly, (ii) the risk of component and structural failure must be assessed carefully, and (iii) any suspect components and structures must be replaced before failure occurs.

Newfoundland's weather and environment subjects transmission lines to high winds, salt contamination, lightning, ice and snow loading, and frequent freeze/thaw and wet/dry cycles. Wooden components of transmission lines are susceptible to fungi growth (rot), insect damage and weathering causing deep splits and cracks which further advances rotting. Wind causes stresses and vibration on structures with resulting wear and tear on hardware components and conductors. Exposure to lightning, salt contamination and mechanical stresses can cause insulators to age and breakdown. After 40 to 50 years of exposure to the elements many line components are deteriorated to the point they are weakened and at risk of failure.

Transmission lines of sub-standard design and lines that are not engineered to withstand the local environmental conditions in which the line operates will be more susceptible to failure.

6.0 Line Rebuild and Maintenance Strategy

The important role transmission lines play in providing reliable service to large numbers of customers requires that they be rebuilt before they deteriorate to the point that they are at significant risk of failure. While the Company's approach to distribution reliability improvement includes rebuilding and upgrading those feeders that have the worst reliability performance, that approach is not recommended for establishing priority for transmission line upgrading and rebuilding. Transmission lines serve more customers and have a higher degree of overall electrical system criticality than distribution lines. Therefore the strategy is to proactively rebuild transmission lines before they start experiencing failures due to deteriorated condition and aging.

Rebuilding lines after they have collapsed is expensive and the pressure to restore service quickly does not permit sufficient time to design and construct the new line to a higher standard (i.e. often the only practical approach following a major line failure is to put back the line as it was beforehand). This replacement strategy identifies lines at risk and establishes a plan for replacement in a proactive manner.

6.1 Sub-Standard Lines

Sub-standard lines will be rebuilt completely to meet present design and construction standards. Newfoundland Power will rebuild its oldest and most deteriorated lines on a priority basis. Priority will be determined by the physical condition of the lines, the risk of line failure and the impact failure would have on customers.

Some 37 transmission lines built in the 1940s, 50s and 60s have been identified as sub-standard lines to be rebuilt over the next 10 years.

6.2 Standard Lines

Those lines built in the 1970s and beyond, and some built in the 1960s, were designed and built to a higher standard than many of the older lines and are close to, or meet, present design and construction standards.

Standard lines are expected to require only regular maintenance and component replacement to maintain their integrity through the 10 year transmission planning horizon.

7.0 Proposed Transmission Line Rebuilds: 2006 to 2015

To redesign and rebuild Newfoundland Power's sub-standard transmission lines will require an expenditure of approximately $43.5 million. To fulfill the Company's obligation to provide reliable electric service at least cost, it is recommended that these capital costs be allocated over a ten year period beginning in 2006. The rebuilding of sub-standard transmission lines is prioritized based on several factors including age, condition, location and impact on customers should the line fail.

Table 5 shows the proposed transmission rebuilds for the period 2006 to 2015.

The timing of actual rebuilds may change, however, it is anticipated that proposed expenditures for transmission rebuilds for each year will form part of Newfoundland Power's annual capital budget applications through to 2015.

Table 5
Transmission Line Rebuilds: 2006 – 2015 ($000s)

Line	Year Built	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Totals
12L KBR-MUN	1950			240								**240**
13L SJM-SLA	1962										180	**180**
14L SLA-MUN	1950				70							**70**
15L SLA-MOL	1958				140							**140**
16L PEP-KBR	1950						250					**250**
18L GOU-GDL	1952				420							**420**
20L MOB-CAB	1951		675	567	567							**1,809**
21L 20L-HCP	1952					355						**355**
23L MOB-PBK	1942					357						**357**
25L GOU-SJM	1954			760								**760**
30L RRD-KBR	1959		340									**340**
32L OXP-RRD	1963					217						**217**
35L OXP-KEN	1959					238					160	**398**
41L CAR-HCT	1958					1,425						**1,425**
43L HCT-NCH	1956	1,081	441									**1,522**
49L HWD-CHA	1966				189							**189**
55L BLK-CLK (upgrading)	1971		250									**250**
57L BRB-HGR	1958				1,350							**1,350**
68L HGR-CAR	1958				390							**390**
69L KEN-SLA	1951		269									**269**
94L BLK-RVH (upgrading)	1969				250							**250**
95L RVH-TRP (upgrading)	1969		250									**250**
102L GAN-RBK	1958					690	1,193	1,500		1,193		**4,576**
110L CLV-LOK	1958	604	1,269		900		990				990	**4,753**
111L LOK-CAT	1956			2,325								**2,325**
124L CLV-GAM	1964		390				1,000	756	1,500	1,593	900	**6,139**
146L GAN-GAM	1964			1,105					1,190	1,190		**3,485**
302L SPO-LAU	1959		200			1,560						**1,760**
407L STV-STG	1956	658										**658**
24L MOB-BIG	1964							539				**539**
53L 38L-GEA	1961						420					**420**
301L SPO-GRH	1959								70			**70**
100L SUN-CLV	1964							1,500				**1,500**
101L GFS-RBK	1957						2,100					**2,100**
105L GFS-SBK	1963								980			**980**
400L BBK-WHE	1967										2,000	**2,000**
403L TAP-ROB	1960								280			**280**
Total		**$ 2,343**	**$ 4,084**	**$ 4,997**	**$ 4,276**	**$ 4,842**	**$ 5,953**	**$ 4,295**	**$ 4,020**	**$ 3,976**	**$ 4,230**	**$43,016**

110L Transmission Line Rebuild

June 2005

Prepared by:

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1.0 Description of Line

110L is a 66,000 volt transmission line built in 1958 between Clarenville Substation and Lockston Substation on the Bonavista Peninsula. Much of the line is within several kilometres of the coastline and is subjected to salt contamination, high winds and icing. The line has a total length of 79 km and is of single wood pole construction. In 1966, a 17.4 km section of the line was upgraded and between 1972 and 1974, an 18.2 km section was upgraded. The majority of the existing line (43.4 km) is the original 1958 construction.

110L serves approximately 4000 customers of the Bonavista Peninsula between Milton and Lockston. This line also connects the Lockston hydro plant to the main electrical grid.

2.0 Condition of line

Since 2001, there have been 10 outages on this line due to wind and ice conditions causing conductors to slap together. This results in conductor damage and often conductor failure. The most recent occurrences happened in December 2003 and April 2004 when ice build-up on overhead conductors caused the line to fail resulting in outages to customers.

The table below summarizes unplanned power interruptions experienced on 110L since 2001.

Date of Outage	Length of Outage (minutes)	Cause of Outage	Part that Failed
2001-05-09	39	Deterioration	Insulator
2002-08-17	60	Lightning	Insulator
2002-08-18	123	Lightning	Insulator
2002-09-12	69	Wind	Conductor
2003-04-13	52	Ice	Guy wire
2003-06-02	35	Lightning	Insulator
2003-12-09	2	Ice	Conductor
2003-12-09	2	Ice	Conductor
2003-12-09	36	Ice	Conductor
2004-04-25	32	Ice	Conductor

This report focuses on the 21 km section of 110L west of the Community of Lockston (see topographical map in Appendix A). Apart from a 9 km section that was rebuilt in 1974, this section is the most deteriorated of the entire 110L transmission line.

Inspections of this section of the line have identified substantial deterioration with evidence of external and/or internal rotting, insect and woodpecker damage, cracks and splits in poles, crossarms and other hardware. Many of the components of the line are in advanced stages of deterioration and require replacement. (See pictures in Appendix B.)

The existing conductor is a 1/0 ACSR (small by current standards) and is damaged and deteriorated in many places. The conductor has been subjected to ice loading since its original installation in 1958. The steel core of the conductor shows evidence of rust and the aluminum strands are corroded which reduces the physical strength and the electrical capacity of the conductor. This conductor has deteriorated to the point that the line has been de-rated to 30% of its original load carrying capacity out of concern that it will burn off and fall to the ground.

3.0 Recommendations

The poles, conductor, crossarms and hardware are deteriorated and in a weakened state. This places the line at risk of causing more frequent power outages and vulnerable to large scale damage should it become exposed to heavy wind, ice and snow loading.

Based on the condition of this line, it is recommended that 6.7 km of 110L be rebuilt in 2006 at a cost of $604,000. The report *3.2.1 Bonavista Loop Transmission Planning* compared alternatives for addressing transmission line requirements on the Bonavista Peninsula, including the rebuilding of 110L as recommended in this report. The analysis determined that the rebuilding of 110L, which is required in order to ensure the continued provision of safe, reliable electrical service, is the most cost-effective alternative.

Appendix A

Topographical Map

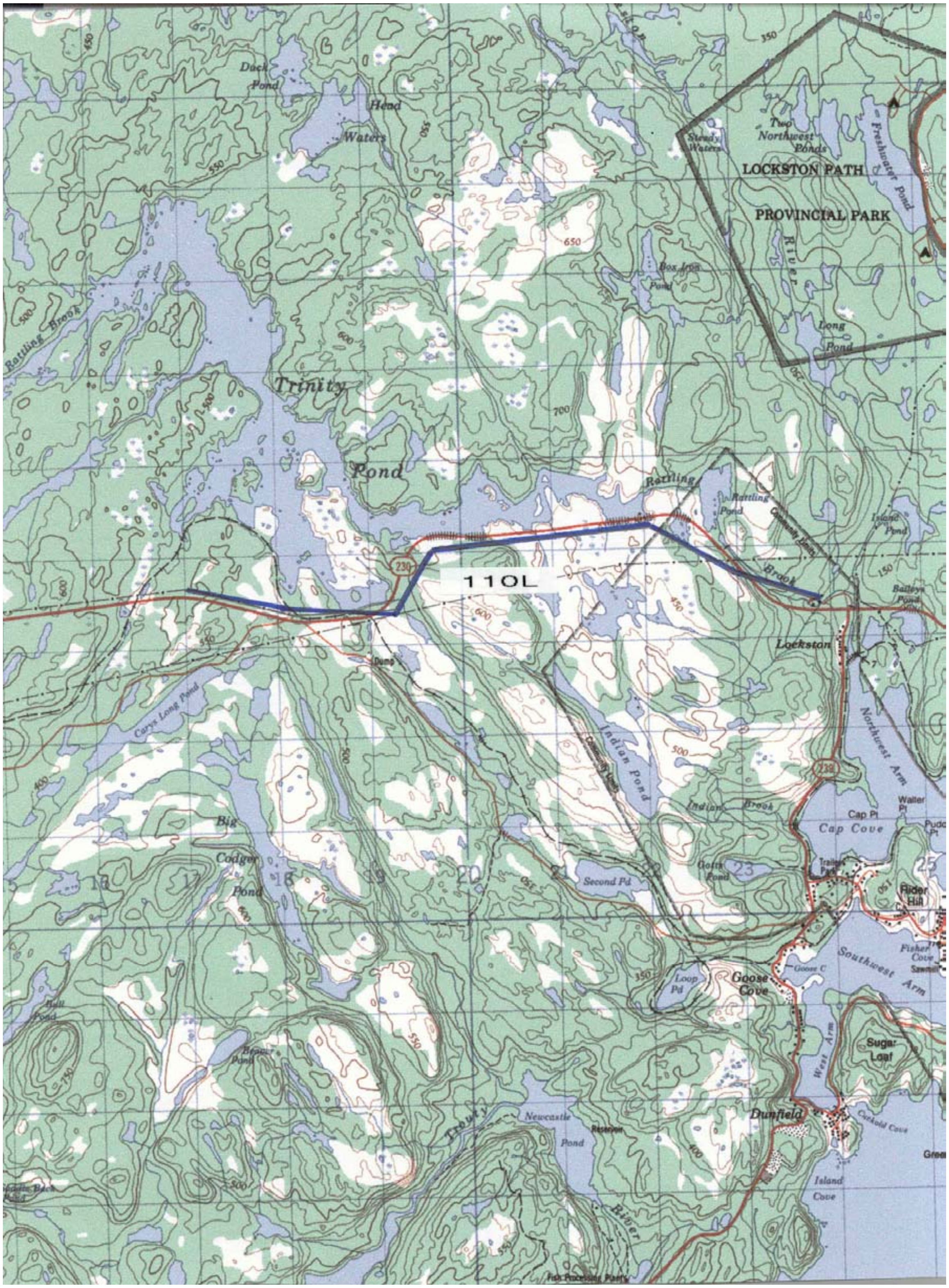

Figure 1 Section of 110L to be rebuilt (outlined in blue)

Appendix B

Pictures of Transmission Line

Figure 2 110L Ice Storm Damage December 2003

Figure 3 110L Broken conductor - ice build up December, 2003

Figure 4 Deteriorated pole 110L

Figure 5 Deteriorated pole 110L

Bonavista Loop Transmission Planning

June 2005

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1.0 Introduction & Executive Summary

Consistent with the Newfoundland Power transmission line rebuild strategy, the "110L Transmission Line Rebuild" report recommends the rebuilding of the 66 kV transmission line (110L) between Clarenville and Lockston beginning in 2006. This presents an opportunity to evaluate whether 110L should be rebuilt at 66 kV or whether that system should be rebuilt and operated at 138 kV.

This report examines the current Bonavista Peninsula system and evaluates the alternatives associated with the replacement of 110L and 111L transmission lines. Reliability of supply to customers is an important consideration when developing alternatives for the Bonavista Peninsula. The extent to which normal supply can be maintained to all customers during an outage is an important element in examining alternatives.

The Bonavista Peninsula is supplied electricity via two transmission routes (110L/111L-66 kV and 123L-138 kV, see diagram on page 2). The ability to supply the Bonavista Peninsula with only a 66 kV system is limited. System modeling indicates that with an outage to 123L (93.7 km 138 kV line from Clarenville to Catalina) the transmission system can supply a voltage within acceptable standards to the Bonavista Peninsula for up to 45% of the peak load[1], typically between July 9th to August 22nd (refer to load curve in Appendix 1).

The recommended alternative rebuilds 110L and 111L (at the existing 66 kV voltage) using 477 ASC conductor. With this alternative the worst-case contingency of an outage to 123L permits 75% of peak load to be supplied[2]. The increase in load carrying capability from 45% to 75% of peak load permits the window for 123L planned or unplanned outages without significant customer outages, to be increased from 6 weeks to 38 weeks. In the remaining weeks of the year it permits continued supply to all customers but with times of day when load shedding would be required. The recommended alternative is summarized in Table 1.

Year	Activity	Capital Cost
2006	Rebuild 110L (LOK - SMV) 6.7 km	$ 604,000
2007	Rebuild 110L (LOK - SMV) 14.1 km	$1,269,000
2008	Rebuild 111L (LOK - CAT) 31 km	$2,325,000
2009	Rebuild 110L (SMV - LET) 10 km	$ 900,000
2011	Rebuild 110L (SMV - LET) 11 km	$ 990,000
2015	Rebuild 110L (LET - MIL) 11 km	$ 990,000
2016	Rebuild 110L (LET - MIL) 9.6 km	$ 864,000
2018	Rebuild 110L (MIL - CLV) 16.5 km	$1,485,000
TOTAL		**$9,427,000**

Table 1: Recommended Alternative

[1] When the voltage at the CLV 66 bus is boosted to 1.05 p.u. and the hydraulic generation at Lockston and Port Union is used to supply voltage support. P.U. means per unit. It is the voltage divided by the nominal voltage for that transmission or distribution bus. For example, 69.3 kV on a 66 kV nominal bus would be 1.05 p.u.

[2] Ibid

2.0 The Existing System

A diagram of the Bonavista Peninsula transmission system is shown below in Figure 1.

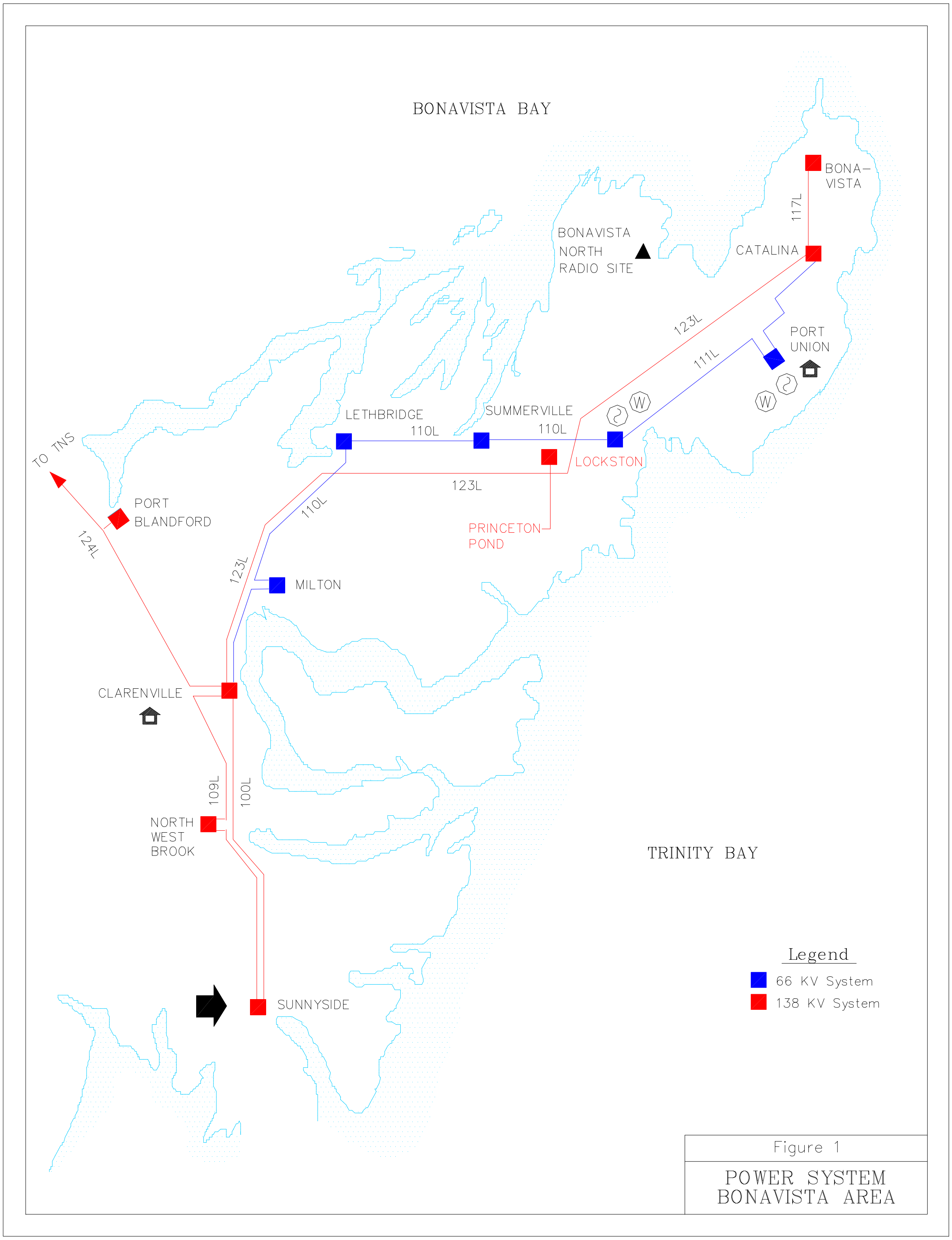

Figure 1

POWER SYSTEM BONAVISTA AREA

2.1 Power Supply for the Bonavista Peninsula

The Bonavista area is supplied electricity from Newfoundland & Labrador Hydro's (NLH) 230 kV grid through Sunnyside. An NP owned 138 kV system extends from Sunnyside and consists of the following transmission lines:

- 100L and 109L, from Sunnyside (SUN) to Clarenville (CLV)
- 123L, from Clarenville (CLV) to Catalina (CAT)
- 117L, from Catalina (CAT) to Bonavista (BVA)

The 138 kV system supplies electricity to Bonavista area’s 66 kV system, which consists of the following transmission lines:

- 110L, from CLV to Lockston (LOK) via Milton (MIL) Lethbridge (LET) and Summerville (SMV)
- 111L, from LOK to CAT, via Port Union (PUN)

A list of the Bonavista area transmission lines is provided in Appendix 2.

There is a combined total of 3.56 MW of hydroelectric generation in the Bonavista area, from the following sources:

- 3.00 MW at Lockston Plant
- 0.56 MW at Port Union Plant

This study will focus on that part of the Bonavista system that serves customers supplied from the following substations:

- MIL - 2,122 customers
- LET - 1,840 customers
- SMV - 1,020 customers
- LOK - 1,022 customers
- CAT - 1,095 customers
- BVA - 2,399 customers

The remaining Bonavista system customers supplied via Clarenville, Sunnyside and Northwest Brook substations are unaffected by the options chosen to replace the existing 110L/111L transmission lines.

2.2 Operation of the Existing Transmission System

As part of the operation of the existing transmission line, when deficiencies are identified, the repair can either be done with the line energized or de-energized. If 123L is de-energized to perform maintenance, the existing system capacity is limited to 45% of the peak load. As seen in the 2003 load curve in Appendix 1, this translates into approximately a 6-week window in mid summer when maintenance can be completed on the transmission line without causing an outage to customers. Extending the window of opportunity permits greater flexibility for planning and scheduling transmission line repair. These same windows apply in circumstances where a transmission line fails unexpectedly and where customers can be supplied without significant outages.

3.0 Load Forecast

The forecasted substation peak demands for the Bonavista Peninsula are indicated in Table 2.

	Peak (MVA)	Forecasted Peaks (MVA)					
Substation	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Bonavista	12.7	13.7	13.8	13.8	13.9	14.0	14.1
Catalina	4.9	5.3	5.3	5.3	5.4	5.4	5.5
Lethbridge	6.1	6.3	6.4	6.4	6.4	6.5	6.5
Lockston	2.8	3.0	3.0	3.0	3.1	3.1	3.1
Milton	7.2	7.7	7.8	7.8	7.9	7.9	8.0
Summerville	2.3	2.5	2.5	2.5	2.6	2.6	2.6
Total	**36.0**	**38.5**	**38.8**	**38.8**	**39.3**	**39.5**	**39.8**

Table 2: 5 Year Substation Forecast

Newfoundland Power's substation forecasting methodology is based on the previous year's peak, forecasted energy growth and for the first year, consideration for a 1 in 10 year worst than normal peak. Referring to Table 2, the increase from 2004 to 2005 is primarily due to consideration for the 1 in 10 year worst than normal peak. The remaining years of the forecast (2006 – 2010) are then adjusted from the previous year by forecasted energy growth only.

4.0 Technical Analysis and Development of Alternatives

Based on substation forecasted peaks for a given year, load flow analysis can indicate whether or not the alternatives can perform within the established technical criteria. Appendix 3 of this report outlines the technical criteria used to evaluate the existing system and the associated alternatives.

4.1 Analysis of Existing System

The analysis is completed for several operating conditions but of particular importance is an outage to the 123L 138 kV transmission line from Clarenville to Catalina. Since 123L is the main electrical supply to the Bonavista Peninsula (also supplying 111L and part of 110L through a 138 kV to 66 kV transformation at CAT) it has the greatest impact on system loading should it fail. Under normal peak conditions the system can operate within the technical criteria. However for an outage on the 123L transmission line, the low voltage criterion is violated. The maximum load that can be supplied for the existing system with 123L out is 45% of peak provided the following changes are implemented:

- PUN and LOK must be used to provide voltage support to the system.
- CLV-T1 must be set to supply 1.05 P.U. voltage on the 66 kV bus
- CAT-T1 onload tap changer must be set to maintain voltage on the 138 kV bus.

Under these circumstances, all Bonavista Peninsula substations are supplied via the 66 kV transmission system that extends from Clarenville within the technical criteria, to a maximum of 45% of peak. Beyond 45% of peak under these circumstances, load rationing must occur.

4.2 Analysis of Alternatives Considered

Two alternatives were developed as part of rebuilding the Bonavista System. Opportunities are sought to improve reliability and enhance system capabilities while still meeting the technical criteria.

1) Rebuild 110L & 111L at 66 kV

Rebuilding transmission lines 110L & 111L from CLV to CAT with 477 ASC enables the system to supply 75% of the peak load with 123L out of service and 100% of the peak load when 110L from CLV to MIL is out of service late March to mid December[3]. Table 3 outlines the capital costs involved with this option.

Year	Activity	Capital Cost
2006	Rebuild 110L (LOK - SMV) 6.7 km	$ 604,000
2007	Rebuild 110L (LOK - SMV) 14.1 km	$1,269,000
2008	Rebuild 111L (LOK - CAT) 31 km	$2,325,000
2009	Rebuild 110L (SMV - LET) 10 km	$ 900,000
2011	Rebuild 110L (SMV - LET) 11 km	$ 990,000
2015	Rebuild 110L (LET - MIL) 11 km	$ 990,000
2016	Rebuild 110L (LET - MIL) 9.6 km	$ 864,000
2018	Rebuild 110L (MIL - CLV) 16.5 km	$1,485,000
TOTAL		**$9,427,000**

Table 3: Capital Costs Associated With Rebuilding 110L & 111L at 66 kV

2) Upgrade 110L & 111L 66 kV System to 138 kV

Rebuilding transmission lines 110L & 111L from CLV to CAT with 397.5 ACSR and operating them at 138 kV, will enable the system to supply 100% of the peak load with 123L out of service and 100% of the peak load when 110L from CLV to MIL is out of service. Table 4 outlines the capital costs involved with this option.

[3] PUN and LOK must be used to provide voltage support to the system, CLV-T1 must be set to supply 1.05 P.U. voltage on the 66 kV bus and the CAT-T1 onload tap changer must be set to maintain the voltage on the 138 kV bus.

Year	Activity	Capital Cost
2006	Rebuild 110L (LOK - SMV) 6.7 km	$ 636,500
2006	Rebuild LOK to 138 kV	$ 2,000,000
2007	Rebuild 110L (LOK - SMV) 14.1 km	$ 1,339,500
2007	Rebuild SMV to 138 kV	$ 1,250,000
2008	Rebuild 111L (LOK - CAT) 31 km	$ 2,945,000
2008	Rebuild CAT to 138 kV	$ 600,000
2009	Rebuild 110L (SMV - LET) 10 km	$ 950,000
2011	Rebuild 110L (SMV - LET) 11 km	$ 1,045,000
2011	Rebuild LET to 138 kV	$ 1,250,000
2015	Rebuild 110L (LET - MIL) 11 km	$ 1,045,000
2016	Rebuild 110L (LET - MIL) 9.6 km	$ 912,000
2016	Rebuild MIL to 138 kV	$ 1,250,000
2018	Rebuild 110L (MIL - CLV) 16.5 km	$ 1,867,500
2018	Rebuild PUN to 138 kV	$ 1,250,000
TOTAL		**$18,340,500**

Table 4: Capital Costs Associated With Upgrading 110L & 111L 66 kV System to 138 kV

5.0 Economic Analysis

The economic analysis methodology used is a revenue requirement or customer cash flow method. The method projects revenue required for each year based on operating costs (including losses) and on capital related revenue requirements including income tax, depreciation and investor returns. Revenue requirements for each year are then subject to a net present value calculation using the corporate average incremental cost of capital.

Included in the economic analysis is a 66 kV and 138 kV transmission line energy loss analysis. The analysis calculates the cost of losses based on the short run avoided energy cost. These costs are then used as operating costs of each alternative.

As part of the economic analysis, capital expenditures were projected over the 20 year period of the study, while operating costs and revenue requirements were projected over a 35 year period using a Net Present Value model. The corporate average incremental cost of capital used was 8.29% providing a net present value (NPV) revenue requirement for each scenario as indicated in Table 5. The revenue requirement analysis spreadsheets are contained in Appendix 4 of this report. The operation and maintenance costs for both alternatives were assumed to be the same over the study period.

Options	Description	NPV
Option 1	Rebuild 110L & 111L at 66 kV	$ 7,500,295
Option 2	Upgrade 66 kV System to 138 kV	$ 14,162,352

Table 5: Net Present Value of Alternatives

6.0 Conclusion and Recommendations

Table 6 summarizes the outcome of the various alternatives.

Options	Description	Net Present Value	Capital Costs	Loss of 123L Load Carrying Capabilities
Option 1	Rebuild 110L & 111L at 66 kV	$ 7,500,295	$ 9,427,000	75%
Option 2	Upgrade 66 kV System to 138 kV.	$ 14,162,352	$18,340,500	100%

Table 6: Comparison of Alternatives

Comparing the alternatives, option 1 is recommended because it provides the lowest NPV cost and provides a significant improvement over the existing situation providing up to 75% peak load backing compared to only 45% at present. Option 2 provides 100% peak load backup however, the capital cost is $8,913,500 higher than Option 1 and the NPV cost is $6,662,057 higher than Option 1.

The recommended work, which is the most cost-effective of the alternatives considered, is required in order to ensure the continued provision of safe, reliable electrical service.

The schedule and cost associated with Option 1 are shown in Table 7.

Year	Activity	Capital Cost
2006	Rebuild 110L (LOK - SMV) 6.7 km	$ 604,000
2007	Rebuild 110L (LOK - SMV) 14.1 km	$ 1,269,000
2008	Rebuild 111L (LOK - CAT) 31 km	$ 2,325,000
2009	Rebuild 110L (SMV - LET) 10 km	$ 900,000
2011	Rebuild 110L (SMV - LET) 11 km	$ 990,000
2015	Rebuild 110L (LET - MIL) 11 km	$ 990,000
2016	Rebuild 110L (LET - MIL) 9.6 km	$ 864,000
2018	Rebuild 110L (MIL - CLV) 16.5 km	$ 1,485,000
TOTAL		**$ 9,427,000**

Table 7: Schedule for the Recommended Bonavista Area Upgrade

Appendix 1

2003 SUN-T1 Load Curve

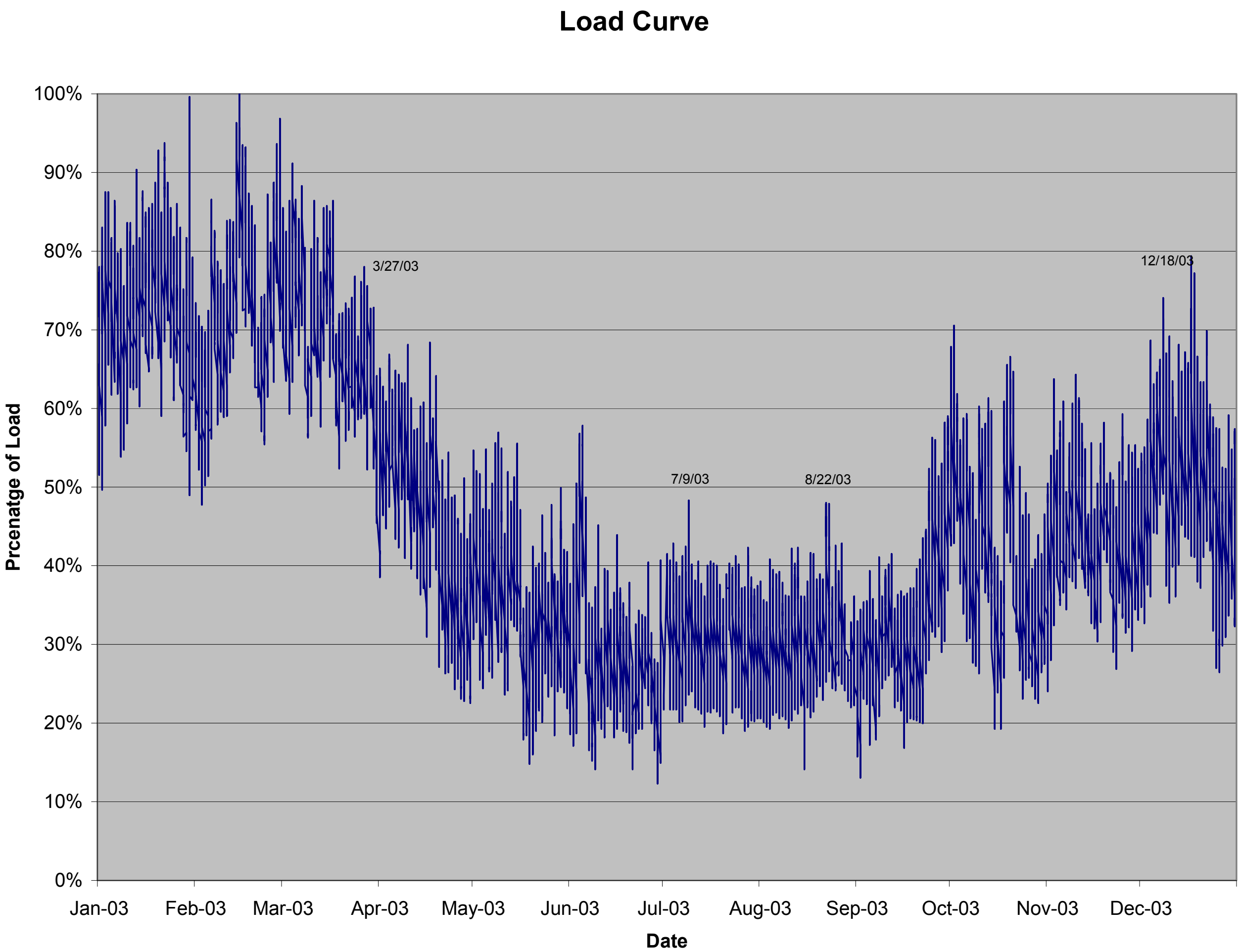

Figure 1: 2003 SUN-T1 Load Curve

The 45% load carrying capability has a 6 week maintenance window from July 9th to August 22nd. The 75% load carrying capability has a 38 week maintenance window from March 27th to December 18th.

Appendix 2

Bonavista Area Transmission Lines

NEWFOUNDLAND POWER TRANSMISSION LINE LISTING

AREA	LINE #		LOCATION		LENGTH	YEAR	LINE TYPE		R.O.W.	VOLTS	CONDUCTOR		
			FROM	TO	Km	BUILT			Width	kV	SIZE	TYPE	STATUS
4	100	L	Sunnyside	Point A	32.12	1964	H FRAME	Loop	30.5	138	397.5	ACSR	STAND
4	100	L	Point A	Clarenville	2.01	1975	H FRAME	Loop	45	138	397.5	ACSR	STAND
4	109	L	Sunnyside	Clarenville	34.44	1976	H FRAME	Loop	45	138	397.5	ACSR	STAND
4	110	L	Clarenville	Point A (Tap)	14.72	1966	S POLE	Loop	18.3	66	2/0	ACSR	NONSTD
4	110	L	Point A (Tap)	Milton	1.77	1974	S POLE	Loop	22.9	66	4/0	AASC	STAND
4	110	L	Milton	Point B	1.77	1974	S POLE	Loop	22.9	66	4/0	AASC	STAND
4	110	L	Point B	Point C (George's Bk)	2.72	1966	S POLE	Loop	18.3	66	2/0	ACSR	NONSTD
4	110	L	Point C (George's Bk)	Point D	10.94	1958	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	110	L	Point D	Lethbridge	5.15	1972	S POLE	Loop	15	66	2/0	ACSR	NONSTD
4	110	L	Lethbridge	Summerville	21.08	1958	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	110	L	Summerville	Point E	6.56	1958	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	110	L	Point E	Point F	7.52	1973	S POLE	Loop	15	66	4/0	AASC	STAND
4	110	L	Point F	Point G	3.20	1958	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	110	L	Point G	Point H	1.92	1973	S POLE	Loop	15	66	4/0	AASC	STAND
4	110	L	Point H	Lockston	1.60	1958	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	111	L	Lockston	Port Union	28.32	1956	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	111	L	Port Union	Catalina	2.41	1956	S POLE	Loop	15	66	1/0	ACSR	NONSTD
4	117	L	Catalina	Bonavista	14.25	1991	H FRAME	Radial		138	397.5	ACSR	STAND
4	123	L	Clarenville	Point A (Str # 261)	60.20	1976	H FRAME	Radial	24.4	138	397.5	ACSR	STAND
4	123	L	Point A (Str # 261)	Point B (Str # 280)	4.30	1992	H FRAME	Radial	24.4	138	244.4	ACSR	STAND
4	123	L	Point B (Str # 280)	Catalina	29.16	1976	H FRAME	Radial	24.4	138	397.5	ACSR	STAND
4	124	L	Clarenville	Point A	1.99	1986	H FRAME	Loop		138	397.5	ACSR	STAND
4	124	L	Point A	Point B	0.41	1998	H FRAME	Loop		138	397.5	ACSR	STAND
4	124	L	Point B	Point C	5.50	2003	H FRAME	Loop		138	397.5	ACSR	STAND
4	124	L	Point C	Point D	5.20	2001	H FRAME	Loop		138	397.5	ACSR	STAND
4	124	L	Point E	PBD Tap	19.83	1964	H FRAME	Loop	30.5	138	397.5	ACSR	STAND
4	124	L	PBD Tap	Port Blandford	3.46	1990	H FRAME	Loop		138	397.5	ACSR	STAND

Appendix 3

Technical Criteria

Technical Criteria

Type of Bus	Normal		Emergency	
	Max. P.U.	**Min P.U.**	**Max P.U.**	**Min P.U.**
Unregulated Distribution	1.054	1.000	1.054	0.967
Source of Voltage Regulation	1.100	0.955	1.100	0.924
Regulated Distribution	1.050	1.050	1.054	1.017
Transmission	1.050	0.950	1.070	0.900

Under normal system operation, system transformers are not permitted to exceed 100% of their nameplate rating. Under emergency conditions the system transformers are permitted to be loaded to 120% of their nameplate rating and beyond during the winter and 100% of their nameplate rating during the summer. However, loading a transformer beyond its rating may result in loss of transformer life.

Appendix 4

Net Present Value Calculations

Option 1

Present Worth Analysis

Weighted Average Incremental Cost of Capital							8.29%		
Escalation Rate				See following worksheet					
PW Year			2,005						
	Transmission	**Substation**	**Buildings**	**Capital**	**Operating**	**Operating**	**Net**	**Present**	**Cumulative**
	30.6 yrs	38.5 yrs	33 yrs	**Revenue**	**Costs**	**Benefits**	**Benefit**	**Worth**	**Present Worth**
YEAR	8% CCA	8% CCA	4% CCA						**Benefit**
2006	604,000	0	0	80,503	15,589	0	-96,092	-88,736	-88,736
2007	1,269,000	0	0	234,968	16,318	0	-251,285	-214,284	-303,020
2008	2,325,000	0	0	514,023	16,977	0	-531,000	-418,147	-721,168
2009	900,000	0	0	577,325	17,949	0	-595,274	-432,876	-1,154,043
2010	0	0	0	554,761	18,698	0	-573,458	-385,088	-1,539,132
2011	990,000	0	0	684,888	19,619	0	-704,507	-436,873	-1,976,005
2012	0	0	0	657,745	20,566	0	-678,311	-388,428	-2,364,433
2013	0	0	0	653,469	21,577	0	-675,046	-356,966	-2,721,398
2014	0	0	0	647,841	22,555	0	-670,396	-327,368	-3,048,766
2015	990,000	0	0	772,917	23,644	0	-796,560	-359,199	-3,407,965
2016	864,000	0	0	856,007	24,833	0	-880,841	-366,797	-3,774,762
2017	0	0	0	825,942	26,157	0	-852,098	-327,665	-4,102,427
2018	1,485,000	0	0	1,013,536	27,450	0	-1,040,986	-369,655	-4,472,081
2019	0	0	0	965,751	28,831	0	-994,582	-326,140	-4,798,221
2020	0	0	0	952,751	30,253	0	-983,003	-297,666	-5,095,887
2021	0	0	0	938,165	31,802	0	-969,967	-271,233	-5,367,121
2022	0	0	0	922,121	33,342	0	-955,463	-246,724	-5,613,845
2023	0	0	0	904,735	35,089	0	-939,824	-224,107	-5,837,952
2024	0	0	0	886,115	36,927	0	-923,042	-203,256	-6,041,208
2025	0	0	0	866,360	38,856	0	-905,216	-184,071	-6,225,279
2026	0	0	0	845,560	40,697	0	-886,257	-166,420	-6,391,699
2027	0	0	0	823,798	42,704	0	-866,502	-150,254	-6,541,952
2028	0	0	0	801,152	44,809	0	-845,961	-135,462	-6,677,415
2029	0	0	0	777,693	47,104	0	-824,797	-121,963	-6,799,377
2030	0	0	0	753,486	49,336	0	-802,821	-109,625	-6,909,002
2031	0	0	0	728,589	51,768	0	-780,357	-98,400	-7,007,403
2032	0	0	0	703,060	54,320	0	-757,379	-88,192	-7,095,594

Present Worth Analysis

Option 1

Weighted Average Incremental Cost of Capital 8.29%

Escalation Rate See following worksheet

PW Year 2,005

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2033	0	0	0	676,947	57,102	0	-734,048	-78,932	-7,174,526
2034	0	0	0	650,298	59,807	0	-710,105	-70,512	-7,245,038
2035	0	0	0	623,156	62,756	0	-685,912	-62,895	-7,307,933
2036	0	0	0	569,853	65,849	0	-635,702	-53,829	-7,361,762
2037	0	0	0	486,699	69,221	0	-555,921	-43,470	-7,405,231
2038	0	0	0	358,903	72,501	0	-431,405	-31,151	-7,436,382
2039	0	0	0	293,500	76,076	0	-369,576	-24,643	-7,461,025
2040	0	0	0	276,215	79,826	0	-356,041	-21,923	-7,482,949
2041	0	0	0	221,144	83,914	0	-305,058	-17,346	-7,500,295

Option 2

Present Worth Analysis

Weighted Average Incremental Cost of Capital 8.29%

Escalation Rate See following worksheet

PW Year 2,005

YEAR	Transmission 30.6 yrs 8% CCA	Substation 38.5 yrs 8% CCA	Buildings 33 yrs 4% CCA	Capital Revenue	Operating Costs	Operating Benefits	Net Benefit	Present Worth	Cumulative Present Worth Benefit
2006	636,500	2,000,000	0	331,136	3,897	0	-335,033	-309,385	-309,385
2007	1,339,500	1,250,000	0	600,995	4,079	0	-605,075	-515,979	-825,365
2008	2,945,000	600,000	0	1,006,807	4,244	0	-1,011,051	-796,174	-1,621,539
2009	950,000	0	0	1,049,298	4,487	0	-1,053,785	-766,300	-2,387,838
2010	0	0	0	1,026,782	4,674	0	-1,031,457	-692,643	-3,080,481
2011	1,045,000	1,250,000	0	1,318,286	4,905	0	-1,323,191	-820,526	-3,901,007
2012	0	0	0	1,259,369	5,142	0	-1,264,510	-724,109	-4,625,116
2013	0	0	0	1,254,017	5,394	0	-1,259,411	-665,979	-5,291,095
2014	0	0	0	1,246,038	5,639	0	-1,251,677	-611,219	-5,902,314
2015	1,045,000	0	0	1,374,922	5,911	0	-1,380,833	-622,670	-6,524,984
2016	912,000	1,250,000	0	1,612,413	6,208	0	-1,618,622	-674,021	-7,199,005
2017	0	0	0	1,546,120	6,539	0	-1,552,659	-597,057	-7,796,062
2018	1,867,500	1,250,000	0	1,932,996	6,862	0	-1,939,858	-688,845	-8,484,907
2019	0	0	0	1,839,599	7,208	0	-1,846,807	-605,598	-9,090,505
2020	0	0	0	1,819,510	7,563	0	-1,827,073	-553,262	-9,643,767
2021	0	0	0	1,796,355	7,951	0	-1,804,305	-504,541	-10,148,308
2022	0	0	0	1,770,378	8,335	0	-1,778,713	-459,308	-10,607,616
2023	0	0	0	1,741,805	8,772	0	-1,750,577	-417,437	-11,025,053
2024	0	0	0	1,710,845	9,232	0	-1,720,077	-378,764	-11,403,817
2025	0	0	0	1,677,688	9,714	0	-1,687,402	-343,124	-11,746,941
2026	0	0	0	1,642,509	10,174	0	-1,652,684	-310,338	-12,057,279
2027	0	0	0	1,605,471	10,676	0	-1,616,147	-280,245	-12,337,523
2028	0	0	0	1,566,723	11,202	0	-1,577,925	-252,670	-12,590,194
2029	0	0	0	1,526,400	11,776	0	-1,538,176	-227,450	-12,817,643
2030	0	0	0	1,484,630	12,334	0	-1,496,964	-204,410	-13,022,053
2031	0	0	0	1,441,527	12,942	0	-1,454,469	-183,403	-13,205,457

Present Worth Analysis

Option 2

Weighted Average Incremental Cost of Capital							**8.29%**			
Escalation Rate					See following worksheet					
PW Year				2,005						
	Transmission	Substation	Buildings	Capital	Operating	Operating	Net	Present	Cumulative	
	30.6 yrs	38.5 yrs	33 yrs	Revenue	Costs	Benefits	Benefit	Worth	Present Worth	
YEAR	8% CCA	8% CCA	4% CCA						Benefit	
2032	0	0	0	1,397,199	13,580	0	-1,410,779	-164,276	-13,369,733	
2033	0	0	0	1,351,744	14,275	0	-1,366,019	-146,887	-13,516,619	
2034	0	0	0	1,305,251	14,952	0	-1,320,203	-131,093	-13,647,712	
2035	0	0	0	1,257,804	15,689	0	-1,273,492	-116,774	-13,764,486	
2036	0	0	0	1,182,388	16,462	0	-1,198,850	-101,514	-13,866,000	
2037	0	0	0	1,075,053	17,305	0	-1,092,359	-85,416	-13,951,416	
2038	0	0	0	899,363	18,125	0	-917,488	-66,250	-14,017,665	
2039	0	0	0	809,194	19,019	0	-828,212	-55,225	-14,072,891	
2040	0	0	0	772,016	19,956	0	-791,972	-48,766	-14,121,657	
2041	0	0	0	694,702	20,978	0	-715,680	-40,695	-14,162,352	

407L Transmission Line Rebuild

June 2005

Prepared by:

Keith Whiteway, P.Eng.

REGISTERED PROFESSIONAL ENGINEER
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2005-06-27
PROVINCE OF NEWFOUNDLAND

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1.0 Description of Line

407L is a 66,000 volt transmission line built in 1956 between Stephenville Substation and St. George's Substation on the west coast of Newfoundland. Most of the line is within several kilometres of the coastline and is subject to salt contamination and high winds. The line has a total length of 27.9 kilometers and is a combination of H-frame and single wood pole construction. The vintage of the poles ranges from 1956 (7.6 km) to 1976/1978 (9.17 km) to 1992 (1.6 km). The 13 km section between Stephenville Crossing and St. George's was originally built in 1956 with some sections rebuilt in 1978 and 1992.

407L is a radial line that serves in excess of 3000 customers in the Stephenville Crossing, St. George's, Robinson's and Flat Bay areas. This line is also the only tie between the Lookout Brook hydro plant and the main electrical grid. See Appendix A for a topographic view of this line.

2.0 Condition of line

This line is 49 years old and many of the original poles are in a general state of deterioration.

Inspections have identified substantial deterioration due to vandalism, rot, woodpecker holes, insect damage, cracks and splits in the poles, crossarms and other hardware. Many of these components are in advanced stages of deterioration and will require replacement in the next few years. See pictures in Appendix B.

The existing conductor is a #2 copper (small by current standards). Most of the insulators are 49 years old and many show signs of deterioration.

In December, 2004, during a severe wind storm, lengthy outages to customers in the area resulted from salt contamination of the insulators on 407L. Several insulators had to be replaced and many others cleaned before power could be restored.

The table below summarizes unplanned power interruptions experienced on 407L since 2000.

Date of Outage	Length of Outage (minutes)	Cause of Outage	Part that Failed
2000-12-20	185	Salt spray	Insulator
2000-12-20	3	Salt spray	Insulator
2000-12-20	1	Salt spray	Insulator
2001-08-18	171	Deterioration	Insulator
2002-09-05	185	Deterioration	Insulator
2003-01-27	153	Deterioration	Insulator
2003-07-31	5	Salt spray	Insulator
2004-12-07	137	Salt spray	Insulator

3.0 Recommendations

The poles, conductor, crossarms and hardware are generally deteriorated and in a weakened state. This places the line at risk of causing more frequent power outages and it is vulnerable to large scale damages during exposure to heavy wind, ice and snow loading.

Based on the condition of this line, it is recommended that a 7.6 km section of transmission line 407L be rebuilt at a cost of $658K. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Topographical Map

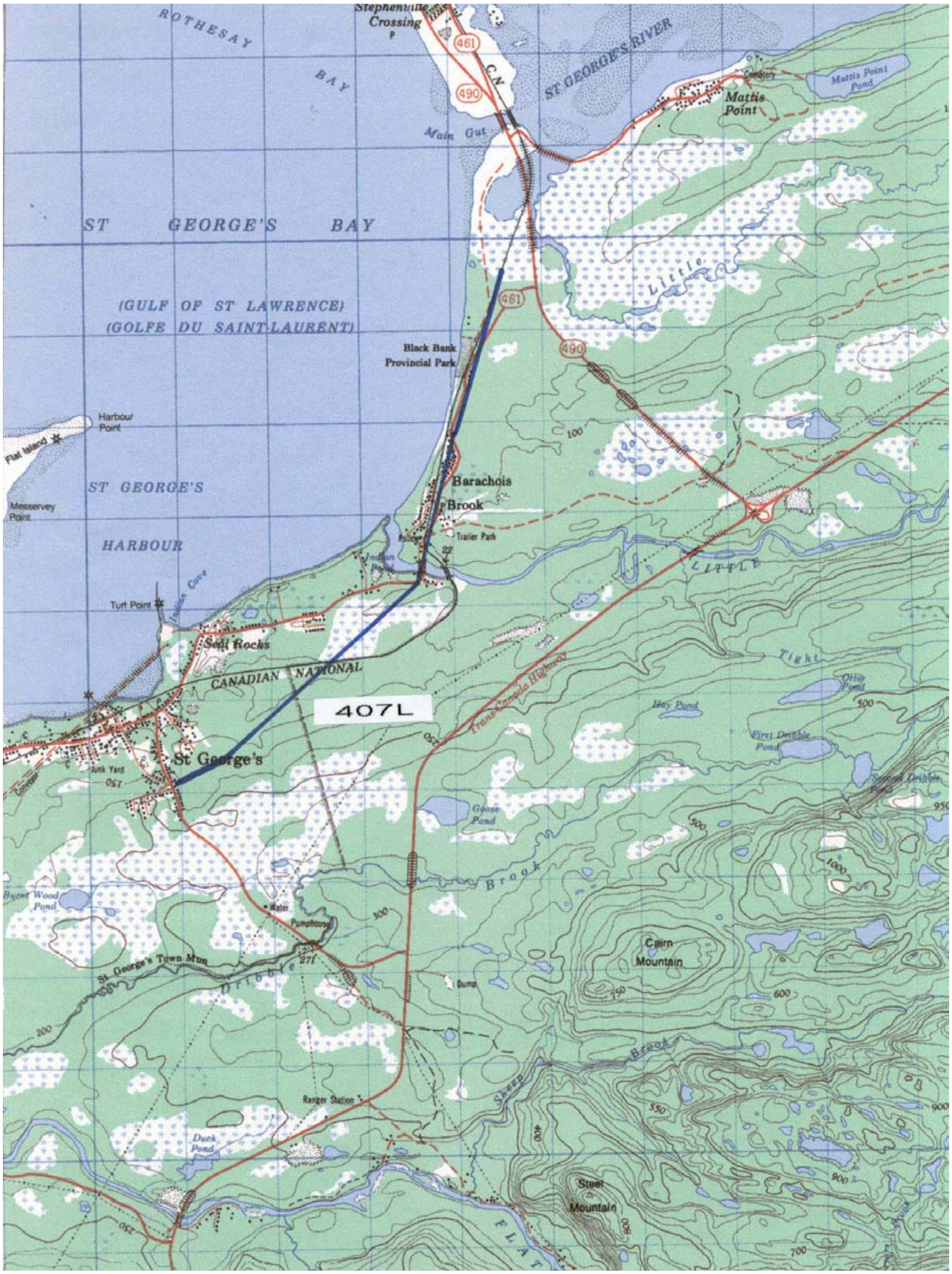

Figure 1 Section of 407L to be rebuilt (outlined in blue)

Appendix B

Pictures of Transmission Line

Figure 2 Deteriorated pole 407L

Figure 3 Deteriorated crib 407L

Figure 4 Vandalized pole 407L

Figure 5 Ground line decay 407L

Figure 6 Deteriorated pole 407L

Figure 7 Deteriorated pole 407L

43L Transmission Line Rebuild

June 2005

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1.0 Description of Line

43L is a 66,000 volt transmission line built in 1956 between Heart's Content Substation and New Chelsea Substation on the Bay de Verde Peninsula. Much of the line is within several kilometres of the coastline and is subjected to salt contamination, high winds and icing. The line has a total length of 25.1 kilometres and is of H-frame wood pole construction.

43L is a radial line that serves in excess of 2500 customers in the New Chelsea to Old Perlican area. This line also is tied into the New Chelsea hydro plant and is this plant's connection to the main electrical grid. See Appendix A for a topographic view of this line.

2.0 Condition of Line

This line is 49 years old and many of the original poles are in a general state of deterioration.

Inspections have identified substantial deterioration due to rot, woodpecker holes, insect damage, cracks and splits in poles, crossarms and other hardware. Many of these components are in advanced stages of deterioration and will require replacement over the next few years. See pictures in Appendix B.

The existing conductor is a #2/0 ACSR (small by current standards). The steel core of the conductor shows evidence of corrosion. Deterioration of the steel core reduces the strength of the conductor. Many of the insulators on this line are 49 years old and are deteriorated.

Because of the age, design, and location of this line, it is prone to cascading failure. Should one structure fail there is risk that the additional loading placed on adjacent structures will cause a chain reaction of multiple structure failures. The following table summarizes unplanned power interruptions experienced on 43L since 2000.

Date of Outage	Length of Outage (minutes)	Cause of Outage	Part that Failed
2000-12-01	1	Snow	Conductor
2002-01-29	6	Salt contamination	Insulator
2002-01-29	34	Salt contamination	Insulator
2002-01-29	8	Salt contamination	Insulator
2002-01-29	3	Salt contamination	Insulator
2002-01-29	2	Salt contamination	Insulator
2002-01-29	1	Salt contamination	Insulator
2002-01-29	1	Salt contamination	Insulator
2002-01-29	1	Salt contamination	Insulator
2004-12-29	6	Salt contamination	Insulator

3.0 Recommendations

The poles, conductor, crossarms and hardware are generally deteriorated and in a weakened state. This places the line at risk of causing more frequent power outages and vulnerable to large scale damage should it become exposed to heavy wind, ice and snow loading.

Currently, as part of the 2005 Capital Program, the Company is rebuilding an 8.0 km section of 43L. The entire transmission line is 25.1 km in length. Based on the overall deteriorated condition of the entire line, the Company should continue with the rebuilding of 43L. It is recommended that in 2006, a 12.0 km section be rebuilt at an estimated cost of $1,081.00. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Topographical Map

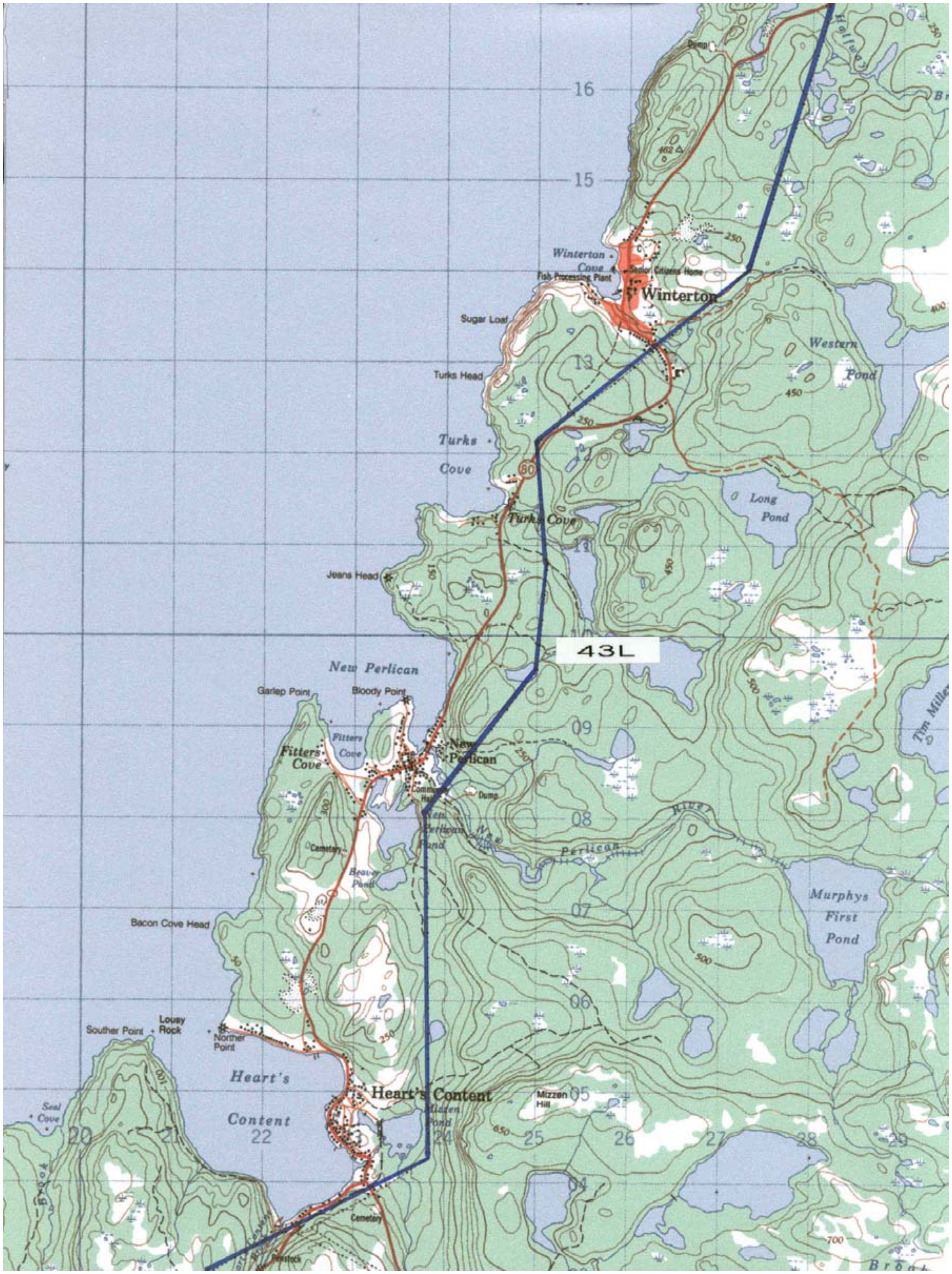

Figure 1 Section of 43L to be rebuilt (outlined in blue)

Appendix B

Pictures of Transmission Line

Figure 2 Rusty guy wire 43L

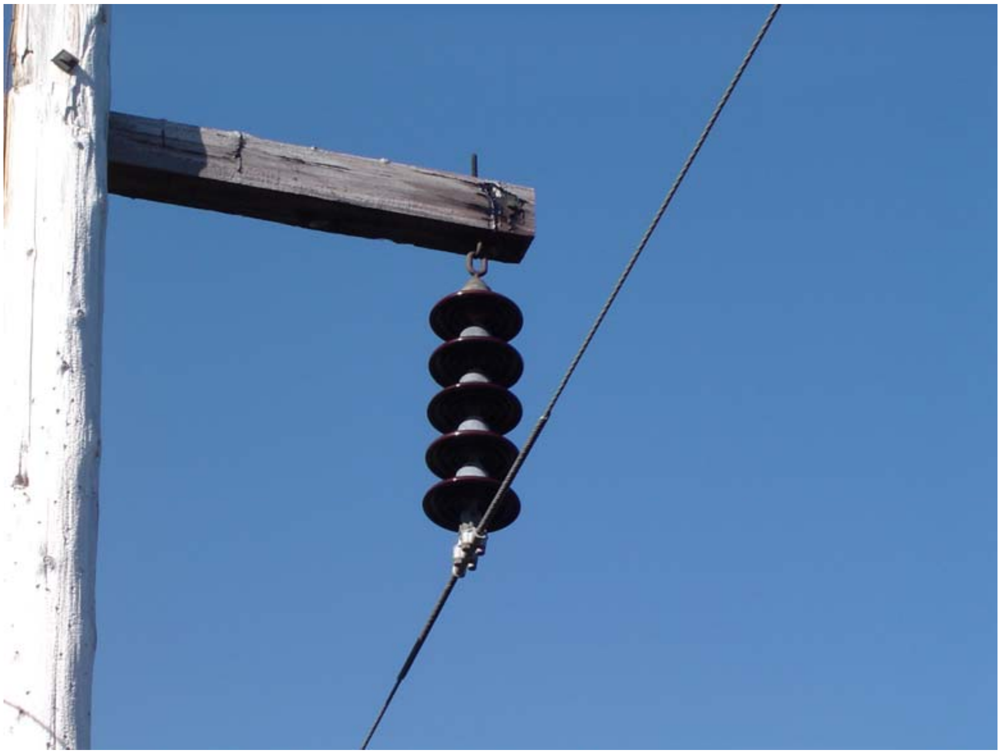

Figure 3 Old insulators 43L

Figure 4 Deteriorated cribs 43L

Figure 5 Woodpecker damage 43L

Figure 6 Deteriorated pole (ant damage) 43L

123L Transmission Line Upgrade

June 2005

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1.0 Background

The weather in Newfoundland subjects transmission lines to salt contamination, high winds, ice and snow loading and frequent freeze/thaw and wet/dry cycles. Because of this, many of the components that make up a transmission line have to be replaced from time to time to ensure the integrity of these lines.

The Bonavista Peninsula is particularly noted for its high winds and freezing rain/sleet conditions. Recognizing this, in 2003, the Canadian Standards Association (CSA) increased the minimum design standard for power lines on the Bonavista Peninsula from 12.5 mm to 18 mm of radial ice, an increase of 44%. Winds on the Bonavista Peninsula regularly reach 150 km/hr.

In 1992, a 4.3 km section of transmission line 123L collapsed because of ice accumulation on the line.

2.0 Description of Line

123L, built in 1976, is a 138kV transmission line between Clarenville Substation and Catalina Substation on the Bonavista Peninsula. The line has a total length of 94 km and is of H-frame wood pole construction. See pictures in Appendix A.

123L serves approximately 5500 customers on the Bonavista Peninsula. While there is some backup capability from 110L, this is limited to light load conditions during the summer. See Appendix B for a topographical view of this line.

3.0 Condition of Line

The continuous wind in this area has accelerated wear on the line's ball link eye bolts, which are the bolts that attach the insulators to the structure. There is also wear on many conductor clamps which attach the conductor to the insulators. The failure of either one of these pieces of hardware would cause the conductor to fall to the ground (see example of this in picture in Appendix C). This would cause an outage to customers and possible failure of the structures themselves, particularly during poor weather conditions. Wear on ball link eye bolts previously replaced on 123L can be seen in Appendix D. This wear reduces the strength of the bolt.

The replacement of worn ball link eye bolts, double arming bolts and conductor clamps has been completed on a 30 km section of 123L. This work has strengthened the line and reduced the likelihood of failure from weakened hardware during ice build-up.

The insulators on this line have an industry known defect (cement growth) causing failures. The defective insulators are prone to increased flashover during lightning strikes. Over the past ten years, approximately 40% of the defective insulators have been replaced.

The poles, crossarms and crossbraces on this line are in good condition as is the conductor. No significant upgrading work is forecast for these components in the next 10 years.
The table below summarizes weather/equipment related unplanned power interruptions experienced on 123L since 1997.

Date of Outage	Length of Outage (minutes)	Cause of Outage	Part that Failed
1997-08-04	687	Lightning	Insulator
1998-03-05	39	Ice	Conductor
1999-04-06	1	Lightning	Insulator
1999-06-18	8	Lightning	Insulator
1999-07-04	1	Lightning	Insulator
2000-08-21	1	Lightning	Insulator
2002-08-17	85	Lightning	Insulator
2002-08-19	145	Deterioration	Insulator
2003-06-02	81	Lightning	Insulator

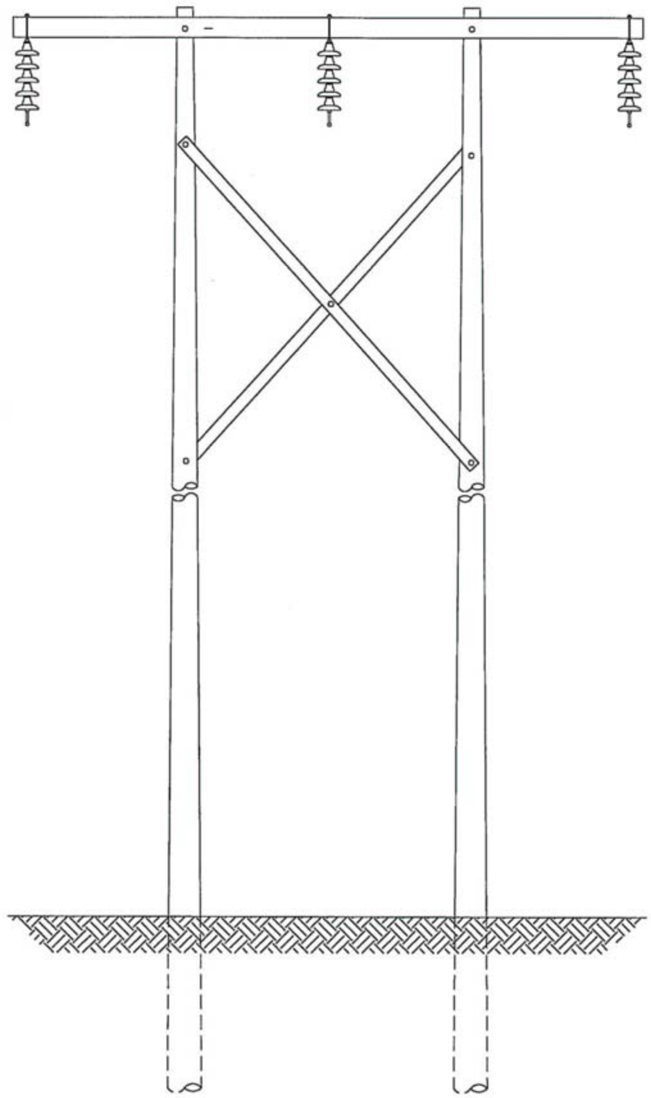
To summarize, the apparatus that connects the conductor to the structures is a weak link in this line. Replacing the remaining worn hardware and defective insulators will reduce the risk of outages.

4.0 Recommendations

It is recommended that deteriorated hardware and insulators be replaced on approximately 56 km of the line in 2006 at a cost of approximately $372,000. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

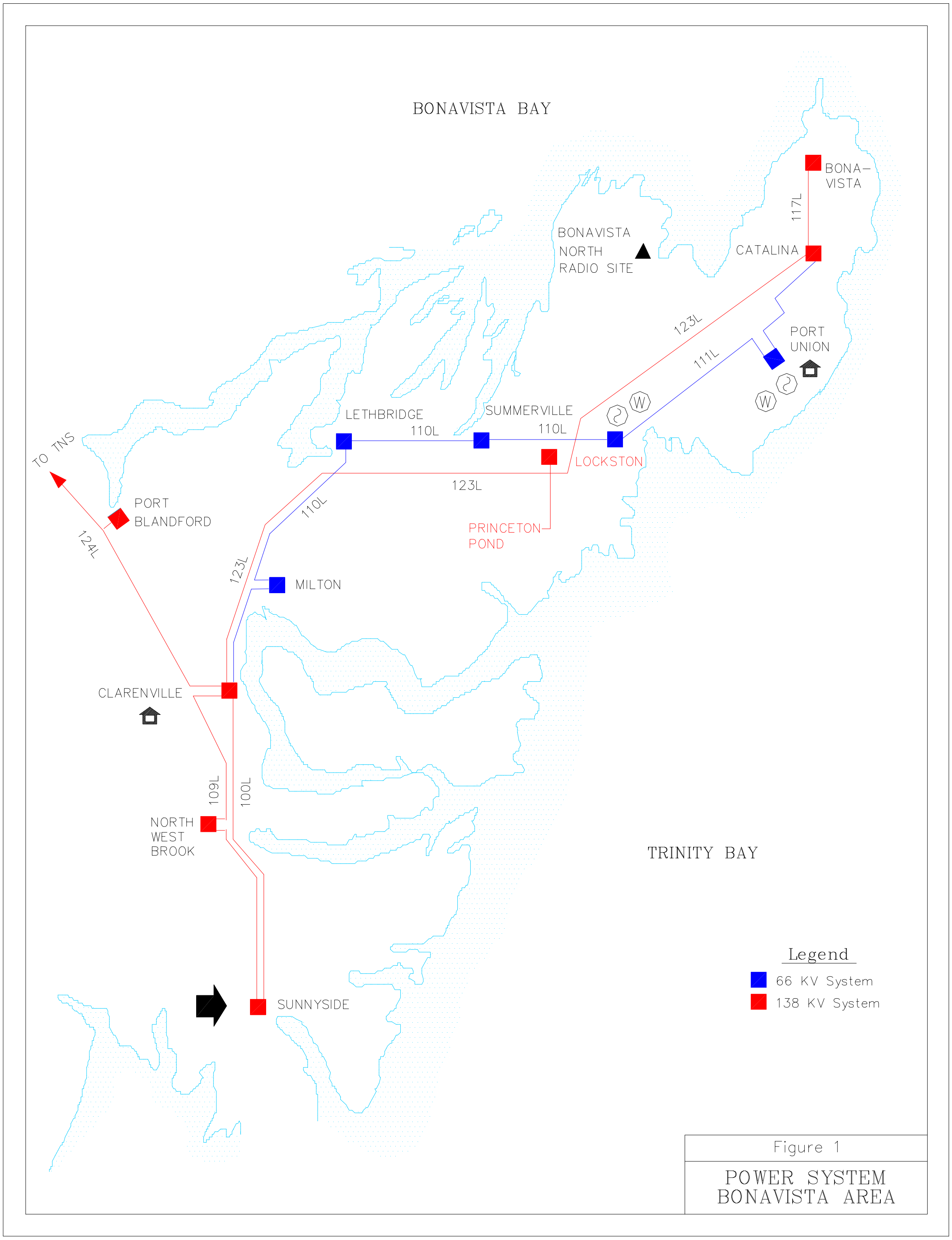
Transmission Line Typical Structure



H-Frame Structure

Appendix B

Topographic Map


BONAVISTA BAY
BONA-
VISTA
117L
CATALINA
BONAVISTA
NORTH
RADIO SITE
123L
111L
PORT
UNION
LETHBRIDGE
SUMMERVILLE
110L
110L
LOCKSTON
123L
TO TNS
PORT
BLANDFORD
124L
110L
PRINCETON
POND
123L
MILTON
CLARENVILLE
109L
100L
NORTH
WEST
BROOK
TRINITY BAY
Legend
66 KV System
138 KV System
SUNNYSIDE
Figure 1
POWER SYSTEM
BONAVISTA AREA

Appendix C

Failed Hardware


20. 8. 2002

Appendix D

Wear on Ball Link Eye Bolts

Metering Strategy

June 2005

NEWFOUNDLAND POWER
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Page

1.0 Background

Each year, Newfoundland Power's capital budget provides for expenditures to purchase and install electrical demand and energy meters. Meters are required where new customers are connected to the electrical system, and to replace meters that are required to be replaced in accordance with federal regulations governing revenue meters.

In recent years, Newfoundland Power has acquired a limited number of meters that allow for automated meter reading (AMR). AMR meters enable a meter to be read remotely, eliminating the need for a meter reader to approach the meter for a visual read. This technology has been employed principally to address meter locations that are difficult to access or that pose safety risks. AMR technology has the potential to lower meter reading costs.

In considering the Company's proposed capital expenditures on meters during the hearing of the 2005 Capital Budget Application, the Board ordered Newfoundland Power to file, no later than its 2006 Capital Budget Application, a copy of its study respecting the Company's strategy to assess all aspects of operating and capital expenditure associated with meter reading.

This report is filed in compliance with the Board's order.

2.0 Balancing Objectives

The Company's metering function is focused on four key objectives: (1) reasonable meter reading accuracy and timeliness, (2) cost management (3) worker safety and (4) ratemaking needs. The relationship between these key objectives is complex. Any initiatives related to metering must ensure that an appropriate balance among the various objectives is maintained.

Accuracy and timeliness in revenue metering is a critical objective. There is a comprehensive regulatory regime in place to ensure it. From a customer perspective, the integrity of the monthly electric bill depends on it. Cost management is also important. But, in managing the costs, it is important that accuracy and timeliness are not compromised. Correcting billing inaccuracies and contacting affected customers takes time and tends to increase costs.

Meter readers operate motor vehicles in all weather, and must daily traverse a variety of terrain on foot. The incidence of accidents and injuries, particularly weather related ones, is higher for meter readers than for all other Newfoundland Power employee groups. Changes in the metering process must be sensitive to the issue of worker safety.

3.0 Metering Costs

3.1 Operating Costs

Operating costs for the Company's metering function are comprised of labour and associated overheads, vehicle and travel costs, and related administrative costs. Table 1 sets out, for the years 2000 through 2004, the total operating costs of the Company's metering function and the cost per customer.

Table 1

Metering Function – Operating Costs

Year	Total Operating Costs	Average Number of Customers	Operating Cost per Customer
2000	$2,544,612	214,426	$11.87
2001	$2,581,421	216,045	$11.95
2002	$2,713,152	217,976	$12.45
2003	$2, 878,571	220,363	$13.06
2004	$2,982,318	223,059	$13.37

Newfoundland Power's metering costs are well within the range of those experienced by other North American utilities. The Company participates in an annual benchmarking survey conducted by the Edison Electric Institute (the "EEI"). Table 2 sets out a comparison of metering costs, on a per-customer and per-read basis, from the 2004 EEI benchmarking survey.

Table 2

2004 EEI Benchmarking Survey
Metering Function – Operating Costs [1]

	Newfoundland Power	Average	Ranking[2]
Operating cost per Customer[3]	$9.29	$9.98	28
Operating Cost per Read[3]	$0.81	$0.74	18

1 Cost figures based on 2003 data.
2 Ranking out of 53 participants with the rank of 1representing the lowest cost.
3 Cost excludes unscheduled reads and is therefore not comparable to the cost information in Table 1.

The Company's operating cost per customer is 6.9% lower than the average experienced by survey participants. On a per-read basis, the Company's operating cost is 9.5% higher than average. The rankings in the study, however, are influenced by the inclusion in the survey of utilities that employ bi-monthly meter reading, utilities with compact service territories and utilities providing both gas and electricity service, which can read both meters in a single visit.

As shown in Table 1, the total operating cost per customer for the Company's metering function has increased from $11.87 in 2000 to $13.37 in 2004, or an average annual rate of approximately 3%. These increases are largely attributable to rising labour and fuel costs.

3.2 Capital Costs

Table 3 sets out the capital costs of the Company's metering function for 2000 through 2004.

Table 3

Metering Function – Capital Costs

Year	Regular Meters	AMR Meters[1]	Meter Reading System	Vehicles	Total Costs
2000	$540,348	$ 23,352	$ -	$134,303	$ 698,003
2001	$569,305	$ -	$ 52,930	$ 52,761	$ 674,996
2002	$562,238	$143,811	$625,879	$198,671	$1,530,599
2003	$487,867	$106,638	$ -	$131,883	$ 726,388
2004	$951,454 [2]	$345,782	$ -	$ -	$1,297,236

1 Comprised of handheld AMR devices, technology licence and installation costs.

2 The increased capital expenditures in 2004 for regular meters reflects (i) the replacement of a large group of D5S type meters that failed compliance testing, (ii) the purchase of 500 single phase demand meters to upgrade commercial customers, and (iii) customer growth.

The AMR Meters costs in Table 3 reflect the deployment of 100 demand enabled AMR meters in commercial locations in St. John's and the deployment of 4,832 residential AMR meters, which can be read remotely through hand held units. These meters were installed in locations with accessibility problems to reduce the number of estimates and the number of high-cost reads, and in locations where worker safety was an issue.

4.0 Cost Management

4.1 Customer Growth

Capital costs of the metering function are driven primarily by customer growth and by Measurement Canada requirements for meter testing and retirement pursuant to the *Electricity and Gas Inspection Act (Canada)*. The Company has forecast its annual growth in residential and commercial customers for 2005 through 2009, and the resultant increase in the number of meter reading routes required to service the additional customer base.

Based on existing route sizes, the forecast growth in the customer base will require the establishment by 2009 of approximately an additional 42 meter reading routes, representing more than a 6 per cent increase in the total number of routes, at a cost of over $123,000 per year.

4.2 Route Configuration

Newfoundland Power's operating costs associated with meter reading reflect the rural nature of much of the Company's service territory. Drive times to, from and within rural areas are typically higher than in more urban areas. The longer drive times also necessitate smaller meter reading route sizes. On average, a rural route is comprised of approximately 250 meters, whereas urban routes contain as many as 600 meters.

The Company's ten highest cost meter reading areas are predominantly rural, and account for approximately 11.5% of the Company's customers.

4.3 Ratemaking

Metering requirements can be significantly influenced by ratemaking requirements. For example, demand management and energy conservation initiatives are typically supported with the collection of more detailed consumption information than is provided by conventional metering systems.

Rate initiatives currently supported by the Company's metering function include (i) the Curtailable Service Option, which is supported by load recorder type meters that can verify the success of the requested curtailment via telephone, and (ii) the Company's load research program, which uses load recorder type meters to obtain detailed load information for ratemaking purposes.

The Company is also involved this year with B.C. Hydro in a real time consumption monitoring pilot project, whereby meters that provide real time usage data to customers have been installed in the homes of 100 residential customers for a one-year period. The project will evaluate the usefulness of such information in enabling customers to manage their consumption.

As the emphasis on demand management and energy conservation increases, and particularly in the context of the recent introduction of a demand/energy wholesale rate structure for Newfoundland Power, there will be implications for the Company and its customers. As the issue evolves, the potential exists for the development of conservation initiatives and retail rate options that may necessitate changes in the Company's metering function.

5.0 Current Cost Control Initiatives

Newfoundland Power's management of meter reading costs to date has focused on targeted solutions to minimize the impact of high cost routes and identified high cost reads.

To ensure they are configured as efficiently as possible, meter reading routes are regularly reviewed. Rural routes, where the distance between serviced premises is greater, entail higher vehicle fuel consumption and travel time. In some locations, the Company has been able to reduce travel time by having the readers drive directly to their routes from home, and designing the routes for maximum efficiency given the reader's starting point.

In addition to changes at the route level, the Company also identifies individual service locations where, for any number of reasons, the cost of reading is higher than normal. For example, General Service meters situated inside commercial buildings often require extra time to access and read. In recent years, some of the more problematic locations have been retrofitted with AMR meters, eliminating the need to read the meters visually and thereby minimizing the long-term cost associated with those locations.

Other cost management initiatives are aimed at enhancing the productivity of the meter reading process. The technology of handheld recording devices, for example, has greatly improved the accuracy of meter reading and reduced the need for return visits to check anomalous reading results. To further reduce the need for return visits, the Company recently equipped meter readers with digital cameras. Where an anomalous result is not identified at the time of the read, a digital photograph of the meter is a low-cost substitute for a return visit.

6.0 Looking Forward

6.1 Assessment of Conventional Technology

As noted above, forecast customer growth will require the equivalent of approximately 42 new meter reading routes in the Company's service territory from 2005 through 2009.
While the Company will continue its practice of incrementally improving its meter reading process, normal increases in fuel and labour costs will tend to put upward pressure on overall meter reading costs.

While conventional metering systems are reliable and have low capital costs, the conventional meter reading process is vulnerable to rising labour and transportation costs. Additionally, conventional metering lacks the capability to provide real-time information regarding customers' energy consumption and usage must be estimated whenever a meter cannot be accessed because of location or weather.

6.2 Synopsis of AMR Technology

AMR technology can minimize these difficulties by facilitating one-way or two-way communication between a utility and its customers' metering equipment. Appendix A to this report provides detailed information on available AMR technologies.

Conventional metering systems are still predominant among Canadian electric utilities. Table A-1 in Appendix A presents results from a telephone survey Newfoundland Power conducted of Canadian electric utilities with respect to their deployment of AMR technology. The survey indicates that the adoption of AMR technology in Canada is still in the early stages, with penetration exceeding 6 per cent at only two utilities.

In jurisdictions where there is a need to obtain more detailed consumption information, some utilities have adopted AMR technology on a larger scale. Otherwise, AMR usage by North American utilities tends to mirror Newfoundland Power's experience, with deployment being largely directed at meters that are difficult to access due to location, weather or safety hazards. [1]

6.3 Current Assessment of AMR for Newfoundland Power

In 2002, Newfoundland Power replaced its antiquated Radix handheld meter reading recording system with a new system with radio frequency capabilities. The new system gives the Company the capability to deploy radio frequency AMR technology when it is cost-justified to do so, or on a trial basis when potentially feasible applications are identified.

To date, Newfoundland Power's limited deployment of AMR has allowed the Company to address specific meter reading problems associated with safety and access. The Company's 2006 capital budget proposes a limited expansion of AMR use in specific applications where cost savings will be realized.

Looking forward, AMR technology appears to hold the greatest potential for efficiency improvements in meter reading. However, early adoption on a broader scale presents some risk. Early adoption of technology carries with it the risk that a particular vendor or technology may be overtaken by a competing vendor or technology.

Given that the potential is significant for further evolution in AMR technologies, a measured approach is prudent. It also offers an opportunity to avail of the price reductions that typically occur as newer technologies mature.

[1] Information obtained from AMRA Report on Large-Scale AMR Deployments and supplemented with telephone discussions with various North American electric utilities.

AMR technology offers the promise of operating cost savings over conventional metering systems, but at a comparatively higher capital cost. Newfoundland Power's current assessment is that adoption of AMR technology on a broad basis is not cost-effective. However, as the costs associated with customer growth increase, the potential to realize cost savings from AMR is expected to improve. In addition, AMR technology has the potential to facilitate the collection of the more detailed information on electrical energy usage, which may be required with changes in rates and rate structures.

In the meantime, the Company will continue its current focus on improving the overall efficiency of its conventional meter reading processes, addressing identified worker safety issues and reducing the impact of high cost reads through the deployment of AMR where the potential to achieve cost savings is demonstrated.

7.0 Concluding

As customer growth puts upward pressure on Newfoundland Power's metering costs, the Company must seek ways to manage costs while maintaining a balance among the key metering objectives, as follows:

(i) Accuracy & Timeliness: The Company will continue to monitor and maintain existing meter reading accuracy and timeliness, and will continue to seek cost effective ways to improve the process, through AMR or otherwise.

(ii) Cost Management: The Company will manage metering by identifying and eliminating inefficiencies and by the further use of AMR where the cost benefits clearly justify it.

(iii) Worker Safety: The Company will continue to focus on the safety of its meter readers through existing programs. In addition to the targeted deployment of AMR devices in locations that pose safety risks, the Company will seek additional opportunities to deploy AMR technology in a cost-effective manner to enhance safety.

(iv) Ratemaking: The Company will adjust its metering function as necessary to meet the requirements of changes in rates and rate structures as they arise.

Appendix A

Automated Meter Reading Technologies

Introduction

There are three general categories of meter reading technologies: the conventional metering system requiring visual reads; the "low-tech" AMR technology option using radio frequency (RF) systems; and, the "high-tech" AMR technology options of power line carrier (PLC) and fixed network systems.

According to industry experts, there is no "one size fits all" approach in the deployment of metering technologies that will satisfy all of a utility's objectives. In many cases, utilities employ a combination of AMR technologies, manual reading and outsourcing to meet their objectives.

Some utilities have adopted several different methods, each dependant on specific data and operational requirements. For instance, if the goal is the elimination or reduction of labour costs associated with manual meter reading, radio frequency systems accommodating either walk-by or drive-by reading are considered to be the best fit. Alternatively, if load research data is required to establish peak and off-peak usage patterns, or to implement load control programs, a fixed network system is the appropriate option.

While penetration rates vary among Canadian utilities, most have implemented AMR in a limited, targeted fashion to address specific problems such as high cost reads and hazardous locations. Because of the relatively high capital cost, full-scale implementation of AMR systems cannot currently be justified in the absence of a legitimate requirement for the additional data they can provide.

A description of the most common AMR technologies follows:

Mobile Radio Frequency (RF)

With low-tech mobile RF, the meter is equipped with a telemetry interface unit. When the meter reader approaches the customer's premises on foot, the handheld unit remotely reads the meter. Another application of this technology is the use of a mobile collection unit, whereby a vehicle equipped with a computer and the collection unit is able to pick up readings by simply driving in the vicinity of the meter reading route. Conventional meter reading routes are limited by the distance that can be covered by a meter reader on foot or in a motor vehicle. In urban settings, conventional meter reading routes are practically limited to between 350 and 600 meters. In comparison, an urban route comprised mainly of RF technology could easily include 1,000 meters or more. In fact, it is possible for a mobile collection unit (drive-by reading) to complete up to 24,000 meter readings per day. As a result, these automated reading strategies can significantly impact a utility's meter reading costs.

Of the various AMR technologies, the low-tech mobile RF system has the lowest cost. With a market saturation of 60.3% in North America, it is also the most widely used AMR technology. In Canada, RF accounts for 37.3% of total AMR installations.

This technology is well suited to utilities looking to replace manual meter reading and is typically justified on the basis of its low capital cost and the significant reduction of labour costs. RF can be used for full-scale replacement or in targeted locations. It can even be deployed on specific high cost meters. However, low-tech RF does not support the collection of the detailed customer usage information that would be required to support variable rate options.

Power Line Carrier (PLC)

Power Line Carrier (PLC) technology uses the electric utility's distribution lines to collect and transmit meter readings. This technology transmits readings and other data from customers' meters across the distribution network to collector units, which are typically located in substations. The meter data is then transmitted from the collector units via standard telecommunications lines.

There are two variations of PLC technology. A *one-way* PLC system can provide daily meter readings, load research and load forecasting data, outage detection, and revenue protection (theft detection). It can also provide information with respect to problems on the distribution line. Alternatively, a *two-way* PLC system offers the additional ability to send information back to the meter, enabling the utility to disconnect and reconnect the electric service remotely. Advanced two-way PLC systems also offer the ability to obtain meter readings at fifteen minute intervals.

The one-way PLC system has a lower capital cost than the two-way system. The costs associated with PLC systems are higher than those for RF technologies.

In North America, the saturation of PLC technology accounts for 12.2% of the total AMR market. In Canada, the implementation of PLC technology represents 19.7% of the AMR market. The PLC technology is most suited to rural environments where the distance between meters is great, where the terrain is hilly, mountainous or forest covered, or where distribution feeders are long. In those environments, the use of conventional telecommunications technology as the primary source for transmitting meter information is not as cost-effective. This is why PLC has a higher penetration within Canada, and explains why the Alberta utility ATCO has a significant deployment of PLC meters.

Fixed Network

Fixed network or telephone-based AMR, which was the first AMR technology to be developed, uses telecommunication lines to obtain meter reading information, either directly from individual customer sites or in conjunction with RF meters and pole-top collector units. Telephone-based networks account for 5.1% of the AMR market in North America and 32.9% of the Canadian market. Alberta accounts for 54.2% of total installations in Canada, followed by Quebec with 19.8%.

This technology has the capacity for two-way communications with the meter, enabling remote disconnection and reconnection, as well as load research data collection functionality. The system can utilize a cellular line or a land-based telephone line, which can be shared with the customer. However, this system depends on the availability of the telecommunications line. If communication lines are damaged, or if a customer removes a shared line, the utility's access to the meter will be disrupted.

Canadian Utility Survey

Newfoundland Power surveyed nine Canadian utilities with respect to their AMR deployment. The results are set out in Table A-1.

Table A-1

AMR Deployment
Canadian Utility Survey

Utility	AMR Meters (% of Total Meters)	Technology
ATCO	90.6% [5]	Two-way PLC
BC Hydro	N/A [6]	N/A
Enmax	5.0%	RF and Fixed Telephone
Fortis Alberta	1.0%	RF
Fortis BC	1.5%	RF
Hydro Ottawa	5.5%	RF and Fixed Telephone
Hydro Quebec	5.2%	RF and Fixed Telephone
Maritime Electric	5.9%	RF
Newfoundland & Labrador Hydro	0.4%	One-way PLC [7]
Newfoundland Power	2.2%	RF
New Brunswick Power	19.1%	RF

[5] Reflects a mass retrofit program undertaken to switch to two-way PLC in ATCO's primarily rural service territory.

[6] Metering function is outsourced.

[7] Pilot project on the island of St. Brendan's.

Key AMR Technology Features

Table A-2 provides a comparison of the key features of the AMR technologies described above.

Table A-2

AMT Options
Comparison of Key Features

Key Feature	MRF[1]	FRF[1]	PRF[1]	One-Way PLC	Two-Way PLC	Fixed Telephone
Remote meter reading	√	√	√	√	√	√
Detection of meter tampering	√	√	√	√	√	√
Remote disconnection and reconnection			√		√	√
Low operating costs	√	√	√	√	√	√
Relative capital cost						
Low	√	√				
Moderate			√	√		
High					√	√
Detects and reports outages		√	√	√	√	√
Ability to remotely alter metering parameters such as the hours that peak pricing is in effect			√		√	√
Daily or more frequent meter reads [2]		√	√	√	√	√
Best suited to						
Urban areas		√	√			
Rural areas				√	√	
Equally suitable to both	√					√

1 Mobile radio frequency (MRF) systems utilize meter mounted interface units and handheld or vehicle mounted meter reading units to enable meter readers to automatically read customers' meters by walking or driving near a customers' premises. These systems can be used in targeted locations or for full scale AMR implementation. Fixed radio frequency (FRF) systems are telephone-based systems that transmit information from individual meters to pole top collectors which then transmit the data to the utility using cellular or public telephone networks. A hybrid form of FRF system, known as a public radio frequency ("PRF") system, utilizes radios mounted in electronic meters to transmit metering data via two-way paging or cellular systems.

2 Provides consumption information for load research and load forecasting that can be used in DSM initiatives such as variable rate options.

2006 AMR Initiatives

June 2005

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction & Summary

As outlined in the Metering Strategy, a Company focus is to improve the productivity and efficiency of the meter reading function, reduce high cost read locations and high cost meters, and mitigate the meter reading cost associated with customer growth. The initiatives identified for 2006 support the Company's focus.

Table 1 is a summary table of Automated Meter Reading Initiatives capital project submissions for the 2006 capital budget.

Each initiative is mutually exclusive of the others, and as such, are eligible for implementation based on their own individual NPV analysis and simple payback term.

Table 1

Automated Meter Reading Initiatives

Initiative	Capital Cost ($)	Simple Payback (years)	NPV ($)
Growth in Residential Areas – St. John's	113,729	5.1	43,667
High Cost Demand Readings (Demand)	70,380	3.9	39,009
High Volume Estimates (Residential Meters)	21,402	3.9	24,174
High Cost Meter Reads (Non Demand)	20,706	2.0	63,279
High Cost Demand Multiple Estimate	18,975	1.4	42,004
Humber Valley Resort	12,487	2.4	103,723
New 400 AMP Residential Services	6,120	1.6	5,794
High Cost Demand Reading – School Boards	3,795	2.6	3,794
Total	**267,594**		

2.0 Growth in Residential Areas (St. John's)

Description

Each year the Company experiences growth in the number of residential accounts as a result of new construction. While this growth is spread throughout our service territory, the largest area of growth is in the St. John's area. The growth in the St. John's area is occurring primarily in subdivisions resulting in increases in the number of meter reading routes. This places increased pressure on operating costs associated with meter reading. AMR provides a means to mitigate increasing costs associated with growth in St. John's.

The current customer forecast anticipates 1,537 new services in St. John's in 2006. These will be predominantly located in new subdivisions. The intent of this initiative is to accommodate the growth in new subdivisions in St. John's with AMR meters. This project includes 1,477 standard 200 Amp residential meters. The remaining 60 meters are designated as 400 Amp meters which are covered under a separate item for large residential services.

Justification

The cost of a traditional electronic meter is $34.50, (without AMR capability) while an electronic meter with AMR capability costs $77.00. The difference of $42.50 is the marginal cost of an AMR installation. In this case, the labour required to install either meter is the same.

The total number of meters required in this project to accommodate customer growth in St. John's is 1,477 in 2006. This is equal to 4.1 new meter reading routes, which will cost about $12,711 annually in labour and vehicle costs. The incremental cost of the AMR meters totals approximately $62,772.

Net Present Value Analysis

The total capital cost of purchasing the 1,477 AMR meters is $113,729 which includes $62,772 in capital costs for the AMR component of the meters. The AMR project justification uses the $62,772 incremental cost of the AMR component. The NPV for the AMR project is $43,667, and the simple payback for the AMR project is 5.1 years. The NPV is shown in Appendix A, page A-1.

3.0 High Cost Demand Readings

Description

In the 12 months preceding April 2005, there are 1,325 demand accounts with significantly higher than average meter reading, customer service and billing costs due to lengthy read times, estimates, customer inquiries, and billing adjustments.

In order to minimize meter purchase and labour costs, the existing meters will be replaced with AMR meters in accordance with the existing schedule of meter replacements through the GRO (Government Retest Order) process over the next six years. In 2006, 204 meters will be replaced. This figure includes 124 meters specifically identified plus an additional 80 meters that will be identified during the year and have a similar cost/benefit justification.

Justification

These accounts are billed on demand and energy and when meter readings are not obtainable the demand and energy readings are estimated. Whenever a demand meter cannot be read, the Customer Service System issues a service order for a special read. Conservatively, each special read requires 20 minutes of a meter reader's time. If the meter cannot be read on the second attempt, in most cases a third attempt will be made. If the meter remains inaccessible, it will be billed with an estimated demand and kilowatt hour consumption. Historically, on average 1.5 return visits to a location will be required as part of attempting to read a demand meter which is initially inaccessible, resulting in at least $15 in meter reader time per month per location.

In addition to meter reading time, each special read service order generates additional work by a customer service representative. These customers frequently contact the Company to discuss the meter estimates requiring additional time from the staff involved.

The labour costs associated with the additional meter reading and office activities is estimated at $5,178 annually for the 124 meters identified. The meters involved are widely distributed, so actual reductions in the number of routes will likely be low. However, we expect to see improved efficiencies in route times.

Net Present Value Analysis

The total cost to purchase the 204 meters is $70,380. These meters are already scheduled for GRO replacement in 2006. Consequently, the economic justification for the AMR project only includes the incremental cost of an AMR meter with no additional installation costs. The incremental capital costs for 2006 are $32,640.

We anticipate saving $8,466 annually due to the avoided cost of repeated visits to these sites. This project would have a NPV of $39,009 over a 20-year period. Based on estimated costs and savings, the simple payback associated with this project is 3.9 years. The NPV is shown in Appendix A, page A-2.

4.0 High Volume Estimates (Residential Meters)

Description

In the 12 months prior to April 2005, there were 710 residential meters with six or more readings estimated. The 710 accounts were evaluated and 197 were identified as candidates for AMR based on the fact that they were high cost reads. In each case the customer had subsequently contacted us about the estimate and/or the Company had been attempting contact with the customer to obtain access to the meter.

In 2006, we will replace 246 meters; 197 that have been specifically identified based upon their history of estimates, contacts, and access issues, and another 49 meters that will be identified during the year that have a similar cost/benefit justification.

Justification

When an account has been estimated six or more times, the account is sent to a customer account representative for further action. The customer account representative will spend some time trying to reconcile the billing history on the account. In addition, the customer is contacted and an attempt is made to schedule access to the meter. These activities are estimated as costing approximately $15 per account. In addition, when these meters are read, they have lengthy reading times. The cost of this reading time, plus customer contacts and related billing adjustments, accumulate to the extent that replacement of the meter with an AMR meter is the most cost effective approach.

The locations of the meters to be changed are widespread, so actual reductions in the number of meter reading routes will likely be low. However, we expect to see improved efficiencies in route times.

Net Present Value Analysis

The total cost to purchase and install the 246 meters is $21,402. This includes the replacement cost of the meters plus $10 each for installation costs.

We anticipate saving $5,419 annually due to the avoided cost of repeated visits to these sites. This project has an NPV of $24,174 over a 20-year period. Based on estimated costs and savings, the simple payback associated with this project is 3.9 years. The NPV is shown in Appendix A, page A-3.

5.0 High Cost Meter Reads (Non-Demand)

Description

In the 12 months preceding April 2005, there were 190 residential and small commercial accounts with significantly higher than average meter reading, customer and billing costs, due to lengthy read times, estimates, customer inquiries, and billing adjustments. In 2006 the Company will replace the 190 meters identified plus an additional 48 meters that are expected to arise throughout the year and have similar cost/benefit justifications.

Justification

Daily meter reading timestamps have identified a number of meters that require significant amounts of time to read. The costs of reading time, customer contacts and related billing adjustments for these identified locations are such that replacement of the meter with an AMR meter is the most cost effective approach to reduce the overall meter reading cost.

The locations of the meters to be changed are widespread, so actual reductions in the number of routes will likely be low. However, we expect to see improved efficiencies in route times.

Net Present Value Analysis

The total cost to purchase and install the 238 meters is $20,706. This includes the cost to replace the meters plus $10 each for installation costs. We anticipate a savings of $10,206 annually. This project has a NPV of $63,279 over a 20-year period. Based on estimated costs and savings, the simple payback associated with this project is 2.0 years. The NPV is shown in Appendix A, page A-4.

6.0 High Cost Demand Multiple Estimates

Description

In the 12 months preceding April 2005, a total of 565 commercial accounts were billed on the basis of an estimate four or more times. The consumption patterns of these accounts were evaluated and vacant buildings were removed from the data, resulting in 418 accounts as candidates for AMR meters. In order to minimize meter purchase and installation costs, it is planned to install AMR meters through the GRO (Government Retest Order) process when these meters are replaced over the next six years. In 2006, 44 meters will be replaced.

Justification

These accounts have been estimated four or more times in the last twelve months. Whenever a demand meter cannot be read, the Customer Service System issues a service order for a special read. Conservatively, each special read requires 20 minutes of a meter reader’s time. If the meter cannot be read on the second attempt, in most cases a third attempt will be made. If the meter remains inaccessible, it will be billed with an estimated demand and kilowatt hour consumption. Historically, on average 1.5 return visits to a location will be required, resulting in at least $15 in meter reader time per month per location.

In addition to meter reading time, each special read service order generates additional work by a Customer Service Representative. These customers frequently contact the Company to discuss the meter estimates requiring additional time from the staff involved. The labour costs associated with the additional meter reading and office personnel are $5,036 annually for the 44 meters identified.

The locations of the meters to be changed are widespread, so actual reductions in the number of routes will likely be low. However, improved efficiencies in route times are expected.

Net Present Value Analysis

The total cost to purchase these meters is $18,975. These meters are already scheduled for GRO replacement in 2006, so the economic justification for the AMR project is based on the incremental cost of AMR meters with no additional installation costs. The incremental cost for 2006 is $8,800.

A saving of $6,281 annually is expected due to the avoided cost of repeated visits to these sites. This project has a NPV of $42,004 over a 20-year period. Based on estimated costs and savings, the simple payback associated with this project is 1.4 years. The NPV is shown in Appendix A, page A-5.

7.0 Humber Valley Resort

Description

The Humber Valley Resort at Little Rapids is currently under construction. The Company is proposing to install AMR meters on all the services within the Humber Valley Resort. This proposal includes 150 meters for Humber Valley Resort for the year 2006. The program to install AMR meters at the Humber Valley Resort began in 2005.

Justification

The secluded lot design of the homes in the subdivision has resulted in homes with long driveways. As a result, the meters are difficult and time consuming for the meter reader to access. In addition, the lot sizes are very large and thus, if conventional meters were used, the distances between the properties result in high meter reading labour and vehicle costs.

Net Present Value Analysis

The total cost to purchase the 150 meters required in 2006 is $12,487, of which $5,644 represents the incremental cost of the AMR component. To assess the economic feasibility of this program, the cost of implementing AMR to the full resort was analysed. It is anticipated that construction of the resort will be completed by 2010. Over the course of the period to 2010, the cumulative savings are approximately $70,000 ($2006) for the overall project while the incremental cost of AMR metering is approximately $36,000 ($2006). Annual savings thereafter are $20,290 ($2006) per year. The NPV for the entire project is $103,723. The simple payback for the first year (2005) is 2.4 years. The NPV is shown in Appendix A, page A-6.

8.0 New 400 AMP Residential Services

Description

Each year the Company experiences growth in the number of large residential accounts requiring 400 amp services. The current customer forecast anticipates 60 new services of this type will be required in 2006. Most of these will be located in the St. John's area.

This proposal recommends that we utilize AMR meters for these services due to the low cost differential between an AMR meter and the traditional electronic meter compared to the ongoing cost to read, bill and handle customer contacts.

Justification

These types of meters are used in larger residential properties which typically require longer read times. The average read time is one minute, with a labour cost of approximately $5 annually. In addition, higher than normal consumption plus any estimates required due to snow conditions will generate customer enquires, typically costing $10 each. Consequently, these properties cost $15 per year each to manage with traditional metering.

The cost of adding AMR capability to these meters is $23 each.

Net Present Value Analysis

The total cost to purchase these 60 meters is $6,120, of which $1,380 represents the additional cost of the AMR component. We anticipate annual savings of $884.

The NPV for the project is $5,794. The simple payback would be 1.6 years. The NPV is shown in Appendix A, page A-7.

9.0 High Cost Demand Readings (School Boards)

Description

In the 12 months preceding April 2005, a total of 81 schools billed on demand/energy rates were billed on the basis of an estimate three or more times. It is usually impossible to gain access to obtain meter readings when schools are closed and therefore, estimates are used for billing.

In order to minimize meter purchase and installation costs, these meters will be replaced with AMR meters in accordance with the existing schedule of meter replacements through the GRO (Government Retest Order) process. In 2006, 11 meters will be replaced. This figure includes 9 meters specifically identified plus an additional 2 meters that we anticipate will be identified throughout the year and will have the same cost/benefit justification.

Justification

These accounts are billed on demand and when meter readings are not obtainable, the demand and energy readings are estimated. Whenever a demand meter cannot be read, the Customer Service System issues a service order for a special read. Each special read requires 20 minutes of a meter reader's time. If the meter cannot be read on the second attempt, in most cases a third attempt will be made. If the meter remains inaccessible, it will be billed with an estimated demand and kilowatt hour consumption. Historically, on average 1.5 return visits to a location will be required, resulting in at least $15 in meter reader time per month per location.

In addition to meter reading time, each special read service order generates additional work by a Customer Service Representative. These customers frequently contact the Company to discuss the meter estimates requiring additional time from the staff involved.

The labour costs associated with the additional meter reading and office activities are $550 annually for the 9 meters identified.

Net Present Value Analysis

The total cost to purchase these meters is $3,795.00. These meters are already scheduled for GRO replacement in 2006. The economic justification for the AMR project only includes the incremental costs for AMR meters, with no additional installation costs. The incremental capital cost is $1,760.

We anticipate saving $671 annually due to the avoided cost of repeated visits to these sites. This project has an NPV of $3,794 over a 20-year period. Based on estimated costs and savings, the simple payback associated with this project is 2.6 years. The NPV is shown in Appendix A, page A-8.

Appendix A

Net Present Value Analysis

NET PRESENT VALUE ANALYSIS- Growth in Residential Areas (St. John's)

Calculation of Cash Flow into and (out of) the Company

YEAR	Capital Impacts			CCA Tax Deductions			Ongoing Operating Expenditures				
	New Meters Inc. 5% O/H	Reused Meters Inc. 5% O/H	Net Meters	CCA	Remaining UCC	Total	Operating Cost Increases	Operating Cost Benefits	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
	A	B	C	D	E	F	G	H	I	J	K
2006	($65,911)	$0	($65,911)	($1,318)	($64,593)	($1,318)	($401)	$12,711	$12,310	($3,970)	($57,571)
2007			$0	($2,584)	($62,009)	($2,584)	($408)	$12,927	$12,519	($3,589)	$8,930
2008			$0	($2,480)	($59,529)	($2,480)	($415)	$13,147	$12,732	($3,703)	$9,029
2009			$0	($2,381)	($57,148)	($2,381)	($423)	$13,384	$12,961	($3,822)	$9,140
2010			$0	($2,286)	($54,862)	($2,286)	($430)	$13,625	$13,194	($3,940)	$9,254
2011		$0	$0	($2,194)	($52,667)	($2,194)	($438)	$13,863	$13,425	($4,057)	$9,369
2012			$0	($2,107)	($50,561)	($2,107)	($445)	$14,109	$13,664	($4,174)	$9,489
2013			$0	($2,022)	($48,538)	($2,022)	($453)	$14,343	$13,890	($4,286)	$9,603
2014			$0	($1,942)	($46,597)	($1,942)	($460)	$14,582	$14,122	($4,400)	$9,722
2015			$0	($1,864)	($44,733)	($1,864)	($468)	$14,822	$14,354	($4,512)	$9,843
2016			$0	($1,789)	($42,943)	($1,789)	($476)	$15,075	$14,599	($4,627)	$9,972
2017			$0	($1,718)	($41,226)	($1,718)	($485)	$15,359	$14,874	($4,752)	$10,122
2018			$0	($1,649)	($39,577)	($1,649)	($494)	$15,646	$15,152	($4,877)	$10,275
2019			$0	($1,583)	($37,994)	($1,583)	($503)	$15,935	$15,432	($5,002)	$10,430
2020			$0	($1,520)	($36,474)	($1,520)	($512)	$16,221	$15,709	($5,125)	$10,584
2021			$0	($1,459)	($35,015)	($1,459)	($532)	$16,841	$16,309	($5,364)	$10,945
2022			$0	($1,401)	($33,614)	($1,401)	($542)	$17,160	$16,618	($5,497)	$11,122
2023			$0	($1,345)	($32,270)	($1,345)	($552)	$17,498	$16,945	($5,635)	$11,310
2024			$0	($1,291)	($30,979)	($1,291)	($552)	$17,498	$16,945	($5,654)	$11,291
2025			$0	($1,239)	($29,740)	($1,239)	($563)	$17,835	$17,272	($5,791)	$11,481
CCA Residual Benefits (2025$)						($11,764)				$4,249	$4,249
Present Value (See Note L) @				6.80%							$43,667

NET PRESENT VALUE ANALYSIS – High Cost Demand Readings

Calculation of Cash Flow into and (out of) the Company

YEAR	Capital Impacts New Meters Inc. 5% O/H A	Reused Meters Inc. 5% O/H B	Net Meters C	CCA Tax Deductions CCA D	Remaining UCC E	Total F	Ongoing Operating Expenditures Operating Cost Increases G	Operating Cost Benefits H	Net Operating Expenditures I	Income Tax J	After-Tax Cash Flow K
2006	($34,272)	$0	($34,272)	($685)	($33,587)	($685)	($53)	$8,519	$8,466	($2,810)	($28,617)
2007			$0	($1,343)	($32,243)	($1,343)	($54)	$8,664	$8,609	($2,624)	$5,985
2008			$0	($1,290)	($30,953)	($1,290)	($55)	$8,820	$8,764	($2,700)	$6,065
2009			$0	($1,238)	($29,715)	($1,238)	($56)	$8,978	$8,922	($2,775)	$6,147
2010			$0	($1,189)	($28,527)	($1,189)	($57)	$9,135	$9,078	($2,850)	$6,229
2011		$0	$0	($1,141)	($27,386)	($1,141)	($58)	$9,298	$9,239	($2,925)	$6,314
2012			$0	($1,095)	($26,290)	($1,095)	($59)	$9,451	$9,392	($2,997)	$6,395
2013			$0	($1,052)	($25,239)	($1,052)	($60)	$9,609	$9,549	($3,069)	$6,480
2014			$0	($1,010)	($24,229)	($1,010)	($61)	$9,767	$9,706	($3,141)	$6,565
2015			$0	($969)	($23,260)	($969)	($62)	$9,934	$9,872	($3,216)	$6,656
2016			$0	($930)	($22,329)	($930)	($63)	$10,121	$10,058	($3,297)	$6,761
2017			$0	($893)	($21,436)	($893)	($64)	$10,310	$10,246	($3,378)	$6,868
2018			$0	($857)	($20,579)	($857)	($66)	$10,501	$10,435	($3,460)	$6,976
2019			$0	($823)	($19,756)	($823)	($67)	$10,689	$10,622	($3,540)	$7,083
2020			$0	($790)	($18,965)	($790)	($69)	$11,098	$11,028	($3,698)	$7,330
2021			$0	($759)	($18,207)	($759)	($71)	$11,308	$11,237	($3,785)	$7,452
2022			$0	($728)	($17,479)	($728)	($72)	$11,531	$11,459	($3,876)	$7,583
2023			$0	($699)	($16,779)	($699)	($72)	$11,531	$11,459	($3,886)	$7,572
2024			$0	($671)	($16,108)	($671)	($73)	$11,753	$11,680	($3,976)	$7,703
2025			$0	($644)	($15,464)	($644)	($75)	$11,962	$11,888	($4,061)	$7,827
CCA Residual Benefits (2025$)						($6,117)				$2,209	$2,209
Present Value (See Note L) @				6.80%							$39,009

NET PRESENT VALUE ANALYSIS – High Volume estimates (Residential Meters)

Calculation of Cash Flow into and (out of) the Company

	Capital Impacts			CCA Tax Deductions			Ongoing Operating Expenditures				
YEAR	New Meters Inc. 5% O/H	Reused Meters Inc. 5% O/H	Net Meters	CCA	Remaining UCC	Total	Operating Cost Increases	Operating Cost Benefits	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
	A	B	C	D	E	F	G	H	I	J	K
2006	($22,472)	$1,610	($20,862)	($417)	($20,445)	($417)	($64)	$5,483	$5,419	($1,807)	($17,250)
2007			$0	($818)	($19,627)	($818)	($65)	$5,576	$5,511	($1,695)	$3,816
2008			$0	($785)	($18,842)	($785)	($66)	$5,676	$5,610	($1,743)	$3,867
2009			$0	($754)	($18,089)	($754)	($68)	$5,779	$5,711	($1,791)	$3,920
2010			$0	($724)	($17,365)	($724)	($69)	$5,880	$5,811	($1,838)	$3,973
2011		($2,862)	($2,862)	($752)	($19,475)	($752)	($70)	$5,984	$5,914	($1,865)	$1,188
2012			$0	($779)	($18,696)	($779)	($71)	$6,083	$6,012	($1,890)	$4,122
2013			$0	($748)	($17,948)	($748)	($72)	$6,185	$6,112	($1,938)	$4,175
2014			$0	($718)	($17,230)	($718)	($74)	$6,287	$6,213	($1,985)	$4,228
2015			$0	($689)	($16,541)	($689)	($75)	$6,394	$6,319	($2,033)	$4,286
2016			$0	($662)	($15,879)	($662)	($76)	$6,514	$6,438	($2,086)	$4,351
2017			$0	($635)	($15,244)	($635)	($78)	$6,636	$6,558	($2,139)	$4,419
2018			$0	($610)	($14,634)	($610)	($79)	$6,759	$6,679	($2,192)	$4,487
2019			$0	($585)	($14,049)	($585)	($81)	$6,880	$6,799	($2,244)	$4,555
2020			$0	($562)	($13,487)	($562)	($84)	$7,143	$7,059	($2,347)	$4,712
2021			$0	($539)	($12,948)	($539)	($85)	$7,278	$7,193	($2,403)	$4,790
2022			$0	($518)	($12,430)	($518)	($87)	$7,421	$7,334	($2,462)	$4,872
2023			$0	($497)	($11,932)	($497)	($87)	$7,421	$7,334	($2,470)	$4,865
2024			$0	($477)	($11,455)	($477)	($89)	$7,565	$7,476	($2,528)	$4,948
2025			$0	($458)	($10,997)	($458)	($90)	$7,699	$7,609	($2,583)	$5,026
CCA Residual Benefits (2025$)						($4,350)				$1,571	$1,571
Present Value (See Note L) @				6.8%							$24,174

NET PRESENT VALUE ANALYSIS – High Cost Meter Reads (Non-Demand)

Calculation of Cash Flow into and (out of) the Company

	Capital Impacts			CCA Tax Deductions			Ongoing Operating Expenditures				
YEAR	New Meters Inc. 5% O/H	Reused Meters Inc. 5% O/H	Net Meters	CCA	Remaining UCC	Total	Operating Cost Increases	Operating Cost Benefits	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
	A	B	C	D	E	F	G	H	I	J	K
2006	($21,741)	$2,624	($19,117)	($382)	($18,735)	($382)	($62)	$10,268	$10,206	($3,548)	($12,460)
2007			$0	($749)	($17,986)	($749)	($63)	$10,443	$10,379	($3,478)	$6,901
2008			$0	($719)	($17,266)	($719)	($64)	$10,631	$10,566	($3,557)	$7,010
2009			$0	($691)	($16,576)	($691)	($65)	$10,822	$10,757	($3,636)	$7,121
2010			$0	($663)	($15,913)	($663)	($67)	$11,011	$10,945	($3,714)	$7,231
2011		($2,862)	($2,862)	($694)	($18,081)	($694)	($68)	$11,207	$11,139	($3,773)	$4,504
2012			$0	($723)	($17,357)	($723)	($69)	$11,392	$11,323	($3,829)	$7,495
2013			$0	($694)	($16,663)	($694)	($70)	$11,583	$11,513	($3,908)	$7,605
2014			$0	($667)	($15,996)	($667)	($71)	$11,773	$11,702	($3,986)	$7,716
2015			$0	($640)	($15,357)	($640)	($72)	$11,974	$11,902	($4,068)	$7,834
2016			$0	($614)	($14,742)	($614)	($74)	$12,200	$12,126	($4,158)	$7,968
2017			$0	($590)	($14,153)	($590)	($75)	$12,428	$12,352	($4,249)	$8,104
2018			$0	($566)	($13,587)	($566)	($77)	$12,657	$12,581	($4,340)	$8,241
2019			$0	($543)	($13,043)	($543)	($78)	$12,884	$12,806	($4,429)	$8,377
2020			$0	($522)	($12,521)	($522)	($81)	$13,377	$13,296	($4,614)	$8,682
2021			$0	($501)	($12,021)	($501)	($82)	$13,630	$13,548	($4,713)	$8,835
2022			$0	($481)	($11,540)	($481)	($84)	$13,899	$13,814	($4,816)	$8,998
2023			$0	($462)	($11,078)	($462)	($84)	$13,899	$13,814	($4,823)	$8,991
2024			$0	($443)	($10,635)	($443)	($86)	$14,167	$14,081	($4,926)	$9,155
2025			$0	($425)	($10,210)	($425)	($87)	$14,419	$14,332	($5,023)	$9,309
CCA Residual Benefits (2025$)						($4,038)				$1,459	$1,459
Present Value (See Note L)		@		6.80%							$63,279

<u>NET PRESENT VALUE ANALYSIS – High Cost Demand Multiple Estimates</u>
Calculation of Cash Flow into and (out of) the Company

	Capital Impacts			CCA Tax Deductions			Ongoing Operating Expenditures				
YEAR	New Meters Inc. 5% O/H A	Reused Meters Inc. 5% O/H B	Net Meters C	CCA D	Remaining UCC E	Total F	Operating Cost Increases G	Operating Cost Benefits H	Net Operating Expenditures I	Income Tax J	After-Tax Cash Flow K
2006	($9,240)	$0	($9,240)	($185)	($9,055)	($185)	($14)	$6,295	$6,281	($2,202)	($5,161)
2007			$0	($362)	($8,693)	($362)	($15)	$6,402	$6,388	($2,176)	$4,211
2008			$0	($348)	($8,345)	($348)	($15)	$6,518	$6,503	($2,223)	$4,280
2009			$0	($334)	($8,011)	($334)	($15)	$6,635	$6,620	($2,271)	$4,349
2010			$0	($320)	($7,691)	($320)	($15)	$6,751	$6,736	($2,317)	$4,419
2011		$0	$0	($308)	($7,383)	($308)	($16)	$6,871	$6,855	($2,365)	$4,490
2012			$0	($295)	($7,088)	($295)	($16)	$6,985	$6,969	($2,410)	$4,558
2013			$0	($284)	($6,805)	($284)	($16)	$7,101	$7,085	($2,457)	$4,628
2014			$0	($272)	($6,532)	($272)	($16)	$7,218	$7,202	($2,503)	$4,699
2015			$0	($261)	($6,271)	($261)	($17)	$7,341	$7,325	($2,551)	$4,773
2016			$0	($251)	($6,020)	($251)	($17)	$7,480	$7,463	($2,605)	$4,858
2017			$0	($241)	($5,779)	($241)	($17)	$7,619	$7,602	($2,659)	$4,943
2018			$0	($231)	($5,548)	($231)	($18)	$7,760	$7,743	($2,713)	$5,029
2019			$0	($222)	($5,326)	($222)	($18)	$7,899	$7,881	($2,767)	$5,115
2020			$0	($213)	($5,113)	($213)	($19)	$8,201	$8,183	($2,879)	$5,304
2021			$0	($205)	($4,909)	($205)	($19)	$8,357	$8,338	($2,938)	$5,400
2022			$0	($196)	($4,712)	($196)	($19)	$8,521	$8,502	($3,000)	$5,502
2023			$0	($188)	($4,524)	($188)	($19)	$8,521	$8,502	($3,003)	$5,499
2024			$0	($181)	($4,343)	($181)	($20)	$8,686	$8,666	($3,065)	$5,601
2025			$0	($174)	($4,169)	($174)	($20)	$8,840	$8,820	($3,123)	$5,697
CCA Residual Benefits (2025$)						($1,649)				$596	$596
Present Value (See Note L)		@		6.80%							$42,004

NET PRESENT VALUE ANALYSIS – Humber Valley Resort

Calculation of Cash Flow into and (out of) the Company

	Capital Impacts			CCA Tax Deductions			Ongoing Operating Expenditures				
YEAR	New Meters Inc. 5% O/H	Reused Meters Inc. 5% O/H	Net Meters	CCA	Remaining UCC	Total	Operating Cost Increases	Operating Cost Benefits	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
	A	B	C	D	E	F	G	H	I	J	K
2005	($8,887)	$0	($8,887)	($178)	($8,710)	($178)	($187)	$2,584	$2,396	($801)	($7,293)
2006	($5,926)		($5,926)	($467)	($14,169)	($467)	($565)	$7,602	$7,037	($2,373)	($1,262)
2007	($6,027)		($6,027)	($687)	($19,508)	($687)	($860)	$11,474	$10,614	($3,585)	$1,002
2008	($6,135)		($6,135)	($903)	($24,740)	($903)	($1,166)	$15,491	$14,324	($4,848)	$3,341
2009	($6,246)		($6,246)	($1,115)	($29,871)	($1,115)	($1,483)	$19,648	$18,165	($6,159)	$5,761
2010	($5,508)	$0	($5,508)	($1,305)	($34,074)	($1,305)	($1,810)	$23,939	$22,129	($7,522)	$9,100
2011			$0	($1,363)	($32,711)	($1,363)	($1,842)	$24,364	$22,522	($7,643)	$14,879
2012			$0	($1,308)	($31,403)	($1,308)	($1,873)	$24,767	$22,894	($7,797)	$15,097
2013			$0	($1,256)	($30,146)	($1,256)	($1,904)	$25,181	$23,277	($7,954)	$15,323
2014			$0	($1,206)	($28,941)	($1,206)	($1,935)	$25,595	$23,660	($8,110)	$15,549
2015			$0	($1,158)	($27,783)	($1,158)	($1,968)	$26,032	$24,064	($8,274)	$15,790
2016			$0	($1,111)	($26,672)	($1,111)	($2,005)	$26,522	$24,517	($8,454)	$16,063
2017			$0	($1,067)	($25,605)	($1,067)	($2,043)	$27,017	$24,975	($8,636)	$16,339
2018			$0	($1,024)	($24,581)	($1,024)	($2,080)	$27,517	$25,437	($8,818)	$16,619
2019			$0	($983)	($23,597)	($983)	($2,118)	$28,011	$25,893	($8,997)	$16,895
2020			$0	($944)	($22,653)	($944)	($2,199)	$29,081	$26,882	($9,369)	$17,513
2021			$0	($906)	($21,747)	($906)	($2,240)	$29,632	$27,392	($9,567)	$17,825
2022			$0	($870)	($20,877)	($870)	($2,284)	$30,215	$27,931	($9,774)	$18,156
2023			$0	($835)	($20,042)	($835)	($2,284)	$30,215	$27,931	($9,787)	$18,144
2024			$0	($802)	($19,241)	($802)	($2,329)	$30,798	$28,470	($9,994)	$18,476
CCA Residual Benefits (2024$)						($7,611)				$2,749	$2,749
Present Value (See Note L) @				6.80%							$103,723

NET PRESENT VALUE ANALYSIS – New 400 Amp Residential Services
Calculation of Cash Flow into and (out of) the Company

YEAR	Capital Impacts: New Meters Inc. 5% O/H A	Reused Meters Inc. 5% O/H B	Net Meters C	CCA Tax Deductions: CCA D	Remaining UCC E	Total F	Ongoing Operating Expenditures: Operating Cost Increases G	Operating Cost Benefits H	Net Operating Expenditures I	Income Tax J	After-Tax Cash Flow K
2006	($1,449)	$0	($1,449)	($29)	($1,420)	($29)	($16)	$900	$884	($309)	($874)
2007			$0	($57)	($1,363)	($57)	($16)	$915	$899	($304)	$595
2008			$0	($55)	($1,309)	($55)	($16)	$932	$916	($311)	$605
2009			$0	($52)	($1,256)	($52)	($17)	$949	$932	($318)	$614
2010			$0	($50)	($1,206)	($50)	($17)	$965	$948	($324)	$624
2011		$0	$0	($48)	($1,158)	($48)	($17)	$982	$965	($331)	$634
2012			$0	($46)	($1,112)	($46)	($17)	$999	$981	($338)	$643
2013			$0	($44)	($1,067)	($44)	($18)	$1,015	$998	($344)	$653
2014			$0	($43)	($1,024)	($43)	($18)	$1,032	$1,014	($351)	$663
2015			$0	($41)	($983)	($41)	($18)	$1,050	$1,031	($358)	$674
2016			$0	($39)	($944)	($39)	($19)	$1,069	$1,051	($365)	$685
2017			$0	($38)	($906)	($38)	($19)	$1,089	$1,070	($373)	$697
2018			$0	($36)	($870)	($36)	($19)	$1,109	$1,090	($381)	$709
2019			$0	($35)	($835)	($35)	($20)	$1,129	$1,110	($388)	$721
2020			$0	($33)	($802)	($33)	($20)	$1,172	$1,152	($404)	$748
2021			$0	($32)	($770)	($32)	($21)	$1,195	$1,174	($412)	$761
2022			$0	($31)	($739)	($31)	($21)	$1,218	$1,197	($421)	$776
2023			$0	($30)	($709)	($30)	($21)	$1,218	$1,197	($422)	$775
2024			$0	($28)	($681)	($28)	($22)	$1,242	$1,220	($430)	$790
2025			$0	($27)	($654)	($27)	($22)	$1,264	$1,242	($439)	$803
CCA Residual Benefits (2025$)						($259)				$93	$93
Present Value (See Note L) @				6.80%							$5,794

<u>NET PRESENT VALUE ANALYSIS – High Cost Demand Readings (School Boards)</u>
Calculation of Cash Flow into and (out of) the Company

YEAR	Capital Impacts: New Meters Inc. 5% O/H	Capital Impacts: Reused Meters Inc. 5% O/H	Capital Impacts: Net Meters	CCA Tax Deductions: CCA	CCA Tax Deductions: Remaining UCC	CCA Tax Deductions: Total	Ongoing Operating Expenditures: Operating Cost Increases	Ongoing Operating Expenditures: Operating Cost Benefits	Ongoing Operating Expenditures: Net Operating Expenditures	Income Tax	After-Tax Cash Flow
	A	B	C	D	E	F	G	H	I	J	K
2006	($1,848)	$0	($1,848)	($37)	($1,811)	($37)	($3)	$674	$671	($229)	($1,406)
2007			$0	($72)	($1,739)	($72)	($3)	$686	$683	($220)	$462
2008			$0	($70)	($1,669)	($70)	($3)	$698	$695	($226)	$469
2009			$0	($67)	($1,602)	($67)	($3)	$710	$707	($231)	$476
2010			$0	($64)	($1,538)	($64)	($3)	$723	$720	($237)	$483
2011		$0	$0	($62)	($1,477)	($62)	($3)	$736	$733	($242)	$490
2012			$0	($59)	($1,418)	($59)	($3)	$748	$745	($248)	$497
2013			$0	($57)	($1,361)	($57)	($3)	$760	$757	($253)	$504
2014			$0	($54)	($1,306)	($54)	($3)	$773	$770	($258)	$511
2015			$0	($52)	($1,254)	($52)	($3)	$786	$783	($264)	$519
2016			$0	($50)	($1,204)	($50)	($3)	$801	$797	($270)	$528
2017			$0	($48)	($1,156)	($48)	($3)	$816	$812	($276)	$536
2018			$0	($46)	($1,110)	($46)	($4)	$831	$827	($282)	$545
2019			$0	($44)	($1,065)	($44)	($4)	$846	$842	($288)	$554
2020			$0	($43)	($1,023)	($43)	($4)	$878	$874	($300)	$574
2021			$0	($41)	($982)	($41)	($4)	$895	$891	($307)	$584
2022			$0	($39)	($942)	($39)	($4)	$912	$908	($314)	$595
2023			$0	($38)	($905)	($38)	($4)	$912	$908	($315)	$594
2024			$0	($36)	($869)	($36)	($4)	$930	$926	($321)	$605
2025			$0	($35)	($834)	($35)	($4)	$947	$942	($328)	$615
CCA Residual Benefits (2025$)						($330)				$119	$119
Present Value (See Note L) @				6.80%							$3,794

Net Present Value Analysis Notes

A is the incremental capital cost by year as shown adjusted to include the General Expenses Capitalized amount of 5% of the direct capital cost

B is the avoided capital cost of reused meters by year adjusted to include the General Expenses Capitalized amount of 5% of the direct capital cost.

C is Column A plus B

D is the Capital Cost Allowance deduction for the capital impacts. It was calculated using declining balance depreciation and the 50% rule for capitalizing additions.

E is the remaining Undepreciated Capital Cost.

F is equal to D and includes, when necessary, residual CCA benefits.

G is the operating costs associated with the AMR solution. The cost estimates are escalated to the current year using the GDP Deflator Index.

H is the operating cost benefits associated with elimination of conventional manual reading process. The cost estimate is escalated to current year using the GDP Deflator Index.

I is the sum of columns G, and H.

J is the impact on taxes from the CCA and operating cost deductions. It is equal to columns F plus I times the income tax rate.

K is the after tax cash flow into (out of) the Company which is the sum of Columns A, B, I and J.

L is the present value of Column K. Column K is discounted using NP's weighted after-tax cost of capital.

2005 Corporate Distribution Reliability Review

June 2005

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1.0 Introduction

Newfoundland Power holds reliability of service as a cornerstone of its commitment to customers. In customer satisfaction surveys customers consistently cite the reliability and price of electricity as the two most important attributes of Newfoundland Power's service.

Managing reliability involves learning from past events to prevent problems in the future. At Newfoundland Power distribution reliability concerns are identified in three ways:

(i) Reliability data/statistics – Reliability statistics are compiled as events occur and are reviewed on an ongoing basis. The review/analysis of reliability statistics is primarily intended to identify distribution feeders that exhibit poor reliability performance over time. This review/analysis is a key driver for identifying where need is greatest for feeder reliability upgrades. These reliability upgrades are generally budgeted under the Distribution Reliability Initiative project.

(ii) Feeder assessment/review – This is a structured approach aimed at identifying and correcting potential reliability or safety concerns. Each year Newfoundland Power performs routine inspections of a portion of its total distribution lines. Immediate concerns are addressed as required, however the focus of this approach is to identify, prioritize and correct reliability concerns involving defective or deteriorated components that are common to all distribution feeders. Work required under this approach is generally budgeted under the Rebuild Distribution Lines project.

(iii) Trouble call/follow-up – Trouble call statistics are compiled as events occur and are reviewed on an ongoing basis. Immediate concerns and follow-up items on distribution feeders are generally addressed as required under the Reconstruction project.

This report focuses on analysis of reliability data/statistics. The goal of the review is to ensure that distribution feeders where, statistically, reliability concerns are greatest are identified and that work is planned to address those reliability concerns.

2.0 Methodology

Reliability data/statistics were reviewed and concerns were identified as follows:

- Feeders were ranked according to the statistics for unscheduled distribution related outages. The statistics used were the average annual total number of Customer Minutes of Interruption[1], System Average Interruption Frequency Index (SAIFI) and the System

[1] The Customer Minutes of Interruption for an outage is the duration of the outage multiplied by the number of customers affected. A 5-minute power interruption affecting 100 customers would have a Customer Minutes of Interruption total of 500.

Average Interruption Duration Index (SAIDI). These statistics are commonly used throughout the utility industry to evaluate reliability performance. The statistics were compiled for a five year period from January 1, 2000 to December 31, 2004.

- From the rankings a listing of the worst 15 distribution feeders in each category was generated[2]. This represents approximately 5% of the total number of feeders in the Company's distribution network.

Appendix A lists the 15 worst feeders according to Customer Minutes of Interruption, SAIFI and SAIDI statistics.

3.0 Engineering Assessment

An engineering assessment was carried out on all 15 feeders identified as having relatively poor reliability performance. Each feeder in the listing was reviewed in detail to determine the root cause of the various outages and the components that failed. The assessment involved a field inspection of the distribution feeder and a review of the outage history of the feeder.

In cases where significant capital expenditure is required to improve reliability performance, an engineering report with recommendations for improved reliability performance was produced.

In some cases the engineering assessment determined that significant capital expenditure was not warranted to address the root cause of poor reliability performance on the feeder. For instance, on some feeders the assessment determined that trees coming in contact with the distribution line was the principal source of reliability problems. To address this problem, the assessment recommended a tree trimming solution which is an operating expenditure.

4.0 Conclusions and Recommendations

Table 1 lists the 7 feeders where an engineering assessment has recommended that significant capital expenditure is required to improve the reliability performance of the Company's worst performing distribution feeders. In total, the recommended capital work will cost $3,114,000. This work is budgeted under the Distribution Reliability Initiative project.

Details of the requirements for each feeder are listed in Appendix B. The engineering reports prepared for each feeder are included in the 2006 Capital Budget Application, with the exception of the report for GBY-02 feeder, which was filed with the 2005 Capital Budget Application.

[2] The 15 feeders exclude those feeders that were subject to major upgrades within the past five years.

Table 1		
Feeder	**Addressed In**	**2006 Cost**
BCV – 02	2006	$440,000
BOT – 01	2006/2007/2008	$1,038,000
GBY – 02	2005/2006	$398,000
GLV – 02	2006	$465,000
GPD – 01	2006	$102,000
SMV – 01	2006	$239,000
LEW – 02	2006/2007	$432,000

Appendix A

Results of Ranking Feeders by Customer Minutes of Interruption, SAIFI and SAIDI

Five Year Average Unscheduled Distribution Related Outages 2000-2004 Sorted By Customer Minutes of Interruption				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI[3]**	**Annual Distribution SAIDI[4]**
BOT-01	5074	762673	3.15	7.90
BCV-02	7506	702576	4.91	7.65
PUL-01	5292	621038	2.58	5.04
LEW-02	6018	618762	3.98	6.82
GLV-02	3690	557340	3.02	7.60
SMV-01	3813	488641	3.75	8.01
PUL-02	5164	466174	3.46	5.21
HWD-07	7214	436598	3.32	3.35
WES-02	3618	419760	4.77	9.22
LET-01	3715	378091	2.02	3.43
GBY-02	2259	363218	2.56	6.86
CAB-01	4011	348278	3.64	5.26
GBY-03	1632	324898	2.12	7.02
MOB-01	2928	320775	2.91	5.32
CHA-01	4088	283369	1.22	1.41
Company Average	**1,213**	**97,366**	**1.59**	**2.13**

[3] 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.

[4] 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.

Five Year Average Unscheduled Distribution Related Outages 2000-2004 Sorted By Distribution SAIFI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI[5]**	**Annual Distribution SAIDI[6]**
GBS-02	2220	135890	5.03	5.14
BCV-02	7506	702576	4.91	7.65
WES-02	3618	419760	4.77	9.22
LEW-02	6018	618762	3.98	6.82
LOK-01	3957	254071	3.86	4.14
FER-01	2390	262858	3.82	7.00
SMV-01	3813	488641	3.75	8.01
CAB-01	4011	348278	3.64	5.26
PUL-02	5164	466174	3.46	5.21
GDL-01	2165	82145	3.40	2.15
WES-01	1302	171618	3.33	7.32
HWD-07	7214	436598	3.32	3.35
BUC-02	508	73866	3.19	7.74
BOT-01	5074	762673	3.15	7.90
GLV-02	3690	557340	3.02	7.60
Company Average	**1,213**	**97,366**	**1.59**	**2.13**

5 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.

6 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.

Five Year Average Unscheduled Distribution Related Outages 2000-2004 Sorted By Distribution SAIDI				
Feeder	**Annual Customer Interruptions**	**Annual Customer Minutes of Interruption**	**Annual Distribution SAIFI[7]**	**Annual Distribution SAIDI[8]**
GPD-01	524	207159	2.26	14.88
WES-02	3618	419760	4.77	9.22
WES-03	1548	271039	3.01	8.77
SMV-01	3813	488641	3.75	8.01
BOT-01	5074	762673	3.15	7.90
BUC-02	508	73866	3.19	7.74
BCV-02	7506	702576	4.91	7.65
GLV-02	3690	557340	3.02	7.60
WES-01	1302	171618	3.33	7.32
GBY-03	1632	324898	2.12	7.02
FER-01	2390	262858	3.82	7.00
GBY-02	2259	363218	2.56	6.86
LEW-02	6018	618762	3.98	6.82
SUM-02	1724	229452	2.96	6.57
BLA-01	3448	436964	2.81	5.94
Company Average	**1,213**	**97,366**	**1.59**	**2.13**

7 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.

8 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.

Appendix B

Distribution Reliability Initiative Projects

1. Botwood (BOT-01)

Cost: $1,038,000

Description: Rebuild the trunk of BOT-01 feeder.

Operating Experience: BOT-01 originates in Botwood Substation. It has been prone to outages mainly due to insulator failure and due to the condition of its primary conductor.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for BOT-01 were 762,673 while the average annual SAIFI was 3.15 and SAIDI was 7.90 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company BOT-01 was ranked first in Customer Minutes per Year, fourteenth in SAIFI and fifth in SAIDI. A detailed engineering assessment follows titled *Botwood-01 Feeder Study.*

2. Lewisporte (LEW-02)

Cost: $432,000

Description: Rebuild the trunk of LEW-02 feeder.

Operating Experience: LEW-02 originates in Lewisporte Substation. Due to the proximity to the coast weather conditions play a large role in outages on this feeder. Wind, sleet, salt spray and lightning have accounted for 42% of all customer outages.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for LEW-02 were 618,762 while the average annual SAIFI was 3.98 and SAIDI was 6.82 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company LEW-02 was ranked fourth in Customer Minutes per Year, fourth in SAIFI and thirteenth in SAIDI. A detailed engineering assessment follows titled *Lewisporte-02 Feeder Study*.

3. Glovertown (GLV-02)

Cost: $465,000

Description: Rebuild Cull's Harbour, Happy Adventure and Salvage Taps.

Operating Experience: In 2003 the main trunk section of the GLV-02 feeder that runs through Terra Nova Park was rebuilt. This improved the reliability of that section of the feeder, however, there remains deteriorated conductor on several taps that needs to be replaced due to deterioration.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for GLV-02 were 557,340 while the average annual SAIFI was 3.02 and SAIDI was 7.60 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company GLV-02 was ranked fifth in Customer Minutes per Year, fifteenth in SAIFI and eighth in SAIDI. A detailed engineering assessment follows titled *Glovertown-02 Feeder Study*.

4. Bell Island (BCV-02)

Cost: $440,000

Description: To replace deteriorated poles, conductors and perform some general upgrade on existing structures in order to improve the reliability on the feeder.

Operating Experience: Most of this feeder was built in the 1950's. The feeder is subject to extreme weather conditions. In 1984 there was extensive damage on Bell Island due to a sleet storm.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for BCV-02 were 702,576 while the average annual SAIFI was 4.91 and SAIDI was 7.65 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company BCV-02 was ranked second in Customer Minutes per Year, second in SAIFI and seventh in SAIDI. A detailed engineering assessment follows titled *Broad Cove-02 Feeder Study*.

5. Summerville (SMV-01)

Cost: $239,000

Description: A number of structures require replacement and clamp-top insulators will be added at several locations.

Operating Experience: This feeder has had problems with structures and conductors pulling away from insulators.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for SMV-01 were 488,641 while the average annual SAIFI was 3.75 and SAIDI was 8.01 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company SMV-01 was ranked sixth in Customer Minutes per Year, seventh in SAIFI and fourth in SAIDI. A detailed engineering assessment follows titled *Summerville-01 Feeder Study*.

6. Gander Bay (GBY-02)

Cost: $398,000

Description: Rebuild the trunk of GBY-02 feeder.

Operating Experience: GBY-02 originates in Gander Bay Substation. It has been prone to outages mainly due to the failure of insulators and due to the condition of its primary conductor.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for GBY-02 were 363,218 while the average annual SAIFI was 2.56 and SAIDI was 6.86 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company GBY-02 was ranked eleventh in Customer Minutes per Year, thirty fifth in SAIFI and twelfth in SAIDI. A detailed engineering assessment report was filed with Newfoundland Power's 2005 Capital Budget Application.

7. Greenspond (GPD-01)

Cost: $102,000

Description: Rebuild the trunk of GPD-01 feeder.

Operating Experience: GPD-01 originates in Grenspond Substation. It has been prone to outages mainly due to the condition of its primary conductor.

Justification: Using data from the period 2000 to 2004, the average annual customer minutes for GPD-01 were 207,159 while the average annual SAIFI was 2.26 and SAIDI was 14.88 hours. The company average for the same period was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours. Compared to all feeders in the Company GPD-01 was ranked fortieth in Customer Minutes per Year, fifty-second in SAIFI and first in SAIDI. A detailed engineering assessment follows titled *Greenspond-01 Feeder Study*.

Botwood-01 Feeder Study

June 2005

Prepared by:

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1.0 Executive Summary

BOT-01 originates from Botwood Substation in Botwood. It has been prone to failure mainly due to the condition of some of its primary conductor, #4 Aluminum Conductor Steel Reinforced ("ACSR"), and insulator failures. Outages have been extended due to the inaccessibility of some sections of the line. Weather conditions along this section of the north east coast of the island also subject the feeder to high winds, salt spray, ice loading, and isolated lightning strikes. Significant upgrading is recommended to address these issues.

To improve the performance of this feeder, it is recommended to:

- Relocate / reconductor the existing main trunk of the feeder to the existing road Right-Of-Way (ROW).
- Replace all ACSR with present standard conductors.
- Re-insulate 7.2 kV sections of the feeder to 14.4 kV to eliminate salt contamination problems.
- Ensure all danger trees are removed from the whole feeder.

2.0 BOT-01 Feeder

Located in the Grand Falls-Windsor operating area of the Western Region, BOT-01 is a 25kV line that was originally constructed in 1959 in the Botwood area while the sections extending to Leading Tickles and Fortune Harbour were originally constructed in 1965. The feeder begins at the Botwood Substation in Botwood and serves approximately 1,607 customers. The three-phase portion of the feeder extends from Botwood to Northern Arm, where it splits and goes in two directions (refer to the map in Appendix A).

- The first three-phase section extends on through Phillips Head to the end of Point of Bay. Single phase extends from Point of Bay through Cottrell's Cove to Fortune Harbour.
- The second three-phase section extends to Point Leamington. Single phase extends from Point Leamington to Leading Tickles with a single-phase tap off this line extending to Glovers Harbour. There is also a single-phase tap from Point Leamington to Pleasantview.

Most of the main trunk of this feeder has undergone some upgrading over the years with new pole installations and reconductoring. The single-phase sections to Leading Tickles and Fortune Harbour were originally government rural lines constructed on "blackjack" poles. The three-phase sections from Botwood to Northern Arm and from Northern Arm to Point Leamington are constructed of #4/0 Aluminum Alloy Stranded Conductor ("AASC"). All other sections are a mixture of 4/0 and 1/0 AASC conductor along with long single-phase sections of #2 and #4 ACSR.

The section of three-phase around the bottom of Northern Arm has consistently been a source of problems because of its exposure to salt, high winds and ice loading. There are three sections of three-phase line away from the road between Northern Arm and Point Leamington that are difficult to maintain.

3.0 Outage History for Feeder

The feeder has a long history of outages. Botwood Substation is located 35 km from the Grand Falls Service Center. Sections of the highway in this area are subject to heavy drifting, sometimes making the roads impassible for long periods of time and therefore lengthening outage durations.

BOT-01 has 1,607 customers and is 199 km long. This is the longest feeder in the company. The length of a feeder is a factor in reliability performance. The longer the feeder the more exposure it has to the elements and the more exposure it has to component failure. This can be mitigated to some degree by properly locating and coordinating protection devices on the feeder.

Sections of the main three-phase trunk of the feeder are located up to 1,000 meters off the road right-of-way (ROW). Most of the single-phase sections of the feeder serving the outlying communities are located from 40 to 100 meters off the existing road ROW, making damage difficult to find and repair during winter storms.

The bulk of the single-phase sections are conductored with the original #4 ACSR. Sections of the three-phase main trunk feeder have one phase and the neutral conductored with #4 ACSR. This conductor has been noted to have poor operating characteristics in a salt spray environment. Over time, the outer aluminum strands break, leaving the steel core to carry the load. As the load increases, the steel core melts, breaking the conductor. Broken conductor has accounted for 34% of all distribution outages to the feeder.

2-Piece insulators have been eliminated from the main three-phase section of the feeder. However, a significant number of 14.4 kV pin type insulators remain. These insulators are original to the line and have been prone to failure. They should be replaced with 14.4 kV Clamp Top insulators.

Over the three years of outage statistics examined by this report there were nine outages reported as directly related to trees contacting the line resulting in 823,248 customer minutes or 30% of all customer outage time.

3.1 BOT-01 Feeder by Component that Failed

Table 1 below shows a summary of the 140 interruption reports for the time frame from 2002 to 2004. The table is sorted using the “Component that Failed” as its base. In some occurrences, such as in sleet and windstorms, there are no particular components that failed.

Normally, data for a five-year period would be used for this summary. However, data gathered before 2002 had unusually high customer minutes due to a major fault in 2000 and work completed on the line in 2001. For that reason, data prior to 2002 was not used.

Table 1

Interruption Summary by Component
2002 – 2004

Component that Failed	Number of Outages	Customer Minutes
Conductor	9	930,744
Conductor Hardware	2	4808
Fuses [1]	57	769,341
Insulators	5	187,503
Control Equipment at Sub [2]	4	298,140
Transformers	1	983
Service Wires	41	6,923
Cutout / Switch	18	468,133
Other	3	43,275
Total	**140**	**2,709,850**

[1] Fuses operated as a result of sleet, wind, and lightning.
[2] Includes equipment operated due to wind, trees in line etc. (as it should).

3.2 BOT-01 Feeder by Cause

Table 2 below summarizes the 140 interruption reports for the time frame from 2002 to 2004. Problems are sorted using the “Cause” as its base.

Again, data prior to 2002 was not used due to the unusually high customer outage minutes in 2000 and 2001 as discussed in section 3.1.

Table 2

Interruption Summary by Cause
2002 – 2004

Cause	Number of Outages	Customer Minutes
Salt Spray [1]	5	11,427
Wind	5	519,261
Lightning	1	1,384
Broken/Defective Equipment [2]	63	994,987
Damage Outside Party	4	117,800
Trees	9	823,248
Animals	17	7,009
Sleet	1	15,200
Unexplained	28	174,181
Other	7	45,353
Total	**140**	**2,709,850**

[1] Although only five outages were reported as salt spray, most of the outages reported as wind involved salt contamination.
[2] Broken and Defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

4.0 Recommendations

The BOT-01 feeder was reviewed for location characteristics (i.e. subject to extreme salt spray conditions and ice loading). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended. Following are the recommendations to improve this feeder.

4.1 All Sections of BOT-01 Feeder

1. Replace all 8080 and 2-piece insulators.

2. Relocate Lightning Arrestors on transformers. On this feeder Lightning Arrestors were installed on the source side of the cutout. Therefore, a Lightning Arrestor failure would result in an outage affecting the entire feeder. The Lightning Arrestors are to be relocated to the load side of the cutout where they would be isolated by the transformer fuse if they should fault.

3. All sections of the feeder will be cleared of brush and trees that impose a danger to the line outside of the current ROW. This cost has been added to the estimates.

4. All new construction will be built to 14.4 kV standards.

5. New construction in the 7.2 kV sections of the feeder (Leading Tickles, Moore's Cove, Cottrell's Cove and Fortune Harbour) will also be constructed to 14.4 kV standards. This will provide additional insulation on these sections since they are in more exposed locations and are more susceptible to salt contamination. These sections will remain energized at 7.2 kV.

6. Feeder coordination is to be reviewed and all taps are to be protected by a fused cutout

4.2 Botwood Substation to Intersection of Route 350 and Route 352, Northern Arm

This section of the main trunk of the feeder is conductored using 4/0 AASC. It is located along Route 350 through Botwood and Northern Arm. The location of this section makes it subject to high winds, salt spray and ice loading. Problems on this section of BOT-01 cause all customers on the feeder to be without power. Planned work consists of upgrading this section of the feeder to heavy loading standards. Total estimated cost for this work is approximately $148,000.

4.3 Beginning of Route 352, Northern Arm to end of Charles Brook

This section of the main feeder trunk is comprised of 10.3 km of three-phase construction and 1.0 km of single-phase construction. It is located mostly alongside Route 352 as it passes through the communities of Northern Arm, Phillip's Head, Point of Bay and Charles Brook. Only 0.6 km of the three-phase section is located off the road ROW. The three-phase section consists of two phases with 4/0 AASC conductor while the 3rd phase and the neutral are conductored with #4 ACSR. The last 1 km of line is single-phase #4 ACSR conductor phase and neutral.

It is recommended to relocate the 0.6 km of 3-phase to the road ROW. Also recommended is to replace all #4 ACSR phase conductors on the three-phase section with 4/0 AASC conductor and to upgrade the neutral to 1/0 AASC conductor.

A new remote control recloser should be installed at the intersection of Route 350 and Route 352 on the tap to Fortune Harbour. The addition of a remotely controlled recloser will decrease the length of many customer outages since the device would be operated from the System Control Centre freeing up crews to work on repairs instead of having them travel back to the substation to operate the recloser. This is particularly important on a feeder as long as BOT-01. In addition a new down-line recloser will automatically isolate faults on the tap to Fortune Harbour.

The single-phase section in Charles Brook is to be reconductored with 1/0 AASC phase and neutral.

The total estimate for planned work in this section is approximately \$233,000. This amount includes the cost of the recloser.

4.4 End of Charles Brook to the Beginning of Cottrell's Cove

This portion of single-phase line is currently built away from the existing road ROW and has #4 ACSR phase and neutral conductor. Outages along this section of line are normally related to trees contacting the line, insulator failure and conductor failure. Outage durations are significantly affected by the current location of the line (i.e. away from the road), which make locating a fault difficult.

Recommendations include building a new line along the existing road ROW and removing the existing line completely. New construction will use 14.4 kV clamp top insulators and 1/0 AASC conductor for the phase and neutral. The existing single-phase recloser and voltage regulator will be moved beyond the last customer of Charles Brook to enable better voltage control and sectionalizing of the feeder. The total estimate for planned work in this section is approximately \$720,000.

4.5 Cottrell's Cove to Moore's Cove Tap

This portion of the feeder consists of 3.4 km through the community of Cottrell's Cove. The distribution conductor is #4 ACSR primary and neutral. At the beginning of Cottrell's Cove, there is a voltage regulator and step-down transformer (14.4 kV to 7.2 kV). Most insulators are either 2-piece or small pin type. Some lightning arrestors need to be relocated to the transformer side of the cutouts and the step-down transformer and regulator platform need to be replaced. The step down transformer will remain. Planned work includes replacing primary and neutral conductors with 1/0 AASC and correcting the problems listed above. All new construction will involve insulating the 7.2 kV primary to 14.4 kV. This increase in the insulating value will reduce salt spray problems in this area. The total estimate for planned work in this section is approximately \$53,000.

4.6 Moore's Cove Tap

This portion of the existing feeder consists of 2.3 km of line through the community of Moore's Cove. The existing conductor used is #4 ACSR primary and neutral with damaged conductor and previous repair work. Most insulators are either 2-piece or small pin type. Some lightning arrestors need to be relocated to the transformer side of the cutout.

The new construction would see replacement of all primary and neutral conductors with 1/0 AASC along with re-insulating the line using 14.4 kV insulators. Several poles would require replacement along with the removal of several danger trees. The total estimate for planned work in this section is approximately \$36,000.

As in section 4.5, insulating the 7.2 kV distribution line to 14.4 kV will reduce problems with salt spray in the area. Replacing the #4 ACSR conductor with 1/0 AASC will eliminate known conductor problems.

4.7 Fortune Harbour (from Moore's Cove Tap)

This portion of the feeder consists of 2.8 km of line located away from the road and 4.6 km of line located in the community of Fortune Harbour. Existing conductor, #4 ACSR is in good shape on this section. Planned work consists of re-insulating the line using 14.4 kV insulators. Several poles would require replacement along with the removal of several danger trees. The total estimate for planned work in this section is approximately $21,000.

4.8 Route 350 from Intersection of Route 352 to Point Leamington

This three-phase section of line consists of 13.8 km of distribution located up to 1 km away from the existing road ROW and 4 km located next to Route 350. All primary conductors are 4/0 AASC with a 1/0 AASC neutral. One phase of the line has the older and smaller 14.4 kV pin type insulators. Plans include replacing this smaller insulator with 14.4kV clamp top insulators and relocating all trunk feeder sections to the existing road ROW. This will involve 13.4 km of new three-phase line. Relocating the line to the existing road ROW will eliminate problems in locating faults on the line and will speed any repairs. The existing bank of three voltage regulators will be relocated to maximize their effectiveness.

An existing hydraulic recloser will be replaced with a recloser with remote control capabilities. This will reduce the time needed for crews to return to the recloser in the substation to operate it during outages, thus reducing outage duration.

Since the majority of the section will be relocated to the road ROW there will be minimal impact on customers during construction.

The total estimate for planned work in this section is approximately $506,000.

4.9 Pleasantview Tap

This portion of the feeder is single-phase with #4 ACSR used for its primary conductors. The primary conductor is in good shape and will not be replaced. Planned work involves replacing both 2-piece and older small pin type insulators, relocating lightning arrestors to the load side of the distribution transformer cutouts and adding fuses to unfused taps. The existing line requires extensive tree trimming and danger tree removal.

The total estimate for planned work in this section is approximately $23,000.

4.10 Point Leamington

4.10.1 Point Leamington

This is the final section of the feeder's three phase trunk. Generally, the line is in good shape and work will be limited to replacing smaller pin insulators and relocating lightning arrestors. Other items identified in the 2005 Feeder Inspection will be repaired. The total estimate for planned work in this section is approximately $9,000.

4.10.2 Point Leamington

This portion of the feeder is single-phase with #4 ACSR primary conductor. The primary conductor is in good shape and will not be replaced. Planned work involves replacing both 2 piece and older small pin type insulators and relocating lightning arrestors. One six-pole section will be relocated to the road ROW to eliminate a potential hazard. The total estimate for planned work in this section is approximately $21,000.

4.10.3 Point Leamington to Recloser

This portion of the feeder is single-phase with #4 ACSR primary and 1/0 AASC neutral conductors. Planned work involves replacing both 2-piece and older small pin type insulators and relocating lightning arrestors. The existing phase conductor will be replaced with 1/0 AASC conductor. The total estimate for planned work in this section is approximately $16,000.

4.11 Point Leamington Recloser to Glovers Harbour Tap

This portion of single-phase line is currently built away from the existing road ROW and has #4 ACSR phase and neutral conductor. Problems along this section include trees, insulators and conductor. Plans include building a new line along the existing road ROW and removing the existing line completely. New construction will use 14.4 kV clamp top insulators and 1/0 AASC for the phase and neutral conductors. The existing recloser and voltage regulator will be moved beyond the last customer of Point Leamington to enable better voltage control and sectionalizing of the feeder. The total estimate for planned work in this section is approximately $557,000.

4.12 Glovers Harbour Tap

This portion of the feeder consists of 3.1 km of line located in the community of Glovers Harbour. Existing conductor, #4 ACSR, is in good shape on this section. Planned work consists of re-insulating the line using 14.4 kV insulators. Several poles would require replacement along with the removal of several danger trees. The total estimate for planned work in this section is approximately $17,000.

4.13 Leading Tickles (from Glovers Harbour Tap)

This portion of the feeder consists of 5.4 km of line located away from the road and 4.7 km of line located in the community of Leading Tickles. Existing conductor, #4 ACSR, has been joined in several places and show signs of burn marks in other places. There is a step-down transformer at the beginning of this section, which lowers the voltage to 7.2 kV. Planned work consists of relocating the step down transformer to the beginning of Leading Tickles to improve voltage in the area. The 5.4 km of line will be relocated to the existing road ROW and built to 14.4 kV standards. The section of line through the community will be reconductored with 1/0 AASC along with the re-insulating of the area to 14.4 kV standards. Several poles require replacement along with the removal of several danger trees. The total estimate for planned work in this section is approximately $225,000.

5.0 Conclusion

Outage data indicates that 45% of all outages were directly related to conductor, conductor and pole hardware, cutout failure and insulators. Trees that came in contact with the distribution line accounted for 30% of all outages. Large sections of BOT-01 lines are located away from the road. Lines away from the road ROW are prone to outages due to trees. Relocating the feeder will correct these problems. Relocating the feeder will also shorten patrol times in responding to problem calls as well as help in the isolation of the problem area from the rest of the feeder. New right-of-ways that are clear of brush and danger trees along with extensive tree trimming and danger tree removal along existing sections will improve reliability.

Rebuilding and relocating BOT-01 trunk feeder offers the best solution to the current problems on this feeder. In addition, by installing remote control reclosers and fusing taps the impact of outages will be minimized. Relocating voltage regulators and replacing smaller primary conductors will improve voltages on the feeder. All of these measures will positively impact the reliability of all customers on BOT-01.

It is recommended that BOT-01 be rebuilt and relocated as per sections 4.2 to 4.13. The total estimate for planned work in this section is approximately $2,585,000.

Due to the size and nature of the project, it is proposed to complete all the work over a three-year period.

- 2006 – Complete work in sections 4.2, 4.3, 4.8, 4.10.1, 4.12 and 4.13, not including remote control reclosers (approximately $1,038,000).

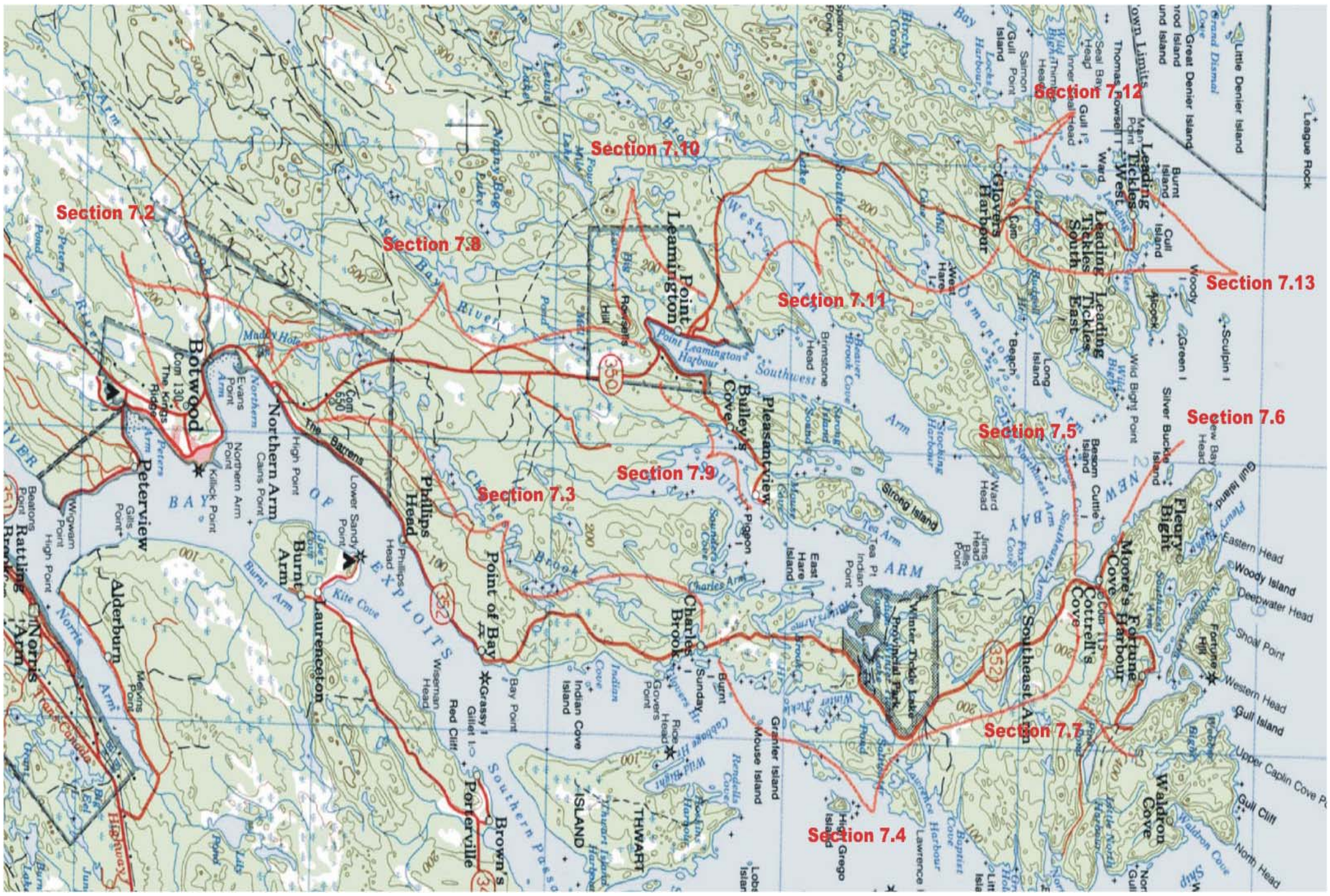
- 2007 – Complete work in sections 4.4, 4.5, 4.6, and 4.7 (approximately $830,000).

- 2008 – Complete work in sections 4.9, 4.10.2, 4.10.3, 4.11 and install remote control reclosers as in sections 4.2 and 4.3 (approximately $717,000).

The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Map Showing
Areas Serviced by BOT-01


Section 7.2
Section 7.3
Section 7.4
Section 7.5
Section 7.6
Section 7.7
Section 7.8
Section 7.9
Section 7.10
Section 7.11
Section 7.12
Section 7.13
Botwood
Peterview
Northern Arm
Point Leamington
Pleasantview
Bulley's Cove
Phillips Head
Point of Bay
Charles Brook
Laurenceton
Burnt Arm
Alderburn
Leading Tickles West
Leading Tickles South
Leading Tickles East
Glovers Harbour
Cottrell's Cove
Moore's Harbour
Fortune Harbour
Fleury Bight
Waldron Cove
Southeast Arm
Brown's
Porterville
Norris Arm
THWART
ISLAND

Lewisporte-02 Feeder Study

June 2005

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Table of Contents

1.0 Executive Summary

LEW-02 originates from Lewisporte Substation in Lewisporte. It has been prone to failure mainly due to the condition of some of its primary Aluminum Conductor Steel Reinforced ("ACSR"). Environmental conditions along this section of the north central coast of the island subjects the feeder to high winds, salt spray, ice loading, and isolated lightning strikes. Significant upgrading is recommended to address those issues.

To improve the performance of this feeder, it is recommended to:

- Replace all structures on the main trunk of the feeder with structures designed for heavy loading.
- Replace most ACSR primary conductor with Aluminum Alloy Stranded Conductor ("AASC").
- Relocate sections of the line to the road Right of Way ("ROW").

2.0 LEW-02 Feeder

Located in the Grand Falls-Windsor operating area of the Western Region, LEW-02 feeder is a 25 kV line that originates at the Lewisporte Substation located in Lewisporte and serves approximately 1,550 customers. The three-phase portion of this line extends from Lewisporte to Comfort Cove-Newstead passing through the communities of Lewisporte, Michael's Harbour, Campbellton and Loon Bay with a three-phase tap to Notre Dame Junction. Single and two-phase taps also service the communities of Baytona, Birchy Bay and the Indian Arm cabin area (refer to map in Appendix A).

This line was originally constructed in 1964 and was conductored with #2 and #4 ACSR (Aluminum Conductor Steel Reinforced) conductor. The sections from Lewisporte substation to Michael's Harbour and the tap to Notre Dame Junction, have been reconductored with 1/0 and 4/0 AASC (Aluminum Alloy Stranded Conductor). The line beyond Michael's Harbour was originally single phase with an additional two 1/0 AASC phases extended to Comfort Cove-Newstead and a second 1/0 AASC phase to Baytona around 1980. Except for small sections, the original #2 phase and # 4 neutral conductor is still in place beyond Michael's Harbour. It is Newfoundland Power's experience that this conductor has poor operating characteristics in a salt spray environment. Over time the outer aluminum strands break, leaving the steel core to carry the load.

The poles in the13 km section from Route 340 to Comfort Cove-Newstead were replaced in 1974 and mid-span poles installed in 1980. Most of these mid-span poles and replacement poles were installed "hot" and consequently no armor rods were installed, leading to excessive conductor wear at the insulator attachment point. Two sections of this line (approximately 1 km each) are along sections of abandoned road, making these sections difficult to maintain and time consuming to repair in emergency conditions. This entire feeder is in an exposed area and is subject to salt contamination, very high winds, ice loading, and isolated lightning strikes. This line is not constructed to heavy ice loading standards.

A Distribution Feeder Inspection was completed on the Comfort Cove-Newstead tap in early 2004. The inspection revealed a number of items to be addressed with the feeder. These include:

- Two piece insulators.
- CP 8080 deadend insulators.
- Porcelain cutout replacements.
- Lightning arrestors.
- Grounding and guying issues.
- Deteriorated crossarms involving cracks, rotting wood, woodpecker holes, etc.
- Conductor conditions such as broken strands, burn marks, etc.
- No armor rods on conductor at insulator attachment points.
- Deteriorated poles (woodpecker holes, burned etc.)
- 5 long spans requiring mid-span poles or reconstruction.

Sections of this feeder in the Loon Bay, Baytona and Birchy Bay areas are the original line constructed with “blackjack”, creosote treated poles and original insulators of 1964 vintage.

3.0 Outage History for Feeder

This feeder has a long history of outages. The feeder is located 80 km from the Grand Falls Service Centre. Sections of the highway in these areas are subject to heavy drifting, sometimes making the roads impassable for long periods of time. This can sometimes impact the outage durations.

Some smaller sections of the main trunk of the feeder are located up to 50 meters off the road ROW making damage difficult to find and repair during winter storms.

The bulk of the single-phase sections are conductored with the original #4 ACSR. Sections of the three-phase main trunk feeder have one phase and the neutral conductored with #4 ACSR. This conductor has been noted to have poor operating characteristics in a salt spray environment. Over time, the outer aluminum strands break, leaving the steel core to carry the load. As the load increases, the steel core melts, breaking the conductor. Broken conductor has accounted for 44% of all distribution caused outages to the feeder.

Due to the proximity of the feeder to the ocean, severe weather conditions play a large role in the frequency of outages. Wind, sleet, salt spray and lightning have accounted directly for 42% of all customer outages.

3.1 LEW-02 Feeder by Component that Failed

Table 1 below shows a summary of the 185 interruption reports for the time frame from 2000 to 2004. The table is sorted using the “Component that Failed” as its base. In some occurrences, such as in sleet and windstorms, there are no components that failed. Fuses and Substation Equipment that operate under these conditions are operating properly.

Table 1

Interruption Summary by Component
2000 – 2004

Component that Failed	Number of Outages	Customer Minutes
Conductor	23	1,353,316
Conductor Hardware	4	120,503
Fuses [1]	66	413,196
Insulators	8	205,594
Control Equipment at Sub [2]	6	392,627
Transformers	21	38,083
Service Wires	36	3,885
Cutout / Switch	16	220,447
Lightning Arrestor	2	203,466
Pole	2	119,968
Other	1	840
Total	**185**	**3,071,925**

[1] Fuses operated as a result of sleet, wind, and lightning.
[2] Includes equipment operations for wind, trees in line etc. operating as it should.

3.2 LEW-02 Feeder by Cause

Table 2 below summarizes the 185 interruption reports for the time frame from 2000 to 2004. Problems are sorted using the "Cause" as its base.

Table 2

Interruption Summary by Cause
2000 – 2004

Cause	Number of Outages	Customer Minutes
Salt Spray [1]	3	43,887
Wind	9	356,702
Lightning	22	551,205
Broken/Defective Equipment [2]	71	782,519
Damage Outside Party	5	56,410
Trees	10	86,444
Animals	15	374,246
Sleet	5	343,749
Unexplained	42	356,255
Other	3	120,508
Total	**185**	**3,071,925**

[1] Although only three outages were reported as salt spray, most of the outages reported as wind involved salt contamination also.
[2] Broken and defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

4.0 Recommendations

The LEW-02 feeder was reviewed for location characteristics (i.e. subject to extreme salt spray conditions, ice loading etc.). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended.

4.1 All Sections of LEW-02 Feeder

1. Replace all 8080 and 2-piece insulators.

2. Relocation of lightning arrestors on transformers. On this feeder lightning arrestors were installed on the source side of the cutout. This is an old standard and a lightning arrestor failure would result in an outage affecting the entire feeder. The lightning arrestors are to be relocated to the load side of the cutout where they would be isolated by the transformer fuse if they should fault.

3. All sections of the feeder will be cleared of brush and trees that impose a danger to the line outside of the current ROW. This cost has been added to the estimates.

4. Use 34 kV clamp top insulators and heavy loading construction on all Main Trunk sections of the feeder

4.2 Lewisporte Substation to LEW-02-D10 (near Mall)

This section of the main trunk of the feeder is conductored using 4/0 AASC and 1/0 AASC neutral. The general condition of the line is good but is located on the rear of the buildings along Main Street, making it winter inaccessible. Planned work is to replace all crossarms and insulators with heavy loading construction. Poles and conductor are in good condition and do not need to be replaced.

Additionally, the section of LEW-02 feeder that feeds Notre Dame Junction will be transferred to LEW-04. This will eliminate the exposure of LEW-02 to outages on this section. The Notre Dame Junction tap will be a fused tap at the end of the LEW-04 feeder that will allow it to coordinate better with the LEW-04 protection than it did with the LEW-02 protection (it was near the beginning of the LEW-02 feeder). With proper coordination the LEW-04 customers will not see any degradation of their reliability. Total estimated cost for this work is approximately $68,000.

4.3 LEW-02-D10 to LEW-02-D33 (just Past Michael's Harbour 10.6 km)

This section of the main feeder trunk is located mostly alongside Route 340. Only 0.6 km of the three-phase section is located off the road ROW. The three-phase section consists of 4/0 AASC primary and 1/0 AASC neutral. Recommendations are to relocate the 0.6 km of 3-phase to the ROW and build all structures to heavy loading construction. The total estimated cost of this work is approximately $171,000.

4.4 LEW-02-D33 to the intersection of Campbellton North (3.2 km)

This portion of feeder is built along side the existing Route 340 ROW. A & C phases are 1/0 AASC conductor while B and the neutral are #2 ACSR conductor. Plans include to replace all #2 ACSR conductor with 1/0 AASC conductor and build all framing to heavy loading construction. The total estimated cost of this work is approximately $60,000.

4.5 Campbellton North intersection to Indian Cove Brook (1 km)

This portion of the feeder was rebuilt in 2005 due to multiple problems following a sleet storm in early 2005. No additional work is required in this section. All new structures have been built using heavy loading standards.

4.6 Indian Cove Brook to Comfort Cove Tap (2 km)

This 2 km section is located alongside Route 340 ROW. The feeder consists of 1.2 km of three-phase #2 ACSR conductor and 0.8 km of three-phase 1/0 AASC conductor. The new construction would see replacement of all #2 ACSR primary and neutral conductors with 1/0 AASC along with all existing structures built to heavy loading standards. Several poles would require replacement along with the removal of several danger trees. The cost estimate for this reconstruction is approximately $45,000.

4.7 Comfort Cove Tap (15.4 km)

This portion of the feeder was rebuilt in 2005 due to multiple problems following a sleet storm in early 2005. No additional work is required in this section. All new structures have been built using heavy loading standards.

4.8 Comfort Cove Tap to Loon Bay North Tap (3.2 km)

This three-phase section of line consists of 3.2 km of distribution located next to the existing road ROW. The primary and neutral conductors are a combination of #2 and #4 ACSR. Three-phase power is no longer required here as the one building requiring a three-phase service has closed and the amount of load downstream can be handled by two phases. Plans are to build the structures to a heavy loading standard and install 1/0 AASC, primary and neutral conductors. This portion will now become a two-phase line. The installation of a remote control recloser on this section of feeder will speed power restoration to customers along with reducing outages to other customers on the feeder for problems downstream from here. Cost estimates for rebuilding this section of feeder is approximately $88,000.

4.9 Loon Bay North to the end of the existing Three Phase (1 km)

This portion of the feeder was rebuilt in 2005 due to multiple problems following a sleet storm in early 2005. No additional work is required in this section. All new structures have been built using heavy loading construction practices.

4.10 End of existing Three Phase to Baytona Tap (7.8 km)

This portion of the feeder is two-phase with #2 and #4 ACSR conductors. There is a 1 km portion that is located off Route 340 ROW, through the community of Loon Bay. Planned work involves relocating this to Route 340 ROW, building all structures to heavy loading standards. The community of Loon Bay would then be placed on two single-phase fused taps. The 6.8 km section along Route 340 requires 23 pole replacements, retiring poles that are 40 years old. Another 15 poles will require trenching to be straightened. All existing phase and neutral conductors will be replaced with 1/0 AASC. Costs estimate for rebuilding this section of feeder is approximately $191,000.

4.11 Baytona Tap to Birchy Bay Tap (18 km)

This portion of single-phase line consists of 0.9 km built away from Route 340 ROW and 2.3 km alongside Route 340. Several sections have long span construction (100 meters plus). All conductor is #4 ACSR. Plans include replacing all primary and neutral conductors with 1/0 AASC, Mid-spanning long spans, relocating all distribution to the road ROW and building the line to heavy loading standards. The cost estimate for this work is approximately $75,000.

4.12 Birchy Bay Tap (4.6 km)

This portion of the feeder consists of 4.6 km of line located in the community of Birchy Bay. The existing #4 ACSR conductor is in poor condition and several sections are located away from the road. Some clearance deficiencies exist with primary conductors and buildings. Planned work consists of replacing all smaller pin type insulators with 14.4 kV clamp tops insulators. 25 poles are of 1960's vintage will require replacement along with the removal of several danger trees. Several sections will be relocated to the road ROW to eliminate hazards. The cost estimate for this reconstruction is approximately $68,000.

4.13 Baytona Tap (4.9 km)

This portion of the feeder consists of 4.9 km of line located in the community of Baytona. The existing #4 ACSR conductor is in poor condition and 50 poles are of the 1950's vintage. Planned work consists of replacing all smaller pin type insulators with 14.4 kV clamp tops insulators, replacing all poles approaching 50 years old and replacing all primary conductor. The cost estimate for this reconstruction is approximately $87,000.

4.14 Loon Bay North Tap (1.1 km)

This portion of the feeder consists of 1.1 km of line located in the community of Loon Bay. The existing #4 ACSR conductor is in good condition, but several 2-piece insulators remain. Planned work consists of replacing all 2-piece and small pin type insulators. The cost estimate for this reconstruction is approximately $2,000.

4.15 Campbellton North Tap (4.6 km)

This portion of the feeder consists of 4.6 km of line located in the community of Campbellton. The existing conductor for 3 km is #4 ACSR that is in poor condition. Planned work consists of replacing all smaller pin type and 2-piece insulators with 14.4 kV clamp top insulators and replacing all ACSR conductor with 1/0 AASC. Several poles will require replacement. The cost estimate for this reconstruction is approximately $33,000.

5.0 Conclusion

Outage data indicates that LEW-02 should be rebuilt using heavy loading construction. 42% of all outages were directly related to adverse weather conditions. 44% of outages involved a problem with the existing primary conductors. Rebuilding of the feeder to heavy loading standards will correct these problems. Tree trimming and danger tree removal along existing sections are required to improve reliability.

The proposed work on LEW-02 offers the best solution to the current problems on this feeder. This will result in a reduction in the number and duration of outages to customers. By installing a remote control recloser and fusing taps, we will be minimizing the impact of a problem on one section of the feeder causing outages to a larger section. All of these measures will positively impact reliability for all customers on LEW-02.

It is recommended that LEW-02 be rebuilt and relocated as per sections 4.2 to 4.15. To minimize the impact of outage to customers in the area, portable generation will be used for some sections of the rebuild. Total cost for the work outlined in these sections is approximately $888,000.

Overall, the investment to improve areas of the feeder with known problems will result in improved reliability for the customers. Due to the size and nature of the project, it is proposed to complete all the work over a two-year period.

- 2006 – Complete work in sections 4.2, 4.3, 4.4, 4.6 and 4.8, not including the remote control recloser (approximately $432,000). Temporary generation will be required for work on these sections of the feeder.

- 2007 – Complete work in sections 4.10, 4.11, 4.12, 4.13, 4.14, 4.15 and installing the remote control recloser in section 4.8 (approximately $456,000).

The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Map showing
Areas Serviced by LEW-02


Section 7.2
Section 7.3
Section 7.4
Section 7.5
Section 7.6
Section 7.7
Section 7.8
Section 7.9
Section 7.10
Section 7.11
Section 7.12
Section 7.13
Section 7.14
Lewisporte
South Side
Campbellton
Michael's Harbour
Loon Bay
Birchy Bay
Baytona
Comfort Cove-Newstead
Little Burnt Bay
Masons Cove
Salt Pond Cove
Embree
Stanhope
Indian Cove Neck Provincial Park
INDIAN ARM
LOON BAY
Coal All Island
Knights Island
Birchy Island

Glovertown-02 Feeder Study

June 2005

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June 1, 2005
DATE
NEWFOUNDLAND & LABRADOR

NEWFOUNDLAND POWER
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1.0 Executive Summary

GLV-02 originates from Glovertown Substation in Glovertown. It has been prone to failure mainly due to insulator failure and to the condition of some of its primary conductor, #2 Aluminum Conductor Steel Reinforced ("ACSR"). Outages have been extended due to the inaccessibility of some sections of the line. Climatic conditions along this section of the north east coast of the island subject the feeder to high winds, salt spray, ice loading, and isolated lightning strikes. Significant upgrading is recommended to address these issues.

To improve the performance of this feeder, it is recommended to:

- Relocate and re-conductor parts of the existing main trunk of the feeder to the road Right-Of-Way (ROW).
- Replace all ACSR with present standard conductors.
- Rebuild remote sections of the feeder using Heavy Loading Standards.
- Ensure all danger trees are removed from the whole feeder.

2.0 GLV-02 Feeder

Located in the Gander operating area of the Western Region, GLV-02 is a 25kV line that originates at the Glovertown Substation in Glovertown and serves approximately 1,222 customers. The three-phase portion of the feeder extends from Glovertown to Traytown, where it splits and goes in two directions (refer to map in Appendix A).

- The first three-phase section extends on through to the Trans Canada Highway to service Terra Nova National Park. In 2005, plans are to add a one-phase tap to Charlottetown to replace the existing submarine cable.
- The second three-phase section extends through Sandringham to Eastport. A one-phase tap extends to the community of Culls Harbour from Traytown. At Eastport, there are taps extending to: Salvage (three-phase), Happy Adventure (three-phase), Sandy Point (one-phase) and Burnside (three-phase and one-phase).

Originally built in 1964 as a one-phase line from Gambo, the feeder has undergone some changes over the years. In 1976 with the addition of Glovertown Substation, two additional phases were added. In 2003, the main trunk section from the end of Traytown to the end of Sandringham was rebuilt. A 6.6 km section through Terra Nova Park in a remote location was rebuilt using heavy loading structures.

Most of the remaining three phase sections have #2 ACSR conductor as one-phase and the neutral. Most of the one-phase sections are #2 ACSR. Failure of this conductor remains the leading cause of outages on this feeder.

3.0 Outage History for Feeder

The feeder has a long history of outages. Glovertown Substation is located 40 km from the Gander Service Centre. Sections of the highway in these areas are subject to heavy drifting, sometimes making the roads impassable for long periods of time. This can sometimes impact the outage durations.

Extreme weather plays a major role in the power outages to our customers in this area. In 2004, a sleet storm damaged conductor on the tap to Salvage resulting in 117,446 customer outage minutes. Two other conductor failures in Eastport and Happy Adventure resulted in another 183,498 customer outage minutes. Two insulator failures in 2003 resulted in 589,590 customer outage minutes.

Sections at the beginning of the feeder are located up to 4 km off the road right-of-way. Finding and repairing problems in this section during winter storms is extremely difficult.

The bulk of the single-phase sections are conductored with the original #2 ACSR. Sections of the three-phase main trunk feeder have one phase and the neutral conductored with #2 ACSR. This conductor has been noted to have poor operating characteristics in a salt spray environment. Over time, the outer aluminum strands break, leaving the steel core to carry the load. As the load increases, the steel core melts, breaking the conductor. Broken conductor has accounted for 48% of all distribution caused outages to the feeder.

3.1 GLV-02 Feeder by Component that Failed

Table 1 below shows a summary of the 151 interruption reports for the time frame from 2000 to 2004. The table is sorted using the "Component that Failed" as its base. In some occurrences, such as in sleet and windstorms, there are no components that failed. Fuses and Substation Equipment that operate under these conditions are operating properly.

Normally, all data for the five-year period would be used for this summary. In 2003 and 2004, work was completed on a 12.6 km section of the feeder. Outages that occurred on this section before the rebuild have not been included in this summary. No outages occurred in this section after the rebuild.

Table 1

Interruption Summary by Component
2000 – 2004

Component that Failed	Number of Outages	Customer Minutes
Conductor	9	701,774
Pole Hardware	2	508
Fuses [1]	72	44,354
Insulators	7	374,431
Metering	1	15
Transformers	8	2,313
Service Wires	22	1,711
Cutout / Switch	25	161,772
Other	5	189,822
Total	**151**	**1,476,700**

[1] Fuses operated as a result of sleet, wind, and lightning.

3.2 GLV-02 Feeder by Cause

Table 2 below summarizes the 151 interruption reports for the time frame from 2000 to 2004. Problems are sorted using the "Cause" as its base.

Normally, all data for the five-year period would be used for this summary. In 2003/2004, work was completed on a 12.6 km section of the feeder. Outages that occurred on this section before the rebuild have not been included in this summary. No outages occurred in this section after the rebuild.

Table 2

Interruption Summary by Cause
2002 – 2004

Cause	Number of Outages	Customer Minutes
Salt Spray [1]	4	2,075
Wind	4	144,026
Lightning	3	1,731
Broken/Defective Equipment [2]	98	782,967
Fire	2	6,540
Unexplained	3	175
Other	6	5,554
Animals	27	19,706
Sleet	4	513,926
Total	**151**	**1,476,700**

[1] Although only four outages were reported as salt spray, most of the outages reported as wind involved salt contamination also.
[2] Broken and Defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

4.0 Recommendations

The GLV-02 feeder was reviewed for location characteristics (i.e. subject to extreme salt spray conditions, ice loading, etc.). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended.

4.1 All Sections of GLV-02 Feeder

1. Replace all 8080 and 2-piece insulators.

2. Replace all #2 ACSR conductors with standard conductors.

3. All sections of the feeder will be cleared of brush and trees that impose a danger to the line outside of the current ROW. This cost has been added to the estimates.

4. All new construction will be completed using 14.4 kV clamp top insulators. Remote locations are to be built to heavy load standards.

5. Feeder coordination is to be reviewed and all taps are to be protected by a fused cutout.

4.2 Glovertown Substation to Pit Lane, Traytown

This section of the main trunk of the feeder is conductored using 4/0 Aluminum Alloy Stranded Conductor (“AASC”). It is located up to 4 km off the road ROW in a very remote location. This section has been midspanned but the original poles are in need of replacement. Some brush and danger trees need to be cut. A problem on this section of GLV-02 will cause all customers on the feeder to be without power. Planned work consists of upgrading this section of the feeder to heavy loading standards and replacing the original poles. The total estimated cost for this work is approximately $109,000.

4.3 Pit Lane, Traytown to Culls Harbour Tap

This section of the main feeder trunk is comprised 4/0 AASC primary and 1/0 AASC neutral conductors. Some of the original crossarms are shorter than current standards and show signs of deterioration. A 750 meter section of the line is off the road ROW through a heavily treed area and could pose a hazard.

It is recommended to relocate the 750 meter section of 3-phase line to the road ROW. Also recommended is to replace all deteriorated crossarms and to install all clamp top insulators. All other deficiencies such as hot line clamps and bonding will be corrected. The total estimate for planned work in this section is approximately $73,000.

4.4 Culls Harbour Tap

This single-phase tap is currently built along the existing road ROW and has #2 ACSR phase and neutral conductor. Outages along this section of line are normally related to trees contacting the line, insulator failure and conductor failure. Recommendations include replacing all # 2 ACSR with 1/0 AASC conductor and using clamp top insulators. A 300 meter section of line will be relocated to the road ROW along with rebuilding of the harbour crossing. The total estimate for planned work in this section is approximately $48,000.

4.5 Culls Harbour Tap to the end of Traytown

This section of the main feeder trunk is comprised of 4/0 AASC primary and 1/0 AASC neutral conductors. Some of the original crossarms are shorter than current standards and show signs of deterioration. A 650 meter section of the line is located off the road ROW through a heavily treed area and could pose a hazard.

It is recommended to relocate the 650 meter section of 3-phase to the road ROW. Also recommended is to replace all deteriorated crossarms and to install all clamp top insulators. All other deficiencies such as hot line clamps and bonding will be corrected. The total estimate for planned work in this section is approximately $93,000.

4.6 End of Traytown to the end of Sandringham

This 12.6 km portion of the feeder was rebuilt in 2002 and 2003. No additional work is planned for this area.

4.7 Sandringham up to and Including Eastport

This three-phase portion of the feeder consists of #2 ACSR for one phase and neutral conductors while the side phases are 1/0 AASC conductor. Some crossarms and cutouts need replacing. Plans are to correct known deficiencies along with the replacement of all insulators, using 14.4 kV clamp tops. All existing phase conductors would be replaced with 4/0 AASC and the neutral conductor replaced with 1/0 AASC conductor. Several poles would require replacement along with the removal of several danger trees. The cost estimate of this reconstruction is approximately $142,000.

4.8 Tap to Happy Adventure

This three-phase tap consists #2 ACSR conductor for the center phase and neutral with 1/0 AASC conductor used for the side phases. Most of the single phase taps in the area use #2 ACSR conductor. Estimates provide for the replacement of all #2 ACSR conductor with standard conductors and installing 14.4 clamp top insulators. Deficiencies such as deteriorated crossarms, poles and guying and bonding issues would be corrected. The cost estimate of rebuilding this section of feeder is approximately $62,000.

4.9 Sandy Cove

This portion of the feeder is single-phase with #2 ACSR used for its primary and neutral conductor. The poles are in good shape but several sections require corrective measures to address secondary, service and bonding issues. Some tree trimming is required in this area. Plans include replacement of the existing conductor with standard conductors along with replacing insulators with 14.4 kV clamp top insulators. The cost estimate of rebuilding this section of feeder is approximately $52,000.

4.10 Tap to Burnside

4.10.1 Tap to Burnside (Three Phase)

This three-phase tap consists of #2 ACSR conductor for the center phase and neutral with 1/0 AASC conductor used for the side phases. Estimates provide for the replacement of all #2 ACSR conductor with standard conductors and installing 14.4 kV clamp top insulators. Deficiencies such as deteriorated crossarms, poles and guying and bonding issues would be corrected along with tree trimming issues. The cost estimate of rebuilding this section of feeder is approximately $78,000.

4.10.2 End of Three Phase to beginning of St. Chad's

This portion of the feeder is single-phase with #2 ACSR used for its primary conductors. Most of the line is located in the road ROW but a 1.2 km section is located 200 meters away from the road. Plans include replacing all #2 ACSR with standard conductors and replacing all insulators using clamp top insulators. The 1.2 km section is to be relocated to the road ROW utilizing an existing Aliant ROW. This will involve the purchase of 23 poles. The estimate includes brush clearing and tree trimming. The cost estimate for relocating/rebuilding this section of feeder is approximately $46,000.

4.10.3 St. Chad's

This portion of the feeder is single-phase with #2 ACSR used for its primary conductors. The existing line leaves the road ROW and extends through the town. Plans include building 800 meters of new construction along the road ROW and placing St. Chads on a tap off the main line. All #2 ACSR will be replaced with standard conductors along with utilizing 14.4 kV clamp top insulators. All other deficiencies such as poles, secondary, service and bonding issues will be corrected. The estimate includes brush clearing and tree trimming. The cost estimate for relocating/rebuilding this section of feeder is approximately $41,000.

4.10.4 St. Chad's up to and Including Burnside

This portion of the feeder is single-phase with #2 ACSR used for its primary conductors. One 500-meter section is located away from the road ROW. Several areas have very long spans. All #2 ACSR will be replaced with standard conductors along with utilizing 14.4 kV clamp tops. The 500-meter section will be relocated to the road ROW and midspan poles will be installed on the sections with long spans. All other deficiencies in the town of Burnside such as secondary, service and bonding issues will be corrected. The estimate includes brush clearing and tree trimming. The cost estimate for relocating/rebuilding this section of feeder is approximately $82,000.

4.11 Tap to Salvage

This section of the feeder consists of sections #2 ACSR for all conductors, sections with 1/0 AASC for all conductors and sections that are a combination of both #2 ACSR and 1/0 AASC. The pole line is located next to the coastline in extremely rough terrain. Plans include replacing all # 2 ACSR with standard conductors, replacing deteriorated poles and correcting deficiencies within the town such as service, secondary, guying and bonding issues. The estimate includes brush clearing and tree trimming. The cost estimate for relocating/rebuilding this section of feeder is approximately $323,000.

4.12 Tap to the Trans Canada Highway

This section of the feeder consists of sections of #2 ACSR for all phase and neutral conductors and it is located in a remote area that is hard to access. Some brush needs to be cut along with ROW clearing. Some poles will need to be replaced. Plans include correcting deficiencies as noted and using heavy loading construction for all structures. The cost estimate for relocating/rebuilding this section of feeder is approximately $96,000.

4.13 Tap to Terra Nova Park

This section of the feeder consists of sections with #2 ACSR for all conductors and it is located in a remote area that is hard to access. Being inland, the conductor here is not as deteriorated as other locations on the feeder.

There are no plans for work in this area.

5.0 Conclusion

Outage data indicates that 83% of all outages were directly related to conductor, cutout failure and insulator failure. Rebuilding the feeder will correct these problems. Relocating the feeder will shorten patrol times in responding to problem calls as well as help in the isolation of the problem area from the rest of the feeder. New right-of-ways that are clear of brush and danger trees along with extensive tree trimming and danger tree removal will improve reliability.

The rebuild/relocate of the GLV-02 feeder offers the best solution to the current problems on this feeder. This will result in a reduction in the frequency and duration of outages. Replacement of conductor that has a proven record of poor performance in salt conditions will positively impact the reliability the feeder.

It is recommended that GLV-02 be rebuilt and relocated as per sections 4.2 to 4.12. The total estimated cost for this work is approximately $1,245,000.

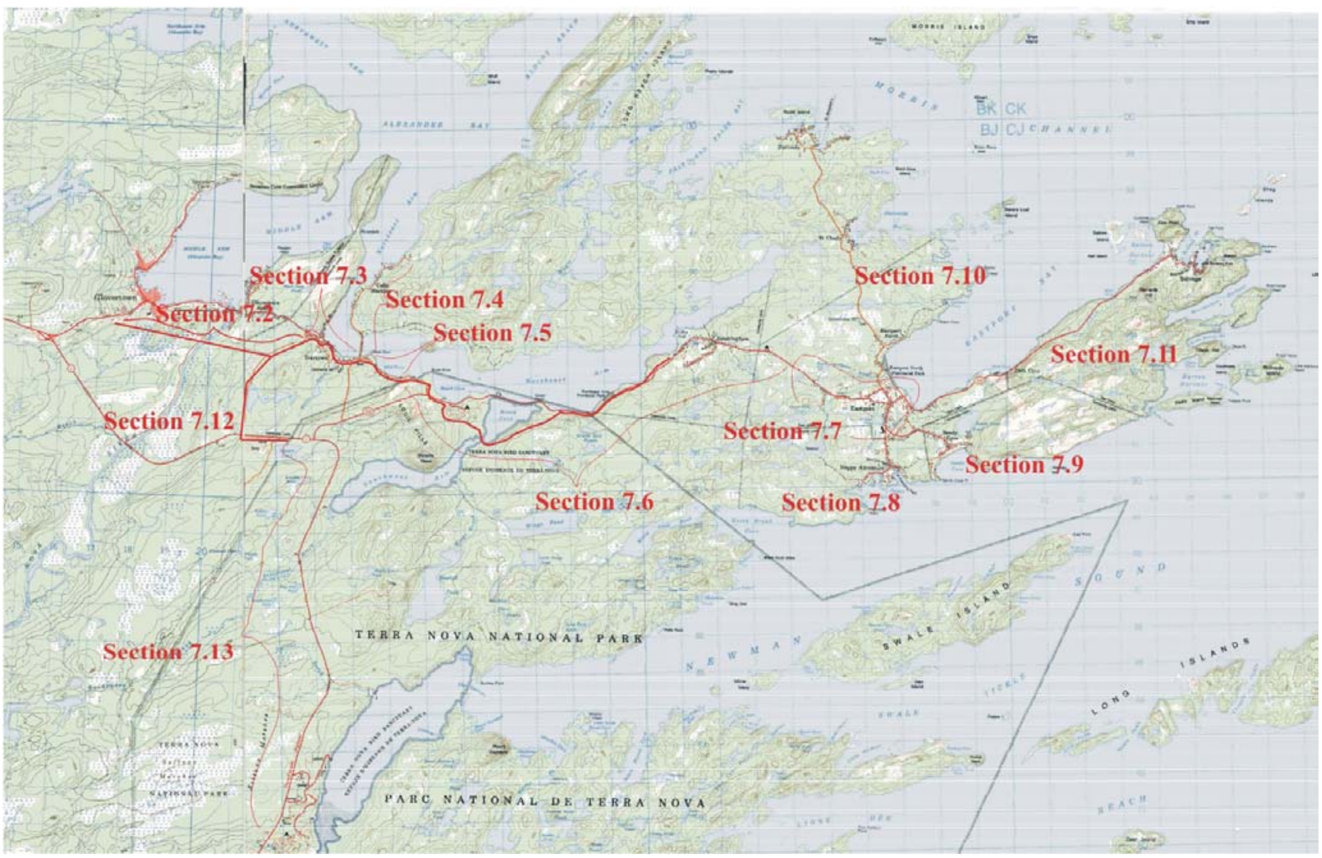
Overall, the $1,244,726 investment to improve areas of the feeder with known problems will result in an improved reliability for the customers. Due to the size and nature of the project, it is proposed to complete all the work over a three-year period.

- 2006 – Complete work in sections 4.2, 4.3, 4.4, 4.5 and 4.7 (approximately $465,000).
- 2007 – Complete work in sections 4.8, 4.9, and 4.10 (approximately $361,000).
- 2008 – Complete work in sections 4.11 and 4.12 (approximately $419,000).

The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Map Showing
Areas Serviced by GLV-02


Section 7.2
Section 7.3
Section 7.4
Section 7.5
Section 7.6
Section 7.7
Section 7.8
Section 7.9
Section 7.10
Section 7.11
Section 7.12
Section 7.13
TERRA NOVA NATIONAL PARK
PARC NATIONAL DE TERRA NOVA
NEWMAN
SOUND
SWALE ISLAND
LONG ISLANDS
MORRIS CHANNEL
BK CK
BJ CJ

Broad Cove-02 Feeder Study

June 2005

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1.0 Executive Summary

BCV-02 originates from Broad Cove Substation in St. Phillips and supplies Bell Island through a submarine cable running under the Bell Island Tickle in Conception Bay. The aerial section of the feeder has been prone to failure due to the condition of the primary #4 copper conductor and deteriorated poles. Weather conditions along the east coast of the island also subject the feeder to high winds, salt spray, ice loading, and isolated lightning strikes. Significant upgrading is recommended to address those issues.

To improve the performance of this feeder, it is recommended to:

- Reconductor existing main trunk with 1/0 AASC conductor.
- Upgrade deteriorated structures on the identified 10km main trunk line of the feeder.
- Correct the deficiencies identified by the 2005 feeder inspection program

2.0 BCV-02 Feeder

BCV-02 is located in the St. John's operating area of the Eastern Region. The feeder is a 12.5 kV line that was originally constructed in the early 1930's. The feeder is 62 Km long and begins at the Broad Cove substation in St. Phillips and serves approximately 1,530 customers located on Bell Island through submarine cables under the Bell Island Tickle in Conception Bay. The submarine cable comes ashore at the Beach Switch Yard and splits and runs up to two sets of regulators (BCV-02-VR1 and BCV-02-VR2). BCV-02-VR1 runs along Railroad Street and Bennett Street. It also taps off by the regulators and feeds Lance Cove Road, Davidson Road and West Mines Road. BCV-02-VR2 runs along Front Road, East End Road, Main Road and Quigley's Lane.

Some feeder work has been done as deficiencies were identified and programs such as the 8080 suspension and 2-piece insulator replacement programs were completed. In 1984, there was a severe ice storm that extensively damaged areas of Bell Island and approximately 25% of BCV-02 was rebuilt.

3.0 Reliability Statistics

A report titled "2006 Corporate Distribution Reliability Review" identified feeders that had consistent poor reliability. The report examined such items as the average annual total number of customer minutes of interruption, System Average Interruption Frequency Index (SAIFI), and the System Average Interruption Duration Index (SAIDI). The report also determined if major work was completed on the feeder during the past year or if work was scheduled for 2005. This report concluded that BCV-02 was amongst the poorest performers in the company and should have work completed to correct its performance.

Using data from the period 2000 to 2004, the average annual customer minutes for BCV-02 were 702,576, while the average annual SAIFI was 4.91 interruptions and the average annual SAIDI was 7.65 hours. The company average for the same time frame was 97,366 customer minutes, SAIFI was 1.59 and SAIDI was 2.13 hours.

4.0 Outage History for Feeder

The feeder has a long history of outages. Broad Cove substation is located at the end of Thorburn Road in St. Phillips Area. There are four feeders originating at this substation with BCV-02 crossing underwater to Bell Island via a submarine cable. Bell Island is only accessible by ferry. The ferry does not operate during severe weather conditions throughout the year. Under normal conditions, the ferry crossing is approximately 30 minutes in duration with a 15 minute drive in a line vehicle, this combined with the feeder length increases the challenge of locating outage sources and completing repairs.

BCV-02 has 1,530 customers and is 62 km long. The length of a feeder is a factor in reliability performance. The longer the feeder the more exposure it has to the elements and the more exposure it has to component failure. Being situated in high elevation and close to the Atlantic Ocean, this feeder is subject to high salt contamination and other environmental impurities.

4.1 BCV-02 Feeder by Component that Failed

Table 1 below shows a summary of the 261 problem calls reviewed for the time frame from 2000 to 2004. The table is sorted using the "Component that Failed" as its base. In some occurrences, such as in sleet, lightning and windstorms, there are no components that failed. Fuses and Substation equipment that operate under these conditions are operating properly.

Table 1
Problem Call Summary by Component
2000 – 2004

Component that Failed	Number of Outages	Customer Minutes
Conductor	40	1,199,799
Pole	5	667,520
None	15	647,829
Insulators	11	250,828
Fuses [1]	84	195,527
Cutout / Switch	24	188,644
Recloser	5	163,810
Conductor Hardware	4	74,814
Breaker	1	64,779
Underground Cable	1	42,784
Transformers	25	12,560
Service Wires	41	2,989
Regulator	1	630
Metering	4	369
Total	**261**	**3,512,882**

[1] Fuses operated as a result of sleet, wind, and lightning.

4.2 BCV-02 Feeder by Cause

Table 2 below summarizes the 261 problem calls reviewed for the time frame from 2000 to 2004. Problems are sorted using the "Cause" as its base.

Table 2
Problem Call Summary by Cause
2000 – 2004

Cause	Number of Outages	Customer Minutes
Broken/Defective Equipment [1]	148	1,901,259
Wind	18	506,273
Snow	20	493,192
Other	8	215,976
Lightning	18	203,376
Employee Operated Error	2	132,319
Overloaded Equipment	1	34,560
Salt Spray	16	14,563
Unexplained	2	5,646
Birds	16	4,062
Preventative Maintenance/ Repair	3	830
Vandalism	4	369
Trees	1	267
Animals	2	90
Damage Outside Party	1	70
Fire	1	30
Total	**261**	**3,512,882**

[1] Broken and Defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor or hardware.

5.0 Recommendations

The BCV-02 feeder was reviewed for location characteristics (i.e. subject to high salt spray conditions, ice loading, wind, lightning etc.). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended. Following are the recommendations to improve this feeder.

5.1 Bridal Ave. – 1-phase tap off Lance Cove Road

- 7 poles (1958 vintage) require replacement

5.2 Lance Cove Road

- 20 poles (1958 vintage) require replacement
- 130 spans of deteriorated #4 Cu. conductor require replacement

5.3 Theatre Ave. and the Green and Exile Street

- 5 poles require replacement (1958 vintage)

5.4 West Mines Road East of Wabana Complex

- 4 poles require replacement (1958 vintage)

5.5 Guthro Street, Ford Street Area.

- 4 poles require replacement (1958 vintage)

5.6 Byrne Street, West Mines Convenience Area

- Conductor requires line guards

5.7 Old East End Road

- 12 poles (1958 vintage) require replacement

5.8 #6 Road by Vokeys Lane

- 20 poles (1958 vintage) and 6 anchors require replacement
- 19 spans of deteriorated #4 Cu. conductor require replacement

5.9 #2 Road – West Mines Road

- 5 poles (1958 vintage) require replacement

5.10 Grammar Street

- 7 poles (1958 vintage) require replacement

5.11 Petris Hill

- 1 pole (1958 vintage) require replacement

5.12 Armoury Road – Skanes Road Area

- 5 poles (1958 vintage) require replacement
- Conductor needs to be re-sagged and re-tied

5.13 Armoury Road at the Bottom

- 7 poles (1958 vintage) require replacement

5.14 Martens Road in "The Valley"

- 10 poles (1958 vintage) require replacement

Completing this project will have a positive affect on the performance of this feeder, resulting in fewer outages to customers and lower operating costs.

6.0 Conclusion

Outage data indicates that 28% of all outages were directly weather related and 23% of all outages were directly related to conductor, conductor and pole hardware and insulator failures. Rebuilding BCV-02 using 1/0 primary conductor, lightning arrestors on all transformers and clamp top insulators will improve the reliability performance of this feeder. It is recommended that BCV-02 be rebuilt as per section 5.0. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service. The proposed work is estimated at $440,000.

Summerville-01 Feeder Study

June 2005

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1.0 Executive Summary

The Summerville feeder, SMV-01, originates in the Summerville Substation near Southern Bay. Outages have been extended due to the in-accessibility of some sections of the line. Weather conditions along this section of the coast of Bonavista Bay subjects the feeder to high winds, salt spray, ice loading, and isolated lightning strikes.

To improve the performance of this feeder, it is recommended to:

- Rebuild 1.3 km (34 poles) of SMV-01 Feeder along Route 235 behind the R.C. Church – Plate Cove West to Plate Cove East.
- Rebuild 3.5 km of feeder located on SMV-01 from Plate Cove East - Route 235 to SMV-01-F261 in Open Hall.
- Relocate 1 km of SMV-01 Feeder along Route 235 before the Schooner Lounge in Plate Cove West.
- Replace porcelain cut-outs, 2 piece and CP 8080 insulators.

2.0 SMV-01 Feeder

Located near Southern Bay and in the Bonavista operating area, Eastern Region, SMV-01 is a 25kV line that originates at the Summerville substation and serves approximately 1,016 customers. The feeder is comprised of:

- 15.6 kms of three-phase.
- 26.1 kms of two-phase.
- 56 kms of single-phase.

All transformers on the feeder have had lightning arrestors and new polymer cut-outs installed in 2003-2004. Clamp top insulators will be installed in 2005 in several communities.

3.0 Outage History for Feeder

Summerville substation is located approximately midway between the Clarenville Service Centre and the Port Union office. Sections of the highway in this area are subject to heavy drifting, sometimes making the roads impassible for long periods of time and therefore lengthening outage durations. Under normal conditions the substation is approximately 45 minutes from Clarenville and Port Union; this combined with the feeder length, increases the challenge of locating outage sources and completing repairs.

SMV-01 has 1,016 customers and is 98 km long. The length of a feeder is a factor in reliability performance. The longer the feeder the more exposure it has to the elements and the more exposure it has to component failure.

Nearly 500 2-piece, and over 100 CP8080 insulators were identified during the 2003 feeder inspection. The majority of these are still in service but will be removed in 2006.

3.1 SMV-01 Feeder by Component that Failed

Table 1 below shows a summary of the 226 interruption reports reviewed for the time frame from 2000 to 2004. The table is sorted using the "Component that Failed" as its base. In some occurrences, such as in sleet, lightning and windstorms, there are no components that failed. Fuses and substation equipment that operate under these conditions are operating properly.

The most significant component failures are: conductor at 26 %, and cut-outs at 10%. Conductor hardware and insulator failures combined for an additional 12.5% of the customer outage minutes.

Table 1

Problem Call Summary by Component
2000 – 2004

Component that Failed	Number of Outages	Customer Minutes
Fuses [1]	106	694,400
Conductor	13	634,313
Cutout / Switch	12	243,918
Conductor Hardware	5	180,260
Insulators	16	121,021
Regulator	1	96,384
Transformers	41	85,019
Recloser	1	72,432
Pole	2	67,920
Control Equipment at Sub [2]	2	61,576
Service Wires	17	511
Other	10	156,906
Total	**226**	**2,414,660**

[1] Fuses operated as a result of sleet, wind, and lightning.
[2] Includes operations for wind, trees in line etc. Equipment operated, as it should.

3.2 SMV-01 Feeder by Cause

Table 2 below summarizes the 226 interruption reports reviewed for the time frame from 2000 to 2004. Problems are sorted using the "Cause" as its base. Weather affects including sleet, wind and lightning have caused 71% of the customer outage minutes. Broken or defective equipment, as detailed in Table 1, contributed 20% of the total customer outage minutes.

Table 2

Problem Call Summary by Cause
2000 – 2004

Cause	Number of Outages	Customer Minutes
Sleet	20	963,497
Wind	20	580,668
Broken/Defective Equipment [1]	81	492,106
Lightning	69	118,666
Vandalism	1	101,000
Damage Outside Party	1	65,040
Salt Spray	11	58,906
Trees	3	19,025
Other	9	11,636
Unexplained	6	2,922
Animals	5	1,194
Total	**226**	**2,414,660**

[1] Broken and Defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

4.0 Recommendations

The SMV-01 feeder was reviewed for location characteristics (i.e. subject to high winds, extreme salt spray conditions, ice loading, lightning, etc.).

4.1 All Sections of SMV-01 Feeder

Replace all CP 8080 and 2-piece insulators. This will be completed in 2006.

4.2 Plate Cove, behind R.C. Church

Rebuild 1.3 km (34 poles) of SMV-01 Feeder along Route 235 behind the R.C. Church – Plate Cove West to Plate Cove East. This section of line is currently conductored with #2 ACSR. Past damage has resulted in numerous sleeves along this section of line. The line presently has short cross-arms with clearance and spacing concerns. Many of the cross-arms are in deteriorated condition.

The line is difficult to access and perform maintenance on and a number of outages have occurred over the years that were further compounded due to the difficult location of the line. The average age of the distribution plant is approximately 40 years with pole setting depth being a concern. It is proposed to rebuild this section to heavy construction standards with shorter spans lengths, new conductor and clamp top insulators due to its highly exposed location.

4.3 Rebuild, Plate Cove East to Open Hall

Rebuild 3.5 km of feeder located on SMV-01 from Plate Cove East Route 235 to SMV-01-F261 in Open Hall.

The existing line has #4 Copper conductor with a median pole age of 41 years (with an average age of 37 years) and consists of 30 foot class 4 poles that have not been installed to the proper setting depth. Most of these structures are not accessible via line truck and cannot be climbed due to the substandard setting depth. Several structures have been removed in recent years and setting depths of 3.5 - 4.5ft have been confirmed. This single-phase distribution line feeds the communities of Open Hall, Red Cliff and Tickle Cove serving approximately 120 customers. This section of line will be rebuilt to heavy construction standard with 1/0 conductor.

4.4 Relocated Route 235 – Plate Cove

Relocate 1km of SMV-01 Feeder along Route 235 before the Schooner Lounge in Plate Cove West.

This project will reroute an existing two-phase #2 ACSR conductor distribution line that presently has creosote poles located in and near a water body. This location is hazardous which makes it very difficult to perform maintenance. The average age of the distribution plant is approximately 37 years. In 2001, a new joint use distribution line was built to accommodate a new Aliant Fiber Optic Cable between the communities of Summerville and Plate Cove West and the relocation will use this new joint use line.

5.0 Conclusion

SMV-01 feeder is exposed to severe weather. Outage statistics indicate that 71% of outages were directly attributed to the weather. The installation of clamp top insulators and rebuilding to heavy construction standards in exposed areas will improve this situation.

Rebuilding and reconductoring SMV-01 offers the best solution to the current problems on this feeder. The rebuilds that have been identified will help improve reliability by eliminating substandard construction.

It is recommended that SMV-01 be rebuilt and reconductored as per Sections 4.2 to 4.4. It is also recommended that insulators be replaced as per Section 4.1. The proposed work on SMV-01 will cost approximately $239,000. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Greenspond-01 Feeder Study

June 2005

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1.0 Executive Summary

The Greenspond feeder, GPD-01, originates from Greenspond Substation located at the intersection of Route 320 and the Greenspond Access Road. It has been prone to failure mainly due to the condition of some of its primary conductor, #2 Aluminum Conductor Steel Reinforced ("ACSR") and insulator failure. Outages have been extended due to the inaccessibility of some sections of the line. Weather conditions along this section of the northeast coast of the island also subject the feeder to high winds, salt spray, ice loading, and isolated lightning strikes. Significant upgrading is recommended to address these issues.

To improve the performance of this feeder, it is recommended to:

- Replace all ACSR with present standard conductors.
- Re-insulate the exposed sections of the feeder using 14.4 kV clamp top insulators to eliminate salt contamination problems.
- Replace all aluminum hot line clamps, porcelain cutouts and install lightning arrestors on all transformers.

2.0 GPD-01 Feeder

Located in the Gander operating area of the Western Region, GPD-01 feeder is a 12.5 kV line that originates at Greenspond Substation located 0.5 km off Route 320 on the Greenspond Road and serves approximately 233 customers. This three-phase line extends from Greenspond Substation to the Town of Greenspond, passing through South-West Pond cabin area and Shamblers Cove with single-phase taps within the Town of Greenspond (refer to map in Appendix A).

The line was originally constructed in 1980 and was conductored with 1/0 AASC (Aluminum Alloy Stranded Conductor) from the substation to the Greenspond Causeway. The crossing to Greenspond Island is conductored with ACSR. The Town of Greenspond is conductored mainly with #2 ACSR that is noted to have poor operating characteristics in a salt spray environment, as the outer aluminum strands break leaving the steel core to carry the load.

This feeder is in an area subject to heavy wind and ice loading and is a radial line with no alternate means of supply. The Greenspond Road is in an exposed area making sections of this feeder difficult to access and repair during winter storm conditions.

A number of items have been identified on this feeder that needs to be addressed. These include:

- #2 ACSR conductor replacement.
- Porcelain cutout replacements.
- Lightning arrestors.
- Grounding and guying issues.
- Clearance issues from buildings along Main Street.
- Primary taps without fused disconnects.

- Aluminum hot line clamps.
- Crossarm and insulator replacement in areas subject to the heaviest wind and ice loading to meet heavy loading distribution standards.

3.0 Outage History for Feeder

This feeder has a long history of outages. The feeder is located 100 km from the Gander Service Centre. Sections of the highway in these areas are subject to heavy drifting, sometimes making the roads impassable for long periods of time. This can sometimes impact the outage durations.

Extreme weather plays a major role in the power outages to our customers in this area. In the last 5 years, 2000 to 2004, 56% of all customer outage minutes were directly related to sleet, wind, and salt spray. Other problems such as service connection failure can be attributed to the effects of severe weather conditions over a prolonged period of time.

A winter storm in April 2004 resulted in major outages in the area. Crews were dispatched from Gander, Grand Falls and Corner Brook. The outage to customers on GPD-01 lasted 28 hours and 16 minutes.

In 2005, $25,000 has been allocated for immediate rebuild of some sections of the main line within the Town of Greenspond.

3.1 GPD-01 Feeder by Component that Failed

Table 1 below shows a summary of the 100 interruption reports for the time frame from 2002 to 2004. The table is sorted using the "Component that Failed" as its base. In some occurrences, such as in sleet and windstorms, there are no components that failed. Fuses and Substation Equipment that operate under these conditions are operating properly.

Table 1

Interruption Summary by Component
2002 – 2004

Component that Failed	Number of Outages	Customer Minutes
Conductor	18	1,063,421
Conductor Hardware	6	80,883
Fuses [1]	15	5,568
Insulators	8	245,390
Other	15	251,853
Pole	1	480
Transformers	11	18,915
Service Wires	20	2,763
Cutout / Switch	2	33,434
Customer Owned Equipment	1	50
Pole Hardware	2	9,150
Unexplained	1	44,377
Total	**100**	**1,756,284**

[1] Fuses operated as a result of sleet, wind, and lightning.

3.2 GPD-01 Feeder by Cause

Table 2 below summarizes the 100 interruption reports for the time frame from 2002 to 2004. Problems are sorted using the "Cause" as its base.

Table 2

Interruption Summary by Cause
2002 – 2004

Cause	Number of Outages	Customer Minutes
Salt Spray [1]	1	20
Wind	4	90,733
Lightning	8	4,894
Broken/Defective Equipment [2]	56	442,589
Damage Outside Party	16	198,506
Unexplained	2	45,277
Other	3	1,971
Snow	1	395,168
Animals	1	78,521
Sleet	8	498,605
Total	**100**	**1,756,284**

[1] Although only one outage was reported as salt spray, most of the outages reported as wind involved salt contamination also.

[2] Broken and Defective equipment include items such as insulators, conductor and hardware. In a windstorm, outages can occur due to trees on line, damage to conductor, etc.

4.0 Recommendations

The GPD-01 feeder was reviewed for location characteristics (i.e. subject to extreme salt spray conditions, ice loading, etc.). Each section of the feeder was then analyzed to see if specific causes could be determined and appropriate solutions recommended.

4.1 All Sections of GPD-01 Feeder

1. Replace all 8080 and 2-piece insulators.

2. Installation of Lightning Arrestors on distribution transformers.

3. All new construction will be completed to 14.4 kV standards. Exposed locations (from the water supply to and including the town of Greenspond) are to receive 35 kV line post insulators as an additional measure for salt spray and ice loading.

4. Replace all porcelain cutouts with polymer cutouts.

5. Replace all aluminum hot line clamps.

6. Replace all #2 ACSR with standard conductors

7. Feeder coordination is to be reviewed and all taps are to be protected by a fused cutout.

4.2 Greenspond Substation to the Water Supply (8.9 km)

This section of the main trunk of the feeder is conductored using 1/0 AASC phase and neutral. It is located beside the Greenspond access road. This section of the feeder is in good condition and no work is required.

4.*3 Water Supply to the Causeway (2.5 km)*

This section of the main trunk of the feeder is conductored using 1/0 AASC phase and neutral. It is located beside the Greenspond access road. The location of this section makes it subject to high winds, salt spray and ice loading. Problems on this section of GPD-01 cause all customers on the feeder to be without power. Planned work consists of strengthening this section of the feeder using 35 kV line post insulators. The total estimated cost for this work is approximately $59,000.

4.4 Steel Structures and Span across Pond Tickle (1.0 km)

The crossing to Greenspond Island is conductored with a steel conductor due to high tension loading and is in good condition. The steel towers are 25 years old and are in good condition. The towers will be inspected in 2005.

4.5 Town of Greenspond

This is the most exposed section of the feeder. Some of the primary conductor is 1/0 AASC but the three-phase section along Main Street and several of the single phase taps in the Town of Greenspond are conductored with #2 ACSR. Plans include replacing all #2 ACSR with 1/0 AASC, installing structures for heavy loading, replacing all aluminum hot line clamps and installing lightning arrestors. Grounding, bonding and fuse coordination issues will be addressed. The total estimated cost for planned work in this section is approximately $43,000.

5.0 Conclusion

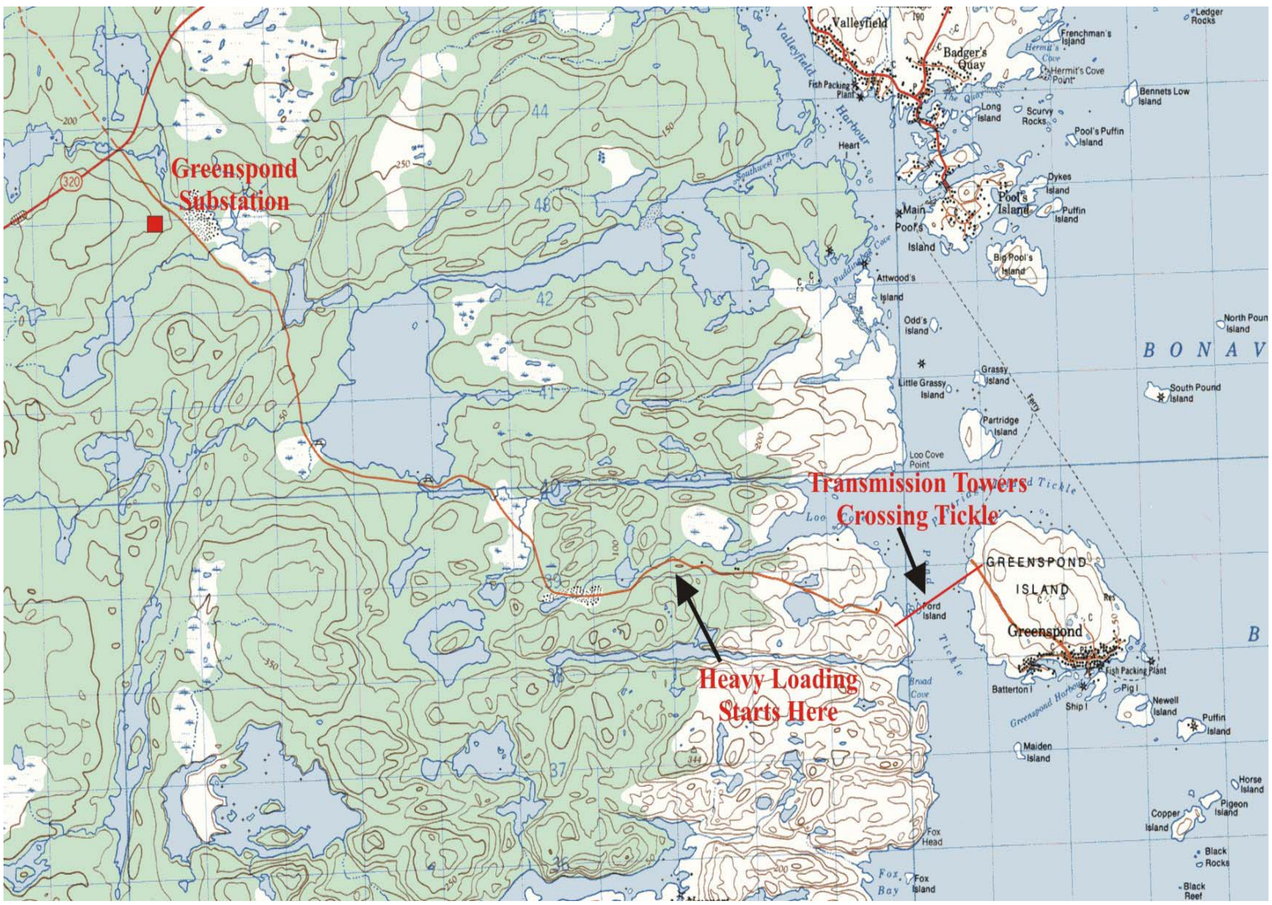
Outage data indicates that 81% of all outages were directly related to conductor, conductor and pole hardware, cutout failure and insulators. Rebuilding of the feeder will correct these problems and will improve reliability.

Strengthening, re-conductoring and re-insulating the exposed sections of the feeder offers the best solution to the current problems. Installing heavy loading structures and insulating the line to a higher standard will eliminate salt spray problems. Correcting known deficiencies such as hot line clamps and porcelain cutouts will positively impact the future reliability of all customers on GPD-01.

It is recommended that GPD-01 be rebuilt and relocated as per sections 4.3 and 4.5. The total estimated cost for this rebuild work is $102,000. Upgrading GPD-01 feeder will result in a reduction in the number and duration of outages. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Appendix A

Map Showing
Areas Serviced by GPD-01


Greenspond
Substation
Transmission Towers
Crossing Tickle
Heavy Loading
Starts Here
Valleyfield
Badger's Quay
Pool's Island
GREENSPOND ISLAND
Greenspond
B O N A V

Feeder Additions and Upgrades to Accommodate Growth

June 2005

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1.0 Background

As our communities grow and expand, loading at specific locations within the electrical system may approach the capacity of the existing electrical facilities. This report addresses two locations where this condition exists. To continue to provide customer service, proactive measures are required.

2.0 Bay Roberts – Offload T1 Transformer ($176,000)

Bay Roberts (BRB) Substation is located along Route 70 (Conception Bay Highway) in the community of Bay Roberts. This substation consists of one 138 kV to 12.5 kV transformer (BRB-T1) & two 138 kV to 66 kV transformers (BRB-T2 & BRB-T3). BRB-T1 has a nameplate rating of 20 MVA and presently has a one in ten year worst case peak forecast for 2005 of 22.7 MVA, which presents an overloaded condition during peak periods.

The Bay Roberts substation has five 12.5 kV distribution feeders. BRB-01 has 451 customers along Route 70 including Coley's Point North and has a 2004 peak load of 5.0 MVA. BRB-02 has 452 customers along Route 70 through the community of Spaniards Bay and has a peak load of 2.4 MVA. BRB-03 has 917 customers feeding the downtown section of Bay Roberts and has a peak load of 4.7 MVA. BRB-04 has 1033 customers feeding Country Road along with the main trunk feed to Port De Grave and has a peak load of 5.3 MVA. BRB-05 has 668 customers along Route 70 including the communities of Shearstown and Butlerville and has a peak load of 3.3 MVA.

BRB-01 can be paralleled with Springfield Substation's SPF-01 Feeder at the tie point TD-228 opposite the Department of Works, Services & Transportation Depot on Route 70. BRB-02 can be paralleled with ICL-02 at the tie point TD-242 in Spaniards Bay.

As can be seen in the table below BRB-T1 existing load carrying capacity (20.0 MVA) was reached in 2001 with a loading of 20.0 MVA and exceeded in 2004 with a loading of 20.2 MVA. Projected load for BRB-T1 in 2006 is 23.4 MVA and will increase to 23.8 MVA at the end of the five-year forecast in 2010.

Substation	2000	2001	2002	2003	2004
BRB-T1 Peak (MVA)	18.2	20.0	19.0	18.0	20.2

In order to prevent this overload from occurring two options were considered:

1. Offload 2.7 MVA from BRB-T1 and equally distribute the load on the adjacent feeders from Island Cove Substation (ICL-02) and SPF-01. This would include the installation of a set of three phase regulators for ICL-02 and SPF-03 and a single phase regulator on ICL-02 to maintain voltages on the feeders within the Company's voltage requirements. The cost of this option is approximately $176,000. This would defer a transformer

overloading condition beyond 2010. The transformers at the Island Cove and Springfield Substations would be impacted by these transferred loads, but would not overload during this period.

2. Replacement of BRB-T1 with a new 25 MVA power transformer. The cost of this option is approximately $1,000,000.

Given the economic deferral of the power transformer purchase for at least five years by the installation of the voltage regulators, the first option was chosen as the preferred alternative.

3.0 Reconductor Glendale-02 Feeder Section ($90,000)

Glendale-02 feeder extends from Glendale substation towards the Canadian Tire Store on Merchant Drive. The existing 1/0 aluminium conductor does not have the capacity rating for future load growth. It is proposed to reconductor this section of Glendale-02 feeder with the higher ampacity 477 ASC conductor.

This capacity upgrade will enable the feeder to supply the Merchant Drive area, and to supply the South Brook Subdivision and future phases of the Southlands Subdivision. The cost of this work is approximately $90,000. The recommended work, for which there is no feasible alternative, is required in order to ensure the continued provision of safe, reliable electrical service.

Standby Generation at Newfoundland Power Facilities

June 2005

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1.0 Introduction

Newfoundland Power recently reviewed and assessed its ability to respond to a major outage where the supply of power to customers (and customer facilities) is interrupted for an extended period of time (several days to weeks). While Newfoundland Power does have Business Continuity plans, it was recognized that the current lack of standby generation at the Company's operations buildings would impact the Company's ability to respond to such a rare, but possible, event.

2.0 Background

The concern with lack of backup generation in operations buildings was heightened following the release of a 2005 study of Nova Scotia Power's response to major power outage situations in its area. From the Liberty Consulting Group's *Report on Nova Scotia Power Company's Transmission System and Outage Communication*, submitted to the Nova Scotia Utility and Review Board, it was evident that Nova Scotia Power's effectiveness in addressing customer concerns and restoring power was materially and negatively impacted as a result of power interruptions to its own facilities. [1]

The consultant's report makes specific reference to the loss of power at Nova Scotia Power's call centre. For instance, the Nova Scotia Power call centre network was effectively shut down for 5 hours, making it impossible for call center agents to use their supporting computer systems to respond to customer inquiries and to accept outage reports. During this period, the call centre was limited to manually capturing only emergency calls and faxing these to regional offices. The company's regional operations personnel were unable to access the outage management system which further delayed determining the extent and location of the outages.

3.0 Newfoundland Power

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 who actually do the physical restoration work, and a large number of support employees (including those involved with 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 major storm and power outage situations power restoration teams would require technology and communications infrastructure that is normally provided by the Company's wide area computer network (WAN) and SCADA system. Computer systems such as outage

[1] The Nova Scotia Utility and Review Board also commissioned a report regarding the issues faced by Nova Scotia Power, Inc. during the November storm. It was written by Power System Outage Response, LLC and was titled *Report to the Nova Scotia Utility and Review Board Review of Nova Scotia Power, Inc. Response Winter Storm – November 13/14, 2004.*

management, asset management, and the various engineering applications are critical to employees involved with the assessment of system damage and the management of the service restoration effort. As well, employees involved with emergency procurement activities, who are required to obtain additional materials and equipment to facilitate reconstruction of the electrical system, must be able to access and use computer applications and various modes of communication. Customer service employees require access to the corporate computer network to facilitate effective response to customer outage reports and inquiries. However, the small uninterruptible power supply (UPS or battery backup) systems that are currently located at many of the Company's buildings are only sufficient to sustain SCADA communications for a short duration (several hours) and cannot support any of the critical computer systems. These limited UPS systems would not support normal operating conditions in those buildings during an outage event.

At a more fundamental level, employees involved with a major restoration effort require a workspace with adequate lighting, heating and /or cooling. Because of the increased workload and stress associated with major outages, these basic needs become significantly more important to a productive workforce but are unlikely to be available without a source of standby generation. Employees need a supportive workspace where they can analyze, organize, prioritize, and plan the recovery efforts, provide a level of reassurance to customers, and allocate materials and communicate instructions to crews working in the field. The circumstances of a major power outage event could dictate that the Company also receive assistance from other areas, contractors, and/or employees from other utilities, requiring effective collaboration and communications among these various groups.

Newfoundland Power currently has adequately sized standby generation at its Head Office on Kenmount Road and at its System Control Centre on Topsail Road. However, at the Duffy Place building the existing standby generation is grossly undersized. Duffy Place houses the Company's Customer Contact Centre, critical computer networks, backup SCADA centre, central stores and warehouse, and is the home base for all line operations in the relatively densely populated north-east Avalon peninsula. The existing standby generator at the Carbonear building is also undersized. None of the Company's other Area Operations buildings have standby generation. Table 1 summarizes the peak building demand, existing standby generation, and employees at each building location.

Table 1

Peak Building Demand, Existing Standby Generation And Employees

Area Operations Buildings	2004 Peak Demand (kW)	Existing Standby Generation (kW)	Total Number of Full-time Employees (in Area)	Number of Linepersons & Apprentices (in Area)
Duffy Place	734	145	163	32
Carbonear	169	80	34	11
Burin	103	Nil	20	10
Clarenville	134	Nil	28	12
Gander	136	Nil	32	15
Grand Falls	145	Nil	24	10
Corner Brook	126	Nil	25	8
Stephenville	81	Nil	21	5

Standby generation in the Area Operations buildings is essential for planning, scheduling, engineering, communications, and the overall organization of a large-scale power restoration effort. The Company's ability to respond quickly should not be limited by unavailability of electricity to its facilities, systems, and employees directly involved in or supporting such an effort. Diesel generators, of a sufficient capacity to supply a normally functioning building, are therefore required at each of the Company's Area Operations buildings.

4.0 Conclusions

To ensure that all required personnel and systems can efficiently and quickly respond to an extended power outage and restore power to its customers in the shortest possible time period, Newfoundland Power requires an adequately sized backup generator at each of its Area Operations buildings.

5.0 Recommendations

To address the highest priority first, in 2006 Newfoundland Power should:

- Install an appropriately sized standby diesel generator at its Duffy Place building; and
- Relocate the existing unit from its Duffy Place building to its Clarenville building where the unit size is closely matched to the building load.

In the coming years, the Company should also install adequately sized standby generation at each of the remaining Area Operations buildings.

2006 Load Control Initiative

June 2005

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1.0 Background

In Order No. P.U. 44(2004) the Board approved the three year phase in of a Demand and Energy Rate for the power and energy supplied to Newfoundland Power (the "Company") by Newfoundland and Labrador Hydro ("Hydro"). The primary benefit of the demand and energy rate is the incentive it provides to the Company for long-term load management. Load management has the potential to benefit customers through reduced purchased power costs in the short term and reduced costs through deferral of generation and other capacity additions in the long term.

In response to the incentive provided by the demand and energy rate the Company is examining load management opportunities. One such opportunity is the reduction of the electrical load that the Company buildings place on the power system. The Company operates office, maintenance, substation and generation plant buildings all of which utilize electrical equipment common to typical customer facilities. By shutting off specific non-critical electrical equipment and, if available, utilizing auxiliary back-up generation available at the Company's buildings, the Company can potentially reduce load at time of high demands, or at times of system generation shortages

2.0 Operating Experience

During the December 6, 2004 system peak, the Company piloted a manual process to reduce Company use of electricity at a number of Company buildings. The process required employees to switch off specific non-critical electrical equipment such as heaters, lights, hot water tanks and HVAC units. In some cases, employees turned on local auxiliary back-up generation units to reduce Company electrical requirements from the distribution system.

It was estimated that this manual approach resulted in a demand reduction of approximately 2.5 MW.

3.0 Automating the Demand Reduction

The process employed on December 6, 2004 was effective in reducing load by approximately 2.5 MW. However, the process required manual intervention by staff who may not be always available to achieve the reduction.

The need to reduce load occurs whenever a system peak is expected, as well as at times when problems are being experienced with system generation. Such events often occur when components of the electrical system are operating near capacity and weather is poor, requiring staff to be available to address potential system problems. Automating the demand reduction will provide greater assurance that the demand reduction will occur when staff may not be available due to other system priorities.

It is difficult to achieve all the potential demand reduction due to the need to employ staff to initiate each element of the reduction. While the Company did achieve an estimated 2.5 MW reduction in 2004, there is further demand reduction available at Company buildings. Auto mation will permit maximizing the potential demand reduction achievable beyond 2.5 MW.

A further element of this load control initiative is the improved monitoring of the demand reduction achieved. Currently, the reduction achieved is a rough estimate based on connected load. As part of the automation, metering will be installed that will allow a more accurate recording of the demand reductions achieved.

4.0 Cost Benefit Analysis

The continued achievement and potential increase in the demand reduction requires automation. Therefore the cost benefit analysis is based on the cost of the automated demand reduction process versus the value of the overall demand reduction achieved.

A 2.5 MW demand reduction on peak can be valued through either its reduction in demand charges to Newfoundland Power (short-term effects) or through its deferral of capacity addition on the island interconnected system (long-term effects).

The phase-in of the demand and energy rate will result in a demand charge of $79.68/KW during the 2006/07 winter season. ($6.64/KW x 12 mo). A 2.5 MW reduction in peak would therefore result in an approximate $200,000 per year reduction in demand charges from Hydro.

While full assessment of long-term benefits are not available at this time[1], Hydro indicated in its 2003 General Rate Application that the demand charge resembles the marginal cost of a generation peaking unit.

The estimated cost of providing the automated load control is $143,000. The useful life of this load control equipment is anticipated to be on the order of 10 to 20 years. It is clear from this analysis that an investment of $143,000 will return annual reduced operating costs that will rise to approximately $200,000 per year in 2007 and continue into future years.

5.0 Implementation of an Automated System

Implementation of the automated system will include upgrading the existing metering systems at 10 of the Company's office buildings and the integration of a two-way communication scheme via the existing SCADA system. Through the utilization of the existing SCADA system, an individual will be able to initiate the demand reductions.

[1] - Long-term load management impacts should be evaluated against future avoided costs. The potential impact of this particular load management initiative on future costs is not available. During 2006, Hydro will be completing a marginal cost study that will provide information that can be used to better assess the potential impact of load management initiatives.

Following such action, confirmation of demand reduction will be possible through polling of the local metering points.

6.0 Recommendation

It is recommended that in order to minimize costs the Company proceed with a load management initiative that, through automation, reduces the Company's demand at its buildings during system peak.

2006 Application Enhancements

June 2005

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1.0 Introduction

The Company operates and supports over fifty computer applications including package software such as Microsoft Great Plains (financial system) and Avantis (asset management system) as well as internally developed software such as the Customer Service System (CSS) and the Outage Management System. These applications assist employees in providing effective customer service as well as allow employees to work effectively and efficiently.

The Company's computer applications are divided into categories including: Customer Systems, Operations and Engineering Systems and Internet/Intranet 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 projects budgeted for 2006.

2.0 Customer Service Systems Enhancements

2.1 Remote Agent Enhancements ($186,000)

Description

This project involves utilizing the Company's Wide Area Network (WAN) and Voice over Internet Protocol (VOIP) technology to allow Company personnel to communicate with customers without incurring additional long distance charges. As well, improvements to the performance of the applications used by Contact Centre Agents who are physically located in an area office ("remote agents") will be completed.

Operating Experience

Employees in area offices across the province are utilized to augment the Contact Centre located in St. John's. When an employee is acting as a Contact Centre Agent they are required to connect to the Contact Centre phone system in order to get customer calls routed to them. During the time they are connected long distance charges are being incurred.

The speed of the WAN which connects area offices to St. John's is slow compared to the speed of the network between offices in St. John's. The slow network performance has a direct impact on employee efficiency and customer service.

Justification

This initiative will reduce long distance charges incurred by Contact Centre agents who are physically located in an area office. As a result of improved performance of the corporate applications they use, remote agents will be able to more promptly and efficiently respond to customer requests and perform account updates.

A financial analysis of the costs and benefits associated with this project, located in Appendix A, results in a positive net present value over the next 5 years.

2.2 Customer Tracking and Setup Improvements ($166,000)

Description

Having timely and accurate customer information available to Contact Centre Agents who provide phone-based service is imperative. This project involves a number of improvements to the tracking and maintaining of customer information. Improvements include (i)) enhancing phone and email contact information, (ii) improving mailroom processing of customer bills and letter correspondence , and (iii) maintaining more identification information regarding customers.

Operating Experience

Currently only home phone numbers and work phone numbers for residential customers and one contact phone number for commercial customers are maintained within the Customer Service System. Mobile phone numbers and alternate contact phone numbers are not maintained.

Customer e-mail addresses are maintained if provided by customers through such programs as e-bills. There are further opportunities to utilize e-mail instead of regular mail when corresponding with customers.

Currently customer letter correspondence and bills are mailed separately to the customer even though they may be produced and mailed to the same address on the same day.

Currently customer identification information is only recorded when the customer requests electrical service and opens an account. Identification information is not tracked when the customer is not the primary person associated with an account.

Justification

This project is justified on customer service and productivity improvements.

Mobile phones and email addresses have become ubiquitous and allow customers to conduct business from practically anywhere they are located. By maintaining mobile phone numbers and other contact information the Company will be able to respond to customer requests in a timely and efficient manner, using whatever method of communication customers prefer.

As well, reduced postage costs are expected through increased use of email and merging bill and letter correspondence into one envelope.

It is expected there will be a reduction in uncollectible bills and labour as a result of improved collections arising from maintaining more customer identification and contact information.

A financial analysis of the costs and benefits associated with this project, located in Appendix A, results in a positive net present value over the next 5 years.

2.3 Group Bill Enhancements ($78,000)

Description

Approximately 10% of the Company's customers have two or more bill accounts. The Company provides these customers with the option to receive a consolidated bill that summarizes the billing information for each bill account within this group of accounts.

The timing of how often a consolidated bill will be produced and the criteria for what accounts may be grouped together will be reviewed and improvements implemented. As well, improvements will be made to reduce the administrative effort associated with the daily operation of the group billing program.

Operating Experience

For customers that have two or more bill accounts, only accounts whose meters are read within a certain number of days of each other may be grouped together on one bill. As a result, there are a number of customers who receive two consolidated bills each month instead of one.

On a daily basis, the group billing process is supported by an assigned Contact Centre Agent. This includes such activities as the set up and maintenance of new and existing accounts; responding to customer enquiries specific to the group bill program; monitoring accounts to ensure accounts bill on a timely basis and payments are applied appropriately.

Justification

This project is justified on improved customer service. The changes to the group billing process will make it easier for customers to manage multiple bill accounts.

2.4 Predictive Dialer ($49,000)

Description

This project involves automating the dialing of outgoing collections calls and passing only those calls where the customer answers, to the Contact Centre Agent.

Operating Experience

Currently, Contact Centre Agents are prompted to make a collection call to a customer via a work queue within the Customer Service System. When prompted, the Contact Centre Agent looks up the phone number and dials the customer. If there is no answer or a busy signal the Contact Centre Agent dials an alternate number if available. If there is still no contact made, they record a note on the account within the Customer Service System and continue on to the next customer call.

Several hundred collection calls are made to customers on a daily basis.

Justification

Contact Centre Agents will not have to spend time making phone calls that the customer does not answer. As well the Contact Centre Agent will no longer have to look up phone numbers and actually dial the phone number for the majority of collection calls. A reduction in labour will arise from automating the dialing of customers.

A financial analysis of the costs and benefits associated with this project, located in Appendix A, results in a positive net present value over the next 5 years.

3.0 Operations and Engineering Enhancements

3.1 Outage Management Enhancements ($104,000)

Description

The Outage Management System captures and tracks customer trouble calls. Crews are dispatched to the field based on the information entered and customer interruption statistics are generated on a regular basis from the data collected. The system will be improved to (i) provide automated trouble call dispatch capabilities using a mobile device (such as confirmation of the crew arriving on-site), (ii) improvements to the process of capturing customer information over the phone, as well as (iii) improved analysis capabilities and more timely production of interruption reports.

Operating Experience

The Company receives approximately 14,000 trouble calls annually, about half of which come from customers on the Avalon Peninsula.

Once entered into the Outage Management System by employees, trouble calls are dispatched to crews via cell phone or VHF radio. As the volume of calls increases (as in a significant outage situation), communicating with crews becomes more difficult as they may be attending to the problem outside the vehicle when the call comes in, increasing the chance of missed calls.

The Customer Service System (CSS) has the capability to automatically display customer information based on the incoming phone number or a Bill Account number entered by the customer. This functionality, known as a “screen pop”, reduces the time spent entering relevant information manually and the risk of incorrectly capturing the information. Currently the Outage

Management System does not have this capability. This means that the employee capturing the call has to ask the customer for information which the Company may already have on file. The manual nature of this process could delay a call being dispatched to the crew, which in turn could extend the resolution of the trouble call.

Interruption statistics are an important part of the Company's productivity measures. The validation and quality assurance process for ensuring correctness and completeness of the numbers is largely a manual process. This increases the time spent by System Control Centre personnel consolidating, analyzing and signing off on the various internal and external interruption reports each month.

Justification

The Outage Management System is an integral part of the Company's trouble call response process. Being able to collect and record accurate information and dispatch crews to the site of the trouble as quickly as possible ensures that the Company is able to provide an effective and sustainable level of customer service.

Through an automated trouble call dispatch process, information will not be lost or misinterpreted as the call will be stored on a mobile device that can be referenced at any time by the crew. As well, when the crew arrives on-site they will be able to confirm their arrival via the mobile device rather than making a phone or radio call back to the dispatcher. Once the job is completed the crew will use the mobile device to determine what their next priority is rather than waiting to be contacted by the dispatcher. This will reduce the duration of outages experienced by customers.

Providing "screen pop" capabilities to the Outage Management System will improve customer service and employee productivity as the customer contact information will be automatically displayed in the system based on the incoming phone number or bill account number. This means that the call can be entered quicker, providing the customer with faster and more accurate service.

As well, efficiency improvements and more timely production of interruption reports by improving the business rules around reasonableness checking of the results (currently a manual process) will ensure the Company is able to meet its internal and external reporting obligations.

A financial analysis of the costs and benefits associated with this project, located in Appendix A, results in a positive net present value over the next 5 years.

3.2 Protection System Management ($174,000)

Description

The Company utilizes a combination of protocols and specialized monitoring and sensing equipment, such as protective relays, to detect and isolate electrical faults. This application is required to protect personnel and electrical equipment during times of faults on the power lines and when performing switching on devices connected to the electrical system. This project will involve the implementation of a protection data management system to improve the management of the protective relay system by enabling the tracking and auditing of device configuration settings.

Operating Experience

Protection data, such as device configuration settings, often require manual checking and in-field confirmation to ensure information used to make decisions regarding the electrical system is consistent and accurate. Data regarding older electro-mechanical devices is stored in an Access database. However, this database does not accommodate more complex data required for newer electronic relays.

Justification

Electrical system devices, such as relays and reclosers, require changes to their configuration settings in order to ensure the system is operating effectively under changing conditions such as the electrical load on a distribution feeder. Improvements in the tracking and follow-up on changes to these settings will reduce the risk of outages caused by using device settings that are out-of-date. As well, outage restoration times will be reduced through a reduced need for field checks.

Having an application to track device configurations will reduce the time required to determine existing device settings and responding to inquiries with respect to these settings. Providing accurate and up to date information regarding equipment settings helps ensure the safety of employees working on the electrical equipment.

3.3 Asset Management System Enhancements ($296,000)

Description

This project involves enhancements to the Company's asset management system. This includes (i) enabling technicians to complete work order checklists in the field using a mobile device that will electronically update the asset management system without the need for additional data entry, and (ii) enabling substation maintenance workers to complete work orders while in the field using a mobile device.

The Company implemented an asset management system in 2003. This has resulted in improvements to the Company's preventative maintenance program. Now that a significant amount of field work is generated from work orders managed by the asset management system, improvements in the collection and recording of this information is possible.

Operating Experience

The Company generates and manages over 7,500 preventative and corrective work orders and over 4,500 customer requests for technical work annually. The process of collecting and recording related field information is currently manual. Information is being hand written in the field, and is then checked for completeness and keyed into the system in the office.

Justification

Enhancing the asset management system will improve customer service by shortening the time between when the information is captured in the field and when the information is available for Contact Centre Agents in the Contact Centre to provide customers with the status of their request.

As well, by utilizing mobile devices to capture data in the field for inspection and maintenance work orders, the need to re-key data is eliminated and data accuracy is improved. Data entered into the mobile device at the time the work is completed will improve the scheduling and execution of follow-up work generated from the inspection and maintenance work orders. This improves overall reliability of the equipment, reducing the likelihood of failures.

A financial analysis of the costs and benefits associated with this project, located in Appendix A, results in a positive net present value over the next 5 years.

3.4 SCADA Enhancements ($93,000)

Description

The SCADA system will be enhanced to enable a configurable time delay for an alarm condition to exist before presenting an alarm to the System Control Centre ("SCC") Operator. As well, the main projection screen display used by the SCC Operators will be enhanced to display transmission line and distribution line voltages from highest to lowest. This will allow operators to more effectively analyze issues when restoring the system during a major power disruption.

Operating Experience

The SCADA system communicates situations requiring SCC attention and control by presenting alarms on the SCC Operator's computer screen.

There are many alarms that don't require attention unless the situation continues for a period of time. Also, less critical alarms can clutter the SCC Operator's screens causing them to potentially not respond quickly to alarms which require immediate attention.

Justification

SCC Operators respond to approximately 10,000 voltage alarms annually. Approximately 25% of these alarms are transient in that the alarms return to normal within 60 seconds. Alarm delay functionality will allow these types of alarms to be filtered. This enables SCC Operators to focus on the highest priority activities to ensure that disruptions to customers are kept to a minimum.

As well, the Company's SCADA application utilizes a projection screen which allows SCC Operators to view and interact with the application. Enhancing the displays will provide the SCC Operators with critical information that is necessary to minimize outage duration to customers.

4.0 Intranet/Internet Enhancements

4.1 Changes to the Intranet ($98,000)

Description

This project involves enhancements to the Company's Intranet to improve access to engineering design and electrical system documentation, corporate documentation as well as employee self service options related to the Information Systems Help Desk.

Operating Experience

Electrical system and engineering design documentation is not readily available to all employees who need to utilize it in outage restoration efforts and other activities related to managing the electrical system.

Currently, employees do not have access to information regarding common information technology problems which may help them resolve their issue without further contact with the Help Desk. As well, employees who have made a call to the Help Desk seeking assistance are not able to determine the status of their request without calling the Help Desk again.

Justification

A portion of this project is justified on customer service improvements. Timely access to accurate documentation regarding the technical details of the electrical system supports outage restoration efforts ensuring the length of outages are minimized and reduces the risk of outages caused by decisions using out of date information.

A portion of this project is justified on productivity improvements. Providing a means for employees to check on the status of their support calls would reduce the number of calls to the Help Desk. Providing more information on the Intranet would empower employees to find solutions to common information technology problems quickly. For the portion of the project related to Help Desk improvements a financial analysis of the costs and benefits associated with this project, located in Appendix A, results in a positive net present value over the next 5 years.

4.2 Changes to the Company's Internet Site ($195,000)

Description

This project involves enhancements to customer self-service options on the Company's Internet site and increases the site's ability to support future customer self-service options. For 2006, initiatives include providing customers with the status of planned and unplanned outages and providing interactive and personalized tools that allow customers to manage their energy consumption.

As well, the software used for maintaining the Internet website will be improved to increase the Company's ability to provide future customer service options.

Operating Experience

Usage of the Company's Internet site has increased an average of 40% annually over the past several years. In that time period, the Company has enhanced the site with a number of customer self-service options such as the ability for customers to view their monthly bill online, access energy efficiency information, and submit a meter reading.

In November 2004 Nova Scotia Power experienced a major storm which caused loss of power of up to 165,000 customers. During the storm and subsequent outage restoration efforts Nova Scotia Power experienced a significant increase in visits to their web site by customers attempting to find more information regarding the status of outages.

The underlying software used to maintain the website is the same level of technology which was used by the website when it was put in place in 1998. This technology does not support customer service features and techniques enabled by recent technology advancements.

Justification

This project is justified on customer service improvements.

The provision of outage information via the Company website will allow customers with power to track the status of outages which may impact them and their families. For example, customers in a location receiving power, such as their place of work, may be able to determine the status of an outage impacting a family member in a location not receiving power.

Customers will be able to analyze their historical usage, utilizing tools which will allow them to determine the impacts of the different types of energy use on their monthly electricity costs. As well customers will be able to perform "what if" analyses to allow them to assess the impact of product purchases and other activities on their energy consumption or to assist them in taking measures to conserve electricity and reduce their monthly bill.

Improvements to the software used to maintain the website will enable the provision of future customer service features which the current website cannot support. For example, the site can be modified in the future to allow the customer to customize their own view of information, rather than all customers seeing their information exactly the same way. Improvements to the software technology will allow for the provision of more customer self-service features in future years.

5.0 Various Minor Enhancements ($150,000)

Description

The purpose of this item is to complete enhancements to the Company’s computer applications in response to unforeseen requirements such as legislative and compliance changes, vendor driven changes and employee identified enhancements designed to improve customer service or staff productivity.

Operating Experience

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

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

Remote Agent Enhancements

		Capital Impacts						Ongoing Operating Expenditures						
				CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software	New Hardware	Software	Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B		C			D		E		F	G	H
0	2006	($132,300)	($63,000)	$66,150	$9,450		$75,600	$0	$0	$15,000	$0	$15,000	$21,889	($158,411)
1	2007			$66,150	$16,065		$82,215	$0	($3,053)	$62,830	$0	$59,777	$8,105	$67,882
2	2008				$11,246		$11,246	$0	($3,109)	$65,343	$0	$62,234	($18,417)	$43,817
3	2009				$7,872		$7,872	$0	($3,168)	$67,303	$0	$64,135	($20,322)	$43,813
4	2010				$5,510	$10,482	$15,992	$0	($3,221)	$69,323	$0	$66,101	($18,099)	$48,002
	Present Value (See Note I)	**@**		**6.80%**										**$16,424**

NOTES:

A is the sum of the software additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
B is the sum of the computer network hardware additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
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 the current year using the GDP Deflator Index.
E is the reduced operating costs. The cost estimate is escalated to current year using the GDP Deflator Index.
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 revenue requirement which is the sum of the capital expenditure (column A) plus operating expenditures (column F) plus the 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 Tracking and Set-up Improvements

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax 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	2006	($173,985)	($173,985)	$86,993	$0	$0	$0	$0	$0	$31,422	($142,563)
1	2007			$86,993	$0	$0	$55,105	$0	$55,105	$11,518	$66,623
2	2008				$0	$0	$57,309	$0	$57,309	($20,700)	$36,609
3	2009				$0	$0	$59,028	$0	$59,028	($21,321)	$37,707
4	2010				$0	$0	$60,799	$0	$60,799	($21,961)	$38,839
	Present Value (See Note I)	@		**6.80%**							**$12,719**

NOTES:

A is the sum of the software additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
B is the amount eligible for capital cost allowance deductions.
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 the current year using the GDP Deflator Index.
E is the reduced operating costs. The cost estimate is escalated to current year using the GDP Deflator Index.
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 revenue requirement which is the sum of the capital expenditures (column A) plus operating expenditures (column F) plus the income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Predictive Dialer

		Capital Impacts			Ongoing Operating Expenditures						
					Cost Increases		Cost Benefits				
	YEAR	New Software	Capitalized for CCA	CCA Tax 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	2006	($51,240)	($51,240)	$25,620	$0	$0	$0	$0	$0	$9,254	($41,986)
1	2007			$25,620	$0	$0	$16,068	$0	$16,068	$3,450	$19,518
2	2008				$0	$0	$16,711	$0	$16,711	($6,036)	$10,675
3	2009				$0	$0	$17,212	$0	$17,212	($6,217)	$10,995
4	2010				$0	$0	$17,728	$0	$17,728	($6,403)	$11,325
	Present Value (See Note I)	@		**6.80%**							**$3,378**

NOTES:

A is the sum of the software additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
B is the amount eligible for capital cost allowance deductions.
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 the current year using the GDP Deflator Index.
E is the reduced operating costs. The cost estimate is escalated to current year using the GDP Deflator Index.
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 revenue requirement which is the sum of the capital expenditures (column A) plus operating expenditures (column F) plus the income tax (column G).
I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Outage Management Enhancements

		Capital Impacts						Ongoing Operating Expenditures						
				CCA Tax Deductions				Cost Increases		Cost Benefits				
	YEAR	New Software	New Hardware	Software	Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B		C			D		E		F	G	H
0	2006	($108,465)	($13,125)	$54,233	$1,969		$56,201	$0	$0	$0	$0	$0	$20,300	($101,290)
1	2007			$54,233	$3,347		$57,579	($3,090)	($1,221)	$44,748	$0	$40,437	$6,192	$46,629
2	2008				$2,343		$2,343	($3,214)	($1,244)	$46,538	$0	$42,081	($14,353)	$27,728
3	2009				$1,640		$1,640	($3,310)	($1,267)	$47,934	$0	$43,357	($15,068)	$28,289
4	2010				$1,148	$2,184	$3,332	($3,409)	($1,289)	$49,372	$0	$44,675	($14,933)	$29,742
	Present Value (See Note I)	@		**6.80%**										**$12,761**

NOTES:

A is the sum of the software additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
B is the sum of the computer network hardware additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
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 the current year using the GDP Deflator Index.
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Asset Management System Enhancements

		Capital Impacts		CCA Tax Deductions				Ongoing Operating Expenditures: Cost Increases		Cost Benefits				
	YEAR	New Software	New Hardware	Software	Hardware	Residual CCA	Total	Labour	Non-Lab	Labour	Non-Lab	Net Operating Expenditures	Income Tax	After-Tax Cash Flow
		A	B		C			D		E		F	G	H
0	2006	($310,800)	($21,000)	$155,400	$3,150		$158,550	$0	$0	$0	$0	$0	$57,268	($274,532)
1	2007			$155,400	$5,355		$160,755	$0	($2,748)	$103,876	$0	$101,128	$21,537	$122,665
2	2008				$3,749		$3,749	$0	($2,798)	$108,031	$0	$105,232	($36,656)	$68,576
3	2009				$2,624		$2,624	$0	($2,851)	$111,271	$0	$108,420	($38,214)	$70,206
4	2010				$1,837	$3,494	$5,331	$0	($2,899)	$114,610	$0	$111,710	($38,424)	$73,286
	Present Value (See Note I)	@		**6.80%**										**$14,406**

NOTES:

A is the sum of the software additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
B is the sum of the computer network hardware additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
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 the current year using the GDP Deflator Index.
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I is the present value of column H. Column H is discounted using the weighted after-tax cost of capital.

Changes to the Intranet - IS Self Service

	YEAR	Capital Impacts New Software A	Capitalized for CCA B	CCA Tax Software C	Ongoing Operating Expenditures Cost Increases Labour D	Cost Increases Non-Lab	Cost Benefits Labour E	Cost Benefits Non-Lab	Net Operating Expenditures F	Income Tax G	After-Tax Cash Flow H
0	2006	($39,690)	($39,690)	$19,845	$0	$0	$0	$0	$0	$7,168	($32,522)
1	2007			$19,845	$0	$0	$16,480	$0	$16,480	$1,215	$17,695
2	2008				$0	$0	$17,139	$0	$17,139	($6,191)	$10,949
3	2009				$0	$0	$17,653	$0	$17,653	($6,376)	$11,277
4	2010				$0	$0	$18,183	$0	$18,183	($6,568)	$11,615
	Present Value (See Note I)		@	**6.80%**							**$11,830**

NOTES:

A is the sum of the software additions by year adjusted to include an administrative overhead amount of 5% of the direct capital cost.
B is the amount eligible for capital cost allowance deductions.
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 the current year using the GDP Deflator Index.
E is the reduced operating costs. The cost estimate is escalated to current year using the GDP Deflator Index.
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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.
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2006 System Upgrades

June 2005

Table of Contents

1.0 Introduction

The Company depends on the effective implementation and on-going operation of its business applications. These applications need to be upgraded to address vendor obsolescence, ensure continued vendor support and software compatibility to take advantage of newly developed capabilities.

This project consists of three parts:
1) the purchase of Microsoft software under a Microsoft Enterprise Agreement;
2) upgrades to several of the Company's business applications; and
3) managing the information technology used to operate and support the Company's business applications.

2.0 Microsoft Enterprise Agreement

2.1 Description

This Agreement covers the purchase of Microsoft software and provides access to all supported versions of each software product purchased under this agreement.

The purchase of the Microsoft Enterprise Agreement ensures that Newfoundland Power achieves an overall cost savings. This is a fixed, annual price agreement based on the number of eligible personal computers and shared servers. Under this agreement, the Company distributes its purchasing costs for these licenses over three years. The budget for this item is $210,000 each year for three years.

2.2 Operating Experience

In April 2005, the Company investigated the three options for the purchase of the following Microsoft licenses: Windows Professional, Office Professional as well as Client Access Licenses for Exchange Server, SQL Server, Windows Server, System Management Server and SharePoint Portal Server. The three options identified by the Company were:

i. Do nothing now, and pay for new licenses to upgrade in the future. The expected cost per personal computer is $1,025 over three years.

ii. Renew the existing Microsoft Enterprise Agreement at the proposed discount. This provides the Company with ownership of all supported releases of the identified software. These licenses are paid for annually per personal computer. Costs are spread over the three-year period. The annual cost per personal computer is $271; $813 over three years.

iii. Purchase a Microsoft Select Agreement for each installation of the software. This provides the Company with ownership of the latest releases of the identified software. These licenses have to be purchased individually as they are needed. The annual cost per personal computer varies over time. The Microsoft Enterprise Agreement pricing model is structured such that for the Company's licensing requirements it is always less costly than the Select Agreement licensing.

2.3 Justification

The purchase of a three year Microsoft Enterprise Agreement is the least expensive and least administratively burdensome option for Newfoundland Power at this time.

3.0 Business Application Upgrades

3.1 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 an assessment is performed to determine which applications require upgrades. For 2006, upgrades include:

i. Microsoft Great Plains Upgrade - $201,000
   This item involves upgrades to the Company's financial system, Microsoft Great Plains, to the most current supported version of the software. The version currently used by the Company will no longer be supported by the vendor after October 31, 2006.

ii. Safety Management System Upgrade - $30,000
   This item involves upgrades to the Company's Safety Management System, Safety First. The current release has been in production since 2002. The vendor's technical support team no longer receives training and information updates to support the version currently operated by the Company. As well, the vendor has stated that the version currently used by the Company will no longer be enhanced.

iii. TVD Outage Notification Upgrade - $142,000
   This item involves upgrading the Company's TVD Outage Notification application used to provide customers with information about electrical system outages via phone. The existing version of TVD contains software bugs that have been fixed by the vendor in the next version of the TVD Outage Notification software. This upgrade will also ensure continued vendor support and software compatibility to take advantage of newly developed capabilities.

iv. Contact Centre Technology Upgrade – $155,000
This item involves upgrading the Aspect Contact Centre software which is used by the Contact Centre to answer customer calls. This upgrade addresses security concerns related to the application's database product. As well, the Contact Centre Reports module which helps measure Contact Centre productivity is no longer supported by the vendor and therefore will be replaced.

v. Transmission Line Design Software Upgrade – $60,000
This item involves an upgrade to the transmission line design software in order to address vendor obsolescence, ensure continued vendor support, and ensure continued efficiency gains through vendor's functional enhancements. The vendor will discontinue support for the existing transmission line design software (TLCADD) in 2007, and has discontinued any upgrades or enhancements since 2002.

3.2 Operating Experience

System upgrades help ensure the reliability and effectiveness of the Company's business applications and mitigate risks associated with technology related problems.

As well, upgrades are often completed in order to take advantage of functional or technical enhancements.

3.3 Justification

Investment in Application Software Upgrades is necessary to upgrade 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.

4.0 Information Technology Management

4.1 Description

Managing the information technology 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, and maintain applications throughout the Company. For 2006 this includes:

1) Business Continuity Improvements - $163,000
This project involves the acquisition and installation of software used to create instantaneous copies of the Company's applications and associated databases. This replication software will be used to improve the availability of corporate systems such as the email and Intranet applications in the event of a disaster impacting a Company building or application. This technology provides immediate access to an exact copy of the application and associated data should a problem occur with the primary copy.

2) Data Management Improvements - $115,000
   This project involves developing databases for the Customer Service System and Great Plains financial system that will provide access to historical information required to respond to customer requests as well as internal and external requests for financial information that can be up to seven years in the past.

4.2 Operating Experience

The Company depends on the stable operation of its over fifty business applications such as the Customer Service System, Great Plains financial system, and the Intranet in order to sustain an effective level of customer service and employee productivity.

These applications have many different information technology components that must work together to achieve this operational effectiveness. Should one of these components fail, the impact of the failure on customer service could be significant. The Company must protect its applications and data from unexpected events such as software bugs, hardware failures, or larger scale events like fires and floods, in order to minimize the negative impact on customer service and employee productivity.

Through normal business activities applications such as Microsoft Great Plains create and store a tremendous amount of data. As the database grows over time, the performance and responsiveness of the application can be negatively impacted. However, this information cannot be merely deleted in order to improve performance. Financial reporting requirements state that financial information must be kept for a minimum of seven years.

4.3 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.

Not having the email or Intranet applications available would negatively impact the Company's ability to respond to customer requests. Email is an integral part of communicating with customers and the Intranet provides access to several key tools and applications such as outage notifications and customer requests for technical work as well as widely used policies, procedures and forms.

Failure to properly manage the data stored within the Company's financial application could result in lost productivity, reduced customer service or failure to comply with financial regulations. Providing access to historical information will ensure an acceptable level of compliance and sustained levels of customer service and productivity. As well, the method of accessing the historical financial information (resulting from this project) will be similar to using the production Microsoft Great Plains application, reducing the need to train staff in new procedures.

2006 Shared Server Infrastructure

June 2005

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

The shared server infrastructure consists of over 100 servers that are used for production, testing, as well as 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 2006, this project includes:

a) The purchase and implementation of additional disk and tape storage, memory, and CPU upgrades for servers which are currently used to run corporate applications. The budget for this item is $265,000.

b) Enhancements to security infrastructure and monitoring capabilities in order to provide adequate protection of customer data and improve protection of the Company's information technology investment. Enhancements will be made to the SCADA application to improve login security. Enhancements will be made to the Citrix application in order to improve the security for employees accessing corporate applications from remote locations. As well, additional security improvements will be made to the Intrusion Detection System that monitors the Company's corporate network for suspicious or illegal activity from external factors such as the Internet. The budget for this item is $193,000.

c) Purchase of additional software licenses. This includes additional Cognos licenses required to provide access to the Company's databases for reporting purposes, as well as additional CymeDist licenses for additional access to the Company's distribution design application. The budget for this item is $50,000.

3.0 Operating Experience

The Shared Server Infrastructure 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.

Technology components such as servers and disks require on-going investment to ensure that they continue to operate effectively. To maintain this effectiveness, upgrades, monitoring and security investments are essential.

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 verses 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 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.

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. The Company selects the least cost alternative when possible.

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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 4,600 associates, including 1,400 research analysts and consultants, in more than 75 locations worldwide.

Deferred Charges and Rate Base

June 2005

NEWFOUNDLAND POWER
A FORTIS COMPANY

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1.0 Introduction

In Order No. P.U. 19 (2003), 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, in particular deferred pension costs, be filed annually at the Company's capital budget hearing.

This report provides evidence with respect to changes in deferred charges.

2.0 Deferred Charges

2.1 General

Table 1 outlines the actual deferred charges included in rate base for 2004 and forecast deferred charges for 2005 and 2006.

Table 1
Deferred Charges: 2004-2006F
($000s)

	Actual	**Forecast**	
	2004	**2005**	**2006**
Weather Normalization Account	$10,477	$9,971	$8,845
Deferred Regulatory Costs	347	-	-
Unamortized Debt Discount & Expense	3,169	3,464	3,262
Unamortized Capital Stock Issue Expense	325	261	199
Deferred Pension Costs	79,008	84,993	92,245
Total Deferred Charges	$93,326	$98,689	$104,551

The total deferred charges in 2004 were approximately $1.1 million lower than what was forecast for 2004 in the Company's Report on Deferred Charges and Rate Base filed in 2004. This was due primarily to the normal operation of the weather normalization account.

2.2 Weather Normalization Account

The Weather Normalization Account has been historically included as a component of rate base. The treatment of the Weather Normalization Account is unchanged by the inclusion of certain 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 2.

Table 2
Weather Normalization Account: 2004-2006F
($000s)

	2004	**2005F**	**Change 2005F vs. 2004**	**2006F**	**Change 2006F vs. 2005F**
Hydro Production Equalization Reserve	7,828	6,164	(1,664)	5,038	(1,126)
Degree Day Normalization Reserve	2,649	3,807	1,158	3,807	-
Total	10,477	9,971	(506)	8,845	(1,126)

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.

In Order No. P.U. 19 (2003), the Board accepted Newfoundland Power's proposal to amortize the recovery of the $5.6 million non-reversing balance in the Hydro Production Equalization Reserve over a period of five years. A reduction in the Hydro Production Equalization Reserve of $1.126 million was made in 2003 and 2004 and is included in the forecast for 2005 and 2006. The remaining change in the Hydro Production Equalization Reserve in 2005 relates to the normal operation of the reserve.

Both the Hydro Production Equalization Reserve and the Degree Day Normalization Reserve are affected by actual weather patterns compared to normal weather patterns. The difference between normal weather and weather actually experienced to the end of May 2005 has been reflected in the 2005 forecast. The 2005 and 2006 forecasts assume normal weather conditions from June 2005 through December 2006.

Order No. P.U. 13 (2005) approved the balance in the Weather Normalization Account as of December 31, 2004.

2.3 Deferred Regulatory Costs & Other

The reduction in deferred regulatory costs in 2005 reflects the incurrence of approximately $1 million of hearing costs, and their subsequent amortization over three years beginning in 2003 in accordance with Order No. P.U. 19 (2003). At the end of 2005 these deferred regulatory costs will be fully amortized. The details of the changes are set out in Table 3.

Table 3
Deferred Regulatory Costs: 2004-2006F
($000s)

	2004	2005F	Change 2005F vs. 2004	2006F	Change 2006F vs. 2005F
Deferred Regulatory Costs	347	0	(347)	0	0

Unamortized Debt Discount and Capital Stock Issue Expenses

Changes in unamortized debt discount and capital stock issue expenses are set out in Table 4.

Table 4
Capital Issue Expenses: 2004-2006F
($000s)

	2004	2005F	Change 2005F vs. 2004	2006F	Change 2006F vs. 2005F
Unamortized Debt Discount & Expense	3,169	3,464	295	3,262	(202)
Unamortized Capital Stock Issue Expense	325	261	(64)	199	(62)

The increase in unamortized debt discount & expense relates to a first mortgage sinking fund bond issue forecast for 2005, offset by the normal amortization of existing debt issue costs. Issue expenses for the new bond financing are forecast to be approximately $500,000.

The decline in the Unamortized Capital Stock Issue Expense each year reflects the normal amortization of these costs over a 20-year period.

2.4 Deferred Pension Costs

The difference between pension plan *funding* and pension plan *expense* is captured as a deferred pension cost on the balance sheet in accordance with Order No. P.U. 17 (1987).

Forecast changes in deferred pension costs for 2004 to 2006F are set out in Table 5.

Table 5
Forecast Deferred Pension Costs: 2004-2006F
($000s)

	2004	2005F	2006F
Deferred Pension Costs, January 1st	72,787	79,008	84,993
Pension Plan Funding			
- Current Service Funding	3,367	3,162	3,241
- Special Funding	6,384	7,414	7,391
Total Pension Plan Funding	9,751	10,576	10,632
Pension Plan Expense	(3,530)	(4,591)	(3,380)
Increase in Deferred Pension Costs	6,221	5,985	7,252
Deferred Pension Costs, December 31st	79,008	84,993	92,245

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 refers to 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 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 concerning the amortization of costs associated with the 2005 Early Retirement Program. The expense and the funding associated with this program is being amortized over 10 years commencing April 1, 2005.

The forecasting of pension plan expense for 2006 is subject to changes based upon the following factors:

1. The final pension plan expense for 2006 can only be determined early in 2006, once actual pension plan asset balances for 2005 are known. This determination is made based on the December 31, 2005 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 2006 pension expense is the actual market rate of interest at December 31, 2005. Pension expense for 2006 in Table 5 above is calculated assuming a 6.25% discount rate at December 31, 2005. Current market rates are lower. May 31, 2005

market rates of interest imply a discount rate of 5.75%. If a 5.75% discount rate is required based on December 31, 2005 market interest rates, 2006 pension expense would increase by approximately $1.3 million.

While pension plan expense for 2006 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 PUB orders.