AN APPLICATION TO THE
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2010 CAPITAL BUDGET APPLICATION

VOLUME II

August 2009

newfoundland labrador hydro
a nalcor energy company

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador ANDREA MACDONALD Andrea MacDonald SIGNATURE July 31/09 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

PLANT LIFE EXTENSION UPGRADES

Hardwoods Gas Turbine

June 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates two 50 MW Gas Turbine plants as part of the Island Interconnected System. They are: the Stephenville Gas Turbine Plant, located in Stephenville; and the Hardwoods Gas Turbine Plant (Hardwoods), located in the west end of St. John's (see Figure 1). These facilities are primarily used to control the voltage of the Island Interconnected System. They are also used to produce power during peak and emergency periods. However, since Hardwoods and Stephenville are fueled by distillate (diesel), producing power at these facilities is more costly than producing power at the Holyrood Thermal Generating Station.

Figure 1: Hardwoods Gas Turbine Plant

Hardwoods is predominantly used to level out voltage fluctuations on the Island Interconnected System. Voltage fluctuations are undesirable and result from changes in the supply and demand of electricity. Using a process known as synchronous condensing, the system voltage is corrected and the proper voltage levels are maintained. Synchronous condensing stabilizes the voltage of the system. During synchronous condensing, the voltage drop is limited to no more than five percent below the nominal operating levels of 230, 138, or 66 kV.

Hardwoods has been in service since 1977 and will remain in service even in the event of an infeed from the Lower Churchill. This facility is ageing and has experienced equipment failures in recent years. For instance, the inverter failed in 2006 and the Human Machine Interface (HMI) failed in 2007. As well, various components installed at this facility are obsolete. This facility requires refurbishment work to maintain its operational reliability until its planned retirement in the mid 2020's.

In 2007, an engineering consulting company, Stantec Inc. (Stantec), completed a condition assessment and life cycle cost analysis study of the Hardwoods and Stephenville Gas Turbine Plants. Hydro commissioned the study to determine the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years for both sites. Major equipment such as gas turbine engines, power turbines and power generators (also called alternators), as well as auxiliary systems such as lubricating oil systems, fuel systems, electrical systems and control systems were assessed during the study. Structures such as buildings, equipment enclosures, and exhaust stacks were also assessed. The consultant's final report, known as the Stantec Report, provides a comprehensive description of the required site refurbishments to ensure operational reliability for the next 15 years. The Stantec Report is over 600 pages in length and extracts have been presented herein rather than the entire document.

In 2009, Hydro initiated a four-year refurbishment program to implement the recommendations for Hardwoods put forth in the Stantec Report (see Appendix B). In 2012, Hydro plans to initiate a three-year program to implement Stantec's recommendations for the Stephenville Gas Turbine Plant.

2 PROJECT DESCRIPTION

This project is to complete work scheduled for years two, three and four of a four-year upgrade program of Hardwoods. The program will include refurbishment of the following equipment and systems:

- Gas Turbine Engines / Power Turbine Equipment;
- Inlet Air Systems End A and End B;
- Exhaust Stacks End A and End B;
- Glycol Cooler for Main Lube Oil;
- Gas Generator / Power Turbine Enclosures End A and End B;
- Alternator and Excitation System;
- Alternator Enclosure;
- Fuel Oil Storage System;
- Electrical Systems;
- Control and Instrumentation Systems; and
- Buildings.

The scope of work for the four-year program includes the implementation of all recommended refurbishments described in Stantec's final Condition Assessment and Life Cycle Cost Analysis report for Hardwoods. Additional items requiring refurbishment were identified after the completion of the Stantec Report. These items include grounding of the fuel storage system and modifications to fall arrest systems. These items are also included in the scope of work for this project. Refer to Appendix B for the detailed scope of work for the four-year program. Once all of the recommended work is completed, Hardwoods will be able to operate reliably for the next 15 years.

This project will complete the 2010 to 2012 scheduled work items. Further details are included in Appendix B and estimated costs are included in Appendix F.

3 EXISTING SYSTEM

The Hardwoods Gas Turbine Plant is located within the Hardwoods terminal station. This 50 MW facility consists of two identical 25 MW Rolls-Royce Olympus C gas turbine engines (see figure 2), Curtiss-Wright power turbines, and a Brush power generator. Each power turbine is connected to the power generator by a clutch. Auxiliary components, critical to the operation of the facility, include inlet air systems, fuel oil system, electrical system, and control and instrumentation systems. Buildings and structures on site include exhaust stacks, inlet air intakes, control building, fuel unloading building, fuel forwarding module, auxiliary module building, maintenance and parts storage building, high voltage switchgear building, and emergency backup diesel generator building.

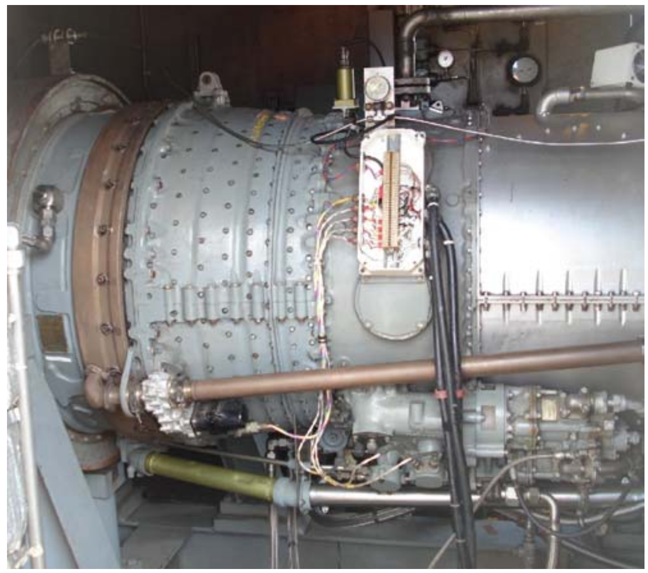


Figure 2: Gas Turbine Engine

It is stated in Stantec's Condition Assessment and Life Cycle Cost Analysis report for Hardwoods, that the gas turbine engines and power turbines show signs of operational wear and require remedial work (Appendix A: Executive Summary, page A-2). Further testing is required to determine the condition of the alternator. Auxiliary systems and structures were found to be in generally good condition, however, some refurbishment work is required.

The photo below (Figure 3), taken during an internal inspection on May 30, 2007, shows corrosion due to coating loss inside the End B gas turbine engine at Hardwoods.

Figure 3: Corrosion on End B Engine

3.1 Age of Equipment or System

Hardwoods was placed in service in 1977. All major equipment, including the gas turbine engines, alternator, clutches and power turbines, is original.

3.2 Major Work and/or Upgrades

The End B gas turbine engine was overhauled in 1993 and both power turbines received casing replacements in 1988. Other upgrades at this facility include:

- exhaust stacks (1992);
- Distributed Control System (DCS) (1997);
- main breaker (1998);
- fire system replacement (2002);
- black start diesel generator (2005);
- fuel piping from the tank farm (2007);
- vibration system upgrade (planned for 2009); and
- repairs and site refurbishments (planned for 2009).

Appendix C contains a comprehensive listing of major work and upgrades that have taken place at Hardwoods since it was placed in service in 1977.

3.3 Anticipated Useful life

A gas turbine has an anticipated service life of 25 years. The upgrade will extend the life of the gas turbine plant by 15 years.

3.4 Maintenance History

The five-year maintenance history for Hardwoods is shown in Table 1.

Table 1
Hardwoods Gas Turbine Plant Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	26.3	269.0	295.3
2007	12.4	393.5	405.9
2006	5.6	441.9	447.5
2005	17.1	239.4	256.5
2004	14.9	258.8	273.7

3.5 Outage Statistics

Table 2 lists the 2004 to 2008 average Capability Factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for Hardwoods compared to all of Hydro's gas turbine units and the latest Canadian Electrical Association (CEA) average (2002 to 2006).

Table 2
Hardwoods Gas Turbine Five Year Average (2004-2008) All Causes

Unit	Capability Factor (%)[1]	UFOP (%)[2]	Failure Rate[3]
Hardwoods	82.45	10.94	183.57
All Hydro Gas Turbine Units	87.02	11.39	42.12
CEA (2002-2006)	88.62	8.11	10.82

[1]Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.

[2]UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.

[3]Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.

Hardwoods has an average failure rate over four times the average rate for all of Hydro’s gas turbine units and almost 17 times the average rate posted for the CEA.

3.6 Industry Experience

The Hardwoods plant mainly operates as a synchronous condenser but produces electricity during peak and emergency times. This results in a very high number of starts and stops of the equipment annually. Frequent starts and stops of the equipment reduce its useful life far below the anticipated useful life of a base load plant.

Gas turbine engines, power turbines and clutches degrade over time. The degree of degradation increases as the operating hours increase and as the number of start/stop cycles increases. For gas turbine units that produce electricity during peak times, such as those at Hardwoods, thermal mechanical fatigue caused by start/stop cycles is the dominant limiter of life.

Stantec reports that 90 percent of all unscheduled shutdowns of gas turbine facilities are caused by faulty electrical and control components in auxiliary systems. In addition, since Hardwoods experiences many starts/stops in synchronous condensing and peak/emergency power generation modes, it is expected that the insulation on the alternator's windings will have a life of only 15 to 20 years as compared to 30 years for a power generation unit. An alternator problem may result in major unplanned outages.

3.7 Maintenance or Support Arrangements

Hydro personnel perform routine maintenance at Hardwoods on structures, auxiliary systems and parts of the major equipment. Any work involving removal of the gas turbine engine casing is performed by external contractors specializing in gas turbine repairs. Internal work on other major equipment is also performed by specialized contractors.

3.8 Vendor Recommendations

There are no vendor recommendations applicable to this project.

3.9 Availability of Replacement Parts

The model of gas turbine engine installed at Hardwoods is no longer manufactured, however, the engines will be supported by the manufacturer for the foreseeable future. Sourcing replacement parts for the gas turbine engines has not been an issue to date, however, the availability of spare parts is very limited worldwide. Original manufacturers still support other major components such as the alternator and clutches. It is difficult to acquire spare parts for the power turbine since the manufacturer is no longer in the power turbine business, therefore, spare parts for the power turbine would either need to be sourced on the second hand market, or reverse engineered and manufactured. Reverse engineering refers to a process of designing a new component by taking apart and analyzing an existing component.

Other pieces of equipment installed at Hardwoods are now obsolete or are no longer being supported by the manufacturer. These include ignition exciters, vibration monitoring system, speed governors/fuel valve assemblies, starter motor (no longer supported), power supply for the distributed control system and protection electro-mechanical relays. Spares are readily available for the speed governors, however, the technology is considered obsolete. Spares are limited for the electromechanical relays. Spare parts may be easily sourced for some auxiliary systems. However, replacement parts may not be exactly the same as the original components. Further system modifications may be required when replacing older parts. Control module cards are still available from the manufacturer and will be supported for at least ten years from the date they are discontinued.

3.10 Safety Performance

Stantec reported that kick plates are missing on maintenance walkway guard railings. Rusty stair treads or loose ladder rungs were also reported. These items will be upgraded during the 2009 refurbishment project. Installation of emergency stop buttons for the fuel pumps located inside the fuel forwarding module as well as grounding of the fuel tank will also take place in 2009.

3.11 Environmental Performance

There are no identified environmental performance issues related to Hardwoods.

3.12 Operating Regime

Hardwoods operates mainly as a synchronous condenser but also as a power generator. Appendix D contains information on the operating hours, number of start/stop cycles, power generation hours and synchronous condensing hours for the facility. It operates approximately 60 percent of the time, as a synchronous condenser.

The facility operates in power generation mode during peak usage times which is less than one percent of the time. This may occur anytime throughout the year but is most common from mid December to March. As well, this facility is placed in standby mode for emergency electricity generation during unplanned outages. The facility may also be placed in service to generate electricity during planned outages.

4 JUSTIFICATION

The operational reliability of Hardwoods is critical to ensure voltage regulation on the Island Interconnected System. As well, this facility is critical for the generation of peak and emergency power. Unless the reliability of this facility is improved (see Section 3.5), the Island Interconnected System may experience voltage fluctuations and power shortages. The major equipment installed at this facility is over 30 years old and has reached the end of its operating life. Plant refurbishment is now required.

The condition assessment and life cycle cost analysis report for Hardwoods, completed by Stantec in 2007, contains a description of recommended refurbishments. All site refurbishments recommended by Stantec will take place during the four-year refurbishment program. A number of additional items requiring refurbishment were noted by Hydro after the completion of the Stantec Report. Most of these additional items are justified on the basis that they are safety or environmental issues. The remaining additional items will serve to increase the operational reliability of the facility. It is important that these recommended refurbishments take place so that voltage on the Island Interconnected System will continue to be stable and peak and emergency power generation is available whenever it is needed.

4.1 Net Present Value

A net present value calculation of alternatives was completed by Stantec and is included in Section 8 of the Condition Assessment and Life Cycle Cost Analysis report. This section of the report is attached as Appendix E.

4.2 Levelized Cost of Energy

This facility generates electricity only during peak/emergency periods. Levelized cost of energy is not a factor in this project.

4.3 Cost Benefit Analysis

A cost benefit analysis has been completed and is attached as Appendix E. Each alternative solution was reviewed. It was determined that Option 1B, Hardwoods refurbishment with no mobile gas turbine rental allowance, was the least-cost option to achieve a high degree of reliability at Hardwoods for the next 15 years. Please refer to Section 4.10 for a list of alternative solutions.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements that justify this project.

4.5 Historical Information

In 2009, the first year of the four-year refurbishment program at Hardwoods, budgeted at a cost of $450,300, was initiated. The work to be completed in 2009 is on the following equipment and systems.

- Inlet Air Systems End A and End B;
- Exhaust Stacks End A and End B;
- Fuel Oil Storage System;
- Electrical Systems; and
- Control and Instrumentation Systems.

Additional work on the same equipment and systems will occur in 2010 to 2012. Further details are included in Appendix B. Refurbishment of the Glycol Cooler for Main Lube Oil System will not take place in 2009. The following items were prioritized higher and were completed in 2009.

- Replace underground sump drainage piping and sump pit cover; and
- Replace various pumps.

4.6 Forecast Customer Growth

This project is not required to accommodate customer growth.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits within the justification for this project.

4.8 Losses during Construction

There will be no losses during construction as the work will take place during a planned outage.

4.9 Status Quo

If this project is not completed, plant reliability will decrease and the frequency of unplanned outages will increase. This affects the voltage control on the power grid and the plant's ability to generate power during peak and emergency periods.

4.10 Alternatives

Table 3 contains six alternatives that Stantec presented to Hydro at the completion of the Condition Assessment and Life Cycle Cost Analysis Study. Hydro evaluated each alternative and determined that Option 1B, refurbish existing equipment with no mobile gas turbine rental allowance, was the preferred option.

Table 3
Alternatives

Alternative	Description	Capital Cost Estimate[1] ($000)
1A	Refurbish existing equipment – Hardwoods. Includes optional gas turbine rental allowance.	7,814
1B	Refurbish existing equipment – Hardwoods.	4,507
1	New gas turbine engines and power turbines. Refurbish balance of equipment.	26,420
2	New alternator/exciter. Refurbish balance of equipment.	7,163
3	New gas turbine facility, including fuel forwarding module, controls and electrical auxiliary equipment. Dismantle existing gas turbines and use as spares.	36,900
4	Replace Hardwoods with new dynamic Volts-Amperes reactive (VAR) compensator.	10,000

After evaluating each option, it was determined that option 1B achieves Hydro's objective of increasing reliability at least-cost for the next 15 years at Hardwoods. Stantec's study determined that there is no need to replace the complete facility, auxiliary systems and major components such as the gas turbine engines and turbines. Therefore, options 1, 2, and 3 were eliminated since all involve the replacement of major equipment. Option 4 was eliminated since dynamic VAR compensation only provides synchronous condensing and does not permit the plant to generate power. Option 1A was eliminated because Hydro has no requirement for a backup gas turbine engine while an existing gas turbine engine is being overhauled.

[1] The Capital Cost Estimate is based on Stantec's 2007 budget estimate and does not include escalation.

5 CONCLUSION

It is important for Hydro to have a reliable facility for synchronous condensing and peak/emergency power generation on the Avalon Peninsula. A four-year refurbishment program for Hardwoods was initiated to implement a list of recommendations contained in a condition assessment and life cycle cost analysis report of the facility that was completed in 2007 by Stantec. The results of the condition assessment and life cycle cost analysis were used to determine the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years for Hardwoods.

5.1 Budget Estimate

The budget estimate for this three-year project is shown in Table 4.

Table 4
Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**2012**	**Total**
Material Supply	71.4	71.4	8.7	151.4
Labour	180.2	183.6	140.4	504.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	807.9	796.9	2,482.5	4,087.3
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	139.0	166.5	471.8	777.3
Contingency	106.0	105.2	263.2	474.4
TOTAL	**1,304.5**	**1,323.6**	**3,366.6**	**5,994.7**

The budget estimate for this project, as well as the overall estimate for the entire four-year refurbishment program, is based on the construction cost estimate provided in the Stantec Report in 2007 (attached as Appendix F). The accuracy of Stantec's estimate is stated to be (+/-) 30 percent. Stantec's figures were escalated from 2007 to 2009 using appropriate multipliers. Additional costs were added to Stantec's estimate to cover engineering design and project management. Costs were also added for the additional refurbishment items noted by Hydro after the completion of the Stantec report. Table 5 contains the annual budget estimates for the four-year program.

Table 5
Hardwoods Four-Year Refurbishment Budget

Year	Budget
2009	450.3
2010	1,304.5
2011	1,323.6
2012	3,366.6
Total	**6,445.0**

5.2 Project Schedule

This project will be complete by 2012. This will mark the end the four-year refurbishment program for Hardwoods. Work measures to be completed each year are identified in Table 6 below.

Table 6
Work Schedule

Activity	Year
Refurbish End B gas turbine equipment. Site retrofits and upgrades.	2010
Refurbish End A gas turbine equipment. Site retrofits and upgrades.	2011
Refurbish generator and exciter Site retrofits and upgrades.	2012

APPENDIX A

Extract (Executive Summary) from Stantec Final Report
Condition Assessment and Life Cycle Cost Analysis
Hardwoods and Stephenville Gas Turbine Facilities

Executive Summary

Stantec (formerly Neill and Gunter) conducted a Condition Assessment and Life Cycle Cost Analysis Study of the Newfoundland and Labrador Hydro ("HYDRO") Hardwoods and Stephenville Gas Turbine Facilities over the period July through December 2007. The Gas Turbines at each site have been in service since the mid 1970's. The objective of the Study is to provide HYDRO with recommendations on the best course of action to achieve a high degree of operating reliability at each site, at least cost, for a further 15 years of operation.

During the Study period meetings were held with HYDRO officials, visits were made to each site and available HYDRO documentation was reviewed in order to assess the current condition of the equipment and structures at each site and determine the best course of action to allow a further 15 years of reliable service. The Gas Turbines at each site have operated over the years primarily as synchronous condensers providing MVAR support of system voltage. While the Gas Turbines can provide 50 MWs of emergency generation capacity, there has been very little generation provided by the units over the past 30 years. Refer to Report Section 2 for an overview of the Gas Turbine Facilities at each site.

The Gas Turbine Facilities consist of major equipment such as the gas generator engines, power turbines and alternator supported by balance-of-plant auxiliary systems such as the oil fuel supply system; lube oil system; electrical systems (switchgear; motor control centres, dc batteries); control & instrumentation systems (distributed control system; temperature and vibration monitoring equipment). Structures such as buildings, equipment enclosures and exhaust stacks comprise the balance of components that make up the Gas Turbine Facilities at each site.

The condition assessment portion of the Study found that the gas generator engines and power turbines at each site show signs of operational wear and will require remedial work to allow reliable operation over the next 15 years. Since HYDRO was unable to provide any historical electrical testing data or visual inspection information on the alternator at either site, it was not possible to assess the current condition of either alternator and determine the extent of remedial work required to allow reliable operation over the next 15 years. HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the alternator's stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. The existing balance-of-plant system equipment, buildings and structures at each site are generally in good condition however there is some degree of minimal refurbishment work required in these systems. Refer to Report Section 5 (Hardwoods) and Section 6 (Stephenville) for details on the condition assessment of each Gas Turbine Facility.

A review of the Operator's Logs provided by HYDRO, particularly over the past 5 years of operation, revealed numerous failed starts and trips of the Gas Turbines at both sites resulting

Stantec

FINAL REPORT
CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS
HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES
EXECUTIVE SUMMARY
December 18, 2007

from sporadic mechanical and electrical issues associated with auxiliary equipment on the gas generators engines and alternator and in the balance-of-plant systems. These sporadic issues are deemed fixable with the proper allocation of time, resources and budget. Refer to Report Section 4 for details on these operational issues.

In response to the findings of the condition assessment portion of the Study, options studied to provide reliable operation over the next 15 years included: (i) the refurbishment of the existing equipment and structures at each site; (ii) the replacement of specific major equipment items (gas generator engines, power turbines and alternator) with new equipment as well as the refurbishment of balance-of-plant systems at one or both sites; (iii) the addition of a new gas turbine to replace one or both existing gas turbines and (iv) for HYDRO's consideration, the addition of a dynamic var compensator (D-VAR) to replace one or both gas turbines for system MVAR support only, the dominant operating mode of the Gas Turbines over the past 30 years. Refer to Report Section 7 for details on the costs and technical aspects of the Options considered.

The 15 year life cycle cost analysis study of each Option included capital costs for engineering, equipment supply and installation, as well as fuel, operational and maintenance costs at each site. The 15 year life cycle cost analysis of each Option was performed using HYDRO's Cost/Benefit Financial Analysis Model which uses the Cumulative Net Present Value (CPW) approach to perform economic analyses comparisons of alternatives. Refer to Report Section 8 for details on the life cycle cost analysis of the various life extension Options considered. The following Table provides a summary of the Options evaluated and the ranking and CPW of each Option.

15 Year Life Extension Options
Cumulative Net Present Value (CPW)

Ranking	Option	CPW (2007 Cdn$)	
		Sub-Case #1	Sub-Case #2
1	Option 4 – DVAR	$8,995,597	$8,995,597
2	Base Case 2B- Stephenville Refurbishment - No GT Rental	$9,548,569	$24,996,028
3	Base Case 1B- Hardwoods Refurbishment - No GT Rental	$11,467,914	$26,930,650
4	Base Case 2A- Stephenville Refurbishment - GT Rental	$13,842,768	$27,711,405
5	Base Case 1A- Hardwoods Refurbishment - GT Rental	$16,010,747	$29,894,660
6	Option 2 – New Alternator/Refurbish Engines & Turbines – GT Rental	$16,248,954	$28,574,070
7	Option 1 – New Engines & Turbines/Refurbish Alternator – GT Rental	$33,088,681	$36,221,835
8	Option 3 – Complete New GT Unit	$38,145,919	$38,145,919

s f:\jobs\21061\pm\reports\final report\master copy - final report\final wgh - report (december 14, 2007) - nlh hardwoods & stephenville gas turbines study.doc E.2

A decision on the role of the Hardwoods and Stephenville Gas Turbines in the HYDRO system beyond 2023 (the specified 15 years of further service) has not been determined by HYDRO at this time. The financial analysis results in the Table reflect two scenarios beyond 2023. The first scenario (Sub-Case 1) assumes further refurbishment work in 2023, whereas the second scenario (Sub-Case 2) assumes the equipment will generally be totally replaced in 2023 with new equipment. The two scenarios however do not affect the overall ranking of the Options.

While Option 4, the Dynamic VAR Compensator (D-VAR) addition at one site, is ranked 1 in the Options considered, primarily due to significantly reduced operations and maintenance costs going forward, the capital costs used in the life cycle cost analysis of this Option are at best ballpark estimates and can only be confirmed through a detailed study on the application of this technology at one or both sites. In this Option, a D-VAR would replace a gas turbine at one or both sites for MVAR system voltage support only. The question that HYDRO must address regarding this Option is whether backup emergency generating capability is absolutely required at either site going forward. If the answer is yes, this Option can be dismissed from further consideration. If the answer is no, then a more detailed study of this Option should be conducted with the involvement of the equipment supplier to confirm costs and technical details. It is Stantec's opinion that this Option would be competitive with the Base Case existing equipment refurbishment Options 1 and 2 for MVAR system voltage support only, should HYDRO decide to forego generation capability at either site. Refer to Report Section 7 for details on the application of D-VAR technology.

The Base Case Options (1A/1B – Hardwoods) and (2A/2B – Stephenville) rank 2, 3, 4 and 5 of the Options studied. These Options, involving the refurbishment of the existing equipment at each site, assume the alternator will have to be extensively refurbished off-site at a supplier's facilities, over an estimated 4 month period. As noted previously, HYDRO will have to conduct, at some point, a thorough electrical testing and visual inspection of the stator and rotor in order to arrive at a decision as to whether refurbishment or replacement is required. Base Cases 1A and 2A assume that HYDRO will rent a mobile gas turbine to cover the alternator refurbishment period, whereas Base Cases 1B and 2B assume that HYDRO will schedule an estimated 4 month outage at each site when the alternator is being refurbished. The decision on the use of a rental unit is HYDRO's.

Option 2, ranked 6 of the Options studied would only be considered if pending a thorough testing and visual inspection of the alternator, it is determined the alternator cannot be refurbished and replacement is necessary to allow reliable operation over the next 15 years.

Options 1 and 3 ranked 7 and 8 respectively, have high CPWs and are not be considered as Options to pursue.

The Stantec team is of the opinion that the existing equipment, particularly the gas generator engines, power turbines and alternator, as well as the balance-of-plant equipment and structures can be refurbished sufficiently to allow reliable operation over the next 15 years. It is recommended that Base Case Options 1 and 2 at each site be pursued with a decision required on whether a rental mobile gas turbine will be employed at each site. Since no information was available to assess the condition of the alternator, the decision on the extent of refurbishment work required on this equipment will not be known until a thorough electrical testing and visual inspection of the stator and rotor is conducted. At that time, HYDRO will have to make a decision as to whether refurbishment or replacement is required. If replacement is necessary at one site or the other, then Option 2 should be pursued.

APPENDIX B

Recommended Site Refurbishments for Hardwoods Gas Turbine Plant

Recommended Site Refurbishments to

Hardwoods Gas Turbine Plant

Recommended by Stantec, 2007

Gas Turbine Engines / Power Turbine Equipment

- Disassemble End A and End B gas turbine engines. Inspect and refurbish as required.
- Inspect End A and End B power turbines upon removal of gas turbine engines. Perform required repairs.
- Completely disassemble and inspect End A and End B clutches.
- Replace ignition igniters.
- Replace speed governors/fuel valve assemblies.

Inlet Air Systems (End A and End B)

- Sandblast interior surfaces and recoat surfaces and silencer.
- Clean exterior of surface corrosion and recoat.
- Clean filter enclosure and recoat.
- Repair seals and recoat plenum access doors.
- Clean and recoat air inlet screens on End B.
- Re-align inlet bellmouth assembly on End B.
- Replace access ladders and modify guardrails.

Exhaust Stacks (End A and End B)

- Replace light gauge cladding with heavy gauge cladding on exterior upper portion of stacks.
- Clean and recoat exterior lower portion of stacks.
- Repair cracks in exhaust stack access door openings, in inner liner and internal rolled edge.
- Replace snow doors.

- Replace access doors with hinged doors.
- Replace access ladders.

Glycol Cooler for Main Lube Oil

- Clean and recoat entire structure.

Gas Generator and Power Turbine Enclosures (End A and End B)

- Clean and recoat exterior surfaces.
- Clean, sandblast, and recoat interior surfaces.

Alternator and Excitation Systems

- Conduct electrical tests on alternator, as per consultant's recommendations.
- Remove rotor for complete inspection of rotor/stator/exciter/bearings.
- Carry out refurbishment work based on inspection results. This may include rewind of stator and rotor, rewind/refurbishment of exciter.
- Perform a trim balance on the rotor to address vibration issues.

Alternator Enclosure

- Clean and recoat exterior surface.
- Fuel Oil System.
- Clean and recoat exterior of fuel oil storage tank.
- Repair and recoat various access stairs and handrails.

Electrical Systems

- Replace alternator 13.8 kV circuit breaker.
- Modify 13.8 kV cabling.
- Repair bus duct leaks.
- Replace 125 Vdc battery charger.
- Replace electromechanical protection relays with digital relays.

- Replace 15 kV power cable supplying the 750 kVA Station Service Transformer.

Control and Instrumentation Systems

- Stock spare input module cards for DCS system.
- Replace DCS power supply.
- Replace obsolete vibration monitoring system.
- Replace obsolete vibration transducers with new accelerometers.
- Replace existing thermocouple terminal blocks with terminal blocks for thermocouple use.
- Install low level cut out switch in oil storage tank.
- Relocate on-engine junction boxes to an off-engine site to reduce affects of vibration and heat.

Buildings

- Control Building: Clean and recoat building and install new roof.
- Fuel Unloading Building: Replace roof, pave area near off-loading containment dyke, replace posts and guardrails.
- Fuel Forwarding Building: Clean and recoat roof, replace posts and guardrails.
- Auxiliary Module Building: Clean and recoat roof.
- Maintenance and Parts Building: Clean and recoat roof.
- High Voltage Switchgear Building: Clean and recoat exterior walls. Replace roof.

Recommended Site Refurbishments to

Hardwoods Gas Turbine Plant

Additional Work Identified After Completion of Stantec Report

- Grounding of fuel storage system.
    - Noted in the Stantec Report as requiring further assessment;
    - After an assessment of FM Global Property Loss Prevention Data Sheet 7-88 – Flammable Liquid Storage Tanks (March 2009), it was determined by Hydro that grounding is required because the fuel storage tank is installed on top of a liner and the associated piping is not known to be grounded.
        - FM Global Property Loss Prevention Data Sheet 7-88 (Section 2.5 Ignition Source Control) states: "Provide static grounding connections on tanks that are out of contact with the earth if piping is ungrounded or nonconductive".
- Replace underground sump drainage piping and sump pit cover.
    - Leaks were discovered in 2007, 2008, and 2009.
- Replace various pumps.
    - Stantec Report recommends purchasing spares;
    - Installing the spare pumps will increase operational reliability.
- Provide position monitoring capability for liquid fuel valves.
    - Existing liquid fuel valves are original from 1976;
    - Existing valves do not have any position feedback to the DCS;
    - Without position feedback, it is impossible to determine the actual position of the valve (i.e. full open, full closed, or partially open);
    - The installation of valves with position monitoring capability will assist operations staff in troubleshooting fuel flow problems on the gas turbines.
- Repair or replace motorized valve on main fuel line.
    - This electrically-actuated valve closes off the main supply of fuel to the plant

    and is required to protect the environment;
    - Currently, this valve does not open fully after it is fully closed;
    - An assessment is required to determine the cause of failure of this valve.
        - Possible causes are incorrect valve programming or a failed valve actuator.
- Inspect MLO and glycol piping and replace if required.
    - Existing outdoor piping is over 30 years old;
    - Piping failure will cause a forced outage.
- Install emergency shutoff for fuel pumps in fuel forwarding module.
    - The fuel forwarding module is a confined space building;
    - In an emergency situation, the operator must leave this building to shut down the pumps;
    - This has been entered as a SWOP (#2008004790);
    - Emergency shutoff will increase safety of personnel working in the module by giving them the ability to immediately shut down the fuel pumps during an emergency.
- Replace junction boxes JB-7A and JB-7B.
    - Existing outdoor electrical junction boxes are not watertight.

APPENDIX C

Hardwoods Gas Turbine Plant - Major Upgrades

Hardwoods Gas Turbine Plant

Major Upgrades

Civil Engineering Projects

1996 – 1997: Tank Farm upgrades.

- One tank was completely removed.
- Remaining tank was cleaned, welds were repaired, and interior floor was painted.
- New dyke liner was installed throughout (Tank was lifted).
- Dykes were re-shaped.
- New dyke section was installed (to reduce size of containment area).
- New piping was installed within tank farm.

2000: Painted exterior of tanks.

Electrical Engineering Projects

Early 1990s: Rotor rewinding and other associated repairs.

1994: Brushless exciter vibration issues.

- In October of 1994 high frequency vibration signatures were observed on the exciter and 'B' end alternator bearing.
- 1995 – 1996: Governor repairs.
- During the 1994 outage very low ramp rates existed and problems were experienced with the governor. Repairs were made to the governor in 1995 and 1996. Governors were calibrated and droops were setup.

1998: Switchgear upgrades.

- Purchase and installation of new main breaker. This breaker will be rated at 3000 Amp with an interrupting capacity of 28 kA. The existing breaker will be assessed for use as a system spare to serve both the Stephenville and Hardwoods site.
- Post insulators and insulation coverings on the rigid bus bars will be replaced/upgraded sufficient to re-rate the switchgear to 15 kV class.

2005: Battery bank replacements.

- The 125V 900 amp-hour VRLA bank for Hardwoods was replaced in 2005.

Mechanical Engineering Projects

Mid 1980's: Snow door actuation was converted from electric to pneumatic.

1988: Fern Engineering modifications.

- Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million.

Early 1990's: Redesign of inlet air filtration system for gas engine and generator.

1992: Exhaust stack replacement.

- Existing interior silencer panel was reused.

1993: Hardwoods B engine serial # 202223 overhaul.

2002: Gas turbine and generator modules fire systems replacement (Inergen).

2003: Installed new core in Heat Exchanger for MLO system.

2004: Installed new expansion joints in stacks.

2005: Air conditioner, for gas turbine control room, replaced.

2005: New double walled fuel tank for diesel generator.

2005: Black start diesel generator replaced.

- This generator restores Hardwoods to operation without relying on external energy sources.

2005: New flow meter for gas turbine.

2005: Installed motorized valve fuel line by main tank.

2005: Fuel lines for gas turbine installed above ground between unit and the fuel forwarding pumphouse.

2006: Repairs to glycol housing.

2007: Both Air compressors have been replaced.

2007: Underground fuel piping replaced.

Protection and Control Engineering Projects

1997: Control system upgrade

- This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system. The DCS included a PC-based operator interface. Commissioning of controls performed by ABB (ETSI).

2003: Thermocouple blocks replaced

Misc.:

- Terminal blocks in junction boxes located around the unit were replaced due to the condition of the original set.
- Snubbers (free-wheeling diodes) were replaced at Hardwoods. Some had shorted out a year ago. These were for noise reduction.

2005: Emergency backup diesel generating units installed.

- Diesel Generating Unit #572 including 600V control panel and backup battery charger installed in existing diesel building.
- The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery charger which ensures the integrity of the 125 Vdc supply to the gas turbine itself during its starting cycle.
- The diesel unit also provides a backup AC supply for one of the air compressors should the

stored air supply run low during attempted start(s) of the gas turbine unit.

2006: AVR Replacement

- The Brush BAVR was removed and a new ABB AVR was installed.

2006: Inverter replacement

- Inverter failed and was replaced.

2007: Human Machine Interface (HMI) replaced after Nov 2007 failure of computer.

APPENDIX D

Operational Data – 2004 to 2009
Hardwoods Gas Turbine Plant

Operational Data for Hardwoods Gas Turbine Plant	
May 31, 2004 to May 31, 2009	
Operating Hours	536.4
Available but not Operating Hours	41026.67
Forced Outage Hours	430.43
Maintenance Outage Hours	177.35
Planned Outage Hours	1184.42
Number of Forced Outages	59
Number of Unit Starts	217

APPENDIX E

Extract (Section 8.0) from
"Condition Assessment and Life Cycle Cost Analysis
- Hardwoods and Stephenville Gas Turbine Facilities"
Stantec, December 2007

Stantec

FINAL REPORT
CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS
HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES
December 18, 2007

8.0 LIFE CYCLE COST ANALYSIS OF REFURBISHMENT OPTIONS

8.1 GENERAL

The primary focus of the life cycle cost analysis aspects of the study involves an economic evaluation of the costs associated with the Base Cases and the various Options outlined in Section 7.0 i.e. refurbishing the existing units, the replacement of existing equipment with new, as well as other economic opportunities for improvement. The 15 year life cycle analysis includes capital costs for equipment supply and installation as well as operational and maintenance costs at each site.

The life cycle cost analysis of each Gas Turbine option was performed by using Hydro's Cost/Benefit Financial Analysis Model. The HYDRO cost/benefit analysis template uses the Cumulative Net Present Value (CPW) approach to perform economic or financial analyses of alternatives as part of the justification of a project. For the purposes of this Study, the CPW approach compares the various options available for Hardwoods and Stephenville Gas Turbines to provide reliable operation for a further 15 years.

8.2 FINANCIAL MODEL INPUT DATA/CRITERIA/COSTS

In discussions with HYDRO, it was agreed that the future operational mode of the Gas Turbines at each site, on an annual basis, will reflect to a large degree its annual operation over the past 5 years in terms of MW and MVAR output, operational and maintenance budgets. In a series of emails throughout October 2007, HYDRO provided the following Financial Model Input information. A copy of the various emails is included in Appendix 11.

8.2.1 MWHRS AND MVAR OUTPUT

The MWhrs loadings forecast for each Gas Turbine for the next 15 years is a very variable number as dictated by changing power system operational conditions. It was recommended in an October 26, 2007 HYDRO email (Email No. 1) to use 1200 MWhrs annually for each of Hardwoods and Stephenville Gas Turbines. It is recognized this number could change significantly over the next 15 years.

A HYDRO email of November 2, 2007 (Email No. 2) provided daily MVAR loadings on each Gas Turbine over the period June 10, 2006 – November 1, 2007. The daily average for both Hardwoods and Stephenville was typically under 10 MVAR with occasional peaks up to 25 MVAR. It will be assumed that this MVAR mode of operation will continue for the next 15 years.

The synchronous condenser operating hours, over the past 5 years at each site, as advised in a HYDRO email of October 26, 2007 (Email No. 1), are as follows:

- Hardwoods – 15,512 hours or an average of 3102 hours annually
- Stephenville – 4,799 hours or an average of 960 hours annually

The average annual hours of synchronous condenser operation will be carried forward as the annual MVAR operating mode for the next 15 years.

8.2.2 Operations and Maintenance Budgets

HYDRO, in an email of October 24, 2007 (Email No. 3) provided the following information on Operations and Maintenance Budgets at Hardwoods and Stephenville over the period 2002 through 2006 with a forecast for 2007. These Budget costs exclude fuel costs.

Table 7
Operational and Maintenance Costs
Hardwoods and Stephenville
(Excludes Fuel Costs)

Year	Hardwoods	Stephenville
2002	$178,000	$83,000
2003	$236,000	$105,000
2004	$114,000	$175,000
2005	$425,000	$114,000
2006	$486,000	$355,000
2007 (Forecast)	$300,000	$160,000
5 Yr Ave (Excluding 2007)	**$287,800**	**$166,400**

The 5 year average will be carried forward, adjusted for inflation, as an annual operations and maintenance cost for the next 15 years.

8.2.3 Gas Turbine #2 Oil Fuel Price Forecast

HYDRO, in an email of October 11, 2007 (Email No. 4), provided a forecast of #2 Oil fuel prices per liter over the period 2008 through 2037. For the purposes of the options life cycle cost analysis exercise, the 15 year forecast costs between 2008 and 2023 will be used.

Table 8

 # 2 Oil Fuel Price Forecast (Cdn$/l)

2008 - 2023

Year		Hardwoods		Stephenville
2008		0.624		0.686
2009		0.552		0.613
2010		0.557		0.619
2011		0.578		0.640
2012		0.606		0.668
2013		0.631		0.694
2014		0.666		0.730
2015		0.686		0.752
2016		0.721		0.788
2017		0.751		0.820
2018		0.786		0.856
2019		0.816		0.888
2020		0.847		0.919
2021		0.867		0.941
2022		0.882		0.957
2023		0.902		0.979

These annual fuel forecasts will be carried forward to compute fuel costs at each site for the next 15 years.

8.2.4 Inflation and Escalation Forecast

HYDRO, in an email of October 26, 2007 (Email No. 5), provided a forecast of inflation and escalation for the period 2000 through 2027. The forecast, included in Appendix 11, provides forecasts for General Inflation, Electric Utility Construction Price Escalation (5 categories) and Operating and Maintenance Cost Escalation.

The figures for the period 2008 through 2023 will be used in the life cycle cost analysis of the various Gas Turbine options.

8.2.5 Fuel Consumption at Each Site

HYDRO, in an email of November 13, 2007 (Email No. 6) provided the following information on fuel consumption at Hardwoods and Stephenville over the period 2004 through 2007. The 2007 figures are for a partial year assumed to cover 9 months. The consumption numbers are as follows:

Table 9
#2 Fuel Oil Consumption (litres)
Hardwoods and Stephenville
(2004 - 2007)

Year	Hardwoods	Stephenville
2004	95,288	50,241
2005	433,380	147,566
2006	738,552	389,686
2007 (partial year)	*262,691*	*204,485*
2007 (full year forecast)	350,255	272,646
3 Yr Ave (Excluding 2004)	**507,395**	**269,966**

The 3 year average will be carried forward as an annual fuel consumption figure for the next 15 years.

8.3 SUMMARY OF GAS TURBINE FACILITY REFURBISHMENT CAPITAL COSTS

The following Table 10 is a summary of the capital costs of the Gas Turbine Facility refurbishments – Base Case and Options - presented in Section 7.0 of this Report, which will be the subject of the life cycle cost analysis exercise. As noted in the various Tables in Section 7.0, there are further costs, associated with a number of the options, primarily modifications to existing enclosures to accommodate new equipment that will require further detailed investigation by the new equipment suppliers.

Table 10

Gas Turbine Facility Refurbishment Capital Costs

(2007 Costs)

Cost Analysis Alternatives		Description		Capital Costs (Cdn$)
Base Case				
1A		Refurbish Existing Equipment - Hardwoods GT Allowance for Temporary Gas Turbine Rental (1)		$4,506,880.00 3,307,500.00
1B		Refurbish Existing Equipment - Hardwoods GT No allowance for Temporary Gas Turbine Rental		$4,506,880.00
2A		Refurbish Existing Equipment - Stephenville GT Allowance for Temporary Gas Turbine Rental (1)		$4,538,883.00 3,307,500.00
2B		Refurbish Existing Equipment - Stephenville GT No allowance for Temporary Gas Turbine Rental		$4,538,883.00
Options				
1		New Engines & Power Turbines – Refurbish Balance of Equipment (2) – one site Allowance for Temporary Gas Turbine Rental (1)		$26,419,761.00 3,307,500.00
2		New Alternator / Exciter – Refurbish Balance of Equipment (2) – one site Allowance for Temporary Gas Turbine Rental (1)		$7,163,381.00 3,307,500.00
3		New Gas Turbine – Dismantle existing Gas Turbine and use as Spare Parts – one site		$36,900,000.00
4		Dynamic Var Compensation – Ballpark estimate at this time as a more detailed study is required to define scope and costs		$10,000,000.00

Note (1): The Gas Turbine rental covers a period of 4 months at the site.

Note (2): There are further costs associated with these options, primarily modifications to existing enclosures to accommodate the new equipment, which will require further detailed investigation by the new equipment suppliers.

8.4 LIFE CYCLE COST ANALYSIS ASSUMPTIONS AND COMMENTARY

A life cycle cost analysis of each option was performed using Hydro's Cost/Benefit Financial Analysis Model. The following sub-sections provide an overview of the analysis, assumptions and other criteria. Commentary is provided on the financial analysis of each Gas Turbine Facility Option. A copy of the various Life Cycle Cost Analysis Model runs is included in Appendix 12.

For the purposes of this study, the following assumptions have been used throughout all of the options:

Initial project capital cost is incurred end of year 2008

- Annual costs (fuel and O&M) begin 2009
- Annual costs are escalated through 2023 using the default indices in the NLH
- financial analysis tool
- The average fuel consumption over the past three years has been used as the base
- case for projections of future fuel consumption at both Hardwoods and
- Stephenville sites
- The 2007 project capital costs provided in Section 7.0 have been escalated to 2008
- to determine the "Project In-Service Cost," using the built-in "Hydro and Thermal
- Plant Indices" escalation factors in the NLH financial analysis tool
- O&M costs have been assumed as 50% materials and 50% labour
- Cumulative net present values are expressed in January 2007 dollars

Each of the options described below were analyzed to determine the comparative cumulative net present value (CPW) over 15 years of operation. Note that two sub-cases were run for each scenario, in order to gauge the possible impact of future HYDRO maintenance requirements:

Sub-Case #1: Additional refurbishment costs are assumed to be required in 15 years, and are accounted for in the financial model as replacement costs occurring in 2023. Future refurbishment costs are adjusted to reflect the degree of work completed in 2008 for each option.

Sub-Case #2: It is assumed that equipment refurbished in 2008 will require replacement in 15 years. These costs are accounted for in the financial model as replacement costs occurring in 2023.

8.4.1 Base Case 1A – Hardwoods Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario considers refurbishment at the Hardwoods site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $16.0 million and $29.9 million for Sub-cases #1 and #2, respectively.

8.4.2 Base Case 1B – Hardwoods Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Hardwoods site (i.e. identical to the Hardwoods base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $11.5 million and $26.9 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 1A illustrate the financial impact of rental unit expenses during refurbishment.

8.4.3 Base Case 2A – Stephenville Refurbishment with Mobile Gas Turbine Rental Allowance

This scenario is for refurbishment at the Stephenville site, with an allowance included for 4 months of rental mobile equipment during the refurbishment period.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub- Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine. Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $11.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $13.8 million and $27.7 million for Sub-cases #1 and #2, respectively. Note that while the Stephenville refurbishment capital costs are similar to Hardwoods, the CPW is considerably lower due to Stephenville’s lower utilization and fuel costs.

8.4.4 Base Case 2B – Stephenville Refurbishment with No Mobile Gas Turbine Rental Allowance

This option considers refurbishment at the Stephenville site (i.e. identical to the Stephenville base case), except that no allowance for rental equipment is included.

For projecting future annual costs, 100% of historical fuel consumption and 90% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs are expected to modestly improve.

For Sub-Case #1, it is assumed that a complete refurbishment of the unit will again be required in 2023 at identical refurbishment costs as incurred in 2008 escalated forward to 2023. For Sub-Case #2, an allowance is made for complete replacement of the unit in 2023 with a new gas turbine.

Future costs are escalated using the default value in the NLH model. Resulting replacement costs in 2023 dollars are $6.8 million and $55.6 million for Sub-Cases #1 and #2, respectively.

The estimated CPW of costs for this option is $9.5 million and $25.0 million for Sub-cases #1 and #2, respectively. The lower costs than Base Case 2A illustrate the financial impact of rental unit expenses during refurbishment.

8.4.5 Option No. 1 – Replacement of Engines and Power Turbines

This option is for replacement of the gas engines and power turbines, and refurbishment of the alternator and auxiliaries. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 90% of historical fuel consumption and 75% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new machines.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original alternator would still be in place at that time, and that the engines will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the alternator in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $15.8 million in 2023 dollars.

The estimated CPW of costs for this option is $33.1 million and $36.2 million for Sub-cases #1 and #2, respectively. This is one of the highest cost options, due to the high costs of the engine replacement which are incurred early in the project's life.

8.4.6 Option No. 2 – Replacement of Alternator and Exciter

This option considers replacement of the alternator, and refurbishment of the gas engines and power turbines. The Hardwood site is assumed as the base case. An allowance for 4 months of rental mobile equipment during the refurbishment period is included.

For projecting future annual costs, 100% of historical fuel consumption and 80% of historical O&M costs have been assumed. This is to reflect that fuel consumption is unlikely to change significantly following refurbishment, and that annual O&M costs will be improved by installation of the new alternator.

For Sub-Case #1, it is assumed that partial refurbishment/major maintenance of the unit will again be required in 2023. This is to account for the fact that the original engines would still be in place at that time, and that the alternator will have been operating for 15 years. A cost of $5.9 million in 2023 dollars is assumed, based on 50% of the complete 2008 refurbishment cost estimate. For Sub-Case #2, an allowance is made for complete replacement of the engines in 2023 as well as other required balance-of-plant refurbishments similar to that work done in 2008. Future costs are escalated using the default value in the NLH model, for a total cost of $44.8 million in 2023 dollars.

The estimated CPW of costs for this option is $16.2 million and $28.6 million for Sub-cases #1 and #2, respectively.

8.4.7 Option No. 3 - New Gas Turbine Facility

This option is for installation of a complete new gas turbine, including engine, alternator and auxiliaries. The Hardwoods site is assumed as the base case. No allowance is included for rental equipment, as it is assumed that the new unit would be installed while the old system was still operational.

For projecting future annual costs, 90% of historical fuel consumption and 70% of historical O&M costs have been assumed. This is to reflect that fuel consumption is expected to improve following installation of modern engines, and that less maintenance will be required on the new unit. A capital maintenance expense of $2.0 million in 2023 is allowed for both Sub-Cases.

The estimated CPW of costs for this option is $38.1 million for both Sub-cases #1 and #2. It is assumed that only routine major maintenance will be required in 2023.

8.4.8 Option No. 4 - Dynamic Var Compensation

Although this option requires additional investigation, a scenario was developed to gauge the potential of dynamic VAR compensation. No allowance is included for rental equipment, as it is assumed that the new equipment would be installed while the old system was still operational. For future annual costs, it is assumed that fuel consumption will be eliminated and O&M costs will be reduced to 10% of historical.

With these assumptions, the DVAR option appears very competitive with the refurbishment options. The CPW of this option is $9.0 million, placing it ahead of all the alternatives. Additional work is required to further develop the technical and financial aspects of this option; however, it is evident that it deserves additional consideration.

8.5 LIFE CYCLE COST ANALYSIS RESULTS AND RANKING OF OPTIONS

The results of the life cycle cost analysis are summarized below in Table 11. In general, the refurbishment options are the least cost alternatives, regardless of the capital expenditure that is assumed to be incurred in 15 years time.

Table 11
CPW of Alternatives

Ranking	Option	CPW (2007 Cdn$)	
		Sub-Case #1	Sub-Case #2
1	Option 4 – DVAR	$8,995,597	$8,995,597
2	Base Case 2B – Stephenville Refurbishment, No Rental Allowance	$9,548,569	$24,996,028
3	Base Case 1B – Hardwoods Refurbishment, No Rental Allowance	$11,467,914	$26,930,650
4	Base Case 2A – Stephenville Refurbishment, with Rental Allowance	$13,842,768	$27,711,405
5	Base Case 1A – Hardwoods Refurbishment with Rental Allowance	$16,010,747	$29,894,660
6	Option 2 – New Alternator/Refurbish Engines & Turbines	$16,248,954	$28,574,070
7	Option 1 – New Engines/Refurbish Alternator	$33,088,681	$36,221,835
8	Option 3 – Complete New GT Unit	$38,145,919	$38,145,919

Figures 1 and 2 provide a graphical summary of the options for Sub-Case #1. Note that the annual operating costs of each alternative have a relatively minor impact on life cycle costs compared to the required capital expenditures. This is due primarily to the ongoing projected synchronous condenser mode of operation of the Facilities over the next 15 years. If generation at each site should increase significantly in the next 15 years, O&M costs will increase accordingly. The lower O&M and fuel savings expected for the options where major equipment replacements are completed in 2008 therefore do not outweigh the early capital expenditure.

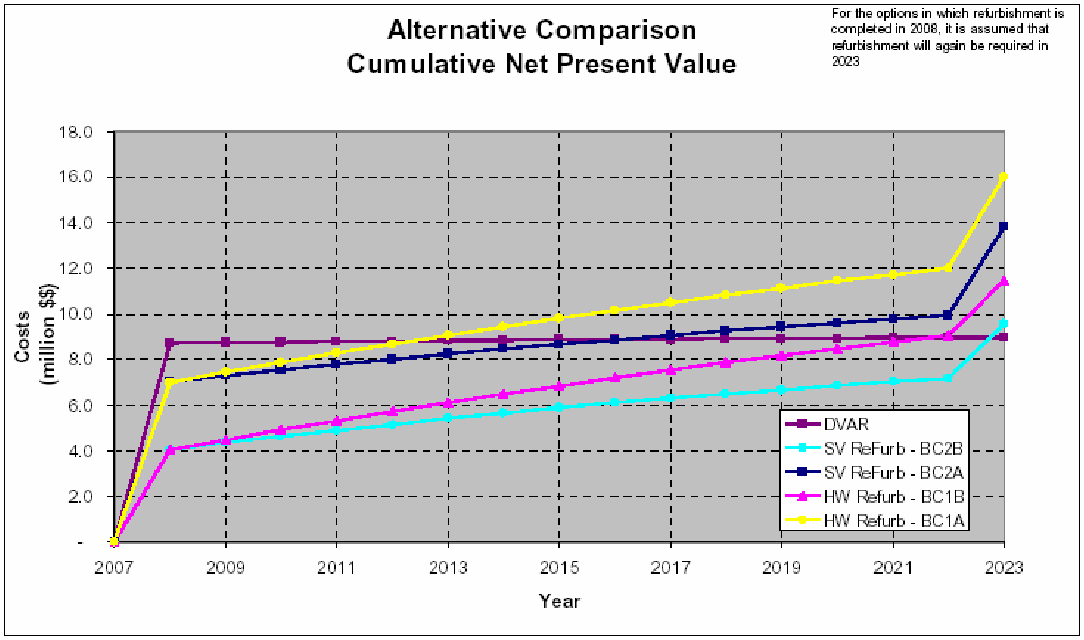


Figure 1
Sub-Case #1 – Base Cases and DVAR Compensation

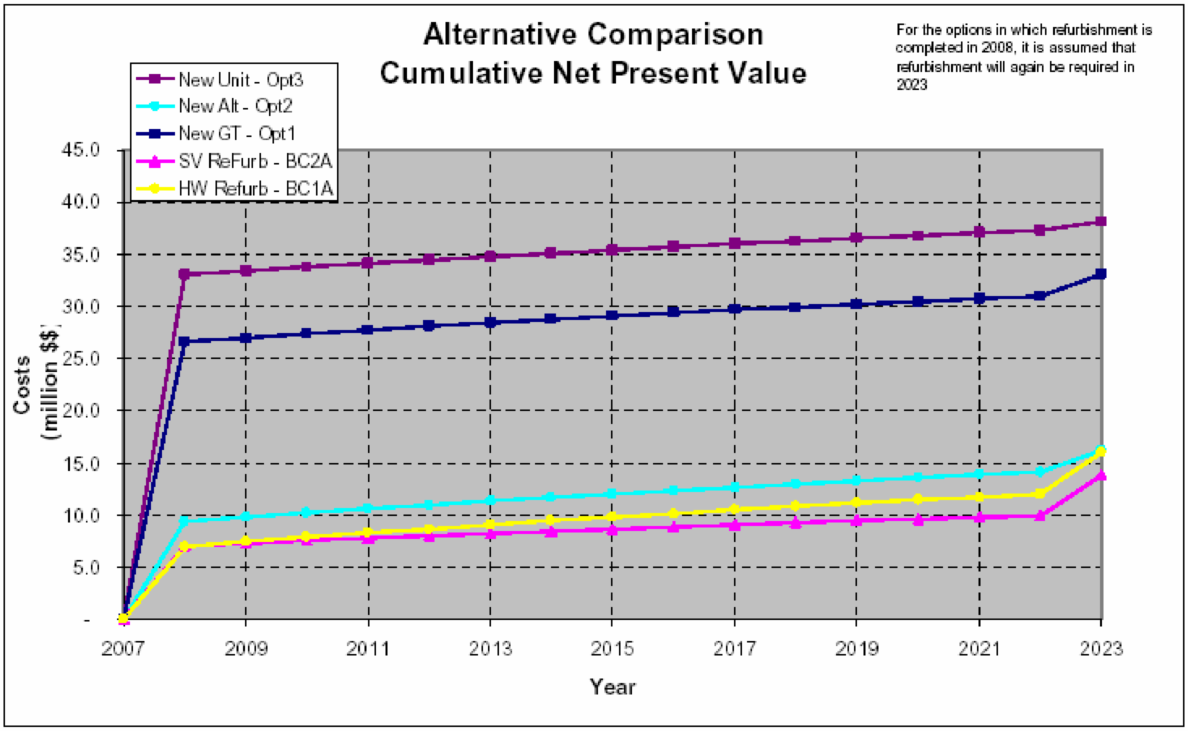


Figure 2
Sub-Case #1 – Base Cases and Equipment Replacement Options

APPENDIX F

Extract (Appendix 6) from "Condition Assessment and Life Cycle Cost Analysis - Hardwoods and Stephenville Gas Turbine Facilities" Stantec, December 2007.

COST ESTIMATE SPREADSHEET No. 1

HARDWOODS GAS TURBINE FACILITY

REFURBISHMENT RECOMMENDATIONS

Newfoundland and Labrador Hydro		
Stephenville and Hardwoods Gas Turbine Condition Assessment Study		
NG Job No. 21061		
Rev 1 ------ 2007-12-14		
	COST ESTIMATE SPREADSHEET No. 1	
	HARDWOODS GAS TURBINE REFURBISHMENT RECOMMENDATIONS	
Item	**Hardwoods Recommendations**	**Cost Total**
1--	**Gas Generators / Power Turbines Equipment**	
1	Engine A assembly be removed, disassembled to allow for	
	detailed internal inspection with major refurbishments as required	
	(Report para. 5.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$515,000.00
	o Cost to transport engine assembly to BC & back	3,200.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
2	Engine B assembly be removed, disassembled to allow for	
	detailed internal inspection with major refurbishments as required	
	(Report para. 5.2.1)	
	o S&S Turbines Cost to refurbish and test engine assembly in BC	$460,000.00
	o Cost to transport engine assembly to BC & back	3,200.00
	o Engine removal & reinstallation by S&S Turbines Technicians	14,000.00
3	Inspect the Power Turbine assemblies A & B in detail upon removal of	$120,000.00
	the Engines as noted in Items 1 & 2 to verify the mechanical integrity	
	of the units. Inspect and refurbish the following: (Report para. 5.2.5)	
	o Main line bearings inspection	
	o Remove turbine blades and perform metallurgical sampling to	
	verify alloy composition and wear to the blade roots	
	o Remove turbine disks and perform metallurgical sampling to verify	
	alloy composition and creep growth.	

		o Apply anti-corrosion/thermal protection coatings to the turbine blades and nozzles.		
4		Completely disassemble and inspect the Power Turbine Clutches A & B.	$13,000.00	
		Determine and resolve the interference problem between the clutches		
		and the proximity switches. (Report para. 5.2.6)		
5		Spare Item		
6		Spare Item		
7		It is recommended that HYDRO replace the following obsolete		
		auxiliary components with components of current design:		
		(Report para. 5.2.2)		
	Quantity	**Device**		
		o Replace Ignition Exciters	$24,000.00	
		o Replace Speed Governors/fuel valve assemblies	$56,000.00	
8		**Option:**		
		S&S Turbines provides a rental engine for the period when an engine		
		leaves site for refurbishment in BC until its return to site (estimated at		
		120 days per engine - assumes only one engine off-site at any time)		
		o 120 days per engine x 2 = 240 days (8 months)		
		o Fee for installation and removal = $14,000.00		
		o Monthly on-site rental fee = $2,450.00 x 8 = $19,600.00		
		o Fired hour charge = $42.00 per hour		
		(Assume 60 hours in 8 months = $2,520.00)		
		o Return transport from/to BC = $5,200.00		
		Total:	$41,320.00	$1,263,720.00
2--		**Inlet Air Systems A & B**		
9		Interior of both Inlet Air Plenums A and B be sand blasted and the	$ 18,000	
		surface of the Inlet Air Plenums and the silencers re-coated.		
		(Report para. 5.2.3)		
10		The exterior of both Inlet Air Structures be cleaned of surface corrosion	$ 24,000	

	& flaking and re-coated. (Report para. 5.2.3)			
11	Clean the surface corrosion inside the filter enclosure at the top of	$	4,000	
	each Inlet Air Structure and re-coat. (Report para. 5.2.3)			
12	Replace the inner row of rubber sealing strips in Inlet Air Plenum A	$	1,500	
	(Report para. 5.2.3)			
13	Complete following items regarding the access doors to both Air			
	Plenum structures: (Report para. 5.2.3)			
	o Sand blast and coat all areas corroded under the access doors	$	700	
	o Weld new plates inside the troughts	$	600	
	o Replace the weather stripping on the access doors	$	1,000	
	o Install a new drip cap over both access doors			
14	Replace the ladders providing access to the platforms attached to each	$	5,500	
	Inlet Air Structure and install kick plates on the ends of the platforms.			
	(Report para 5.2.3)			
15	Clean the highly corroded screens on the Unit B Inlet Air Structure and	$	2,000	
	re-coat. (Report para. 5.2.3)			
16	Re-align the inlet bellmouth assembly on Engine B (Report para. 5.2.3)		$5,000	$ 62,300
3--	**Exhaust Stacks A & B**			
17	Replace the light gauge exterior cladding on the upper portion of each	$	22,000	
	Exhaust Stack with a new corrogated metal cladding system. (Report			
	para. 5.2.4)			
18	Clean the surface corrosion and coating failures on the heavy gauge	$	15,000	
	cladding on the lower portion of each Exhaust Stack and re-coat.			
	(Report para. 5.2.4)			
19	Repair cracks at two corners of the Exhaust Stack A access door	$	800	
	opening in the inner liner, as well as cracks in the welds holding the			
	interior mesh and insulation in place. (Report para. 5.2.4)			

20	Repair cracks at two corners of the Exhaust Stack B access door opening in the inner liner, as well as cracks in the inner liner below the door opening and the internal rolled edge. (Report para. 5.2.4)	$ 1,200	
21	Replace the snow doors on each Exhaust Stack. (Report para. 5.2.4)	$ 34,000	
22	Replace existing access doors on the Exhaust Stacks with operable hinged doors with proper flashings and weather stripping In addition, modify the hatches below these doors, in the roof of the gas turbine enclosures, to prevent water leaks. (Report para. 5.2.4)	$ 16,500	
23	Replace the ladders providing access to the platforms on each Exhaust Stack. (Report para. 5.2.4)	$ 5,500	$ 95,000
4--	**Glycol Cooler for Main Lube Oil**		
24	The entire Glycol Cooler steel structure and associated cladding be cleaned, prepared and re-coated within next 2 years. (Report para. 5.2.9)	$ 9,500	$ 9,500
5--	**Gas Generator / Power Turbine Enclosures A & B**		
25	The exterior of both Gas Generator / Power Turbine Enclosures be cleaned of corrosion, prepared and re-coated within next 2 years. (Report para. 5.2.10)	$ 10,000	
26	The interior of both Gas Generator / Power Turbine Enclosures be cleaned, areas with corrosion sandblasted and re-coated. (Report para. 5.2.10)	$ 11,000	
27	Modify the existing man doors to both Power Turbine Modules to have inspection windows added. (Report para. 5.2.10)	$ 1,600	$ 22,600
6--	**Alternator & Excitation System**		
28	Conduct Electrical Tests on the Alternator and Exciter while in its	$7,000.00	

		enclosure to determine condition as follows: (Report para. 5.3.3)				
		o Alternator Stator EL-CID Test				
		o Alternator Stator Polarization Index Test				
		o Alternator Stator Partial Discharge Test				
		o Alternator Rotor Megger Test - 500 vdc				
		o Measure Alternator Rotor Winding Resistance				
		o Rotating Exciter Stator and Rotor Megger Tests				
		o Measure Rotating Exciter Stator and Rotor Winding Resistance				
29		Remove & replace the Alternator from its Enclosure and remove the rotor		$50,000.00		
		for a complete visual inspection of the stator / rotor / exciter. Inspections				
		shall include: (Report para. 5.3.3)				
		Stator Inspection to include but not limited to:				
		o Loose or damaged Wedges				
		o Loose or cracked or failed winding connections				
		o Dusting, greasing and other signs of windings movement				
		o Indications of arcing (hot spots) and damaged core laminations				
		o Loose core bolts				
		o Signs of corrosion, contamination and excessive dirt				
		Rotor Inspection to include but not limited to:				
		o Signs of physical damage				
		o Loose or cracked or failed winding connectors				
		o Slot wedge migration and possible contact with retaining rings				
		o Signs of overheating				
		o Loose rotor wedges				
		o Dye penetrant examinations and magnetic particle tests on				
		forgings; retaining rings and fan components to detect				
		fatigue cracks.				
		Bearings Inspection to include but not limited to:				
		o Assess general condition of the bearings				
		o Determine if the bearings require re-babbiting or machining.				
		Carry out refurbishment work as required following				
		completion of electrical tests (Item 27) and visual inspections				

	(Item 28). Estimate includes:		
	o Rewind of stator at supplier's shop	$1,200,000.00	
	o Rewind of rotor c/w new end caps and overspeed testing at supplier's shop	$800,000.00	
	o Rewind /refurbishment of exciter	$25,000.00	
	o Transport costs to/from supplier's shop - assume UK	$30,000.00	
30	Perform a trim balance on the rotor to address the vibration issue observed physically and noted on the vibration monitoring system. There is a residual imbalance between the non-exciter and exciter of the alternator. (Report para. 5.2.7)	$10,000.00	$2,122,000.00
7--	**Alternator Enclosure**		
31	The exterior of the Alternator Enclosure be cleaned to remove surface corrosion and flaking, prepared and re-coated within next 2 years. (Report para. 5.3.7)	$ 9,000	
32	Add inspection windows to the man doors in the alternator module for safety purposes. (Report para. 5.3.7)	$ 1,600	$ 10,600
8--	**Fuel oil System**		
33	Clean, prepare and re-coat the storage tank exterior within the next 5 to 7 years. (Report para. 5.4.1)	$ 40,000	
34	Clean, prepare and re-coat the storage yank stairs and handrail within the next 2 to 3 years. (Report para. 5.4.1)	$ 4,000	
35	Replace two corrode stair treads on the storage tank stairs. (Report para. 5.4.1)	$ 750	
36	Install a kickplate at the handrail on the top of the storage tank. (Report para. 5.4.1)	$ 500	$ 45,250

9--	**Electrical Systems**		
37	Replace the alternator existing 13.8 kV circuit breaker with a new	$60,000	
	circuit breaker. (Report para. 5.5.1)		
38	Modify cabling in the 13.8 kV cable entrance cubicle as follows:		
	o Short term - install dividers to separate the power cables from the	$3,500.00	
	control and instrumentation cables.		
	o Long term - Replace and install power cables in a separate	$9,500	
	compartment from the control and instrumentation cables.		
	(Report para. 5.5.1)		
39	Repair bus duct leaks by either (i) applying rubberized asphalt roofing	$6,000	
	compound over the duct or (ii) cover the bus duct with cladding.		
	(Report para. 5.5.3)		
40	Replace the existing 125 Vdc Battery Charger due to obsolence.	$17,000	
	(Report para. 5.5.5)		
41	Recommendation for HYDRO to prepare a replacement program and	$21,000	
	budget to replace over time the electro-mechanical generator		
	protection relays with digital relays. (Report para. 5.5.6)		
42	Replace the 15 kV power cable supplying the 750 kVA Station Service	$6,100	
	Transformer. (Report para. 5.5.7)		$123,100
10--	**Control & Instrumentation Systems**		
43	Stock spares for input channel modules in the ELSAG Bailey INFI 90	$8,000	
	DCS System. (Report para. 5.6.1)		
44	Replace the existing DCS System interface computer (PC) with a new	$4,500	
	PC with the latest PCV and QNX software. (Report para. 5.6.1)	$8,000	
45	Replace the existing obsolete DCS power supply system with a new	$24,000	
	power supply. (Report para. 5.6.1)		

46	Due to hot and humid conditions in the Control Building, it is	$1,000	
	recommended that an air conditioning unit be installed in the area of		
	the DCS equipment. (Report para. 5.6.1)		
47	Replace the obsolete vibration monitoring system. (Report para. 5.6.3)	$20,000	
48	Replace the existing obsolete vibration transducers with new		
	accelerometers. (Report para. 5.6.3)		
49	Replace the existing terminal blocks for thermocouple terminations	$600	
	with terminal blocks designed for thermocouple use. (Report para. 5.6.4)		
50	Install a low level cut out switch in the oil storage tank as a backup	$2,500	
	to the level transmitter. (Report para. 5.6.9)		
51	Relocate the on-engine electrical junction boxes off the engines to	$1,500	$70,100
	isolate the terminations from vibration and heat. (Report para. 5.6.12)		
11--	**Buildings**		
52	Control Building Refurbishments: (Report para. 5.7.1)		
	o The exterior of the Building be cleaned of corrosion, prepared and	$ 11,000	
	re-coated within next 2 to 5 years.		
	o Install a new sloped roof over the existing flat roof for water	$ 7,000	
	tightness purposes.		
53	Fuel Unloading Building Refurbishments: (Report para. 5.7.2)		
	o Replace the roof of the Building within next 2 years.	$ 5,000	
	o Pave the area surrounding the concrete off-loading containment	$ 1,200	
	dyke to facilitate the clean up of any spills.		
	o The timber posts and guardrail protecting the concrete off-loading	$ 1,000	
	dyke and piping should be replaced.		
54	Fuel Forwarding Building Refurbishments: (Report para. 5.7.3)		
	o Clean the roof, remove corrosion and repaint within 1 year.	$ 3,000	
	o Clean the roof, remove corrosion and repaint within 1 year.	$ 1,500	

			o The timber posts and guardrail protecting the Building should be replaced.		
55			Auxiliary Module Building Refurbishments: (Report para. 5.7.4)	$ 2,500	
			o Clean the roof, remove corrosion and repaint within 1 year.		
56			Maintenance and Parts Storage Building Refurbishments: (Report para. 5.7.5)	$ 5,000	
			o Clean the roof, remove corrosion and repaint within the next 2 years.		
57			High Voltage Switchgear Building Refurbishments: (Report para. 5.7.6)	$ 4,500	
			o Clean, remove surface corrosion and re-coat the exterior walls of the Building within the next 5 years.	$ 3,000	
			o Install a new roofing system such as a modified bitumen roofing membrane applied with hot asphalt directly over the existing roof to ensure water tightness.		$ 44,700
12--			**Miscellaneous Work on Ongoing Operational Issues**		
58			A number of ongoing operational issues were identified by HYDRO personnel during the Study. It was not possible to provide detailed solutions to these issues during the Study due to schedule and budget constraints. It is recommended that HYDRO, as part of the overall refurbishment works, include money to address these issues. A figure of $250,000 is proposed.	$250,000.00	$250,000.00
			SUB-TOTAL:		$ 4,118,870
			HYDRO labour & overhead costs for Items A - K at 8% of Sub-total:		$ 329,510
13--			**Spare Parts -- (Common To both Sites)**		
59			It is recommended that HYDRO stock the following spare parts to increase the overall reliability of the Gas Turbine:		
	Quantity		**Device**		
	-1-	o	Fuel Injection Nozzles (spare set)	$16,500.00	
	-1-	o	Spare Starter Assembly	$12,000.00	
	-1-	o	Spare Glycol Circulation Pump Set	$2,000.00	
	-1-	o	Spare 3-way Glycol Mixing Valve	$14,000	
	-1-	o	Spare Pressure Control Valve for Lube oil System	$6,000	
	-1-	o	Spare Control Valve for Fuel Oil System	$6,000	
	-1-	o	Install the facility for hook-up of a rental compressor.	$2,000	$58,500.00
			TOTAL:		**$ 4,506,880**

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER
DAVID W. HICKS
David W. Hicks
SIGNATURE
July 31 2009
DATE
NEWFOUNDLAND & LABRADOR

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACEMENT OF STATOR WINDINGS

At The Bay d'Espoir
Hydroelectric Generating Station

July 2009

newfoundland labrador
hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro) largest hydroelectric generating station on the Island Interconnected system is located at Bay d'Espoir. The Bay d'Espoir Hydroelectric Generating Station consists of seven generating units producing a total capacity of 604 MW which is approximately 39 percent of the Island Interconnected System's installed capacity. Units 1 through 3 and Unit 4 were commissioned in 1967 and 1968, respectively, and each unit has a rated capacity of 75 MW.

Each generating unit is approximately three meters high with an approximate diameter of six meters. A generator consists of two main parts: a rotor and a stator. The rotor is connected to a turbine and rotates because of the force of moving water on the turbine blades. The stator is the stationary part of the generator, and for Units 1 through 4, the stator is composed of a series of copper wire windings. When the rotor, which is a series of large magnets, rotates in a ring of copper coils, electricity is produced. The copper wiring in the stator windings on Units 1 through 4 is insulated with an asphalt tape system. This system is analogous to insulating bare copper strands with regular electric tape to prevent the strands from coming in contact with each other. Because of age, the asphalt tape insulation on the units has become dry and brittle and is prone to failure. A failure of any single coil will result in the entire machine having to be rewound. The process of replacing a single coil involves removing approximately 25 additional coils because of the complexity in the electric generator design that requires the inter-twining of various copper coils. Since the coils are very dry and brittle, a repair of this magnitude is expected to lead to failure of the winding as a whole.

From the experience and knowledge of Hydro personnel, there is no question that these stator windings of each of Units 1 through 4 will fail, although the exact time cannot be accurately predicted. This report describes the justification for the replacement of the stator windings of Units 1 through 4 for continued operational support of Hydro's Bay d'Espoir Hydroelectric Generating Station.

As part of a 2007 approved capital project titled "Bay d'Espoir Units 1 - 4 Stator Winding Design Review", Hydro commissioned General Electric Energy (GE) to inspect the condition of the existing stator winding for generating Units 1 through 4 at the Bay d'Espoir Hydroelectric Generating Station. Also, GE was directed to conduct a design review to ensure that the existing stator winding of Units 1 through 4 could be replaced with windings of modern copper bar construction. This review confirmed that a suitable winding, can be produced to replace the existing, asphalt insulated, wound coils.

2 PROJECT DESCRIPTION

In Board Order No. P.U. 36 (2008), Hydro received approval from the Board of Commissioners of Public Utilities to purchase a new stator winding in 2009 to be delivered to the Bay d'Espoir Hydroelectric Generating Station in early 2010. Originally, it was proposed that this winding would be tested and stored, on site, as a spare to be installed when a winding failure occurred. However after further consideration of the test results, condition and age of the winding, it is prudent that a strategically planned stator winding replacement program be initiated to ensure reliability to the system. Generating Unit 2 was determined to be in the most deteriorated condition, so this unit will be the first to be fitted with a new winding.

The 2009 project to purchase the winding is underway and delivery is still forecast for early 2010. This 2010 project consists of the installation of this new stator winding for generating Unit 2. The work will also include an upgrade to the generator protection and refurbishment of other generator components such as the stator core and rotor poles to ensure the new windings operate to their full capability. It is Hydro's intention to also replace the windings in Units 1, 3 and 4 over the next five years therefore, this 2010 project also includes the purchase of a second winding, to be stored at site and be ready to install in one of the other units when required.

3 EXISTING SYSTEM

The existing windings were thought to be in good condition for their age. However, inspections in June 2007 found signs of wear in critical locations within the existing windings. This wear, along with results from electrical tests on the windings, indicate that the stator winding on Unit 2 is closer to failure than the windings on the other units. Electrical tests involve applying an increasing test voltage to the stator winding while monitoring the current flow in the winding insulation. Under ideal conditions for a winding with good insulation, the test voltage of 28kV can be applied with no increase in the current flow through the insulation. This indicates a strong insulation. In the case of Unit 2, as the test voltage was being applied (as low as 13 kV), the current flow increased. This indicated a weak insulation. Continued application of the test voltage would have damaged the winding so it was decided to abort the test rather than damage the winding. It was thus confirmed that there is significant deterioration in the stator winding insulation of Unit 2. It is no longer possible to perform this type of electrical testing on the stator winding of Unit 2 as severe damage resulting from the testing has become a near certainty.

While Unit 2 is closer to failure than the other three units, there are similar indications of deterioration on Units 1, 3 and 4. The insulation on these windings is cracking in places, with asphalt seeping from within the windings, indicating impending insulation break down. As the insulation continues to deteriorate with age and use, the windings of Units 1, 3 and 4, much like Unit 2, required that a spare be available in case of failure before the planned rewinding.

3.1 Age of Equipment or System

Generating Units 1 through 3 and Unit 4 were installed and commissioned in 1967 and 1968 respectively and are of wound stator construction. Units 5 and 6 (commissioned in 1969) and Unit 7 (commissioned in 1978) are of a more modern design using solid copper bars to form the stator winding.

3.2 Major Work and/or Upgrades

Table 1 shows the upgrades that have occurred on the generating units since installation.

Table 1
Major Work Upgrades

Year	Major Work/Upgrade	Cost ($000)
2001	Unit 1 Repair of Stator Windings	88.2
1998	Unit 1 DC Exciter Replacement	330.6
1998	Unit 4 DC Exciter Replacement	330.6
1997	Unit 2 DC Exciter Replacement	333.6
1997	Unit 3 DC Exciter Replacement	333.6
1996	Unit 1 Runner Replacement	1,578.0
1994	Unit 3 Runner Replacement	1,449.0
1994	Unit 4 Runner Replacement	1,387.0
1993	Unit 2 Runner Replacement	1,381.0

3.3 Anticipated Useful life

Hydroelectric generator stator windings are depreciated over 25 years. However, windings can have an estimated service life of 40 years depending on operating conditions and maintenance.

3.4 Maintenance History

Since their installation in 1967 and 1968, the stator windings of Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station have had minimal preventive maintenance costs associated with them. Typically, the preventive maintenance costs associated with the stator winding of each unit averaged $1,000 annually, and the maintenance was performed during scheduled outages. This maintenance generally included a visual inspection and the standard electrical tests. The most recent corrective maintenance took place in 2001, when a failure during testing resulted in damage to a single stator winding coil in Unit 1. This repair involved the removal and replacement of one of the 180 coils which make up the stator winding. The cost of this repair was $88,175. Similar repairs were performed on Unit 1 in 1986 and Unit 2 in 1992. Other than these three major repairs, the only maintenance performed on the stator windings of Units 1 through 4 over the past 17 years has been cleaning and replacing wedges that keep the stator windings in place.

3.5 Outage Statistics

In the last five years, there have been no outages which were the direct result of the Stator Windings.

3.6 Industry Experience

This type of asphalt insulated, multi-turn coil stator winding was manufactured by General Electric between the years 1930 and 1968. This was the common design used in most hydroelectric generators built during this period.

Multi-turn coil windings with asphalt insulation have varying service lives, which are highly dependant on operating conditions and regular maintenance. If the stator windings are not overstressed and the manufacturer's recommended maintenance is performed regularly, the service life of the windings can range from 40 to 50 years. However, for the most part, this type of winding operating under normal conditions will need to be rewound within 40 years. GE has indicated that the majority of generators of this type throughout the world have already undergone a stator rewind.

3.7 Maintenance or Support Arrangements

All maintenance performed on the stator windings has been done by Hydro personnel, with support and technical advice being provided by the manufacturer.

3.8 Vendor Recommendations

General Electric Energy (GE) is the original manufacturer of these windings and participated in the inspection and testing of these windings in June 2007. Based on their inspections and the results of the tests performed by Hydro, GE recommends that the stator windings be either replaced or a spare winding be purchased and stored on site. It has been determined that the more prudent option is to replace the windings.

3.9 Availability of Replacement Parts

GE, the original manufacturer of the existing stator windings, halted production of this particular type of winding in 1969, shortly after Bay d'Espoir Units 1 through 4 were installed. GE as well as the other large generator manufacturers can provide replacement windings designed specifically for the Bay d'Espoir units and provide delivery times suitable to meet the schedule for this project.

3.10 Safety Performance

There are no specific safety issues related to this project.

3.11 Environmental Performance

There are no specific environmental issues related to this project.

3.12 Operating Regime

Units 1 through 4 of the Bay d'Espoir Generating Station are designed for continuous operation with varying loads to meet system requirements. With the exception of maintenance outages, these four units have been operating continuously, within their design capabilities, since they were commissioned in 1967-1968.

4 JUSTIFICATION

This project is justified to maintain system reliability by replacing the Unit 2 stator winding before a failure occurs and by maintaining a spare winding on site in case another unit fails. Should a winding fail in service, it would cause significant damage to the stator core and rotor. Thus failure to replace the windings in Unit 2 and not having a spare winding on hand will impair Hydro's ability to provide least-cost, reliable electrical service.

The life expectancy for asphalt insulated stator windings is 40 years. However, this varies based on such operating conditions as temperature, number of starts and stops, maintenance and care and unit loading. Since the windings of Units 1 through 4, and especially Unit 2, have reached the end of their 40 year useful service lives, winding replacements are necessary.

Hydro has commissioned two independent reviews of the condition of the stator windings at Bay d'Espoir. The first consultant, GE Armstrong, estimated in 1998 that the remaining reliable service life of the windings was between seven and 15 years. During the summer of 2007, a second consultant, GE Energy confirmed the 1998 findings and further concluded that a failure of the Unit 2 winding is imminent.

Taking the above recommendations into consideration, the stator windings of Units 1 through 4 will likely begin to fail over the next few years. If failure occurs with the current 40 year old electro-mechanical protection in place, it is very likely that damage to the stator core and rotor will occur. The generator protection is supposed to prevent damage to the stator core and rotor when a failure occurs. The current protection equipment cannot prevent this damage and therefore, must be upgraded. In order to prevent unnecessary damage to this equipment the stator windings of Units 1 through 4 must be replaced and the priority replacement is Unit 2.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no direct effect on the levelized cost of energy.

4.3 Cost Benefit Analysis

A cost benefit analysis is not applicable for this project.

4.4 Legislative or Regulatory Requirements

There are no specific legislative or regulatory requirements which affect this project.

4.5 Historical Information

There is no historical information associated with this proposal.

4.6 Forecast Customer Growth

The forecasted customer load on the system has no affect on this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits anticipated from this project.

4.8 Losses during Construction

As the stators of the units will be rewound during scheduled outages during the summer months, there will be no losses during construction.

4.9 Status Quo

The stator windings of Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station are operating beyond their expected useful service lives. Inspections and testing have confirmed that a winding can fail at any time. Therefore the status quo of operating without a replacement plan is not an option.

4.10 Alternatives

There are no viable alternatives to this project. The stator windings of Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station have exceeded their 40 year useful service lives, and must be replaced.

5 CONCLUSION

Units 1 through 4 of the Bay d'Espoir Hydroelectric Generating Station have been in service since their commissioning in 1967 – 1968. The stator windings of these units are now past the end of their useful service lives of 40 years, and according to June 2007 tests and inspections, failure is imminent for the Unit 2 winding. If the windings for the four Units are left in service and run to failure, it is likely that the machine stator cores will be damaged when the windings fail. For these reasons, the stator windings of Units 1 through 4 should be replaced. This project will see the installation of a new winding in Unit 2 and the purchase of the additional winding if required for either Unit 1, 3 or 4. Proposals for purchase and installation of the other two windings will be made in future years.

5.1 Budget Estimate

The estimate for the project is $4.7 million. The budget estimate is shown in Table 2. The budget estimate for the installation of the Unit 2 winding as approved in the 2009 capital budget Board Order No. P.U. 36; (2008) is $1.5 million.

Table 2
Budget Estimate

Project Cost: *($ 1,000)*	**2010**	**2011**	**Beyond**	**TOTAL**
Material Supply	2,300.0	0.0	0.0	2,300.0
Labour	136.5	0.0	0.0	136.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	1,475.0	0.0	0.0	1,475.0
Other Direct Costs	12.5	0.0	0.0	12.5
O/H, AFUDC & Escln.	406.0	0.0	0.0	406.0
Contingency	357.1	0.0	0.0	357.1
TOTAL	**4,687.1**	**0.0**	**0.0**	**4,687.1**

5.2 Project Schedule

The schedule for this project is shown in Table 3 below.

Table 3
Project Schedule

Activity	Milestone
Delivery of Unit 2 Winding	February 2010
Equipment Ordering – Spare Winding	February 2010
Installation of Unit 2 Winding	August 2010
Factory Testing – Spare Winding	September 2010
Equipment Delivery - Spare Winding	November 2010
Project Completion	December 2010

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER A.C. WARREN SIGNATURE JULY 31, 2009 DATE PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACE PROGRAMMABLE LOGIC CONTROLLERS

At the Holyrood Thermal Generating Station

June 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

Table of Contents (cont'd.)

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates the Holyrood Thermal Generating Station (Holyrood) which has a generating capacity of 490 MW. Holyrood is an essential part of the Island Interconnected System. The station has the capability of generating over 3,000,000 MWh of energy annually which is approximately 40 percent of the Island Interconnected System's energy requirement.

Holyrood is composed of three thermal generating units along with sub-systems that are vital to its daily operation. The generating station consists of a central plant, which is an 11 story structure containing all thermal generating equipment used for the production of electricity and several support buildings in an area stretching over one square kilometer. The generating station was constructed in two stages. The first stage, which was commissioned in 1971, consists of two Combustion Engineering oil fired steam generators and two Canadian General Electric turbine generator sets. The second stage was commissioned in 1979 and consists of a Babcock and Wilcox steam generator and a Hitachi turbine generator set. All three generating units were originally rated at 150 MW, but in 1988 and 1989 the two Combustion Engineering/Canadian General Electric units were upgraded to a capacity of 170 MW each.

The generating units burn approximately 18,000 barrels of No. 6 heavy fuel oil per day at full load. This fuel is burned in a boiler to convert water to steam. The high-pressure steam is then directed into a turbine that is connected to an electric generator that produces electricity.

The operation of a thermal generating station requires complex processes that must be controlled. The water treatment plant, waste-water treatment plant, warm air make-up system, and Units 1 and 2 burner management systems at Holyrood are controlled by Programmable Logic Controllers (PLCs). A PLC is an array of electronic components consisting of a processor and interface cards (input and output) used for process automation. The Input and Output (I/O) cards are wired to the devices which the PLC controls and monitors. Units 1, 2 and 3 boiler controls and Unit 3 burner management and station services are controlled by Invensys

Systems (Foxboro) Distributed Control System (DCS) units. A DCS is similar to a PLC in basic functionality of controlling and monitoring. PLCs, although able to be connected together, are suited to more discrete applications whereas DCS units are more network-oriented. Both DCS and PLC systems use computer interfaces to provide the operator with a real-time graphical interface to monitor and control processes. A software and computer combination, usually purchased from the PLC or DCS supplier, is called a Human Machine Interface (HMI). The software also maintains a history of events and operational data such as pressures, temperatures and levels. Some of the PLCs at Holyrood are operating beyond their service lives and need to be replaced before a component failure exhausts all spare component quantities available from inventory or external sources. Such an event would render at least one process, and possibly the generating capability of the plant, inoperative for a period of time. There is also a problem with inconsistent software packages for the HMIs used throughout the plant.

This project is required to replace five PLCs and associated HMIs installed throughout Holyrood in order to ensure reliability of the facility and its subsystems. The replacement will also bring the control systems to a consistent level of technology and a consistent platform to increase efficiency and ease of use.

This report describes the existing control systems from an overall reliability perspective, providing details as to why these replacements are necessary to maintain reliable service to Hydro's customers. A detailed explanation is presented of the scope of the proposed project along with an explanation of why this project is an immediate priority. In addition, an analysis of the risk of continuing to operate with the existing control systems is addressed with a discussion on the costs associated with upgrading each of the individual systems.

2 PROJECT DESCRIPTION

The PLCs which control the following systems at Holyrood are at, or near, the end of their service lives:

- The Burner Management Systems on Units 1 and 2,
- The Water Treatment Plant,
- The Waste Water Treatment Plant, and
- The Warm Air Make-Up System.

The controls for these systems will be upgraded to a consistent hardware and software platform with operational data points such as levels, pressures, and positions integrated into the existing plant DCS manufactured by Foxboro.

3 EXISTING SYSTEM

The existing PLCs are at or near the end of their service lives. The systems controlled by these PLCs are necessary for the operation of Holyrood.

3.1 Systems Overview

3.1.1 Burner Management Systems Units 1 and 2 PLCs and HMIs

Identical separate Burner Management Systems control the operation of each of the boiler combustion systems on Units 1 and 2. These systems ensure the safe execution and orderly operation of the fuel firing equipment that is used to heat water inside the boiler and thus create the steam required for electrical generation. These systems provide complete start-up and shut-down control of the boiler burner systems and provide the main protection against malfunction of the fuel firing equipment and its associated air systems. Overall, these two systems are vital to the boiler operation and are required to:

- Prevent any fuel firing unless a satisfactory furnace exhausting of all combustible explosive gases has been completed;
- Initiate a furnace trip if certain adverse operating conditions develop;
- Provide flame supervision when fuel firing equipment is in service;
- Provide component status feedback to the operator and an alarm under unsafe conditions;
- Prevent startup of individual fuel firing equipment unless certain permissive interlocks have first been satisfied;
- Monitor and control component sequencing during startup and shutdown of fuel firing equipment; and
- Ensure safe continued operation of fuel firing equipment in accordance with National Fire Protection Association (NFPA) regulations.

Each Burner Management System is comprised of a Modicon PLC and Operator Console (HMI) that permits control room operators to monitor and control the system. The Operator Consoles for these systems consist of two personal computers, one per unit, located in the control room. Only Unit 1 console can communicate with the Unit 1 PLC and only Unit 2 console can communicate with the Unit 2 PLC. There is also a spare console located in the control room that allows the operator to access either the Unit 1 or Unit 2 PLC in the event of a failure of any of the two main Burner Management System control HMIs. The Burner Management System for Unit 3 is already controlled by the DCS.

See Table 1 - Existing PLC and HMI Equipment for PLC technical details.

3.1.2 Water Treatment Plant PLC and HMI

Holyrood, with three fuel fired boilers that create steam, requires a process to provide clean water to the boilers to replace water that is lost during the steam manufacturing process. To meet this requirement, Holyrood has its own water treatment facility. The water required for the station's steam boilers is extracted from a local reservoir, Quarry Brook, and is treated in the Water Treatment Plant before entering the continuous water/steam cycle as replenished water. Each time that water is recycled through the boiler, it must be purified. Any untreated water that passes into the boiler may cause the following problems:

- Formation of scales in the boiler tubes and other heat exchangers, which decreases their overall efficiency and results in malfunctions and/or failures because of overheating;
- Formation of deposits on the blades of the turbines resulting in a rapid decrease in turbine efficiency; and
- Corrosion of metal surfaces including piping, valves and the turbine due to exposure to the process water and steam.

The Water Treatment Plant is controlled by a PLC that is mounted in the facility. The PLC is used to control the various processes required to remove contaminants in the water before it enters the boilers and it provides system alarms.

Two HMIs allow the operator to access the water treatment process. One HMI is located in the PLC cabinet in the Water Treatment Plant and the second is located in the Chemical Lab which is a room inside the Water Treatment Plant.

There is an interface with the central Foxboro DCS which allows alarm conditions and various data points to be exchanged.

See Table 1 - Existing PLC and HMI Equipment for PLC technical details.

3.1.3 Waste Water Treatment Plant PLC and HMI

Holyrood has its own Waste Water Treatment Plant that was built in 1992 to meet provincial wastewater effluent criteria. This plant was converted to a new operating method in 1999 and a PLC control system was installed. The Waste Water Treatment Plant monitors and treats Holyrood's waste water before releasing it back into the local environment.

There are two types of waste water produced at Holyrood. The first type is relatively clean streams such as those from the Water Treatment Plant, filter backwashes, sample lines, boiler blowdown and other similar activities. The second type results from periodic events such as boiler washes, air preheater washes and run-off from the on-site storage landfill. The latter is contaminated with fuel ash including metals such as vanadium and nickel. These periodic streams require treatment to reduce metal concentrations to acceptable levels prior to release into Conception Bay.

The main controls for the Waste Water Treatment Plant consist of a locally mounted control panel that houses a PLC and a HMI. This PLC functions as the primary controller, interfacing directly with the field instruments and control equipment located in the plant. Its main function is to monitor critical values and control the process until the effluent levels are acceptable.

Two HMIs allow the operator to access the waste water treatment process. One HMI is located in the PLC cabinet in the Waste Water Treatment Plant and the second is located in the Water Treatment Plant. There is an interface back to the central Foxboro DCS which allows data to be exchanged.

See Table 1 - Existing PLC and HMI Equipment for PLC technical details.

3.1.4 Warm Air Make-Up System PLC and HMI

Make-up air handling equipment is provided to supply all of the boiler house and turbine hall ventilation air requirements. Six air handling units (two per generating unit) are installed on the north side of the plant to supply combustion air for each of the three generating units. Three additional make-up air handling units are installed on the south side to provide sufficient ventilation for the powerhouse.

The operation of the make-up air handling equipment, the powerhouse exhaust fans and the boiler combustion air duct inlet dampers are automatically controlled by a PLC located on the operating floor in the middle of the plant. This PLC operates the make-up air handling system which provides the ventilation air required, depending on the number of generating units in service. The PLC regulates the amount of inside air used for combustion and the amount of air exhausted from the powerhouse and then balances this air by equalizing the air pressure inside and outside the powerhouse. This system also aids in exhausting the hot air that is usually trapped in the upper elevations.

With the operation of the make-up air units, combustion air for the boilers will be taken from the preheated air inside the powerhouse as much as possible, thereby increasing the overall efficiency of the boilers. The PLC is also equipped with several monitoring devices such as fire detectors and limit switches that perform alarm and shutdown sequences as required. The HMI for the Warm Air Make-Up System is located in the Holyrood Central Control Room.

See Table 1 - Existing PLC and HMI Equipment for PLC technical details.

Table 1: Existing PLC and HMI Equipment

System	Year Installed	PLC Hardware	PLC Software	HMI Hardware	HMI Software
Unit 1 Burner Management System	1995	Modicon 984 CPU 800 Series I/O	Schneider Electric Proworx	PC	Factory Link Version 6.5
Unit 2 Burner Management System	1995	Modicon 984 CPU 800 Series I/O	Schneider Electric Proworx	PC	Factory Link Version 6.5
Burner Management System Spare Console	1995	Not applicable	Not applicable	PC	Factory Link Version 6.5
Water Treatment Plant	1997	Modicon 984 CPU 800 Series I/O	Schneider Electric Proworx	PCs	Schneider Electric Monitor Pro V 6.5.0
Waste Water Treatment Plant	1999	Modicon 984 CPU 800 Series I/O	Schneider Electric Proworx	PCs	Wonderware Intouch Version 7.0
Warm Air Make-up System	1993	Modicon 984 CPU 800 Series I/O	Schneider Electric Proworx	Magellis	Schneider Electric Video Designer Version 4.4.0

3.2 Age of Equipment or System

See Table 1 - Existing PLC and HMI Equipment, which contains the year the equipment was installed.

3.3 Major Work/or Upgrades

3.3.1 Burner Management Systems Units 1 and 2 PLCs and HMIs

In 1995, a major system upgrade was completed, which resulted in significant changes to the Burner Management Systems on both units. Combustion Engineering Cygnus operator consoles were removed and replaced with personal computer based HMI consoles. As part of this upgrade, a Windows based Graphical User Interface (GUI), called Factory Link Version 6.5 was installed on the consoles.

During this upgrade, the original Modicon 884 processors on both systems were also replaced with 984 Series processors. The existing original 800 Series I/O modules remain today despite the fact that they are over 22 years old.

3.3.2 Water Treatment Plant PLC and HMI

Since the installation of the Water Treatment Plant PLC and HMIs in 1997, there have been no major work or upgrades completed on this system.

3.3.3 Waste Water Treatment Plant PLC and HMI

Since the installation of the Waste Water Treatment Plant PLC and HMIs in 1999, there have been no major work or upgrades completed on this system.

3.3.4 Warm Air Make-Up System PLC and HMI

In the fall of 2007, a communications failure between a processor and a HMI resulted in the replacement of these components. The age of the failed components required newer components at the time of replacement. These components will not remain in service.

3.4 Anticipated Useful life

The service life of a PLC is estimated to be 15 years.

3.5 Maintenance History

The maintenance history over the past five years of each of the systems is provided in Tables 2 through 7.

Table 2: Burner Management System (BMS) Unit 1 PLC and HMI

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.1	1.7	1.8
2007	0.0	0.6	0.6
2006	0.0	0.0	0.0
2005	0.0	0.2	0.2
2004	0.0	0.0	0.0

Table 3: Burner Management System (BMS) Unit 2 PLC and HMI

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.2	1.7	1.9
2007	0.0	0.0	0.0
2006	0.0	0.0	0.0
2005	0.0	0.2	0.2
2004	0.0	0.0	0.0

Table 4: Water Treatment Plant (WTP) PLC and HMI

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	0.7	0.7
2007	0.3	0.3	0.6
2006	0.3	0.4	0.7
2005	0.3	0.3	0.6
2004	0.4	2.1	2.5

Table 5: Waste Water Treatment Plant (WWTP) PLC and HMI

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	0.0	0.0
2007	0.0	0.0	0.0
2006	0.0	0.0	0.0
2005	0.0	1.8	1.8
2004	0.0	0.0	0.0

Table 6: Warm Air Make-Up (WAM) System PLC and HMI

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	0.0	0.0
2007	0.0	7.1	7.1
2006	0.0	0.5	0.5
2005	0.0	3.0	3.0
2004	0.0	0.2	0.2

Table 7: Total System Maintenance Costs ($000)

Year	BMS #1	BMS #2	WTP	WWTP	WAM	Total Maintenance
2008	1.8	1.9	0.7	0.0	0.0	4.4
2007	0.6	0.0	0.6	0.0	7.1	8.3
2006	0.0	0.0	0.7	0.0	0.5	1.2
2005	0.2	0.2	0.6	1.8	3.0	5.8
2004	0.0	0.0	2.5	0.0	0.2	2.7

3.6 Outage Statistics

3.6.1 Burner Management Systems Units 1 and 2 PLCs and HMIs

The Burner Management System on Generating Unit 1 has not experienced a major failure that resulted in a generating unit outage. However, there have been minor failures on the system that resulted in the operators having to manipulate the system while the generating unit was in service.

A failure of almost any component on the PLC or the communication system between the HMI and PLC would result in a complete and immediate loss of the applicable generating unit. In light of PLC obsolescence, this type of failure could put the generating station’s production at a severe risk until compatible replacements are located and installed. Failure of this PLC during the winter season may result in Hydro's inability to meet power and energy requirements.

3.6.2 Water Treatment Plant PLC and HMI

In 2002 and 2003, the Water Treatment Plant PLC experienced two separate failures of I/O modules. This resulted in the shutdown of several processes within the Water Treatment Plant, with these systems having to be operated manually until the problem was solved.

There have been two occasions when one of the Water Treatment Plant HMIs failed during operation. Each resulted in a loss of the HMI that failed and forced operators to use the backup HMI to control the system and to run various reports.

A PLC failure would result in the Water Treatment Plant having to be operated manually if the generating units were to remain in service. An operator would have to be very familiar with the manual controls of the system and be stationed at this system for the entire time that the system is in manual operation. Several chemical tests would have to be completed at appropriate times to ensure that acceptable chemical levels are maintained. During this time, alarm functionality would be lost and there would be a risk that untreated water would reach the boilers causing the problems described in Section 3.1.2 of this document.

3.6.3 Waste Water Treatment Plant PLC and HMI

There have been no major failures on the Waste Water Treatment Plant PLC that resulted in the facility being non-operational. There have been several HMI computer failures such as a failed computer in 2003, a failed monitor in 2001 and 2005 and a computer power supply failure. Currently the local HMI system is operating with a modified power supply (assembled from old scrap computers) as a result of spare parts not being available. Maintenance crews were required to locate and purchase used and obsolete computer parts and modify them to work in this system. There is no assurance that in the event of another failure, scrap parts would be available.

A PLC failure on this system would have detrimental effects on the operation of the Waste Water Treatment Plant. The Waste Water Treatment process would have to shut down, as there are no capabilities to run this system with manual controls. Depending on the level of storage in the periodic basin, the plant would be capable of operating for six to 20 days before the existing storage capacity would be full. As a result of regulations concerning the requirement to treat the waste water before discharging it, after this occurred, waste water could not be treated, requiring the shut down of the generating facility. In addition, the land fill run-off has to be treated, therefore, depending on the rainfall experienced during the failure, this time frame may be shortened. Complete failure of this PLC would therefore result in a shutdown, albeit delayed, of the Holyrood Thermal Generating Station.

3.6.4 Warm Air Make-Up System PLC and HMI

Since this system was installed, there have been many failures that resulted in the system being shut down or run manually. In 2004-2006, three I/O modules failed and in 2007 a main CPU and a HMI failed. As a result of the lack of spare parts, during the 2007 CPU failure, Hydro searched for and purchased a CPU from the eBay website. These failures resulted in automatic control of the system being lost and required the operators to manually operate the various fans and louvers in order to maintain unit efficiencies and appropriate ventilation levels in the plant.

A failure of this system could lead to losses in boiler efficiency and poor ventilation within the plant. There is a significant safety aspect to this system and an unmanaged failure could result in several safety concerns (see Section 3.11.4 for details). When this system was not in service, problems were experienced with equipment freezing or operating slowly on the lower elevations of the plant.

3.7 Industry Experience

DCS and PLC use are common in utility and manufacturing plants. They can each be used in isolated applications or wide-spread and networked throughout an entire plant. The following provides examples of installations for both DCS and PLC platforms.

In Atlantic Canada, Foxboro is a widely used control system supplier. Foxboro has DCS installations in several Atlantic Canadian industries including Abitibi Consolidated in Grand Falls, Corner Brook Pulp and Paper, International Matex Tank Terminals in Arnold's Cove, Iron Ore Company of Canada in Labrador City, NewPage Paper in Nova Scotia, AV Nackawic in New Brunswick and Lake Utopia Paper in New Brunswick. Foxboro DCS is used to control electrical generation installations at Bruce Power, a nuclear facility in Ontario, Burrard Thermal Generating Station in Port Moody, BC, and Nanticoke Generating Station, a coal-burning generating station on Lake Erie in Ontario. Foxboro offers local support services and has a local field technician to support various installations for maintenance procedures and sudden failures. Holyrood Plant technical personnel are familiar with the Foxboro I/A Series DCS and HMIs since this system has been in service since 2004.

Schneider Automation Quantum PLCs are used in Hydro terminal stations located at Hardwoods, Oxen Pond and Wabush as well as other utilities and companies across the country. Other installations of Schneider Quantum PLCs in Atlantic Canada include Lafarge Cement Plant in Brookfield, Nova Scotia, Corner Brook Pulp and Paper and Scenda Marine in Halifax, Nova Scotia. As well, Schneider Automation has major installations in the United States, Brazil, Australia and China.

3.8 Maintenance or Support Arrangements

Maintenance on all existing PLC systems described in this document consists mainly of an annual inspection and software backup. Corrective maintenance procedures are performed by

Hydro personnel and when significant problems are encountered, maintenance crews often use telephone technical service for a solution. Due to the differences in the existing PLCs' software and hardware, the infrequent need to perform a system restore, and changing personnel as staff retire and are replaced, Hydro personnel must review the procedures when required which can result in a longer than expected outage.

Hydro has a system support agreement in place with Foxboro (Invensys Systems Canada) that was renegotiated in 2008. Because of the importance of the system that it serves, this service agreement has been renewed for the next five years. This agreement is a contract between Invensys Systems (Foxboro) and Hydro to have Foxboro provide continued operational support on the existing DCS system. It provides Hydro personnel with unlimited access to their system support program including local Foxboro technical support, remote system support, ten hours of on site support a year, as well as several reduced cost training benefits. Over the years, this service agreement has proven to be beneficial and has resulted in faster troubleshooting and recording of plant equipment problems.

3.9 Vendor Recommendations

Invensys (Foxboro) are able to expand the existing DCS with the purchase and installation of controllers, I/O modules and communicating links to include the controls for the systems to be replaced. A budget estimate was prepared by Invensys (Foxboro) on April 23, 2007 and updated on September 22, 2008 to upgrade all PLCs and HMIs to the Foxboro DCS platform.

A report, including a budget estimate, was prepared in 2006 by a local controls contractor (Avalon Controls & Instrumentation) to replace the existing PLCs and HMIs with new PLCs and HMIs from Schneider Automation. This report reviewed all systems in question and presented a migration strategy for the upgrades. The PLC model and software and HMI model has been changed in this report to reflect the most recent product line available from the manufacturer. The report addressed revisions at the system level but did not address modifications to the

Operator's central control room. This issue will be discussed later in this report.

These estimates were used to prepare the budgetary proposals for PLC and DCS options. Neither proposal included the removal of existing components or the installation of new equipment. It is intended to acquire the services of an independent contractor for the PLC removal and installation work.

3.10 Availability of Replacement Parts

All the Modicon 984 PLC control systems that are currently installed in Holyrood are past their recommended service lives. As of June 30, 2006, the entire Modicon 984 Series and 800 Series I/O modules reached the end of commercialization and will only be supported for repair after this date. The manufacturer will provide service for eight years after June 30, 2006 unless otherwise stated in the Product Life Cycle document. This service duration can be reduced if components needed to make repairs are not available.

Tables 8 through 14 list the spare parts in Hydro's inventory that are used for each PLC system described in this report. These parts are identified separately for each system and then the Modicon systems are grouped together to present a complete listing of all the Modicon inventory currently kept within the plant. The number of spare parts currently available in inventory was then compared to the required installed parts to indicate which parts currently do not have any safety spares in stock.

Table 8: Burner Management System Units #1 PLC

Description	Manufacturer Part Number	Quantity Installed
4-20mA/1-5V Analog Input Module 8ch.	B875-001	2
115VAC Discrete Input Module 16pt.	B805-116	16
115VAC Discrete Output Module 16pt.	B804-116	8
115VAC Discrete Output Module 2A 8pt.	B802-008	3
24VDC Discrete Output Module 32pt.	B826-032	1
Processor CPU	984-685E	1
984 Series Backplane	AS-H827-209	1
Gould Series Backplane	AS-H827-100	2

Table 9: Burner Management System Units #2 PLC

Description	Manufacturer Part Number	Quantity Installed
4-20mA/1-5V Analog Input Module 8ch.	B875-111	2
115VAC Discrete Input Module 16pt.	B805-116	16
115VAC Discrete Output Module 16pt.	B804-116	8
115VAC Discrete Output Module 2A 8pt.	B802-008	3
24VDC Discrete Output Module 32pt.	B826-032	1
Processor CPU	984-685E	1
984 Series Backplane	AS-H827-209	1
Gould Series Backplane	AS-H827-100	2

Table 10: Water Treatment Plant PLC

Description	Manufacturer Part Number	Quantity Installed
4-20mA Analog Output Module 4 ch.	B872-100	3
4-20mA/1-5V Analog Input Module 8ch.	B875-111/B877-111	5
115VAC Discrete Output Module 16pt.	B804-116	9
115VAC Discrete Input Module 16pt.	B805-116	3
Selectable NO/NC Relay Output Module 8 pt.	B814-108	5
115VAC Isolated Input Module 16 pt.	B817-116	3
Remote I/O Processor	J890-101	5
Remote I/O Module	AS-S908-110	4
Power Supply	P840	5
Processor CPU	984-685E	1
Backplane 11 Slot	AS-H827-103	5
Backplane 4 Slot	AS-H810-209	1

Table 11: Waste Water Treatment Plant PLC

Description	Manufacturer Part Number	Quantity Installed
4-20mA Analog Output Module 4 ch.	B872-100	3
4-20mA/1-5V Analog Input Module 8ch.	B875-111/B877-111	1
115VAC Discrete Output Module 16pt.	B804-116	2
Selectable NO/NC Relay Output Module 8 pt.	B814-108	2
115VAC Discrete Input Module 32pt.	B807-132	2
115VAC Isolated Input Module 16 pt.	B817-116	1
Power Supply	P810	1
Processor CPU	984-385E	1
984 Series Backplane 6 Slot	6 SLOT BACK	2

Table 12: Warm Air Make-Up System PLC

Description	Manufacturer Part Number	Quantity Installed
Telemecanique Touch Screen	XBTZGMBP	1
120VAC Discrete Input Module 32 pt.	B807-132	5
115VAC Isolated Discrete Output Module 8 pt.	B810-008	4
120VAC Discrete Output Module 32 pt.	B806-032	2
4-20mA Analog Output Module 4 ch.	B872-100	3
4-20mA/1-5V Analog Input Module 8ch.	B875-111/B877-111	3
Thermocouple Input Module (10 inputs)	B883-200	1
Remote I/O Module	J890-101	1
Power Supply	P840	1
Processor CPU	984-485E	1
984 Series Backplane	AS-9536-000	1
800 Series Backplane	AS-H827-103	1
800 Series Backplane	AS-H819-100	1

Table 13: Total Modicon Modules Currently Installed and Spares

Description	Manufacturer Part Number	Quantity Installed	Spares in Warehouse
984 Series Backplane 6 Slot	6 SLOT BACK	2	
Processor CPU 385E	984-385E	1	
Processor CPU 485E	984-485E	1	
Processor CPU 685E	984-685E	3	1
984 Series Backplane	AS-9536-000	1	
Backplane 4 Slot	AS-H810-209	1	
800 Series Backplane	AS-H819-100	1	
Gould Series Backplane	AS-H827-100	4	
800 Series Backplane 11 slot	AS-H827-103	6	1

Description	Manufacturer Part Number	Quantity Installed	Spares in Warehouse
984 Series Backplane	AS-H827-209	2	
Remote I/O Module	AS-S908-110	4	
115VAC Discrete Output Module 2A 8pt.	B802-008	6	
115VAC Discrete Output Module 16pt.	B804-116	27	1
115VAC Discrete Input Module 16pt.	B805-116	35	
120VAC Discrete Output Module 32 pt.	B806-032	2	
120VAC Discrete Input Module 32 pt.	B807-132	7	
115VAC Isolated Discrete Output 8 pt.	B810-008	4	
Selectable NO/NC Relay Output 8 pt.	B814-108	7	1
115VAC Isolated Input Module 16 pt.	B817-116	4	1
24VDC Discrete Output Module 32pt.	B826-032	2	
4-20mA Analog Output Module 4 ch.	B872-100	9	1
4-20mA/1-5V Analog Input Module 8ch.	B875-001	2	1
4-20mA/1-5V Analog Input Module 8ch.	B875-111	11	1
Thermocouple Input Module (10 inputs)	B883-200	1	
Remote I/O Processor	J890-101	6	
Power Supply	P810	1	
Power Supply	P840	6	1
Telemecanique Touch Screen	XBTZGMBP	1	

Table 14: Total PLC Modules Installed without any Spares

Description	Manufacturer Part Number	Quantity Installed
MODICON PLC		
984 Series Backplane 6 Slot		2
Processor CPU 385E	984-385E	1
Processor CPU 485E	984-485E	1
984 Series Backplane	AS-9536-000	1
Backplane 4 Slot	AS-H810-209	1
800 Series Backplane	AS-H819-100	1
Gould Series Backplane	AS-H827-100	4
984 Series Backplane	AS-H827-209	2
Remote I/O Module	AS-S908-110	4
115VAC Discrete Output Module 2A 8pt.	B802-008	6
115VAC Discrete Input Module 16pt.	B805-116	35
120VAC Discrete Output Module 32 pt.	B806-032	2
120VAC Discrete Input Module 32 pt.	B807-132	7
115VAC Isolated Discrete Output 8 pt.	B810-008	4
24VDC Discrete Output Module 32pt.	B826-032	2
Thermocouple Input Module (10 inputs)	B883-200	1
Remote I/O Processor	J890-101	6
Power Supply	P810	1
Telemecanique Touch Screen	XBTZGMBP	1

As indicated in the tables above, there are PLC components that are currently installed within the plant for which Hydro has no spares in stock. Components such as processors, I/O modules and power supplies have failed in the past and are critical items in case of failure. If a failure were to occur on any of these parts, Hydro would have to send the parts out for repair, provided components are available, or try to source the part from other third party distributors. Neither repair nor third party sourcing can offer a reliable source for PLC parts critical to the reliability of the Holyrood Thermal Generating Station.

3.11 Safety Performance

The various control systems discussed in this report are critical systems that together maintain and assure a safe plant environment and safe operational processes.

3.11.1 Burner Management System Units 1 and 2 PLCs and HMIs

Since the main purpose of each of the burner management systems is to monitor and assure the safe operation of the combustion boilers, these systems are required in order to maintain safe boiler operation. Without them, the boilers would shut down as no provisions are available to run the system manually.

3.11.2 Water Treatment Plant PLC and HMI

The water treatment plant raises several safety concerns if a PLC failure was to occur. If a failure occurs, operators are required to manage flow rates manually by throttling several isolation valves located throughout the plant and this could expose them to certain hazardous chemicals, such as sodium hydroxide and sulfuric acid, if a line rupture was to occur while completing the task. A dependable system would significantly reduce this risk.

3.11.3 Waste Water Treatment Plant PLC and HMI

There are currently no significant safety concerns with the Waste Water Treatment Plant PLC.

3.11.4 Warm Air Make-Up System PLC and HMI

The Warm Air Make-Up System was installed to meet Occupational Health and Safety regulations that state that "employers whose process gives off fumes of a kind and quantity liable to be injurious or offensive to workers, shall provide, maintain and ensure the proper use of a ventilation system sufficient to protect the workers against inhalation of impurities and to prevent it accumulating in a workplace" (Occupational Health and Safety Regulations – sub-section 11.(2)).

During the combustion process, leaks are experienced within the boiler housings which can expend gaseous fumes into the plant. These fumes, which are usually lighter than the normal air, rise to the upper elevations and if not exhausted can pose a significant air quality safety hazard to anyone working in these areas. The Warm Air Make-Up System is used to exhaust this air and supply sufficient quantities of fresh air to all areas within the generating plant.

The system also helps to exhaust the hot air that collects in the upper elevations and makes the environment more comfortable for those working in the area. When this system is not functioning, work can only proceed at the higher elevations while following specific heat stress guidelines. This often leads to significant delays in completing the work.

The system balances the air pressure inside the plant. When the system is not working correctly, personnel entering and exiting the plant experience a high interior vacuum pressure which often makes doors difficult to open, and once opened, the doors can close forcibly. This situation results in personnel safety concerns involving being struck with, or jamming fingers in, slamming doors.

The Warm Air Make-Up System also provides heated air to the plant which assists in the prevention of freezing of the fire system piping and compressors during the cold winter months.

3.12 Environmental Performance

There is only one environmental concern with the existing systems discussed in this report. If a PLC failure was to occur on the Waste Water Treatment Plant and it was unable to process waste water, the generating units could be shut down to prevent an environmental spill from an overfilled basin.

3.13 Operating Regime

Holyrood is in operation 24 hours a day, year round although Holyrood generation is required only seasonally. Hydro has identified that the Holyrood Plant has the following maximum acceptable down times:

Either Holyrood Unit 1, 2 or 3:	336 days maximum
Holyrood Stage 1 (both Unit 1 and 2):	Less than 1 day
Entire Holyrood Generating Plant:	Less than 1 day

These requirements were based on average winter peak loads and assume that all other hydro units are available for full rated generation.

3.13.1 Burner Management Systems Units 1 and 2 PLCs and HMIs

The Burner Management Systems on both Units 1 and 2 are in operation whenever their corresponding boilers are producing steam. They are taken down for maintenance during the summer outage schedule when work is being completed on the generating unit. These systems are essential to the operation of the two largest generators of electricity on the island and to maintaining Hydro's supply of reliable energy to the grid. Should these control systems fail, operators would be unable to start igniters or burners and, therefore, would be unable to produce steam for the turbines.

3.13.2 Water Treatment Plant PLC and HMI

The Water Treatment Plant is in operation whenever any of the boilers at Holyrood are producing steam. This system is common to all three units and it can provide about 200 gallons per minute of clean make up water to each of the boilers. This system is in service 24 hours a day, year round but is usually shut down once a year during the total plant outage.

3.13.3 Waste Water Treatment Plant PLC and HMI

The Waste Water Treatment Plant operates whenever there is a significant amount of waste water to be processed at the facility. This is usually determined by the amount of run off from the landfill or the amount of water being used while cleaning fireside equipment in each of the three boilers.

3.13.4 Warm Air Make-Up System PLC and HMI

The Warm Air Make-Up System is in operation 24 hours a day, year round. Due to the nature of this system and Occupational Health and Safety ventilation requirements, this system is required to be operational at all times. This system can be operated with reasonable reliability in manual mode.

4 JUSTIFICATION

This project is justified on the requirement to provide reliable power to the Island Interconnected System. As further discussed below, the significant factors that justify the replacement of PLCs and identify the most feasible option are:

1. **Replacement of obsolete equipment and software:** The existing PLC control systems for several critical processes in Holyrood are, in some cases, over 20 years old and at the end of their service lives. Even though the control systems are still in operation, process reliability rests on the availability of replacement devices in the event of equipment failure. The HMIs used by Operators to control these processes are also outdated and no longer supported by new software or hardware. Failures have occurred as per Section 3.6, Outage Statistics, which have caused downtime of equipment because parts were no longer available and, fortuitously, Hydro staff was able to piece together systems to get the equipment running. The age of each of these systems, and the different manufacturers involved, have caused significant problems when trying to maintain the interfaces between each of the PLC systems back to the Foxboro DCS. Software drivers are no longer being produced for the old systems and the existing software is not supported by new operating systems such as Windows XP or Vista. For instance, there have been incidents where a Hydro employee happened to have parts from an old personal computer which was compatible and used it to maintain operation of the existing PLC interface computers. This is an inherently unreliable means of addressing system problems and runs a serious risk of equipment incompatibility failures.

2. **Availability of replacement parts:** Section 3.10 details the lack of spare parts in Hydro's warehouse as well as what has been declared obsolete and no longer available from the manufacturer. This could result in loss of power to customers for extended periods until the parts for repair could be obtained through unreliable sources like eBay or otherwise.

3. **Redundancy:** None of the existing PLC installations have redundant processing capability. In the event of a processor failure, the process would halt. The Foxboro DCS has the benefit of inherent redundant controllers – a "fault tolerant" system. This means the loss of a single controller will not bring a process to a halt. This tolerance of components to faults makes a process more reliable. In a PLC-based system, processing redundancy is available but requires more components than a DCS thereby taking up more physical space in a panel or enclosure and requiring more development effort. Applying processing redundancy to a DCS system is a more straight-forward process than for a PLC system.

4. **Support Agreement:** The plant has an annual service agreement for the existing DCS and it could be expanded to include the new systems, or a comparable maintenance agreement for a PLC platform could be acquired. The existing PLC systems do not have such an agreement in place to provide support for each system. Due to the age of some systems, a maintenance contract to cover all existing PLC systems is not anticipated to be possible.

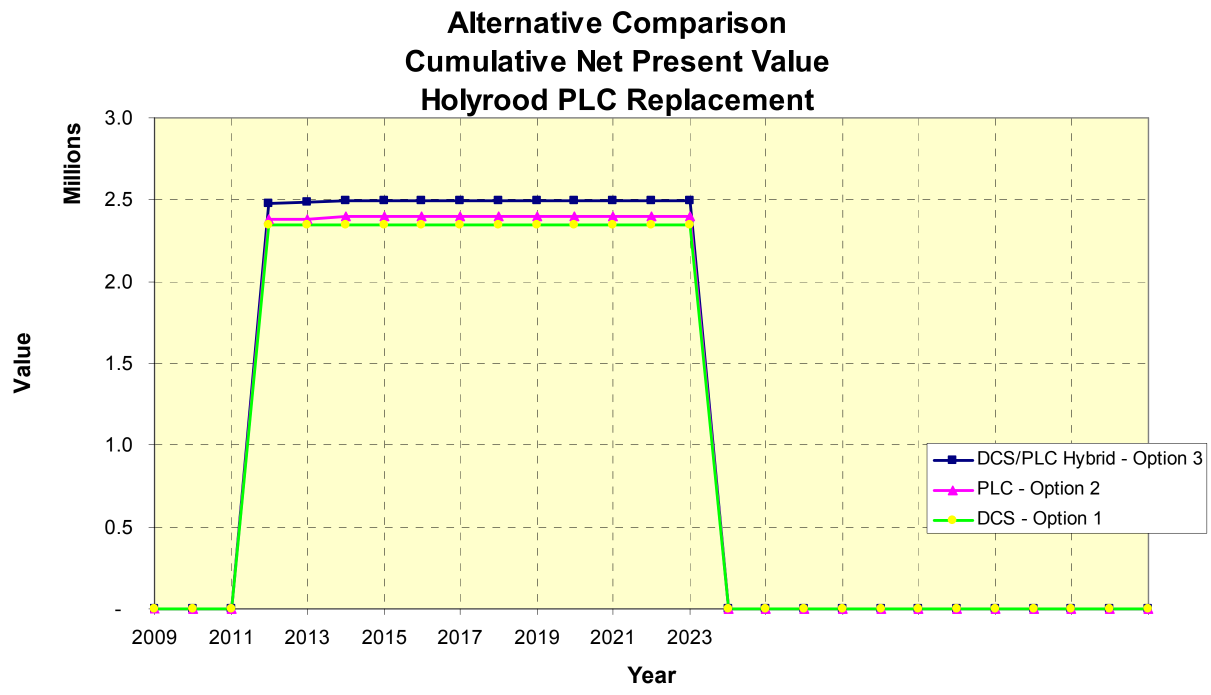
4.1 Net Present Value

A net present value analysis was performed to compare the replacement of existing PLCs and HMIs with a Foxboro DCS platform (option 1), a PLC-based platform (option 2) and a mixture of DCS and PLC platforms (option 3). The result of the calculation is that the DCS (option 1) is the least cost option. Any subsequent budgetary adjustments for future submissions would be applied equally across each option. The result would remain as DCS (option 1) as the preferred option. The following table and graph represent the results.

Table 15: Cumulative Net Present Value

Holyrood PLC Replacement		
Alternative Comparison Cumulative Net Present Value to the Year 2023 from 2009 base		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
DCS – Option 1	2,343,948	0
PLC – Option 2	2,400,458	56,509
Hybrid – Option 3	2,498,337	154,389

Figure 1: Alternative Comparison NPV Analysis



4.2 Levelized Cost of Energy

The levelized cost of energy is a high level means to compare costs of developing two or more alternative generating sources. Therefore, the levelized cost of energy is not applicable in this case.

4.3 Cost Benefit Analysis

Please see Section 4.1, Net Present Value.

4.4 Legislative or Regulatory Requirements

The burner management systems will be updated to meet the new applicable National Fire Protection Association 85 standards as part of replacing the PLCs.

4.5 Historical Information

The PLC system, constituting the sequencing functions, on the gas turbine is undergoing replacement with a Foxboro DCS in 2009. During this time, modifications were also made to the Foxboro network, computers and software located in the main plant control room to facilitate the anticipated growth in the network based on the proposed upgrades. The budget approved for this work was $1,092,900. Final project costs will be available by December, 2009.

4.6 Forecast Customer Growth

Forecasted load growth is not anticipated to impact outage requirements for Holyrood at this time.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits associated with upgrading the existing control systems.

4.8 Losses during Construction

Energy losses are not anticipated while upgrading the existing control systems. The two Burner Management Systems PLCs will be replaced during their respective unit outages and the Waste Water Treatment Plant PLC will be replaced during the total plant outage. All applicable preparations will be completed beforehand to avoid operational delays. The Warm Air Make-Up PLC and the Waste Water Treatment Plant PLC will be replaced when a suitable maintenance opportunity exists.

4.9 Status Quo

Continuing to operate with the existing control systems is not acceptable. Because of the age of the existing PLCs, lack of manufacturer's support and the importance of the systems that they control, Holyrood is currently at risk while continuing to operate using these systems should an unrecoverable component failure occur. There may be long delays in restoring the system following a fault. Depending on the time of year, this could mean a lack of system generation which could cause significant and prolonged customer outages on the Island Interconnected System.

4.10 Alternatives

The alternatives for replacing the PLCs and HMIs are identified in Section 4.1, Net Present Value of this report. Considering the existing PLCs, the most functional choice for Options 2 and 3 would be one from the same manufacturer; in this case, Schneider Automation. The logic in the existing processors can be migrated to the newest line of processors using a service provided by the 'conversion services group' of Schneider Automation. This is a purchased service that provides for translation of older programming to a present-day software platform. The logic would have to be manually rewritten if the conversion service was not acquired and this would be a time consuming and expensive task with greater potential for human error during the transition. The path for migration of logic from the older PLCs to the new PLCs would be the choice of the contractor based on cost. There is, therefore, a potential for additional financial impact to Options 2 and 3, but the detailed cost for this service was not available at the time of this report.

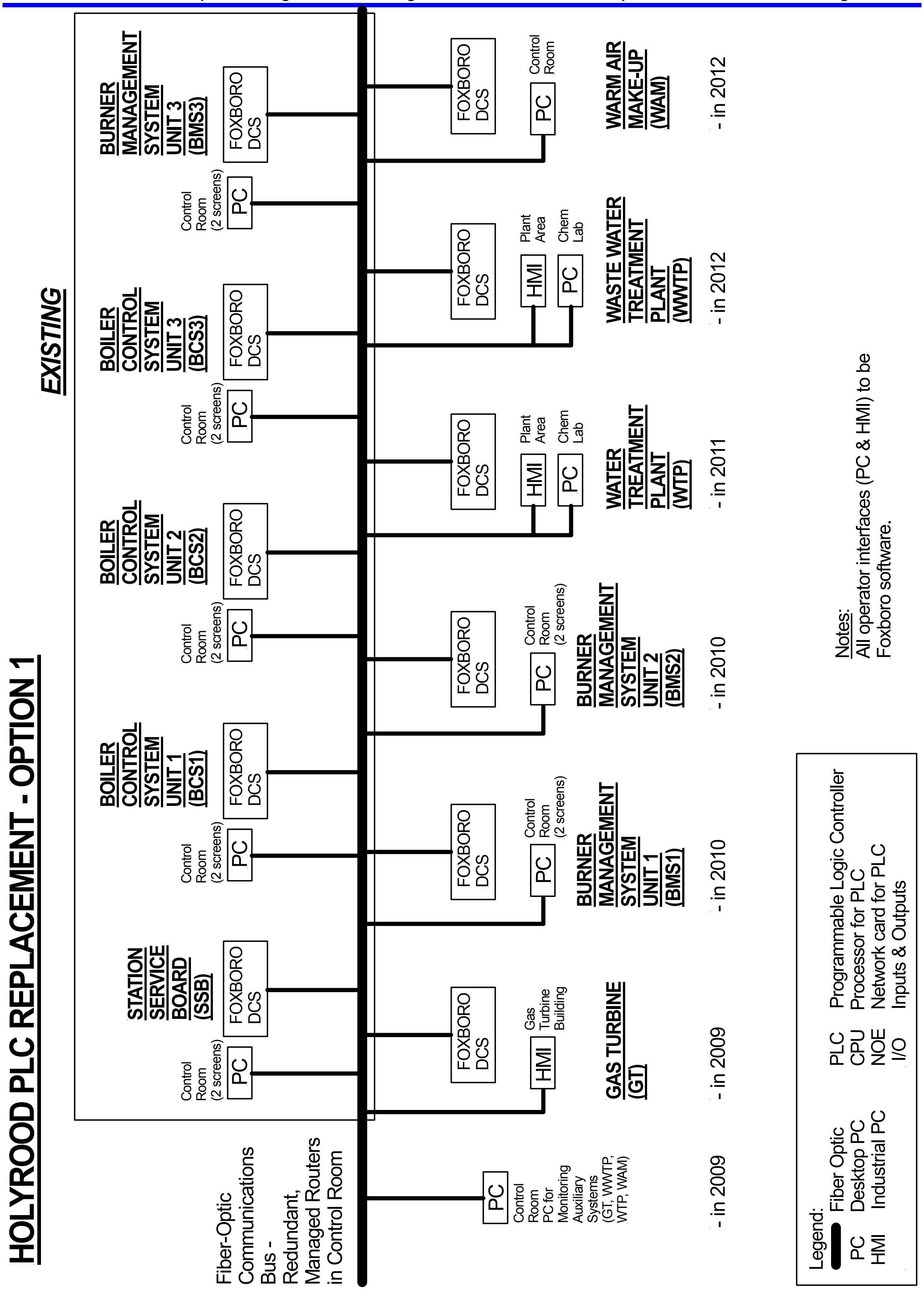
The HMI software chosen for the PLC option was Vijeo CiTect, the most recent graphical software product from Schneider Automation. Considering the interoperability between the PLC and HMI, it would be more advantageous for a maintenance contract to have both products from the same manufacturer.

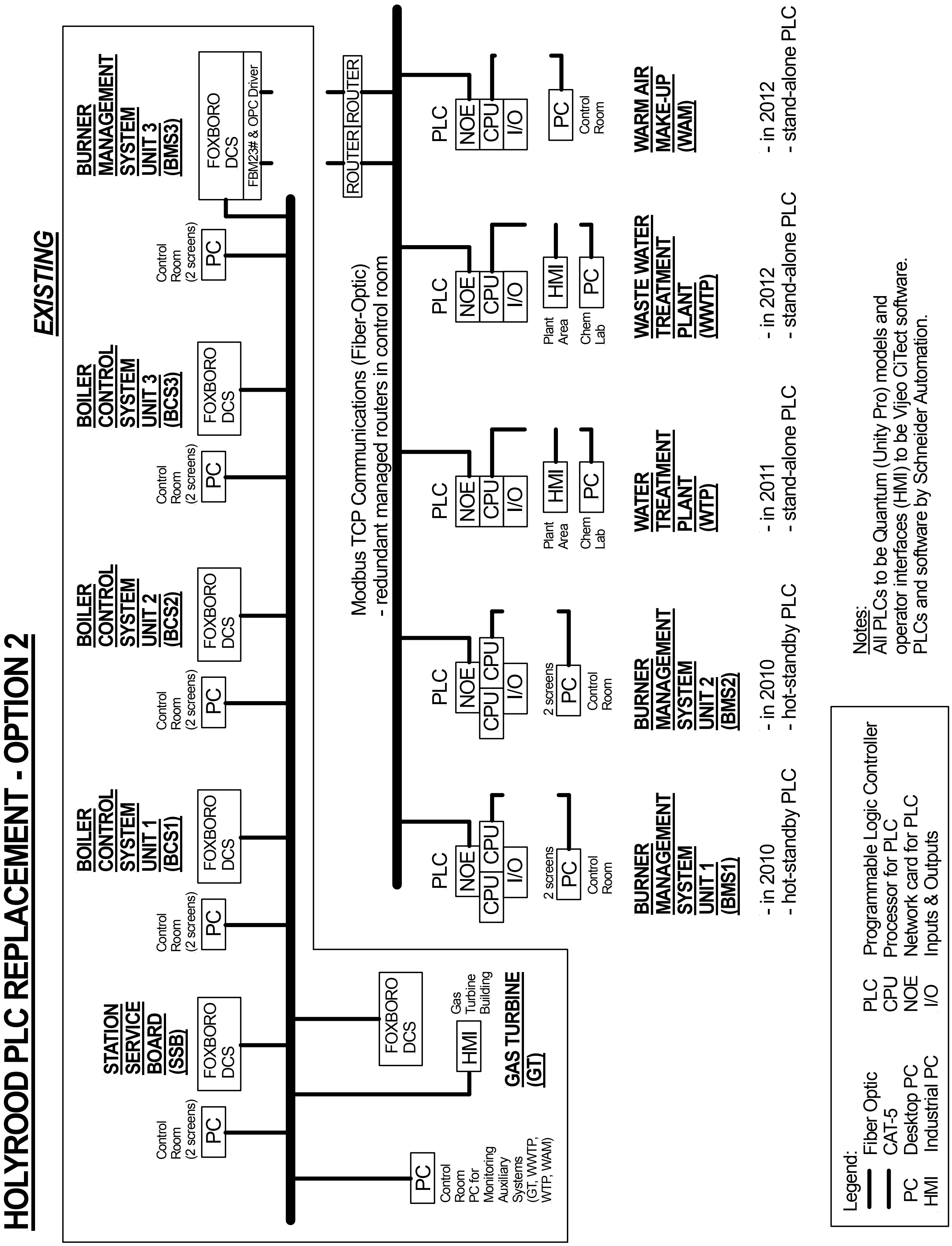
There is a service agreement with Foxboro that has been in place for several years to provide maintenance and troubleshooting support on the existing DCS infrastructure. For the PLC option, a service/maintenance agreement is also required to provide comparable support for the PLCs and HMIs. A request was made to the manufacturer’s regional office for a service agreement comparable to the existing DCS support agreement from Foxboro. The response from the PLC manufacturer on a service agreement stated that there is no provision for in-province, on-site technical support which differs from Foxboro, who have technical support on the island which can be acquired for on-site assistance as part of their existing Service Agreement with the Holyrood plant. The cost for a comprehensive PLC service agreement, to best match the remaining details of the existing agreement provided by Foxboro for the DCS, was not available at the time of this report.

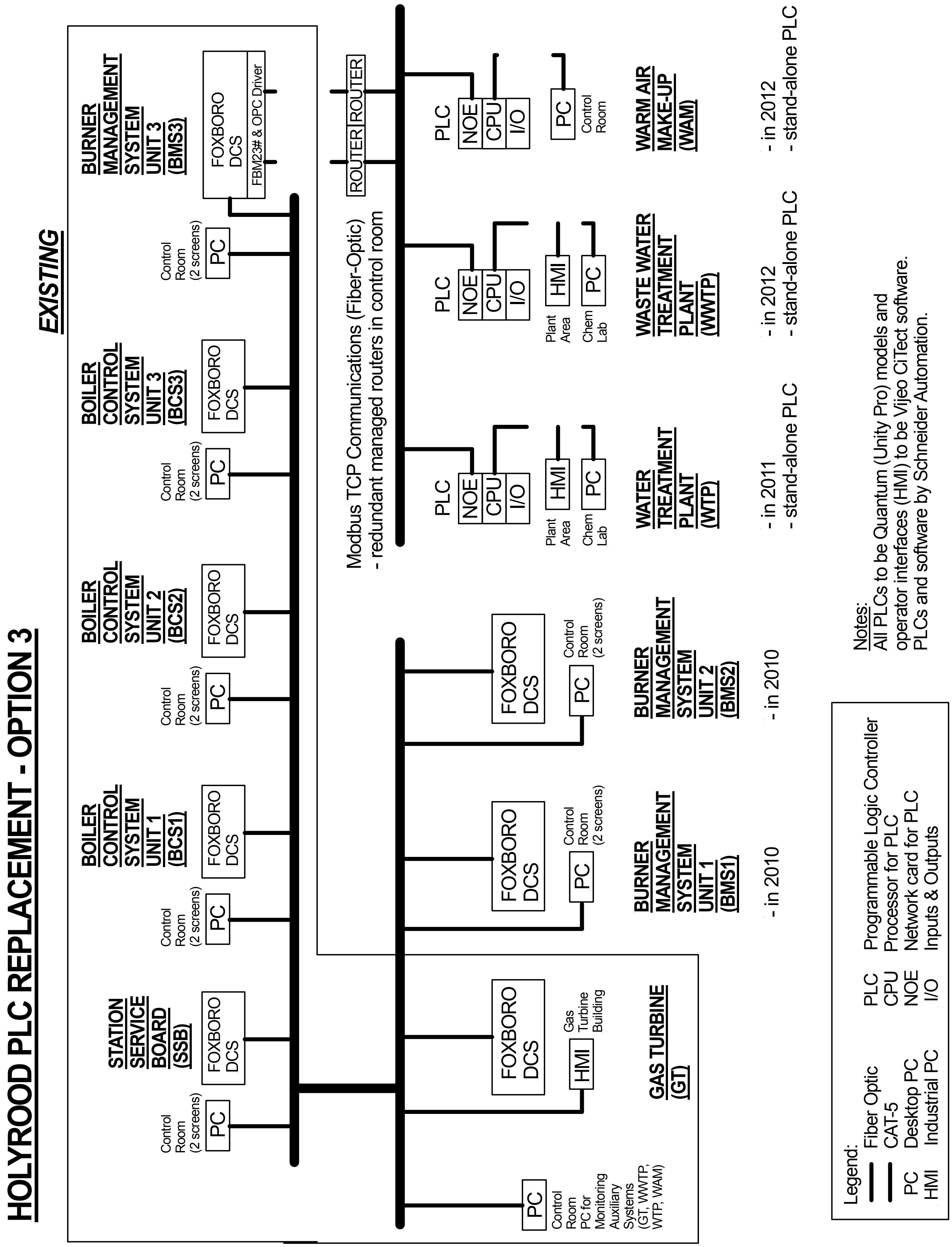
It is anticipated that a financial impact from one or more service agreements will occur regardless of the option that is selected although the budgetary details of these agreements have not been received from the respective manufacturers’ representatives. It is anticipated that an increase to the existing DCS service agreement based on the proposed DCS option would not exceed the full cost of a comparable service agreement for the proposed PLC option. Therefore, the financial elements of service agreements have not been included in this report.

4.11 Topologies

The options to replacing the PLC control systems are presented on the following pages in a graphical format for the purpose of providing a visual overview of the systems to be upgraded in relation to the existing systems.


HOLYROOD PLC REPLACEMENT - OPTION 1
EXISTING
Fiber-Optic Communications Bus - Redundant, Managed Routers in Control Room
STATION SERVICE BOARD (SSB)
BOILER CONTROL SYSTEM UNIT 1 (BCS1)
BOILER CONTROL SYSTEM UNIT 2 (BCS2)
BOILER CONTROL SYSTEM UNIT 3 (BCS3)
BURNER MANAGEMENT SYSTEM UNIT 3 (BMS3)
Control Room (2 screens)
PC
FOXBORO DCS
PC
Control Room PC for Monitoring Auxiliary Systems (GT, WWTP, WTP, WAM)
HMI
Gas Turbine Building
Plant Area
Chem Lab
Control Room
GAS TURBINE (GT)
BURNER MANAGEMENT SYSTEM UNIT 1 (BMS1)
BURNER MANAGEMENT SYSTEM UNIT 2 (BMS2)
WATER TREATMENT PLANT (WTP)
WASTE WATER TREATMENT PLANT (WWTP)
WARM AIR MAKE-UP (WAM)
- in 2009
- in 2009
- in 2010
- in 2010
- in 2011
- in 2012
- in 2012
Notes:
All operator interfaces (PC & HMI) to be Foxboro software.
Legend:
Fiber Optic
PC Desktop PC
HMI Industrial PC
PLC Programmable Logic Controller
CPU Processor for PLC
NOE Network card for PLC
I/O Inputs & Outputs


HOLYROOD PLC REPLACEMENT - OPTION 2
EXISTING
STATION SERVICE BOARD (SSB)
BOILER CONTROL SYSTEM UNIT 1 (BCS1)
BOILER CONTROL SYSTEM UNIT 2 (BCS2)
BOILER CONTROL SYSTEM UNIT 3 (BCS3)
BURNER MANAGEMENT SYSTEM UNIT 3 (BMS3)
Control Room (2 screens)
PC
FOXBORO DCS
FBM23# & OPC Driver
Control Room PC for Monitoring Auxiliary Systems (GT, WWTP, WTP, WAM)
HMI
Gas Turbine Building
GAS TURBINE (GT)
ROUTER
Modbus TCP Communications (Fiber-Optic)
- redundant managed routers in control room
PLC
NOE
CPU
I/O
2 screens
Control Room
Plant Area
Chem Lab
BURNER MANAGEMENT SYSTEM UNIT 1 (BMS1)
- in 2010
- hot-standby PLC
BURNER MANAGEMENT SYSTEM UNIT 2 (BMS2)
- in 2010
- hot-standby PLC
WATER TREATMENT PLANT (WTP)
- in 2011
- stand-alone PLC
WASTE WATER TREATMENT PLANT (WWTP)
- in 2012
- stand-alone PLC
WARM AIR MAKE-UP (WAM)
- in 2012
- stand-alone PLC
Notes:
All PLCs to be Quantum (Unity Pro) models and operator interfaces (HMI) to be Vijeo CiTect software.
PLCs and software by Schneider Automation.
Legend:
Fiber Optic
CAT-5
PC Desktop PC
HMI Industrial PC
PLC Programmable Logic Controller
CPU Processor for PLC
NOE Network card for PLC
I/O Inputs & Outputs


HOLYROOD PLC REPLACEMENT - OPTION 3
EXISTING
STATION SERVICE BOARD (SSB)
BOILER CONTROL SYSTEM UNIT 1 (BCS1)
BOILER CONTROL SYSTEM UNIT 2 (BCS2)
BOILER CONTROL SYSTEM UNIT 3 (BCS3)
BURNER MANAGEMENT SYSTEM UNIT 3 (BMS3)
FOXBORO DCS
FBM23# & OPC Driver
PC
Control Room (2 screens)
ROUTER
ROUTER
Modbus TCP Communications (Fiber-Optic)
- redundant managed routers in control room
PLC
NOE
CPU
I/O
HMI
Plant Area
Chem Lab
Control Room
Gas Turbine Building
GAS TURBINE (GT)
Control Room PC for Monitoring Auxiliary Systems (GT, WWTP, WTP, WAM)
BURNER MANAGEMENT SYSTEM UNIT 1 (BMS1)
- in 2010
BURNER MANAGEMENT SYSTEM UNIT 2 (BMS2)
- in 2010
WATER TREATMENT PLANT (WTP)
- in 2011
- stand-alone PLC
WASTE WATER TREATMENT PLANT (WWTP)
- in 2012
- stand-alone PLC
WARM AIR MAKE-UP (WAM)
- in 2012
- stand-alone PLC
Legend:
Fiber Optic
CAT-5
PC Desktop PC
HMI Industrial PC
PLC Programmable Logic Controller
CPU Processor for PLC
NOE Network card for PLC
I/O Inputs & Outputs
Notes:
All PLCs to be Quantum (Unity Pro) models and operator interfaces (HMI) to be Vijeo CiTect software.
PLCs and software by Schneider Automation.

5 CONCLUSION

The control systems discussed in this report are critical to the operation of the Holyrood Thermal Generating Station. Some of these systems are over 20 years old and are no longer fully supported by the manufacturers. A budgetary analysis of all alternatives resulted in the DCS installation being the lowest cost. The intangible benefits of a plant-wide common platform further support the choice of DCS as the path for this project.

This proposed project using Foxboro DCS offers several advantages such as:

1. Common spare part inventories and less spare parts,
2. Common control system maintenance procedures,
3. Common troubleshooting procedures,
4. Common Operator Interfaces (HMIs) for all systems,
5. Enhanced diagnostic capabilities,
6. A comprehensive support agreement with one manufacturer, and
7. Common and reduced training requirements.

The controls for Burner Management Systems (Units 1 and 2), the Water Treatment Plant, the Waste Water Treatment Plant, and the Warm Air Make-Up System are to be integrated into the existing plant-wide Foxboro DCS to best serve the operation of the Holyrood Thermal Generating Station.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 16.

Table 16: Project Cost

Project Cost: ($ x1,000)	**2010**	**2011**	**2012**	**TOTAL**
Material Supply	10.0	10.0	10.0	30.0
Labour	433.0	313.0	388.0	1,134.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	575.0	295.0	330.0	1,200.0
Other Direct Costs	21.5	16.5	21.5	59.5
O/H, AFUDC & Escln.	116.4	80.9	114.7	312.0
Contingency	52.0	31.7	37.5	121.2
TOTAL	**1,207.9**	**747.1**	**901.7**	**2,856.7**

5.2 Project Schedule

The anticipated project schedule is shown in Table 17.

Table 17: Project Schedule

Year	Project	Activity	Milestone
2010	Units 1 and 2 Burner Management Systems PLC Replacement	Project Initiation 2010 Kickoff Meetings Design & Development Final Design Equipment Delivery Installation Unit 1 Commissioning Unit 1 Installation Unit 2 Commissioning Unit 2 Final Acceptance	January February June July July July August August September October

Year	**Project**	**Activity**	**Milestone**
2011	Water Treatment Plant PLC Replacement	Project Initiation 2011 Kickoff Meetings Design & Development Final Design Equipment Delivery Installation Commissioning Final Acceptance	January February June June July/August August September October
2012	Waste Water Treatment Plant and Warm Air Make-Up PLC Replacement	Project Initiation 2012 Kickoff Meetings Design & Development Final Design Equipment Delivery Installation WWTP Commissioning WWTP Installation WAM Commissioning WAM Final Acceptance	January February June July July July/August August August September October

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER D. A. RENDELL SIGNATURE 09/07/31 PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REFURBISHMENT OF THE FUEL OIL STORAGE FACILITY

Holyrood Thermal Generating Station

April 2009

newfoundland labrador
hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

The purpose of this project is to refurbish the components of the Oil Storage Facility for No. 6 fuel at the Holyrood Thermal Generating Station (Holyrood) to bring the facility to a more reliable condition.

A study completed by SGE Acres entitled *"Evaluation of Fuel Oil Storage Tanks, Associated pipelines and Dyked Drainage System, Holyrood Thermal Generating Station"*, dated March 2006 (attached as Appendix A) identifies a number of deficiencies requiring corrective action. This project is part of a multi-year plan to refurbish the Fuel Oil Storage Facility based on the SGE Acres report, which involves refurbishing Tank 4.

A leak or spill of No. 6 fuel from Tank 4 could cause major environmental and operational issues. As a result of corrosion, the fuel oil storage tanks have deteriorated and require immediate attention to provide a useful life comparable to that of the rest of Holyrood.

Upgrade work previously approved by the PUB for the Fuel Oil Storage Facility includes:

- A 2008 capital project was approved by Board Order No. P.U. 30 (2007) for the refurbishment of Tank 2.
- A 2009 capital project was approved by Board Order No. P.U. 36 (2008) to upgrade the drainage system and pipe supports. This project is currently in-progress.

2 PROJECT DESCRIPTION

This project involves the upgrade of existing components within the Fuel Oil Storage Facility at Holyrood for the purpose of extending its useful life, ensuring system reliability, increasing the level of safety and reducing environmental risks within the facility. The scope of the work is to clean, inspect, replace floor plates, paint floor and install a roof platform for Tank 4. Table 1 below provides the direct costs associated with the project. For a more detailed description of these items reference Section 4 of the SGE Acres Report in Appendix B. Costing of these items is located in Appendix B of the SGE Acres report.

Table 1

Refurbishment of Fuel Oil Tanks

Description	Costs ($000)
Tank 4	
Floor Coating	201
Replace Floor Plate	1,209
Tank Cleaning	280
Roof Platform	18
Third-party Inspection	28
Total Tank 4	1,736

3 EXISTING SYSTEM

There are four 200,000 barrels above ground fuel oil storage tanks containing No. 6 fuel (Bunker C) and associated pipelines at Holyrood. The tanks are 55 metres (180 feet) in diameter and 15 metres (48 feet) high. A significant concern identified by the SGE Acres' inspection in 2004 was the corrosion of the floor of Tank 4.

All four fuel storage tanks require upgrades to correct corrosion problems. Also, SGE Acres recommends continuous monitoring for corrosion of the roof plate. The evidence of water ponding on the roof of the tanks indicates a deflection in the roof and flexibility of the rafters.

3.1 Age of Equipment or System

The first phase of the construction of Holyrood tank farm was completed in 1969, including the construction of fuel storage Tanks 1 and 2, all the associated supply and delivery pipelines and the earth dyke. The second phase of the construction of Holyrood was completed in 1977, including the construction of fuel storage Tanks 3 and 4.

3.2 Major Work and/or Upgrades

An inspection by SGE Acres in 2004 identified the requirement for the installation of patch plates to repair the floor of Tank 4. This work was completed in 2004 and extended the life of the floor on Tank 4 for five years, SGE Acres recommended replacement of the floor plate and installation of a protective coating in 2009.

3.3 Anticipated Useful life

The anticipated useful life of the fuel storage facility is 35 years. The existing facilities are at the end of their useful lives. The recommended upgrades to the tanks are expected to extend the useful life of the storage facility by 20 years, or at least until the fuel storage facility is no longer required if the Lower Churchill project receives sanction. Should the Lower Churchill Project proceed, the earliest that the facility will not be required is 2015/2016.

3.4 Maintenance History

Tank 4 was cleaned and inspected in 2004 at a cost of $179,200. The work included:

- internal cleaning,
- pressure testing of the storage tank platform heaters,
- installing bird screens on storage tank roof vents, and
- relocating a 400 mm diameter valve.

The tank inspection was the basis for the recommendations made in the SGE Acres Report for Tank 4. These recommendations provide the scope of work for this capital project.

3.5 Outage Statistics

There was an internal valve failure on Tank 2 in 2007 necessitating the tank to be taken out of service, thereby reducing the winter storage capacity and increasing the risk of short supply during customer peak load demand periods. The risk involves the inability of a supply tanker to dock because of ice conditions occurring during peak load periods. A project to upgrade Tank 2 was approved by Board Order P.U. No. 30 (2007) for $500,000. This work was completed in 2008.

In 2007, a similar valve failure and an internal tank heater problem put Tank 4 at risk of being removed from service. Although the tank did not have to be removed from service, the internal valve problems limited tank isolation capability and increased environmental risk during the operating months.

3.6 Industry Experience

Industry experience with above ground fuel oil storage tanks indicates that typically, the floors and ceilings of the tanks are affected the most by oxidation. Trapped water within the tank and the air void above the fuel oil subject the tank floor and ceiling to oxidation. Generally, the walls of the steel storage tanks do not oxidize from the inside because they are continuously coated with oil. The main protection against oxidation for the exterior surfaces has been epoxy coating systems.

3.7 Maintenance or Support Arrangements

General maintenance for the fuel oil storage facility has been performed by Hydro personnel. Major maintenance, such as epoxy coating and steel work, has been performed by outside contractors specializing in professional paint work and steel fabrication.

3.8 Vendor Recommendations

There are no relevant vendor recommendations with respect to the improvements to the fuel oil storage facility.

3.9 Availability of Replacement Parts

The availability of replacement parts is not applicable to this project because a complete refurbishment is required and not just the replacement of parts.

3.10 Safety Performance

There are no safety issues associated with upgrading Tank 4.

3.11 Environmental Performance

The deterioration of the tank floors and the settling of tank floor support rings is a result of corrosion. This increases the risk of environmental spills and leakage of No. 6 fuel from the storage tanks. Although the surrounding dyke, if void of water, has the ability to retain the volume of fuel, this environmental risk needs to be addressed.

3.12 Operating Regime

Holyrood is seasonally operated; however, the fuel storage facility is in continuous operation since fuel is always present in the fuel oil storage tanks.

4 JUSTIFICATION

This project is justified on the requirement to replace failing and deteriorated fuel oil storage infrastructure in order for Holyrood to provide safe, environmentally responsible, least-cost, reliable electrical service. Tank 4 has deteriorated to a point where there is a significant risk for oil leakage and inoperability. Corrective action must be taken.

4.1 Net Present Value

A net present value calculation was not performed in this instance as there are no viable alternatives.

4.2 Levelized Cost of Energy

This project does not involve analyzing a new energy generation source or enhancing the existing plant at Holyrood.

4.3 Cost Benefit Analysis

A cost benefit analysis is not applicable for this project because there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

Section 8 of the Storage and Handling of Gasoline and Associated Products Regulations (GAP) states in part that an owner or operator shall not directly or indirectly cause pollution of the soil or water by causing, suffering or permitting leakage or spillage of gasoline or associated product from a storage tank system.

4.5 Historical Information

The fuel oil storage tanks and associated components are inspected and upgraded in accordance with American Petroleum Institute (API) Standard 653 "Tank Inspection, Repair, Alteration, and Reconstruction" which is the upgraded standard for tanks specified under API Standard 650 "Welded Steel Tanks for Oil Storage". Inspections are made after fuel has been transferred to another tank. During these inspections preventative and corrective maintenance is performed to remedy the deficiencies, such as patching holes found in the steel roof and steel floor.

4.6 Forecast Customer Growth

There are no anticipated customer growth implications that can be attributed to this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be expected from this project.

4.8 Losses during Construction

There are no losses during construction as this project will not require Holyrood to be out of service.

4.9 Status Quo

The status quo is not an acceptable option. The existing system has deteriorated components that require upgrades to extend their useful lives and to ensure compliance with regulatory requirements established by GAP and API. Table 6.2 of the SGE Acres Report lists the upgrades as a high priority to be completed in 2009. The project will already be one year behind the recommended completion date and should not be delayed any further.

4.10 Alternatives

The existing system is repairable and this is the only viable alternative. Although full replacement of the whole facility is possible, the cost of replacement is much greater than refurbishment and, thus, not a viable alternative.

5 CONCLUSION

The fuel storage system has deteriorated to a point where action must be taken to correct deficiencies. Tank 4 will be upgraded in accordance with API standard 653 to minimize the risk of any leaks or spills.

5.1 Budget Estimate

The budget estimate for this project is $2.5 million. Table 2 below summarizes the costs.

Table 2
Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	205.0	0.0	0.0	205.0
Consultant	108.0	0.0	0.0	108.0
Contract Work	1,750.0	0.0	0.0	1,750.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	230.9	0.0	0.0	230.9
Contingency	206.3	0.0	0.0	206.3
TOTAL	**2,500.2**	**0.0**	**0.0**	**2,500.2**

5.2 Project Schedule

Table 3 provides the planned project schedule.

Table 3
Project Schedule

Activity	Milestone
Design	March 2010
Tender	April 2010
Award Tender	May 2010
Contract	September 2010
Closeout Project	December 2010

5.3 Future Plans

To correct all of the deficiencies outlined in the SGE Acres Report, work will be proposed in future years as follows.

- Refurbishment of Tank 3 in 2011.
- Refurbishment of Tank 1 in 2012.

See the five-year capital plan (2010 Capital Plan tab, Appendix A).

Upgrade Plant Access Road – Bay d'Espoir Report

To be filed at a later date

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
DANIELLE HICKEY
Danielle Hickey
SIGNATURE
July 31, 2009
DATE
NEWFOUNDLAND & LABRADOR

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACE PUMPHOUSE MOTOR CONTROL CENTERS

Holyrood Thermal Generating Station

May 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) is an integral part of the Island Interconnected System, with three units providing a total capacity of 490 MW. The generating station was constructed in two stages. In 1971, Stage 1 was completed bringing on line generating Units 1 and 2, each rated at 150 MW. In 1979, Stage 2 was completed bringing on line generating Unit 3 rated at 150 MW. In 1988 and 1989, Units 1 and 2 were uprated to 170 MW. The generating station requires a continuous flow of cooling water to supply the steam turbines that power the generating equipment. The source of the water is Indian Pond which is located immediately adjacent to the Holyrood plant.

There are two separate water pumphouses serving the plant. Pumphouse 1 was built as part of Stage 1 to provide water to generating Units 1 and 2. Pumphouse 2 was built as part of Stage 2 to service generating Unit 3. Each pumphouse has one self contained free standing Motor Control Center. A motor control center consists of one or more individual motor controllers that share a common power bus. Figure 1 is a picture of the motor control centre in pumphouse 1.

Figure 1: Motor Control Center in Pumphouse 1

2 PROJECT DESCRIPTION

This project is required to replace the motor control center in each pumphouse, construct a new room in each pumphouse to accommodate the new motor control centres, replace power cables feeding the motor control centres from the main plant, and modify power supply cables and piping in the pumphouses.

Most of the power supply cables running from the motor control centres to the pumphouse equipment will be reused.

In pumphouse 1 mechanical piping will have to be relocated and rerouted to provide space for the new motor control centre and the power cables supplying the motor control center. In pumphouse 2 there is sufficient space available such that this component of the work is not required.

All construction and installation work will be coordinated with the schedules for plant operations and plant outages.

3 EXISTING SYSTEM

Each pumphouse brings water from Indian Pond to the water treatment plant where it is treated before injection into the turbine boilers. The equipment in each pumphouse is comprised of transfer and circulation pumps, ranging in size from 0.5 Hp to 60 Hp, associated fans and other ancillary equipment which is all electrically motor driven. All pumphouse motor drives are controlled from dedicated motor control centers in each pumphouse.

The motor control centers are located in the main open equipment area of the pumphouse and are exposed to a damp and corrosive environment. This environment has caused deterioration to the motor control centers such as moisture buildup and rusting of contacts which results in an unreliable system and unplanned outages.

3.1 Age of Equipment or System

The motor control centre in pumphouse 1 was installed and commissioned in 1969 (prior to commissioning of the units in 1971) and the motor control centre in pumphouse 2 was installed and commissioned in 1979.

3.2 Major Work and/or Upgrades

Since the original installations, there have been no major upgrades or extensions to the existing motor control centers. The only work performed in the existing control centers has been regular maintenance.

3.3 Anticipated Useful life

The anticipated useful life of the Motor Control Centers has been forecast to extend to the year 2020, absent an infeed from Lower Churchill.

3.4 Maintenance History

The five-year maintenance history for both pumphouse motor control centres is shown in Tables 1 and 2:

Table 1
Five-Year Maintenance History
for Pumphouse 1 Motor Control Centre
(motor control centre C6)

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	0.0	0.0
2007	6.3	0.0	6.3
2006	0.8	1.7	2.5
2005	0.0	1.7	1.7
2004	4.9	0.0	4.9

Table 2
Five-Year Maintenance History
for Pumphouse 2 motor control centre
(motor control centre CWP34)

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	0.6	0.6
2007	1.4	0.0	1.4
2006	0.8	0.0	0.8
2005	0.1	0.4	0.6
2004	0.9	0.2	1.1

3.5 Outage Statistics

Outage statistics are only tracked at a unit level and are not specific to subsystems such as the pumphouse motor control centres.

3.6 Industry Experience

Industry adheres to current codes and standards when replacing old equipment. The existing motor control centers are manufactured in what is called a "general purpose" enclosure. The current Canadian Standards Association (CSA) Canadian Electrical Code – Safety Standard for Electrical Installations C22.1-09 requires special purpose enclosures to withstand the damp and corrosive environment of the motor control pumphouse.

3.7 Maintenance or Support Arrangements

All normal operation and maintenance work is performed by Holyrood plant maintenance staff.

3.8 Vendor Recommendations

There are no vendor recommendations associated with this project proposal.

3.9 Availability of Replacement Parts

Replacement parts for the existing equipment are readily available from local distributors or through a special order direct to the manufacturers.

3.10 Safety Performance

There are two main safety deficiencies.

(i) When the individual cells of the motor control center are removed for regular maintenance purposes, the 600 volt energized bus is left exposed. This creates a direct safety hazard for the maintenance staff working on the equipment in that there is no protective barrier on the exposed bus and personnel can accidentally come in contact with the bus and suffer electrical shock or electrocution. The bus bars are what supply power to each individual starter in the motor control centre and therefore cannot be de-energized every time an individual cell is removed for maintenance.

(ii) The existing pumphouse motor control centres were manufactured in the 1960's and 1970's and therefore include asbestos material for isolation barriers and mounting attachments. This asbestos material creates a personal safety hazard for the personnel working on the equipment.

3.11 Environmental Performance

There are no environmental issues related to this project.

3.12 Operating Regime

The equipment is in full time continuous operation. In addition to the equipment required to pump water to the steam turbines, the pumphouse motor control centers also feed a variety of other loads including hoists, cranes, ventilation fans, light fixtures and lighting panels.

4 JUSTIFICATION

The justification for this project is based on safety and reliability.

Safety

The existing equipment, constructed in 1969 and 1979, does not comply with current safety codes and standards. The deficiencies in the motor control centres with respect to the current codes relate to exposed live parts, arc flash protection and the use of certain materials such as asbestos. The Canadian Standards Association (CSA), Canadian Electrical Code - Safety Standard for Electrical Installations C22.1-09 Sections 22 and 26 contain extensive requirements for design and manufacture of motor control centers and other electrical equipment. These requirements exceed the codes and standards of the 1960's and 1970's. Therefore, the replacement equipment must be designed and built to the current standard.

Reliability

The Holyrood generation units cannot operate without a supply of water. The motor control centers are integral to the pumphouse operation, and therefore integral to the Holyrood system and the reliability of generation supply to the Island Interconnected System. As stated earlier, the existing equipment is not suitable for applications where there are levels of corrosive elements or moisture as found in the pumphouse environment. The environment has therefore caused deterioration to the equipment such as moisture build up and rusting of electrical contacts results in interruptions to the reliable supply of water to the plant and unplanned outages to the generation units.

4.1 Net Present Value

A net present value calculation was not performed as there is no alternative to replacing the motor control centres.

4.2 Levelized Cost of Energy

This project does not affect the levelized cost of energy as it does not involve any new source of generation.

4.3 Cost Benefit Analysis

A cost benefit analysis is not required for this project as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

There are no specific legislative or regulatory requirements for this project.

4.5 Historical Information

As this is not a recurring project historical information is not applicable.

4.6 Forecast Customer Growth

Forecast customer load growth has no effect on the scope of this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits associated with this project.

4.8 Losses during Construction

The removal of the old equipment and installation of the new equipment will be coordinated with planned outages for the Holyrood plant. These outages are designed around system load requirements and available System generation. Therefore, there will be no production or revenue losses resulting from this project.

4.9 Status Quo

The status quo is not an option. These motor control centers must be replaced because continued operation with the existing equipment presents unacceptable safety and reliability concerns related to the environment in which they operate.

4.10 Alternatives

There are no alternatives to this project. The motor control centre in each of the two pumphouses can either be replaced, as proposed, or not replaced, leaving the safety and reliability issues not addressed.

5 CONCLUSION

The replacement of the pumphouse motor control centers is necessary because of the safety and reliability concerns described in this report.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 3.

Table 3: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	225.0	0.0	225.0
Labour	41.0	211.0	0.0	252.0
Consultant	5.0	0.0	0.0	5.0
Contract Work	0.0	363.0	0.0	363.0
Other Direct Costs	0.0	4.0	0.0	4.0
O/H, AFUDC & Escln.	4.2	110.7	0.0	114.9
Contingency	0.0	84.9	0.0	84.9
TOTAL	**50.2**	**998.6**	**0.0**	**1,048.8**

5.2 Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	**Milestone**
Project Initiation, Design and Equipment Ordering	September 2010
Project Safety Plan	July 2010
Installation	October 2011
Commissioning	October 2011
In Service	November 2011
Project Completion	December 2011

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEGNL ANDREA MACDONALD Andrea M. MacDonald SIGNATURE July 31/09 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

Upgrade Glycol Systems at Stephenville Gas Turbine Plant

June 2009

newfoundland labrador
hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates two 50 MW Gas Turbine plants as part of the Island Interconnected System. They are: the Stephenville Gas Turbine Plant (Stephenville), located in Stephenville (see Figure 1); and the Hardwoods Gas Turbine Plant (Hardwoods), located in the west end of St. John's. The gas turbines at both sites are used for voltage control, as well as providing power for emergencies and system peaking.

Figure 1: Stephenville Gas Turbine Plant

The Island Interconnected System experiences constant voltage fluctuations that result from changes in supply and demand of electricity. Since voltage fluctuations are undesirable, the system requires constant voltage correction to maintain the proper voltage levels. The system voltage is corrected using a process known as synchronous condensing. This process stabilizes the voltage of the system. During synchronous condensing, the voltage drop is limited to no more than five percent below the nominal operating levels of 230, 138, or 66 kV. Synchronous condensing is the main function of the Hardwoods and Stephenville Gas Turbine Plants.

Hardwoods and Stephenville are capable of producing 50 MW of electricity each during peak and emergency periods. However, at this time, Stephenville has only one gas turbine engine installed so its plant output is reduced to 25 MW of electricity. Both plants are fueled by distillate (diesel).

A gas turbine plant consists of major equipment such as gas turbine engines, power turbines and power generators (also called alternators), as well as auxiliary systems such as lube oil systems, fuel systems, electrical systems and control systems. Structures such as buildings, equipment enclosures, and exhaust stacks comprise the balance of components that make up the facility.

In 2007, an engineering consulting company, Stantec Inc. (Stantec), completed a condition assessment and life cycle cost analysis study of the Hardwoods and Stephenville Gas Turbine Plants. Hydro commissioned the study to determine the best course of action to achieve a high degree of operating reliability at least cost for the next 15 years for both sites. Many recommendations were presented in the consultant's final report.

In 2009, Hydro initiated a four-year refurbishment program to implement the recommendations for Hardwoods put forth in Stantec's report. In 2012, Hydro will propose a three-year refurbishment program to implement the recommendations for Stephenville. However, the alternator glycol cooling system and the main lube oil glycol pump at Stephenville are all in poor condition and must be replaced sooner than 2012 to ensure reliable operation of the plant.

2 PROJECT DESCRIPTION

The following equipment will be replaced at Stephenville under this project:

Alternator glycol cooler, piping, valves, and pumps; and

Main lube oil glycol pump.

This work will be completed by a combination of internal forces and contracted labour and will result in increased reliability for the systems upgraded. A photo of the alternator glycol cooler, taken in 2007, is shown below (Figure 2).

Figure 2: Alternator Glycol Cooler

3 EXISTING SYSTEM

The Stephenville plant normally consists of two identical gas turbine units. However, as described on page 2, only one gas turbine engine is currently installed. Each gas turbine unit consists of one Rolls-Royce Olympus C gas turbine engine and one Curtiss-Wright power turbine. One Brush power generator, or alternator as it is also known, is shared between both gas turbine units. Each gas turbine unit is coupled to the alternator by a clutch. Auxiliary systems, critical to the operation of the facility, include inlet air systems, fuel oil system, electrical system, and control and instrumentation systems. Buildings and structures on site include exhaust stacks, inlet air intakes, control building, fuel unloading building, fuel forwarding module, auxiliary module building, maintenance and parts storage building, high voltage switchgear building, and emergency backup diesel generator building.

All equipment plays an important role in the successful operation of the Stephenville plant. However, the most critical piece of equipment is the alternator. Neither power generation nor synchronous condensing may take place at Stephenville unless the alternator is functioning properly. In order to function properly, the alternator cannot overheat.

3.1 Alternator Cooling System

The alternator gives off heat when operating in power generation and synchronous condensing modes. The heat must be removed, otherwise it will build up inside the alternator enclosure and damage the equipment. The alternator cooling system removes heat from inside the alternator enclosure. This system consists of an outdoor alternator glycol cooler, an air-to-glycol heat exchanger located inside the alternator enclosure, as well as associated valves, pump, and piping. The glycol used is actually a 50-50 mixture of glycol and water. However, it is simply referred to as glycol.

The alternator cooling system components are in critical condition and require replacement. The outdoor glycol cooler has reached the end of its useful life. Photos of the wind box, which is the area inside the outdoor glycol cooler (Figures 3 and 4), were taken in 2007. Note the extensive corrosion inside the wind box unit.

As shown in the photo (Figure 4), the floor of the wind box is extensively corroded causing rust debris to collect in the bottom of the unit. The air stream carries this debris through the cooler. Over time, the debris accumulates in the space between the glycol tubes. This impedes airflow which in turn reduces the cooling capability of the unit.

Figure 3: Inside View of Wind Box – Alternator Glycol Cooler

Figure 4: Inside View of Wind Box - Alternator Glycol Cooler

Another serious issue with the alternator cooling system is the reliability of the glycol circulating pumps. These pumps circulate glycol through the alternator cooling system in a closed-loop. Both the main pump and auxiliary pump are obsolete. The main pump is leaking and cannot be repaired. The auxiliary pump is currently disassembled and replacement parts cannot be sourced. If the main pump fails completely, the plant must be shut down until a replacement pump is installed. The pumps have reached the end of their serviceable lives and require replacement. The three-way glycol regulating valve has also failed and requires replacement. Repairing this valve is not possible since its internal components are damaged. The associated piping, much of which is underground, is original and has reached the end of its useful life as well. If this pipe begins leaking, environmental damage may result and contaminated soil will require remediation. Therefore, it is recommended that all of these components be replaced under this project.

Over the past two summers, the alternator cooling system has been unable to provide adequate cooling and emergency cooling was required to keep the alternator from overheating. Emergency cooling is provided by opening doors in the alternator enclosure, which allows air to flow through and cool the alternator. Figure 5 shows the doors to the alternator enclosure in the open position during the summer of 2007 when emergency cooling was required. Note that the manufacturer does not recommend opening the emergency cooling doors unless in an emergency because the entering air is not filtered. In addition, this puts the generator at risk because when the doors are open the generator is exposed directly to the weather.

Figure 5: Alternator Enclosure – Emergency Doors Open

Water entering the unit can result in an electrical failure, which would put the unit out of service for an extended period.

Examples of alternator cooling problems, taken from the Operator's logbook, are listed below:
June 11, 2007 – Synchronous condensing shut down due to high temperature alarm.
June 15 - 25, 2007 – Alternator overheating; Emergency doors opened.
July 22, 2008 – Alternator cooler sprayed with water to increase cooling effect.
July 28, 2008 – Alternator overheating; Reduce MVARs; Emergency doors opened.

In 2008, the coils of the alternator glycol cooler were cleaned however the performance of the unit did not increase.

3.2 Main Lube Oil System

Another system critical to the operation of the Stephenville plant is the main lube oil (MLO) system. This system supplies lubricating fluid to bearings throughout the facility. The lubricating fluid not only lubricates the bearings but also cools them. As the fluid circulates, through the bearings, it picks up heat. A 50-50 mixture of glycol and water (simply referred to as glycol) cools the lubricating fluid through a heat exchanger. The MLO glycol pump is leaking and is beyond repair. If the MLO glycol pump fails completely, the plant will be out of service until a new pump is installed. Therefore, this pump requires replacement under this project. Since the MLO system is critical to the operation of the gas turbines and the alternator, neither power generation nor synchronous condensing may take place if the MLO system is not operational.

3.3 Age of Equipment or System

Stephenville was placed in service in 1976. All equipment that will be replaced under this project is original.

3.4 Major Work and/or Upgrades

Appendix A contains a comprehensive listing of major work and upgrades that have taken place at Stephenville since it was put into service in 1976. None of the upgrades listed pertain to the equipment to be replaced under this project.

3.5 Anticipated Useful life

A gas turbine plant has an anticipated service life of 25 years.

3.6 Maintenance History

The five-year maintenance history for the Stephenville Gas Turbine Plant is shown in Table 1 below.

Table 1
Stephenville Gas Turbine Plant Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	19.2	113.1	132.3
2007	12.1	159.3	171.4
2006	12.5	343.1	355.6
2005	7.0	94.2	101.2
2004	11.4	164.1	175.5

3.7 Outage Statistics

Table 2 lists the 2004 to 2008 average Capability Factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for Stephenville compared to all of Hydro's gas turbine units and the latest Canadian Electrical Association (CEA) average (2002 to 2006).

Table 2
Stephenville Gas Turbine Five Year Average (2004-2008) All Causes

Unit	Capability Factor (%)[1]	UFOP (%)[2]	Failure Rate[3]
Stephenville	81.05	5.42	469.88
All Hydro Gas Turbine Units	87.02	11.39	42.12
CEA (2002-2006)	88.62	8.11	10.82

[1]Capability Factor is defined as unit available time. It is the ratio of the unit's available time to the total number of unit hours.
[2]UFOP is defined as the Utilization Forced Outage Probability. It is the probability that a generation unit will not be available when required. It is used to measure performance of standby units with low operating time such as gas turbines.
[3]Failure Rate is defined as the rate at which the generating unit encounters a forced outage. It is calculated by dividing the number of transitions from an operating state to a forced outage by the total operating time.

Stephenville has a failure rate over 11 times the rate for all of Hydro's gas turbine units and over 43 times the rate posted for the CEA.

3.8 Industry Experience

There is no industry experience to report that is associated with the equipment being replaced.

3.9 Maintenance or Support Arrangements

Routine maintenance at Stephenville on structures, auxiliary systems and some parts of the major equipment systems is performed by Hydro personnel. Any work involving removal of the gas turbine engine casing is performed by external contractors specializing in gas turbine repairs. Internal work on other major equipment is also performed by specialized contractors.

3.10 Vendor Recommendations

There are no vendor recommendations applicable to this project.

3.11 Availability of Replacement Parts

Spare parts for the glycol pumps are no longer available as these pumps are obsolete.

3.12 Safety Performance

There are no identified safety issues related to the equipment under this project currently installed at Stephenville.

3.13 Environmental Performance

There are no identified environmental performance issues related to this project. There is a potential, however, for leaks in underground glycol piping that may lead to soil contamination.

3.14 Operating Regime

Stephenville operates mainly as a synchronous condenser but also as a power generator. The facility operates in power generation mode during peak usage times, which is less than one percent of the time. This may occur anytime throughout the year but is most common from mid December to March. As well, this facility is placed in standby mode for emergency generation during unplanned outages. The facility may also be placed in service to generate electricity during planned outages.

4 JUSTIFICATION

The operational reliability of Stephenville is critical to ensure voltage regulation of the Island Interconnected System. As well, this facility is critical for the generation of peak and emergency power. Unless the reliability of this facility is improved (see Section 3.5), the Island Interconnected System may experience voltage fluctuations and power shortages. The major equipment installed at this facility is over 30 years old and has reached the end of its operating life. The alternator glycol system and the main lube oil glycol pump are critical to the operation of the facility and require replacement.

4.1 Net Present Value

A net present value calculation has not been performed since only one viable alternative exists.

4.2 Levelized Cost of Energy

This facility generates electricity only during peak/emergency periods. Levelized cost of energy is not a factor in this project.

4.3 Cost Benefit Analysis

A cost benefit analysis has not been completed since there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements that justify this project.

4.5 Historical Information

There have been no similar projects.

4.6 Forecast Customer Growth

This project is not required to accommodate customer growth.

4.7 Energy Efficiency Benefits

There are energy efficiency benefits resulting from this project. New pumps will be purchased with high-efficiency motors. The new alternator glycol cooler will be supplied with high-efficiency fan motors. The resulting energy savings cannot be quantified.

4.8 Losses during Construction

There will be no losses during construction as the work will take place during a planned outage.

4.9 Status Quo

If this project is not completed, plant reliability may decrease and the frequency of unplanned outages may increase. This affects the voltage control on the power grid and the plant's ability to generate power during peak and emergency periods.

4.10 Alternatives

The only alternative is the complete replacement of all equipment within the scope of this project.

5 CONCLUSION

It is very important for Hydro to have a reliable facility for synchronous condensing and peak/emergency power generation on the West Coast. The Upgrade Glycol Systems project was initiated to restore the reliability of critical systems at the Stephenville plant that have reached the end of their operating lives.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 3.

Table 3
Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	206.0	24.0	0.0	230.0
Labour	25.4	43.3	0.0	68.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	122.7	0.0	122.7
Other Direct Costs	1.1	13.5	0.0	14.5
O/H, AFUDC & Escln.	28.8	51.8	0.0	80.6
Contingency	0.0	43.6	0.0	43.6
TOTAL	**261.3**	**298.9**	**0.0**	**560.1**

5.2 Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4
Project Schedule

Activity	Milestone
Issue tender for equipment	May 2010
Delivery of equipment	November 2010
Installation of main lube oil	November 2010
Installation and commissioning of alternator cooling system equipment	June 2011
Project closeout	September 2011

APPENDIX A

Stephenville Gas Turbine Plant - Major Upgrades

Stephenville Gas Turbine Plant

Major Upgrades

Civil Engineering Projects

1999 – 2000: Tank Farm Upgrades:

- Three tanks were refurbished (interior cleaned, weld repairs, floor painted).
- Tanks were inspected.
- New dyke liner was installed throughout (tank was lifted).
- Dykes were re-shaped.
- New granular dyke materials were installed.
- New sump was installed.
- New piping was installed (within tank farm).

2004: Painted exterior of tanks.

2006: Painted exterior of Gas Turbine Enclosure with rubberized coating system.

Electrical Engineering Projects

1998: Installation of 15kV Metal Enclosed Switchgear Assembly and Bus Duct:

- This entailed the design fabrication, factory testing, supply and delivery of a 15kV Metal Enclosed Switchgear Assembly. Scope included:
    - Supply, delivery and placing on existing concrete pad an outdoor, walk-in type 15kV metal enclosed switchgear.
    - All tools, cranks, and other equipment required for normal operation.
    - Spare parts.
    - Two sections of 15kV, 3 phase, non-segregated bus duct between the switchgear and the main transformer, and between the switchgear and the generator.
    - Structural steel supports to support bus duct.

2005: Battery Bank Replacements:

- The 125V 900 amp-hour VRLA bank was replaced.

Mechanical Engineering Projects

1988: Fern Engineering modifications:

- Primarily replaced the casing on each of the 4 Curtiss Wright power turbines (Stephenville and Hardwoods) which were prone to cracking. Other smaller components were replaced as well. Approx. cost $4 million.

1989: Exhaust stack replacement:

- Snow doors were modified from electric actuation to pneumatic. Total cost $1.2 million.

2000: Stephenville B engine serial # 202224 overhaul.

2002: Gas Turbine and Generator Modules Fire Systems Replacement (Inergen).

Protection and Control Engineering Projects

1999: Control System Upgrade:

- This entailed removing approximately 250 electromechanical relays and timers and replacing the controls with a distributed control system.
- The DCS included a PC-based operator interface.
- Commissioning of controls performed by ABB (ETSI).

1999: Miscellaneous:

- The type J and K thermocouple wire and terminal blocks in various junction boxes were replaced during the controls upgrade.

2004: Inverter replacement:

- Inverter failed and was replaced.

2005: Emergency backup diesel generating units installed:

- Diesel Generating Unit #571 including 600V control panel and backup battery chargers installed in new 3.6m x 4.8m building.
- The diesel unit is designed to start automatically with the loss of AC station service supply to the gas turbine unit and in turn supply power to the backup battery chargers which ensures the integrity of the 125 Vdc and 250 Vdc supply to the gas turbine during its starting cycle.
- The diesel unit also provides a backup AC supply for one of the air compressors should the stored air supply run low during attempted start(s) of the gas turbine unit.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACE UNIT 1 STEAM SEAL REGULATOR

Holyrood Thermal Generating Station

May 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW. The generating station was constructed in two stages. In 1971, Stage I was completed bringing on line two generating units, Units 1 and 2, capable of producing 150 MW each. In 1979, Stage II was completed bringing on line one additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units 1 and 2 were up-rated to 170 MW. Holyrood (illustrated in Figure 1) represents approximately one third of Newfoundland and Labrador Hydro's (Hydro) total Island Interconnected generating capacity.

Figure 1: Holyrood Thermal Generating Station

The three main components of each generating unit are the boiler, turbine, and generator. A steam seal regulator is a turbine system which controls the flow of steam to and from the turbine shaft seals. Shaft seals are used to prevent the leakage of process steam along the rotor shaft from the turbine casing. There are two classes of shaft seals: pressure packings and vacuum packings. Vacuum packings shaft seals always require sealing steam whereas pressure packings shaft seals require sealing steam only at low turbine loads. Steam must be relieved from the pressure packings at high turbine loads. All turbine shaft seals are connected to the steam seal regulator through a common header.

2 PROJECT DESCRIPTION

This project is required to replace the existing hydraulic steam seal regulator on Unit 1 with two pneumatically operated steam pressure control valves. One of these pneumatically controlled pressure regulating valves will be used to supply steam to the steam seal header and one will be used to relieve pressure from the steam seal header. The new system will be controlled using a pressure transducer and the existing Foxboro Distributed Control System (DCS). In addition, the steam seal header piping will be modified to allow the new pressure control valves to be installed at a location for easier operator access.

3 EXISTING SYSTEM

The existing Unit 1 steam seal regulator shown in Figure 2 below is an automated hydraulic system with many moving parts and wear points. A daily problem with binding and sticking of the moving parts requires an operator attendant to manually free them. Improper operation of the regulator, due to binding and sticking, allows steam to travel along the turbine rotor shaft and mix with the bearing lubrication oil where it condenses to water and accelerates deterioration of the bearings. Premature failure of the turbine bearings can result in an unplanned unit outage of 10 to 12 weeks duration and a repair cost estimated to be as high as $1 million. An unscheduled unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System which represents approximately 11 percent of Hydro's Island Interconnected system capacity.

Figure 2: Unit 1 Steam Seal Regulator

3.1 Age of Equipment or System

Unit 1 was commissioned in 1971. The existing oil fired boiler and steam turbine are 38 years old.

3.2 Major Work and/or Upgrades

There has been no major work or upgrade performed on the Unit 1 steam seal regulator since it was commissioned in 1971.

3.3 Anticipated Useful life

The anticipated useful life of Unit 1 has been forecasted to extend to the year 2020, absent an infeed from Lower Churchill.

3.4 Maintenance History

Steam seal regulator maintenance is a component of the annual maintenance strategy for Unit 1. During the annual shutdown, Hydro uses a turbine service contractor, General Electric (GE), to perform preventative maintenance inspections on the steam seal regulator. Corrective maintenance is performed by plant internal forces during the annual shutdown. The cost of maintenance for the steam seal regulator is a component of the total maintenance cost for the whole unit. Hydro does not categorize steam seal regulator maintenance cost separately from the total unit maintenance cost. As a result, the actual preventative and corrective maintenance costs for the steam seal regulator are not available. However, the estimated total average annual maintenance cost for the steam seal regulator is $5,000.

3.5 Outage Statistics

There have been no outages on Unit 1 caused by problems with the steam seal regulator. Operations personnel are aware of the issues surrounding the steam seal regulator and the consequences of it malfunctioning. They monitor the regulator operation daily and react to its binding and sticking as quickly as possible.

3.6 Industry Experience

Steam turbine manufacturers have indicated that the industry trend is to convert from the conventional hydraulically controlled steam seal regulator to a simpler and more reliable pneumatic control valve system. The system will provide steam for the turbine shaft seals at the required pressure and flow rate by using a series of pneumatically operated pressure control valves. In comparison to the existing hydraulically controlled steam seal regulator, the new system will have very few moving parts and a low probability of mechanical failure. Appendix A provides an example of a steam seal regulator conversion that was performed on a steam turbine at Alberta Power (2000) Ltd. in 2005.

3.7 Maintenance or Support Arrangements

Hydro uses a combination of external contractors and internal plant resources to perform annual maintenance on Unit 1. Hydro currently has a service contract with Alstom Power, a boiler service contractor, to perform boiler maintenance during the annual scheduled outage. As stated previously, annual turbine maintenance is performed by GE in conjunction with plant internal forces.

3.8 Vendor Recommendations

Steam turbine original equipment manufacturers such as GE are recommending converting from the conventional hydraulically controlled steam seal regulator system to a pneumatic pressure control valve system. Benefits of the pneumatic pressure control valve system include reduced maintenance cost and increased availability of replacement components. Please refer to the Steam Seal System Upgrade Product Overview**,** Appendix B.

3.9 Availability of Replacement Parts

Availability of spare parts for the existing steam seal regulator has been an ongoing issue. The existing steam seal regulator is 38 years old and it is difficult to obtain reliable technical support from GE. In recent years, troubleshooting has been done by Hydro and any required replacement parts have been made by local machine shops by copying the original component.

3.10 Safety Performance

There are no safety code violations with the current operation of the existing steam seal regulator.

3.11 Environmental Performance

There are no environmental code violations with the operation of the existing steam seal regulator. However, there have been several occasions where the regulator's hydraulic controller has leaked oil and required clean-up and investigation.

3.12 Operating Regime

Holyrood operates in a seasonal regime. The full plant capacity is needed to meet the winter electrical requirements on the Island Interconnected System. The steam seal regulator is an integral component of Unit 1.

4 JUSTIFICATION

The steam seal regulator servicing Unit 1 at Holyrood is 38 years old and Hydro has had difficulty obtaining replacement parts and service from the original manufacturer, GE. The majority of replacement parts for the regulator are still manufactured by GE but have been difficult to obtain in recent years due to the age of the equipment. In addition, some replacement parts for the regulator are not manufactured by GE and these components have been increasingly difficult to obtain from subsequent vendors in recent years. Correspondence from GE regarding the availability of spare parts and reliable service is located in Appendix C. This has necessitated replacement parts being made by local machine shops by copying the original components.

Improper operation of the regulator, due to binding and sticking, allows steam to travel along the turbine rotor shaft and mix with bearing lubrication oil where it condenses to water and accelerates deterioration of the bearings. Premature failure of the turbine bearings can result in an unplanned unit outage of 10 to 12 weeks duration and a repair cost estimated to be as high as $1 million. An unscheduled unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System which represents approximately 11 percent of Island Interconnected system capacity.

This project is required to maintain the reliability of generating Unit 1 at Holyrood.

4.1 Net Present Value

A Net Present Value calculation was not performed as there are no viable alternatives.

4.2 Levelized Cost of Energy

The levelized cost of energy is a high level means to compare costs of developing two or more alternative generating sources. Therefore, the levelized cost of energy is not applicable in this case.

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Legislative or Regulatory Requirements

There are no current legislative or regulatory requirements to convert the existing hydraulic steam seal regulator to a pneumatically operated pressure control valve system.

4.5 Historical Information

There have been no capital expenditures in past years on Unit 1's steam seal regulator. However, in its Board Order No. P.U. 36 (2008), Hydro received approval to replace the steam seal regulator on generating Unit 3. This project was budgeted for $475,300 and work is progressing on this project.

The cost to replace the steam seal regulator on generating Unit 1 has increased to $582,200. Due to the tight timelines associated with project design requirements and procurement of materials, it was decided to complete the project over two years as opposed to the one year project duration on generating Unit 3. As a result, the project cost has increased due to escalation. In addition, the project cost has also increased due to the custom pipe fitting requirements associated with installing the new regulator in a new location at the plant that is more operator accessible.

4.6 Forecast Customer Growth

Customer load growth is not affected by this project, since the scope of the project is to upgrade existing equipment.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits projected through the completion of this project.

4.8 Losses during Construction

There are no associated losses during the construction of this project as it will be scheduled during the annual planned unit outage.

4.9 Status Quo

Delays to completing this project could reduce the life of Unit 1's turbine bearing system. Water contamination in bearing lubricating oil will reduce bearing life by 50 percent and can lead to catastrophic failure. A bearing failure on the turbine would result in 10 to 12 weeks of downtime on Unit 1 and repair cost as high as $1,000,000. In addition, an unscheduled failure during the peak winter load demand could result in a loss of 170 MW of power which represents approximately 11 percent of the Island Interconnected System's capacity. Moisture in the oil also requires a weekly centrifuge operation and a large amount of operator attention to monitor the quality of the lube oil system, for all three Holyrood generating units.

4.10 Alternatives

There are no viable alternatives available to the proposed project.

5 CONCLUSION

This project is a replacement of the existing hydraulically controlled steam seal regulator on Unit 1 turbine with a pneumatically operated pressure control valve assembly. The steam seal regulator is 38 years old and contains many moving parts and wear points. Improper operation of the regulator, due to binding and sticking, allows seal steam to travel along the turbine rotor shaft and mix with bearing lubrication oil where it condenses to water. Water entrainment in lubricating oil accelerates deterioration of the bearings, thereby reducing the reliability of the generating unit. The proposed pneumatic system is the standard design used today in the turbine steam seal regulating application.

Failure to install the new steam seal regulator system increases the likelihood of unscheduled downtime on the turbine and increases the risk of being unable to meet customer demands during the peak winter load requirement.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	265.5	0.0	0.0	265.5
Labour	0.0	124.0	0.0	124.0
Consultant	33.6	0.0	0.0	33.6
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	2.0	0.0	4.0
O/H, AFUDC & Escln.	33.6	45.6=0	0.0	78.6
Contingency	0.0	42.7	0.0	42.7
TOTAL	**334.7**	**213.7**	**0.0**	**548.4**

5.2 Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Milestones

Activity	Milestone
Project Kick-off Meeting	January 2010
Complete Design Transmittal	February 2010
Develop RFP for Professional Engineering Services	March 2010
Complete Detailed Engineering Design	July 2010
Develop Materials Tender Specification	August 2010
Procurement of Materials	April 2011
Develop Installation Contract	March 2011
Issue Tender & Award Contract	April 2011
Installation	August 2011
Commissioning	September 2011
Project Final Documentation and Closeout	December 2011

APPENDIX A

ATCO Steam Seal Regulator Conversion

ATCO Power
Alberta Power (2000) Ltd.

Turnover Package

Ref: BR3 Seal Steam Regulator Replacement

Date: April 19, 2005

From: Malcolm Boyd

To: Brent Stenson, Dave Lugg, Dale Hamilton, Andy Nykolaishyn

The new seal steam regulator upgrade was installed during the 2005 BR3 outage. This document can be used to familiarize operators with the new equipment installed as part of upgrade.

The original regulator incorporated a supply valve and a dump valve into a single assembly. The location made it difficult to maintain and operate. The new system utilizes two separate valves to accomplish the same function as before. If additional seal steam pressure is required, the 1" seal steam supply valve (shown on the left hand side of figure 1) is opened and the 6" dump valve (shown on the right hand side of figure 1) is closed. If less seal steam pressure is required the 1" seal steam supply valve is closed and the 6" dump valve is opened.

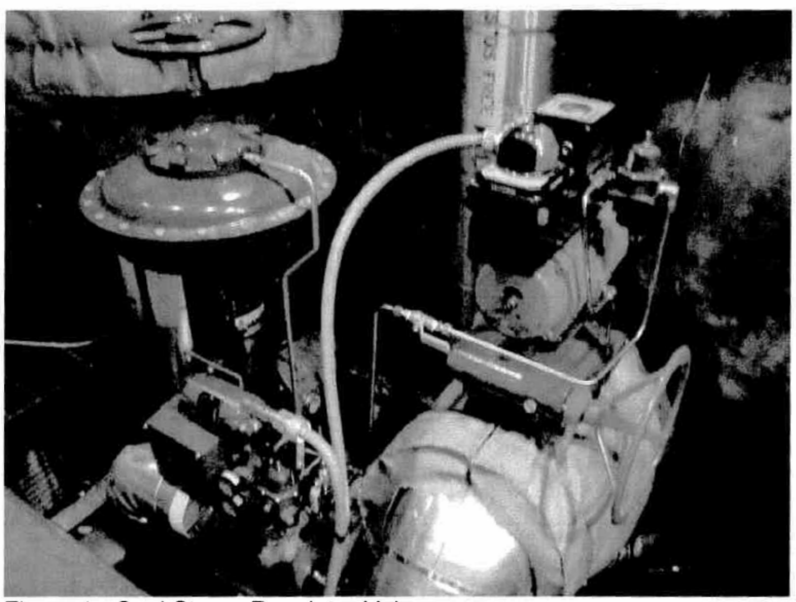


Figure 1 - Seal Steam Regulator Valves

APPENDIX B

Steam Seal System Upgrade Product Overview

GE Excerpt from Optimization and Control Report

With all three solenoids in the reset position, on-line test is achieved by tripping one of the three solenoids allowing the related trip and isolation valves to change position. The hydraulic flow path is redirected but pressure and flow are maintained. Test permissive requirements based on position sensors input preclude any part of the test sequence from proceeding until the proper conditions are met to prevent nuisance trips during testing.

All devices are spring biased to trip upon loss of external fluid supply.

2.2 STEAM SEAL SYSTEM UPGRADE PRODUCT OVERVIEW

A steam seal regulator controls the flow of sealing steam to and from the turbine shaft seals. Sealing steam is used to prevent leakage of process steam along the rotor and into the turbine hall. A detailed explanation of the operation of the steam seal system can be found in GEK-25477, *Turbine Steam Seal System*. A schematic of the system is shown on page 6 of this document.

There are two classes of shaft seals, or packings; pressure packings and vacuum packings. Pressure packings are located in the turbine shells and vacuum packings in the exhaust hood. Vacuum packings always require sealing steam. Pressure packings require sealing steam at low turbine loads but steam must be removed from them at high turbine loads. All the packings are connected together and to the steam seal regulator through a common header; the steam seal header. Reference the schematic below.

A steam seal regulator contains two valves; the SSFV valve (Steam Seal Feed Valve) and the SPUV valve (Steam Packing Unloading Valve). When the steam seal header requires steam the SSFV valve is open and the SPUV valve is closed. When steam must be removed from the header the SSFV valve is closed and the SPUV valve is open.

For a hydraulic steam seal regulator the SSFV and SPUV valves, and the mechanical-hydraulic controls for the valves, are all contained in a single unit, or assembly. See the upper schematic on page 7 of this document. This unit is a build-to-print, GE design that has been found to be costly to maintain.

This conversion replaces the single unit, or assembly, with individual hardware components. The system still functions the same way. See the lower schematic on page 7 of this document. The SSFV and SPUV valves are pneumatically operated valves, the controls are contained in a computer process controller and there is a control panel that contains a header pressure transducer. All of this equipment is purchased from GE vendors and is standard, off-the-shelf hardware.

Benefits:

- ⇨ Reduced maintenance costs
- ⇨ More readily available replacement parts

APPENDIX C

Availability of Replacement Parts and Service

"Santangelo, Antonio (GE Infra, Energy)" <antonio.santangelo@ge .com>

06/25/2009 11:51 AM

To <ToddCollins@nlh.nl.ca>

cc

Subject Availability of Spare Parts & Service

Hello Todd,

We still try to support this however trying to procure outdated mechanical hardware is becoming more difficult for the parts as years pass. GE Parts Edge has a database of all parts with delivery cycles. The site is open to all customer.

PartsEdge URL

http://www.gepower.com/online_tools/parts_edge.htm

Any of the valve parts would be available, stems, seats, bushing, they were all mfg by GE(even these parts are becoming hard to get). The issue is more the bellows and /or bourdon tube, parts of the regulator, which are not mfg by GE, vendor items. These are becoming hard to get commodities (similar issues with MHC Initial Pressure Regulators).

Difficulty with service and parts for outdated devices such as this is a good reason to pursue the retrofit.

Regards,

Tony Santangelo, P.Eng
GE Energy
Optimization & Control
Eastern Canada Sales Manager

T 514-426-2368
M 514-449-5981
antonio.santangelo@ge.com
www.ge-energy.com/oc

From: ToddCollins@nlh.nl.ca [mailto:ToddCollins@nlh.nl.ca]
Sent: Thursday, June 18, 2009 1:55 PM
To: Santangelo, Antonio (GE Infra, Energy)
Subject: Availability of Spare Parts & Service

Hi Tony;

With regards to the existing hydraulically controlled steam seal regulator servicing Unit 1, are spare parts for the regulator still available? If so, does GE still support the regulator and can GE provide the spare parts. The plant has commented that in recent years, spare parts have not been available and any required replacement parts have been acquired by having a local machine shop copy the original part. Please advise when you have a spare minute.

todd

Todd C. Collins, P.Eng.
Mechanical Design Engineer
NF Hydro
Phone: (709) 737 1342
Fax: (709) 737 1900
email: toddcollins@nlh.nl.ca

Voltage Conversion – Labrador City Report

To be filed at a later date

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador Trevor C. Andrews SIGNATURE JULY 31/09 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

GLENBURNIE LINE 2
UPGRADE DISTRIBUTION SYSTEM

April 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Glenburnie Line 2 Distribution feeder extends from the Glenburnie Terminal Station to the community of Trout River and serves approximately 300 customers. The existing line was built in 1968 and has a number of components, including blackjack poles, crossarms and insulators that have exceeded their useful life span and have become deteriorated over the years.

2 PROJECT DESCRIPTION

The scope of this project will include the design, supply and construction of an 18.5 kilometer three phase distribution line from the Tablelands area to Trout River. It will also include the replacement of approximately 20 deteriorated poles located within the first 5.5 kilometers from the Glenburnie Terminal Station. This work will include survey, design, project management, construction management, environmental assessment, inspection and commissioning. The existing line between the Tablelands area and Trout River (see Figure 1) will be removed after the new line is commissioned.

Figure 1: Line 2 Distribution Line to Trout River

3 EXISTING SYSTEM

The existing distribution line is a single 12.5 kV feeder originating from the Glenburnie Terminal Station and extending to the community of Trout River, where it provides service to approximately 300 customers. The line contains deteriorated components such as poles, cross arms and insulators that need replacement. Figures 2 and 3 contain pictures of a typical single pole structure and a deteriorated black pole respectively. The existing line is located at the base of a valley where it is regularly subjected to extreme winds, causing forced outages as a result of structure failures due to long spans and insulator flashovers. The majority of the deteriorated structures are located in the area from the Tablelands to Trout River.

Figure 2: Typical single pole structure.

Figure 3: Typical deteriorated pole (Blackjack).

3.1 Age of Equipment or System

The Glenburnie Line 2 Distribution line to Trout River was constructed in 1968. The majority of the line components in operation today were installed at the time of original construction.

3.2 Major Work and/or Upgrades

Table 1 shows the upgrading costs from the past five years:

Table 1: Major Work and Upgrades

Year	Major Work/Upgrade	Comments
2008	$20,200	Upgrading Cost
2007	$6,300	Upgrading Cost
2006	$2,200	Upgrading Cost
2005	$13,100	Upgrading Cost
2004	$13,400	Upgrading Cost

Past upgrading has included the installation of mid-span poles and the replacement of various cross-arms and insulators that have previously failed.

3.3 Anticipated Useful life

The service life of a distribution feeder, for depreciation purposes, is 30 years. Since the existing line is approximately 40 years old and deteriorating, the line has exceeded its useful life.

3.4 Maintenance History

The five-year maintenance history for the Glenburnie Line 2 Distribution line is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.1	3.6	3.7
2007	1.7	5.9	7.6
2006	0.9	6.5	7.4
2005	0.2	3.8	4.0
2004	2.5	9.1	11.6

3.5 Outage Statistics

Newfoundland and Labrador Hydro tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - (System Average Interruption Frequency Index) indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 3 lists the 2004 to 2008 SAIFI and SAIDI data for Glenburnie Line 2, 2004 to 2008 corporate values, and the latest CEA five year average (2004 to 2008) for comparison.

Table 3: SAIFI SAIDI Five Year Averages

Five Year Averages (2004 to 2008)				
	All Causes		**Defective Equipment**	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Glenburnie System	3.92	10.93	0.5	0.74
Line 2	4.48	11.13	0.43	0.66
Hydro Corporate	5.92	9.50	0.74	1.30
CEA	2.67	8.33	0.48	1.13

Although the outage statistics are not far outside Hydro's average statistics, the line is deteriorated and should be replaced to avoid failure. The work should be conducted proactively to avoid a major failure of the line resulting in an extended outage for the customers. To date, no major failures have occurred. The above statistics are based on the number of outages experienced by a line for numerous reasons, including planned maintenance, inspections and unforeseen failures. These statistics are not representative of failure only and are not meant to be a justification for the required work.

3.6 Industry Experience

Using a standardized inspection/grading system common within the utility industry, the line components proposed for replacement have been identified as close to the end of their useful lives. Hydro performs inspections on all distribution line components classifying them using the following standardized grading system:

- Grade "A" Condition: Excess of 5 years of life remaining,
- Grade "B" Condition: 1 to 5 years of life remaining, and
- Grade "C" Condition: Less than 1 year of life remaining.

3.7 Maintenance or Support Arrangements

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed. The inspection schedule is determined through a Reliability Centered Maintenance Program initiated by Hydro and is dependant on a variety of factors including geographical location, line age, and customer usage. Inspection schedules may vary between lines depending on the existing circumstances. The deteriorated components identified on this line are classified as "B" condition during the last inspection in 2006 and are scheduled to be replaced in 2010.

3.8 Vendor Recommendations

There are no specific vendor recommendations for this project.

3.9 Availability of Replacement Parts

Replacement parts are generally available however some of the existing line components are no longer a standard used by Hydro for line applications therefore increasing the level of difficulty in material procurement for repair.

3.10 Safety Performance

The following safety issues have been identified:

- The poles and cross-arms are deteriorated and pose a considerable risk to the safety of operations personnel who may be performing climbing activities to conduct regular inspections or maintenance work. Blackjack poles are no longer commonly used in the utility industry. Blackjack poles that are currently in use have surpassed their expected life span and are showing signs of major deterioration. Industry experience shows that it is common for blackjack poles to deteriorate from the inside out as a result of the thick layer of tar/creosote on the surface of the pole. The deterioration experienced on the inside of the pole causes a major reduction in strength of the structure. Utility lines comprised of blackjack poles will experience a false sense of security in that they may appear acceptable by visual inspection but the actual strength of the structure may be significantly reduced causing an increased risk of failure. In addition, failure of either of these components on a structure may result in the cascading failure of the line which may result in extended repair time.

- The porcelain insulators that were installed at the time of construction have experienced an industry wide failure. Hydro currently has a replacement program for these insulators. Intermittent failure of these insulators can result in forced outages experienced by the customers. These insulators contain cement and as the insulators age, it grows and cracks exerting increased pressure on the porcelain part of the insulators. The porcelain may crack causing insulators to fail as well as create a safety hazard to the public and Hydro employees when broken insulator parts fall to the ground.

- The porcelain cutouts have experienced numerous failures when being opened and closed. Damaged cutouts may result in equipment becoming energized and pose an electrical contact threat for operation crews. Due to these safety concerns, the porcelain cutouts no longer comply with current Hydro standards and are in the process of being replaced with new polymer cutouts.

- The existing #4 copper conductor becomes very brittle and more susceptible to breakage over time. Since this conductor was strung during original construction, there is a high probability that it has become brittle and weak. A conductor failure would result in lengthy outages and may result in potential injury or damage to persons and property.

3.11 Environmental Performance

The primary factor affecting the environmental performance is:

- The existing Glenburnie Line 2 distribution feeder is located in Gros Morne National Park. The specific area is home to many rare plant species and is an area that is visited regularly by tourists for its natural beauty.

3.12 Operating Regime

Glenburnie Line 2 is in continuous operation providing power to 293 customers in the community of Trout River.

4 JUSTIFICATION

Glenburnie Line 2 is a 12.5 kV distribution feeder that extends from Glenburnie to Trout River. The line was built in 1968. Most components were installed at the time of original construction and have exceeded their service lives of 30 years. In addition, as a result of standardized inspection and testing procedure, it has become evident that line components are deteriorated and may have remaining ultimate life spans of only one to five years before widespread failure occurs.

Failure of such components will have a negative effect on the safety and reliability performance of the line as identified earlier in the report. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions. Depending on the extent of the damage caused by a failure, alternate generation may also be required to supply service to the communities while upgrades or rehabilitation is performed. Alternative generation could be costly and result in environmental concerns such as air emissions.

It has also been recognized that some of the existing line components are no longer a standard used by Hydro for line applications; this increases the level of difficulty in material procurement for repair.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

The levelized cost of energy is a high level means to compare costs of developing two or more alternative generating sources. Therefore, the levelized cost of energy is not applicable in this case.

4.3 Cost Benefit Analysis

A cost benefit analysis calculation was not performed in this instance as only one viable alternative exists.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with this project.

4.5 Historical Information

Historical information on distribution upgrades is shown in Table 4.

Table 4: Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2009F	Upgrade Distribution System - L7 St. Anthony	689.3	
	Replace Insulators - L1 and L2 Jackson's Arm, Hampden	691.5	
	Replace Insulators – L2 Little Bay Islands	182.7	
	Replace Poles - L1 and L2 Jackson's Arm	433.7	
	Replace Poles - L1 Hampden	263.1	
	Upgrade Distribution Feeder - L36 Wabush	498.0	
2008	Replace Distribution Line - L1 South Brook	987.4	1,056.4
	Upgrade Distribution System - L1 Glenburnie	533.9	405.5
	Upgrade Distribution System - L3 St Anthony	480.1	445.0
	Upgrade Distribution System - Mary's Harbour	263.5	215.6
	Upgrade Distribution System - Port Hope Simpson	205.4	215.6
	Upgrade Distribution System - L4 Bear Cove	149.8	96.8
	Upgrade Distribution Line - L11 Wabush	107.2	115.3
	Replace Insulators - Upper Salmon	236.8	194.9
	Replace Insulators - L1 Hind's Lake	168.7	158.0
	Replace Insulators - Coney Arm	126.8	132.1
	Replace Insulators – L2 Westport	90.2	87.2
	Replace Poles – South Brook	377.5	331.2
	Replace Poles - Bay D'Espoir	322.7	257.3

Year	Project Description	Budget ($000)	Actuals ($000)
2007	Replace Poles - Barachoix L4	229.9	276.0
	Insulator Replacement - Barachoix L4	120.1	123.0
	Replace Distribution Line - Brighton	192.9	230.9
	Replace Distribution Line - Seal Cove to Pass Island	547.6	552.1
	Upgrade Distribution System – L2, L3 Farewell Head	385.3	282.0
	Replace Poles - Farewell Head	355.0	295.3
	Replace Poles - St. Brendan's	159.1	175.4
	Extend Mud Lake Submarine Cable	480.9	813.6
	Upgrade Distribution System – L1, L2 St. Anthony	364.3	301.0
	Upgrade Distribution System L1, L2 Rocky Harbour	513.5	393.7
	Upgrade Distribution System – Nain	179.4	185.8
2006	Replace Insulators - L7, L8 Bottom Waters	120.0	126.5
	Replace Insulators - L4, L5 Farewell Head	260.8	270.4
	Replace Insulators - L5, L7 - South Brook	440.7	440.8
	Replace Insulators - L4, L6 - Bottom Waters	197.5	203.4
	Replace Poles - L1 Bottom Waters	152.4	166.5
	Upgrade Distribution System - Black Tickle	281.8	270.3
	Upgrade Distribution System – L6 St. Anthony	778.3	772.2
	Upgrade Distribution System – L6 Bear Cove	577.7	622.8
	Upgrade Distribution System – L1, L3 Hawkes Bay	379.6	421.1
2005	Replace Insulators - L6 Farewell Head	246.1	132.6
	Replace Poles - English Harbour West	167.9	126.6
	Relocate Substation - Robert's Arm/Triton	318.6	331.4
	Upgrade Distribution Line - Northern L'anse au Loup	93.1	50.5
	Upgrade Distribution System – L1, L2 L'anse au Loup	635.6	280.6
	Replace Insulators - L1 Plum Point	433.3	217.7
	Replace Insulators - L3 Hawke's Bay	292.3	103.5
	Upgrade Distribution Line - Cooks Harbour	717.5	477.8
	Install Midspan Poles - L6 Farewell Head	49.5	55.9
2004	Replace Insulators - L1 Bottom Waters	417.9	240.1
	Replace Insulators - L1 and L2 Fleur De Lys	385.1	237.4
	Replace Insulators - L1 South Brook	141.5	75.6
	Replace Poles - Bottom Waters	342.8	249.0
	Replace Poles - L1 St. Anthony	650.4	499.6

4.6 Forecast Customer Growth

Load forecasts performed at the end of 2008 do not show any load change for the Glenburnie Line 2 distribution feeder in the next five years.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4.8 Losses during Construction

There are no anticipated energy losses during construction.

4.9 Status Quo

The status quo is not an acceptable alternative for the following reasons:

- The majority of line components were installed at the time of original construction and have exceeded their service lives of 30 years. They are heavily deteriorated with estimated life spans ranging between one and five years based on regular inspection.

- Failure to upgrade the existing feeder could increase the number of outages of varying durations to the customers it serves.

- Deteriorated/outdated equipment poses considerable safety risk to Hydro operations personnel who maintain the lines, as well as individuals residing in and occupying the area.

4.10 Alternatives

There are no viable alternatives to this upgrade work.

5 CONCLUSION

This project is required to ensure that a reliable energy supply is available for the customers served by the Glenburnie Line 2.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 5.

Table 5: Budget Estimate

Project Cost:($ x1,000)	**2010**	**2011**	**2012**	**2013**	**Total**
Material Supply	0.0	335.0	150.0	0.0	485.0
Labour	210.0	90.0	505.0	110.0	915.0
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	1016.0	0.0	1,016.0
Other Direct Costs	32.0	69.0	96.0	24.0	221.0
O/H, AFUDC & Escln.	25.3	84.2	347.6	194.9	652.0
Contingency	0.0	0.0	0.0	267.7	267.7
TOTAL	**267.3**	**578.2**	**2114.6**	**596.6**	**3,556.7**

5.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	Milestone
Project Startup	June 2010
Field Assessment/Line Design	September 2011
Material Order/Procurement	March 2012
Installation Commences	April 2012
Installation Complete	October 2013
Project Closeout	December 2013

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
Paul Dillon
SIGNATURE
31-JULY-2009
DATE
NEWFOUNDLAND & LABRADOR

Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

2010 WOOD POLE LINE MANAGEMENT

June 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) maintains approximately 2,400 kilometers of wood pole transmission lines operating at 69, 138 and 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages, with the maximum age being 44 years. In 2009 approximately 80 percent of the transmission pole assets are over 20 years old with about 50 percent of these at or over 30 years old. The remaining assets are less than 20 years old.

Prior to 2003, Hydro's pole inspection and maintenance practices followed the traditional utility approach of sounding inspections only. In 1998, Hydro decided to take core samples on selected poles to test for preservative retention levels and pole decay. The results of these tests raised concerns regarding the general preservative retention levels in wood poles. Poles become susceptible to fungi and/or insect attack as the preservative levels deplete. Figure 1 illustrates typical wood pole inspection techniques. Figure 2 shows typical wood pole inspection results.

Figure 1 - WPLM Inspection Techniques

Figure 2 - Typical Wood Pole Inspection Results

Between 1998 and 2003, Hydro undertook additional coring and preservative testing. This testing confirmed that there were a significant number of poles which had a preservative level below that required to maintain the required design criteria. During this period, certain poles were replaced because the preservative level had lowered to the point that decay had advanced and the pole was no longer structurally sound. These inspections and the analysis of the data confirmed that a more rigorous wood pole line management program was required.

Hydro first initiated the Wood Pole Line Management (WPLM) program as a pilot study in 2003. It was determined that the program should continue as a long-term asset management and life extension program. The program was presented to the Board of Commissioners of Public Utilities (the Board) in October 2004 as part of Hydro's 2005 Capital Budget Application and was entitled "Replace Wood Poles – Transmission". The proposal was supported in the application by the Hydro internal report titled "Wood Pole Line Management Using RCM Principles" by Dr. Asim Haldar, Ph.D, P.Eng.

The Board found that "This approach (by Hydro) is a more strategic method of managing wood poles and conductors and associated equipment and is persuaded that the new WPLM Program, based on Reliability Centered Maintenance (RCM) principles, will lead to an extension of the life of the assets, as well as a more reliable method of determining the residual life of each asset. One of the obvious benefits of RCM will be to defer the replacement of these assets thereby resulting in a direct benefit to the ratepayers".

The Board approved the project submitted in the 2005 Capital Budget in Order No. P.U. 53 (2004). As part of its annual Capital Budget Application process, Hydro committed to provide the Board with an update of the program work that includes both a progress report of the work completed as well as a forecast of the future program objectives. This report would be provided with the annual Capital Budget Application.

2 PROJECT DESCRIPTION

The WPLM program is a condition-based program, which uses the basic RCM principles and strategies. Under the program, line inspection data in each year is analyzed and appropriate recommendations are made for necessary refurbishment and/or replacement of line components (poles/structures, hardware, conductor, etc.) in the subsequent year. The inspection data and any refurbishment and/or replacement of assets are recorded in a centralized database for easy access and future tracking.

The program is aimed at early detection and treatment of the wood poles before the integrity of the structures is jeopardized. If the deterioration of the structures is not detected early enough, then the reliability of the structures will affect the reliability of the line and the system as a whole. It may also create safety issues and hazards for Hydro personnel and for the general public.

To give the quantitative benefits on the improvement of transmission line reliability, sufficient long term data, derived from two full inspection cycles will be required to provide adequate statistical evidence. In the absence of this long term data, an analysis of recent ice storms, such as in March of 2008, can provide a snapshot on how the transmission lines are performing. On March 18-19, 2008 there was a severe ice storm on the Avalon Peninsula. Hydro's test site at Hawke Hill recorded more than 25 mm of radial glaze ice which exceeds the design load of the wood poles on the Avalon Peninsula. There were no reported failures because the poles which were not structurally sound were already replaced during the first WPLM inspection cycle between 2003 and 2007. This supports the need for the proactive condition base management program which Hydro is pursuing.

3 EXISTING SYSTEM

As stated previously, Hydro maintains approximately 2,400 km of wood pole transmission lines operating at 69, 138 and 230 kV. These lines consist of approximately 26,000 transmission size poles of varying ages.

As this is a recurring inspection of transmission lines, there is no relevant data for:

- Maintenance History;
- Outage Statistics;
- Safety Performance;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Environmental Performance; or
- Operating Regime.

3.1 Age of Equipment or System

The age of each line can be found in Appendix B.

3.2 Major Work or Upgrades

This section is not applicable since the WPLM Program encompasses the annual inspection, treatment and refurbishment of all of Hydro's wood pole transmission lines.

3.3 Anticipated Useful life

The anticipated useful life of a wood pole transmission line constructed is approximately 40 years. Through this maintenance program, Hydro plans to further extend the life of the lines.

4 JUSTIFICATION

A 1998 inspection on the Avalon Peninsula indicated that 48 percent of the poles sampled did not meet the minimum preservative retention level that would protect the pole against rot or insect damage. A similar program in the Central region verified the results obtained from the Avalon Peninsula. At the time, re-treatment of poles on the Avalon Peninsula was not pursued due to budget constraints. Recent failures near the Hardwoods Terminal Station showed further deterioration of these poles. These conditions justify the strong need for a well-managed wood pole inspection and treatment program. Full scale tests of poles at Memorial University since 1999 indicate a 25 percent reduction of average pole strength over a 35-year period. It is anticipated that Hydro will finalize a proposal with the Faculty of Engineering to support a graduate student in the second quarter of 2009. This student will focus on research and development of a Non-Destructive Evaluation (NDE) of wood poles. Once this is finalized, Hydro will continue its full scale testing of poles at the university.

The WPLM program detects "danger poles" early to avoid safety hazards and to identify poles that are at early stages of decay to ensure that corrective measures can be taken to extend the average life of these poles. Money is saved in the long term by deferring the cost of rebuilding lines and avoiding forced outages.

As this is a recurring inspection of transmission lines, there is no relevant data for the following:

- Net Present Value;
- Levelized Cost of Energy;
- Cost Benefit Analysis;
- Forecast Customer Growth;
- Energy Efficiency Benefits; or
- Losses during Construction.

4.1 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for the project.

4.2 Historical Information

The five-year historical information for the WPLM program is supplied in Table 1 below. No units or cost per unit is available, since the work is not easily defined into individual units such as a line or structure number. The actual work completed is variable and is dependent on the actual condition of the asset. For example, in most cases the work completed on any one structure is not related to the work on the next structure (i.e. one structure may require a pole replacement and the next structure may need a crossarm or an insulator replacement). The same is true for a breakdown by individual transmission line, where the cost will be affected by the configuration and voltage of the line, its age and geographical location. Table 2 provides the annual statistics for pole replacement and pole component replacement for the five years prior to implementation of the WPLM program and for the years since implementation of the program.

Table 1
Historical WPLM Program Expenditures

Year	Budget ($000)	Actuals ($000)
2009F	2,256.2	
2008	2,188.3	2,393.2
2007	2,147.8	2,214.1
2006	2,302.6	2,362.5
2005	2,587.6	2,612.5

Table 2

Annual Statistics of Pole and Pole Component Replacement

Year	Poles	Crossarm	Kneebrace	Crossbrace	Comments
1999	138	7	20	2	
2000	44	30	21	30	
2001	21	16	2	2	
2002	126	53	6	61	
2003	34	29	13	55	
2004	54	13	12	22	Start of WPLM
2005	99	47	43	58	
2006	144	30	18	21	
2007	97	31	11	19	
2008	93	27	27	25	
TOTAL	850	283	173	295	
’99 to ‘03	363	135	62	150	5 Years Before WPLM
’04 to ‘08	487	148	111	145	5 Years Since WPLM

4.3 Update of 2008 Work

The first objective of the 2008 program was to inspect, test and treat at least 2,949 poles and associated line components. The program is built on the strategy of focusing on the older lines first and working towards the newer lines. Table 3 summarizes the inspection accomplishments for 2008.

Table 3

2008 Inspections

Regions	Line Name	Year In Service	Voltage Level	Target Number of Poles Inspected	Actual Poles Inspected	% Complete
Eastern	TL-218	1983	230 kV	19	19	100%
	TL-219	1990	138 kV	400	413	103%
Central	TL-232	1981	230 kV	417	421	101%
	TL-251	1981	69 kV	112	112	100%
	TL-252	1981	69 kV	141	141	100%
	TL-253	1982	69 kV	188	188	100%
Western	TL-215	1969	69 kV	250	250	100%
	TL-250	1987	138 kV	157	157	100%
Northern	TL-229	1976	69 kV	200	197	99%
	TL-239	1982	138 kV	249	250	100%
	TL-244	1983	138 kV	100	102	102%
	TL-257	1970	69 kV	267	269	101%
Labrador	TL-240	1976	138 kV	400	300	75%
Total				2,900	2,819	97%

Overall, the total number of poles inspected was within 3 percent of the target value. Although individual lines may display larger differences, the overall total for most regions was within this margin. The only line that showed a large difference in the actual number of poles inspected was TL-240 in the Labrador region, where labour shortages hampered the inspection progress.

Another objective of the 2008 program was the replacement of defective components identified in the 2007 inspections. A summary of the work completed in 2008 is given in Table 4.

Table 4

Summary of 2008 Refurbishment

Item	TL 232	TL 251	TL 252	TL 220	TL 212	TL 218	TL 219	TL 250	TL 229	TL 239	TL 241	TL 244	TL 257	TL 240
Poles	38	13	2	6	1			4	1	1	3	1	1	
Crossarms	4	13	8	1		1								
Crossbracing	22					1		1		1				
Kneebraces	27													
Insulators	2							4		1				
Miscellaneous Hardware	40	13	5		2	6	3	84	19	2	6	7	19	
Foundations and Anchors	1	1	1		1			3	1	1		3	1	
Leaning Structures		1	3		1			2	1			1	1	

In addition to this scheduled work from the 2007 inspection program, an additional 22 poles were found on TL-215 to be rated 5 and required immediate replacement. Poles that are rated 5 are considered to be in such poor condition, that they should be replaced immediately. This work took place in October 2008.

4.4 2009 Work Plans

In February of 2009, a review of the long term inspection schedule for the WPLM Program was completed. As a result of this review, four transmission lines (TL-256, TL-261, TL-262 and TL-263) that vary in age between 6 and 13 years old, but scheduled for inspection in years 2011 through 2012, were deferred. Because of their young age, there was no perceived benefit in inspecting and treating these lines until they reach 20 years of age. This resulted in the overall inspection schedule, including 2009, being adjusted accordingly. The proposed inspection and treatment work for 2009 is shown summarized in Table 5.

Table 5

2009 Work Plan

Regions	Line Name	Year In Service	Voltage Level	Target Number of Poles to Inspect
Eastern	TL-219	1990	138kV	350
Central	TL-220	1970	69 kV	273
	TL-233	1973	230 kV	334
	TL-234	1981	230 kV	120
Western	TL-215	1969	69 kV	187
	TL-209	1971	230 kV	90
Northern	TL-259	1990	138 kV	202
	TL-257	1970	69 kV	298
Labrador	TL-240	1976	138 kV	400
Total				2,254

As a result of the 2008 inspection program, a refurbishment program will begin during the summer months of 2009 and continue into the fall. This will include the replacement of approximately 80 poles; 25 crossarms; 65 cross-braces; and many other smaller components. A detailed list of the work to be completed in 2009 is provided in Appendix A.

4.5 Alternatives

No alternatives have been explored. In 2005, the Board found that this approach was justified and prudent and approved the expenditures as submitted in the 2005 Capital Budget in Board Order No. P.U. 53 (2004).

This report provides an update of the program work, which includes both a progress report of the work completed as well as a forecast of the future program objectives. This report is provided with the annual Capital Budget Application.

5 CONCLUSION

In conclusion, the major objectives for the 2008 program were achieved, with the exception of those points detailed above. The budget estimate of $2.188 million was exceeded by $204,859 for a total expenditure of $2.393 million. This overrun was mainly caused by the unbudgeted cost to replace the poles on TL-215.

The framework for systematically analyzing a large volume of wood pole transmission line inspection data, developed using the reliability based analysis technique, is still under expansion to include additional components. The method uses a hybrid approach where the uncertainties in load and strength values and the strength deterioration due to aging are taken into account with the condition rating of each pole to develop a condition matrix table.

5.1 Budget Estimate

The WPLM Budget contained in Table 6 includes the complete inspection of the stated lines, including the visual inspection supported by field testing each pole using non-destructive testing, and limited full-scale testing to establish correlation full treatment of the pole (internal and external) as required.

It is assumed that a percentage of those poles inspected will also be rejected according to the IOWA curve (shown in Appendix B) depending on their age and group. Poles rejected in the field will be analyzed with respect to reliability issues, and if rejected after structural analysis, a recommendation to refurbish and/or replace will be made.

Using the average age of the poles being inspected along with the IOWA curve, the anticipated pole replacement rate is calculated and this is used to develop the future refurbishment program. A schedule of the pole inspections from 2010 to 2014 is provided in Appendix B. The table also provides the average age and pole rejection rate for each year.

Table 6
WPLM Budget

Project Cost ($x 1,000):	2010	2011	2012	2013	2014	BEYOND '15 to '23	TOTAL
Material Supply	482.3	412.5	201.2	501.2	633.2	4,145.2	6,375.6
Labour	1,257.9	876.9	974.7	1,946.2	2,275.7	14,900.7	22,232.1
Consultant	100.0	100.0	100.0	100.0	100.0	975.0	1,475.0
Contract Work	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	115.8	93.2	87.5	97.3	113.8	882.5	1,390.1
O/H, AFUDC & Escln.	156.7	172.3	190.7	483.0	709.9	4,648.1	6,360.7
Contingency	195.6	163.7	136.3	264.5	312.3	2,044.8	3,117.2
TOTAL	2,308.3	1,818.6	1,690.4	3,392.2	4,144.9	27,596.3	40,950.7

As a result of the change in the inspection schedule, there have been some adjustments to the five year plan budget. The number of inspections in 2010 and 2011 has been spread over years 2010 through 2012, which has resulted in a flattening out of costs during this time period. We have also bumped up the schedule for some older lines from 2013 into 2012. This was done to replace some of the inspections that were deferred, as well as to correct fluctuations in the schedule that were to take place between 2013 and 2016. This has resulted in a significant increase to the budget in 2013. It should be noted that the increase in the 2013 and 2014 budget was expected as this represents the beginning of the second cycle of inspections which generally focuses on the older lines that are over 40 years of age.

5.2 Project Schedule

The annual project schedule is highly dependent on the annual work load and availability of outages and is therefore determined during the spring of each year.

APPENDIX A

2009 Refurbishment Work

Refurbishment Work to be Completed in 2009

Region	East	Central	West	North	Lab.	Total
Total Number of Poles Inspected in 2008	**432**	**862**	**407**	**818**	**300**	**2819**
Number of Poles	**0**	**57**	**15**	**1**	**10**	**83**
Number of Crossarms	**0**	**19**	**1**	**0**	**0**	**20**
Number of Crossbracing	**0**	**67**	**0**	**0**	**0**	**67**
Number of Kneebraces	**0**	**24**	**0**	**0**	**0**	**24**
Number of Deadend Clamp	**0**	**2**	**2**	**1**	**0**	**5**
Number of Deadend Assembly	**0**	**4**	**1**	**0**	**0**	**5**
Number of Guy Wire	**0**	**3**	**5**	**1**	**0**	**9**
Number of Insulators	**1**	**1**	**2**	**0**	**0**	**4**
Number of Insulator Hardware	**0**	**2**	**0**	**1**	**0**	**3**
Number of Insulator Plumbness	**0**	**4**	**0**	**3**	**0**	**7**
Number of Structure Plumbnes	**0**	**0**	**1**	**6**	**0**	**7**
TOTAL NUMBER OF ITEMS	**1**	**183**	**27**	**13**	**10**	**234**

APPENDIX B

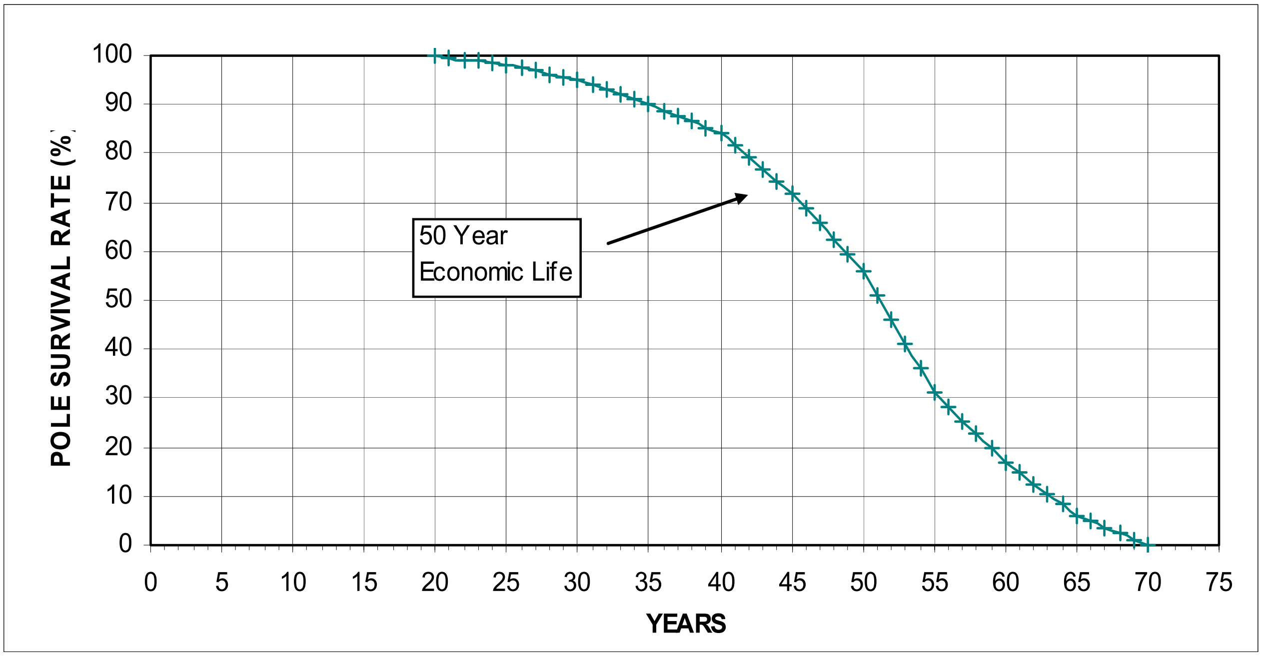
WPLM Inspection Schedule 2009-2014

(with Average Age of Transmission Lines and Estimated Pole Rejection Rates)

WPLM Inspection Schedule 2009 to 2014

Line	# poles	Year	2009	2010	2011	2012	2013	2014
No. of Poles Inspected			**2254**	**2015**	**1727**	**2262**	**2660**	**2658**
Weighted Average Age			**1981**	**1984**	**1984**	**1973**	**1972**	**1974**
Age at Inspection			**28.13**	**26.31**	**26.87**	**39.22**	**40.84**	**39.88**
Rejection Factor			**2.6%**	**1.6%**	**1.6%**	**9.9%**	**10.9%**	**9.9%**
Central								
TL 220	786	1970	273		240	273		
TL 234	489	1981	120	120				
TL 246	274	1981				274		
TL 251	579	1981						
TL 252	652	1981						
TL 260	463	1990		100	363			
TL 210	606	1969						
TL 233	640	1973	334	306				
TL 222	914	1967					500	421
TL 254	218	1988		218				
TL 223	351	1966						280
TL 224	825	1968				300	358	151
TL 253	188	1982						
TL 232	755	1981						
TL 263	730	2002						
Eastern								
TL 201	751	1966				206	230	203
TL 203	417	1965				120	150	178
TL 218	446	1983						
TL 212	312	1966						
TL 219	1750	1990	350	350	363			
Western								
TL 215	437	1969	187					
TL 209	185	1971	90	95				
TL 243	159	1978					171	
TL 225	49	1970						
TL 233	640	1973					150	320
TL 250	1283	1987						
TL 245	285	1969				282		
Labrador								
TL 240	2640	1976	400	400	400	329	380	380
Northern								
TL 221	594	1970				300	221	
TL 229	308	1976						
TL 241 (O)	552	1983						
TL 241 (N)	530	1983						250
TL 244	274	1983						
TL 239	874	1982						
TL 226	893	1970				178	250	250
TL 227	972	1970					250	225
TL 257	691	1988	298	126				
TL 256	524	1996						
TL 259	863	1990	202	300	361			
TL 261	511	1996						
TL 262	25	2002						

IOWA CURVE (Used to Determine Pole Replacement Rates)



The pole rejection rate is one minus the Pole Survival Rate.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador Trevor C. Andrews SIGNATURE July 3/09 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

DISTRIBUTION LINE UPGRADES - 2010

June 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) provides service to residents in select rural communities within the province through the use of existing distribution systems. The distribution systems typically consist of a substation coupled with a wood pole distribution line that directs power from the station to service drops throughout the community. This report will be focused on distribution lines located in the communities of Roddickton and Makkovik that have been identified as requiring upgrades to the existing infrastructure.

The distribution lines referred to in this report were originally constructed over 40 years ago. The majority of line components was installed at the time of original construction and has far exceeded the economic life of 30 years. In addition, as a result of standardized inspection and testing procedures, it has become evident that line components are greatly deteriorated and may have remaining life spans of only one to five years before widespread failure occurs. The majority of the line components identified for replacement are no longer used by Hydro due to the fact that industry experience has shown that they are unsafe by today's standards or commercially unavailable.

If the identified components are not replaced in the near future, widespread failure could possibly occur. Failure of such components will have a negative effect on the safety and reliability performance of the line. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

2 PROJECT DESCRIPTION

This project is required to replace distribution line components on the following distribution systems:

- Roddickton – Line 4 (L4)
    - 261 Poles
    - 220 Pin Type Insulators
    - 200 Suspension Insulators
    - 57 Porcelain Cut-Outs

- Makkovik – Line 1 (L1)
    - 80 Poles
    - 200 Pin Type Insulators
    - 50 Suspension Insulators
    - 50 Porcelain Cut-Outs
    - 50 Distribution Transformers
    - 3.0 km Copper Primary Conductor
    - 2.0 km Bare Secondary Conductor

3 EXISTING SYSTEM

Roddickton

The Roddickton – L4 distribution line is a 12.5 kV three phase feeder that was originally constructed in 1968. The line extends a distance of 6 kilometers reaching the Roddickton Mini Hydro Plant, after which it is a single phase line for 15 kilometers that provides service to the communities of Conche and South West Grouse with approximately 150 customers.

Makkovik – L1

The Makkovik – L1 distribution line is a 4.16 kV three phase feeder that was originally constructed in 1960 and covers a distance of 5.4 kilometers reaching the Ranger Bight Road pump house. L1 has several single phase taps off to a communication tower, the airport, and the sewage lift station. The existing L1 distribution system is the primary supply of power to the community of Makkovik with approximately 200 customers.

3.1 Age of Equipment or System

The Roddickton – L4 distribution line was constructed in 1968 and is currently 41 years old.

The Makkovik – L1 distribution line was constructed in 1960 and is currently 49 years old.

The majority of components on each of these lines were installed at the time of original construction. In addition, minor upgrade/maintenance work has been conducted regularly, including the replacement of various poles, transformers and associated hardware as deemed necessary through regular field inspections.

3.2 Major Work and/or Upgrades

Table 1 shows the upgrades that have occurred since installation:

Table 1: Minor Work and Upgrades

Year	Roddickton – L4	Makkovik – L1
2008	$ 47,400	$ 10,532
2007	$ 5,200	$ 8,200
2006	$ 11,500	$ 24,150
2005	$ 10,700	$ 4,100
2004	$ 3,100	$ 8,371

The majority of these upgrades were only minor. No major upgrade work has been conducted on these lines to date.

Roddickton – L4

The largest amount of upgrade/maintenance work performed on L4 was conducted in 2008 and included the installation of mid-span poles and pole top brackets to remove conductor clearance violations. All other costs were associated with routine maintenance.

Makkovik – L1

The largest amount of upgrade/maintenance work performed on L1 was conducted in 2006 and included the installation of two poles, four spans of primary, and a three gang operated switch. All other costs were associated with service extensions and routine maintenance. Over the past five years, there have been numerous service extensions on the system. Service extensions consist of construction that is required to supply new customers with power and may include tasks such as installing new poles and/or adding a service drop to a new building or facility.

3.3 Anticipated Useful life

The service life of a distribution line is 30 years.

3.4 Maintenance History

The five-year maintenance history for each of the lines is shown in Table 2:

Table 2: Five-Year Maintenance History

Year	Preventative Maintenance (x$1,000)	Corrective Maintenance (x$1,000)	Total Maintenance (x$1,000)
Roddickton – L4			
2008	1.2	8.9	10.0
2007	0.2	7.6	7.9
2006	0.4	5.2	5.6
2005	0.6	7.2	7.8
2004	0.3	7.5	7.8
Makkovik – L1			
2008	47.0	22.0	69.0
2007	46.0	19.0	65.0
2006	45.0	18.0	63.0
2005	40.0	13.0	53.0
2004	40.0	11.0	51.0

Maintenance costs associated with these distribution lines include all work directly linked to preventative maintenance tasks such as line inspection, trouble calls and routine minor maintenance.

3.5 Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - is the System Average Interruption Frequency Index per year which indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 3 lists the 2004 to 2008 SAIFI and SAIDI data, 2004 to 2008 corporate values, and the latest CEA five year average (2004 to 2008) for comparison. These statistics are not justification for this project.

Table 3: Outage Statistics - SAIFI SAIDI Data

Five Year Averages (2004 to 2008)				
Location	**All Causes**		**Defective Equipment**	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Roddickton – L4	7.87	19.08	0.41	0.25
Makkovik – L1	9.15	8.74	0.29	1.05
Hydro Corporate	5.92	9.50	0.74	1.30
CEA (2004 – 2008)	2.67	8.33	0.48	1.13

Although the outage statistics for several of the lines are not far outside Hydro's average statistics, the lines are deteriorated and should be replaced to avoid failure. The work should be conducted proactively to avoid a major failure of the line resulting in an extended outage for the customers. To date, no major failures have occurred. The above statistics are based on the number of outages experienced by a line for numerous reasons, including planned maintenance, inspections and unforeseen failures. These statistics are not representative of failure only and are not meant to be a justification for the required work.

3.6 Industry Experience

Using a standardized inspection/grading system within the utility industry, the line components proposed for replacement have been identified as close to the end of their useful lives. It has also been recognized that some of the existing line components are no longer a standard used by Hydro for line applications; this increases the level of difficulty in material procurement for repair.

Hydro performs inspections on all distribution line components classifying them using the following standardized grading system:

- Grade “A” Condition: Excess of 5 years of life remaining,
- Grade “B” Condition: 1 to 5 years of life remaining, and
- Grade “C” Condition: Less than 1 year of life remaining.

3.7 Maintenance or Support Arrangements

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed. The inspection schedule is determined through a Reliability Centered Maintenance Program initiated by Hydro and is dependant on a variety of factors including geographical location, line age, and customer usage. Inspection schedules may vary between lines depending on the existing circumstances. The deteriorated components identified on each of these lines were classified as “B” condition during the last inspection in 2006 and are scheduled to be replaced in 2010.

3.8 Vendor Recommendations

There are no specific vendor recommendations for this project.

3.9 Availability of Replacement Parts

Replacement parts are generally available however some of the existing line components are no longer a standard used by Hydro for line applications therefore increasing the level of difficulty in material procurement for repair.

3.10 Safety Performance

The following safety issues have been identified:

- The poles are deteriorated and pose a risk to the safety of operations personnel who may be performing climbing activities to conduct regular inspections or maintenance work. The majority of the poles identified as deteriorated are blackjack poles that are no longer commonly used in the utility industry. Industry experience shows that it is common for blackjack poles to deteriorate from the inside out as a result of the thick layer of tar/creosote on the surface of the pole. The deterioration experienced on the inside of the pole causes a major reduction in strength of the structure. Utility lines comprised of blackjack poles will experience a false sense of security in that they may appear acceptable by visual inspection but the actual strength of the structure may be significantly reduced causing an increased risk of failure.

- The porcelain cutouts have experienced numerous failures when being opened and closed. Damaged cutouts may result in equipment becoming energized and pose an electrical contact threat for operation crews. Due to these safety concerns, the porcelain cutouts no longer comply with current Hydro standards and are in the process of being replaced with new polymer cutouts.

- Copper Conductor becomes very brittle and more susceptible to breakage overtime. A conductor failure would result in lengthy outages and may result in potential injury or damage to persons and property.

3.11 Environmental Performance

The following environmental issues have been identified:

- Blackjack poles (see Figure 1) are considered to be environmentally unacceptable due to the threat of ground/water contamination from the presence of the creosote coating on the surface of the pole. Hydro has implemented a policy and procedure to remove and discard all blackjack poles from the system. Hydro has established this initiative in compliance with applicable environmental regulatory authorities.

Figure 1: Typical Blackjack Wood Pole Structure

All work undertaken by Hydro would be assessed, monitored and regulated by the Hydro Environment Group. Hydro would work proactively with any regulating authorities to prevent and reduce any negative environmental affects on the surrounding environment. Environmental permits will be required to complete the proposed work.

3.12 Operating Regime

Roddickton – L4 is in continuous operation providing service to approximately 150 customers in the communities of Conche and South West Grouse.

Makkovik – L1 is in continuous operation providing service to approximately 200 customers in the community of Makkovik.

4 JUSTIFICATION

The distribution lines referred to in this report were originally constructed over 40 years ago. The majority of line components, still in operation, were installed at the time of original construction and has far exceeded their economic and useful life spans. As result of standardized inspection and testing procedures, it has become evident that the line components are greatly deteriorated and may have a remaining life span of only one to five years before widespread failure occurs.

The majority of the line components identified for replacement are no longer used by Hydro due to the fact that industry experience has shown that they are considered unsafe and environmentally unfriendly by today's standards. It has also been recognized that some of the existing line components are no longer a standard item used by Hydro for line applications; this increases the level of difficulty in material procurement for repair.

Failure of such components will have a negative effect on the safety and reliability performance of the line as identified earlier in the report. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather condition. Depending on the extent of the damage caused by a failure, alternate generation may also be required to supply service to the communities while upgrades or rehabilitation is performed. The costs associated with alternative generation could be very costly and result in environmental concerns such as air emissions.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity since no new generation source is involved.

4.3 Cost Benefit Analysis

A cost benefit analysis calculation was not performed in this instance as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with this project.

4.5 Historical Information

A distribution line upgrade consists of the replacement of many different types of equipment such as conductor; poles; insulators; transformers; guy wires; and any other associated hardware. A line could cover several kilometers or only a few. Because of the variety in line lengths and equipment, unit costs for a particular job are not available. Table 4 below lists budgeted and actual costs for line upgrades in the last five years.

Table 4
Distribution Upgrading

Year	Project Description	Budget ($000)	Actuals ($000)
2009F	Upgrade Distribution System - L7 St. Anthony	689.3	
	Replace Insulators - L1 and L2 Jackson's Arm, Hampden	691.5	
	Replace Insulators - L2 Little Bay Islands	182.7	
	Upgrade Distribution Feeder - L36 Wabush	498.0	
2008	Replace Distribution Line - L1 South Brook	987.4	1,056.4
	Upgrade Distribution System - L1 Glenburnie	533.9	405.5
	Upgrade Distribution System - L3 St Anthony	480.1	445.0
	Upgrade Distribution System - Mary's Harbour	263.5	215.6
	Upgrade Distribution System - Port Hope Simpson	205.4	215.6
	Upgrade Distribution System - L4 Bear Cove	149.8	96.8
	Upgrade Distribution Line - L11 Wabush	107.2	115.3
	Replace Insulators - Upper Salmon	236.8	194.9
	Replace Insulators - L1 Hind's Lake	168.7	158.0
	Replace Insulators - Coney Arm	126.8	132.1
	Replace Insulators - L2 Westport	90.2	87.2
2007	Insulator Replacement - Barachoix L4	120.1	123.0
	Replace Distribution Line - Brighton	192.9	230.9
	Replace Distribution Line - Seal Cove to Pass Island	547.6	552.1
	Upgrade Distribution System - L2, L3 Farewell Head	385.3	282.0
	Extend Mud Lake Submarine Cable	480.9	813.6
	Upgrade Distribution System - L1, L2 St. Anthony	364.3	301.0
	Upgrade Distribution System L1, L2 Rocky Harbour	513.5	393.7
	Upgrade Distribution System - Nain	179.4	185.8
	Replace Insulators - L7, L8 Bottom Waters	120.0	126.5
2006	Replace Insulators - L4, L5 Farewell Head	260.8	270.4
	Replace Insulators - L5, L7 - South Brook	440.7	440.8
	Replace Insulators - L4, L6 - Bottom Waters	197.5	203.4
	Upgrade Distribution System - Black Tickle	281.8	270.3
	Upgrade Distribution System - L6 St. Anthony	778.3	772.2
	Upgrade Distribution System - L6 Bear Cove	577.7	622.8
	Upgrade Distribution System - L1, L3 Hawkes Bay	379.6	421.1
2005	Replace Insulators - L6 Farewell Head	246.1	132.6
	Upgrade Distribution Line - Northern L'anse au Loup	93.1	50.5
	Upgrade Distribution System - L1, L2 L'anse au Loup	635.6	280.6
	Replace Insulators - L1 Plum Point	433.3	217.7
	Replace Insulators - L3 Hawke's Bay	292.3	103.5
	Upgrade Distribution Line - Cooks Harbour	717.5	477.8
2004	Replace Insulators - L1 Bottom Waters	417.9	240.1
	Replace Insulators - L1 and L2 Fleur De Lys	385.1	237.4
	Replace Insulators - L1 South Brook	141.5	75.6

4.6 Forecast Customer Growth

There is no anticipated load growth on these systems for the next five years and therefore forecast customer growth will have no impact on this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4.8 Losses during Construction

There are no anticipated energy losses during construction.

4.9 Status Quo

The status quo is not an acceptable alternative for the following reasons:

- The majority of line components were installed at the time of original construction and has far exceeded their economic lives of 30 years. They are heavily deteriorated with an estimated life span ranging between one and five years based on regular inspection.
- Failure to upgrade the existing feeder could increase the number of outages of varying durations to the customers it serves.
- Deteriorated/outdated equipment poses considerable safety risk to Hydro operations personnel who maintain the lines, as well as individuals residing in and occupying the area.

4.10 Alternatives

There are no viable alternatives to replacing the deteriorated line components.

5 CONCLUSION

This project is required to ensure that a reliable energy supply is available for the customers serviced by each of these lines. Since the existing lines are over the age of 40 and various components of these lines are being deteriorated, these items have exceeded their service lives and are recommended for replacement.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 5.

Table 5: Budget Estimate

Location	**Roddickton – L4**		**Makkovik – L1**		
Project Cost: ($ x 1,000)	**2010**	**2011**	**2010**	**2011**	**Total**
Material Supply	100.0	100.0	0.0	150.0	350.0
Labour	41.4	84.5	44.6	88.8	259.3
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	461.0	0.0	336.0	797.0
Other Direct Costs	6.0	61.2	7.4	21.5	96.1
O/H, AFUDC & Escln.	13.2	110.5	5.1	81.3	210.1
Contingency	0.0	85.4	0.0	64.8	150.2
TOTAL	**160.6**	**902.6**	**57.1**	**742.4**	**1,862.7**

5.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Project Milestone	Roddickton – L4	Makkovik – L1
Initiation	June 2010	June 2010
Design Complete	November 2010	November 2010
Equipment Ordered	November 2010	November 2010
Installation Commences	June 2011	July 2011
Installation Complete	September 2011	September 2011
Project Closeout	October 2011	October 2011

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador Paul Dillon SIGNATURE 31-JULY-2009 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

TL-244 LINE UPGRADE

May 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

TL-244 is one of 17 138 kV transmission lines on the Newfoundland and Labrador Hydro (Hydro) Interconnected System. It was originally built in 1983, and is situated between the Plum Point and Bear Cove Terminal Stations on the Northern Peninsula (Figure 1).

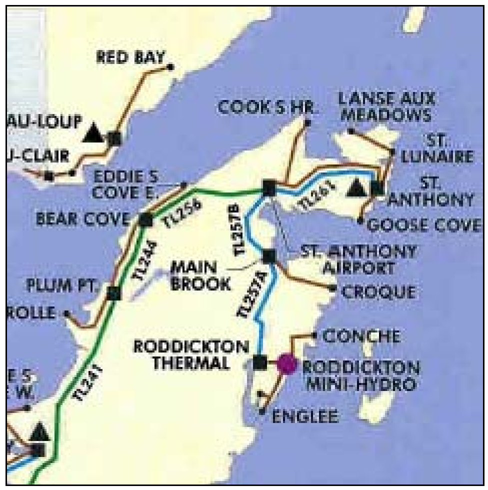


Figure 1: Route Photo of TL-244

TL-244 is part of the 138 kV system that secures reliable power to the most northern regions of the Great Northern Peninsula. This system is comprised of six transmission lines, connected in series, whereby if one line fails the entire region above the failure point will experience an outage. Their upkeep and maintenance are a priority. Because of the lack of redundancy, it is difficult to obtain outages on the line and any proposed work will have to consider these restrictions.

The line has a total length of 23 km, and consists of 131 wood H-frame structures. Figure 2 shows a typical section of the line. The poles generally range in height from 13.7 to 21.3 meters. The line is strung with a 312.8 kcmil aluminium alloy stranded (AASC) 'Butte' conductor with a diameter of 16.3 millimetres.

TL-244 was originally designed as a 69 kV line but with the new interconnection of the Great

Northern Peninsula it was necessary to increase the capacity to 138 kV. Since the upgrade, the line has experienced a number of short, unexplained outages, which may be attributed to the upgrade of the transmission line.

Figure 2: Typical H-Frame Structure on TL-244

As this is a typical transmission line project, there is no relevant data or issue for the following items:

- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Environmental Performance; and
- Operating Regime.

2 PROJECT DESCRIPTION

Since the upgrade to 138 kV in 1996, TL-244 has regularly sustained short, unexplained outages and currently experiences an outage frequency four times higher than the Hydro average for its 138 kV transmission lines.

To determine the cause of this increased outage rate, an engineering assessment was completed by Hydro in 2008. As part of this assessment, the line was modelled in Hydro's transmission design software and analyzed at current environmental loadings to check for deficiencies in the design. The technical results of this assessment have been presented in this report to explain the importance of these upgrades to the reliability and safety performance of the system. Particular attention was paid to the electrical clearances (i.e. conductor clearance to the ground and structures) due to the fact that the original 69 kV clearances were maintained when the line was upgraded to 138 kV.

This project will correct the problems that were identified in the study as possible causes of the outages. The scope of the work is as follows:

- Correct the ground clearance in one span;
- Replace the cross-arms on 41 structures to improve both the structural performance as well as increase the electrical clearance on these structures; and
- Utilize alternate generation to the areas north of Plum Point during the upgrade.

3 EXISTING SYSTEM

Hydro designs and maintains its transmission lines to meet all current Canadian Standard Association (CSA) standards and guidelines and where necessary Hydro has developed its own standards beyond the minimum expected by CSA to account for local conditions.

TL-244 was originally designed to operate under the following conditions:

- Extreme Ice Load: 31.75 millimetres (1.25 inch) of ice accumulation on the conductor;
- Extreme Wind Load: 152 kilometers per hour (95 miles per hour);
- Combined Ice and Wind Load: 12.7 millimetres (0.5 inches) of ice accumulation combined with 88 kilometers per hour (55 miles per hour) of wind; and
- 6.4 meters (21 feet) of ground clearance for thermal loading of 50 degrees Celsius (120 degrees Fahrenheit). Thermal loading is the conductor temperature during periods of high power flow.

With the exception of the ground clearance, all of these conditions meet the CSA C22.3 standard for overhead systems. CSA requires that ground clearance be maintained for the condition of greatest sag. Conductor sag is the distance from the horizontal straight line that a conductor sinks or bends between two structure locations. The amount of sag will change with conductor temperature, ice and wind loading and time. As the conductor heats up, or is loaded with ice, the sag will typically increase. On TL-244, the original conductor sag was designed using the thermal hot curve weather condition, but the condition of greatest sag is calculated to occur when the conductor is loaded under the extreme ice load. This may lead to ground clearance violations under the extreme ice condition.

The H-frame structures (see Figure 2) on TL-244 were designed with sufficient clearances to meet the requirements of Hydro's 69 kV standards at the time of design. When the line was upgraded to a 138 kV in 1996, the major change to the structures included lowering the crossbraces and adding counterweights to each of the phases on the tangent structures. Both of the steps were taken to ensure the conductor had sufficient electrical clearance at the new 138 kV voltage. At the time of the upgrade, 13 structures were noted as having marginal electrical clearance even after the upgrade was completed.

In total, the line is comprised of 131 wooden H-frame structures, that range from the basic tangent structure to the three pole angle and dead-end structures that are supported with guys and anchors. Table 1 gives a summary of the structure types on TL-244.

Table 1: TL-244 - Summary of Structure Types

Structure Type	Quantity	Percent Total	Pole Class
A (Tangent)	111	84.7	4
AA (Tangent)	2	1.5	4
AW (Tangent)	4	3.1	4
AX (Tangent)	1	0.8	4
B (Angle)	1	0.8	2
C (Angle)	5	3.8	2
D (Dead-end)	2	1.5	2
E (Dead-end)	4	3.1	2
H (Dead-end)	1	0.8	2

The line does not cross any road ways or major thoroughfares and spans only one large pond. It has an average span of 199 metres with an average structure height of 17 meters from ground level.

3.1 Age of Equipment or System

TL-244 was constructed in 1983, making the transmission line almost 26 years old.

3.2 Major Work and/or Upgrades

In 1996, TL-244 was upgraded from a 66 kV transmission line to 138 kV transmission line. The original structures were utilized, but a number of 45 - 90 kg counterweights were attached to each phase to maintain electrical clearance. The counterweights were added to offset the swing of the conductor to provide the increased clearance distance required for higher voltage operation. In addition, the crossbraces on structures were lowered 610 millimeters on the poles to accommodate the extra clearance required for the center phase conductor.

3.3 Anticipated Useful life

Without any treatment or refurbishment, the typical life-span of a wood pole structure would be 40 years.

Hydro has implemented a Wood Pole Management (WPLM) program, with the mandate to thoroughly inspect, treat and refurbish the transmission structures prior to any serious failure on the line. Through this type of proper inspection and maintenance the life of a transmission line could be extended to over 50 years.

3.4 Maintenance History

TL-244 is inspected through Hydro’s Wood Pole Line Management (WPLM) program, in which the wood structures undergo a complete inspection every ten years. The five-year maintenance history for TL-244 is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	27.2	5.6	32.8
2007	21.0	-	21.0
2006	13.2	-	13.2
2005	-	-	-
2004	-	-	-

3.5 Outage Statistics

There have been no major failures on TL-244 since it came on line in 1983; however there have been a number of short unexplained outages over the years. As seen in Table 3, the annual outage frequency of TL-244 is almost four times greater than the other 138 kV lines on the island and has 15 times more outages per year than the CEA national average for 138 kV lines.

Table 3: Comparison of Line Outages and Time Lost for Transmission Lines from 2001-2005

	Frequency (per terminal year)	Unavailability (%)
TL -244	2.10	0.0101
Hydro 138 kV (2001-2005)	0.57	0.1054
CEA 138 kV (2001-2005)	0.14	0.0381

Reports from the operations department at Hydro indicate that no root cause can be determined for the large number of outages. It can only be speculated that the close proximity of the conductors to each other and to the supporting structures can be blamed (i.e. they are contacting under high wind and ice and causing the temporary outages).

3.6 Safety Performance

There are numerous safety issues associated with the inadequate electrical clearance of TL-244 that currently need to be addressed.

The original conductor sag was not designed for the weather condition that represents the greatest sag and, therefore, TL-244 does not meet the required ground clearance for the original design load of 31.75 millimetres of ice. Instead, the original design maintained ground clearance requirement with respect to the thermal curve.

With the upgrade to a higher voltage, issues arose pertaining to electrical clearance between the conductor and other parts of the structure such as the poles, crossarm and crossbraces. The required clearances for 69 kV transmission lines are lower than for 138 kV lines and this has implications on the allowable insulator swing for a particular structure type. Insulator swing is the degree to which an insulator can swing before the conductor infringes on the required electrical clearances. The crossarms on the 69 kV structures are shorter, which results in much smaller allowable swing angles for the 138 kV design. Had the crossarms been replaced with the proper 138 kV crossarm, there would not be any issues related to electrical clearance. The solution was to install additional 45 to 90 kg of dead weight to each phase to eliminate much of the swing of the conductor.

Table 4 illustrates the difference in required swing clearance for the four weather conditions the line was designed for. The table illustrates how much the swing clearances at the structures have increased with the augmentation of the line from a 69 kV line to a 138 kV line. The difference in the clearance would normally be accommodated for by the larger 8.8 meters crossarm of the 138 kV line but in the case of TL-244 that extra space is not available.

Table 4: Line Clearance Values for 69 kV and 138 kV Structures

Swing Clearance for Transmission Line Structures		
Weather Condition*	**69 kV Line**	**138 kV Line**
Everyday	500 millimetres	1000 millimetres
Cold	200 millimetres	460 millimetres
5 Year Wind	200 millimetres	380 millimetres
Extreme Wind	200 millimetres	355 millimetres

*Note:

Everyday condition → 4°C with no wind
Cold condition → 56 km/hr wind and -18°C
5 Year Wind → 127 km/hr wind and 4°C
Extreme Wind → 152 km/hr wind and 4°C

Even though there have been precautionary measures taken to ensure that the swing of the conductors is at a minimum there is an increased likelihood that the conductors will violate the standard clearance requirements, causing flashovers or outages.

The addition of 135 to 270 kg to each structure has placed increased stresses on the wooden crossarms, which are now showing fatigue and permanent deflection. The majority of the structures are equipped with only one crossarm and due to the excessive loading the member has begun to deflect and bend under everyday conditions; almost to the point where some structures have reached their maximum stress limits under the design load.

3.7 Discussion of 2008 Engineering Study

The analysis of TL-244 is categorized into three main areas covering all of the main topics associated with the structural safety of the transmission line as well as its compliance with current design standards. The three main issues analyzed in this report are:

1) Ground clearance violations
2) Insulator swing violations
3) Structural violations

3.7.1 Ground Clearance Violations

As indicated in Section 3, CSA dictates that the condition which provides the greatest amount of sag on a line governs the ground clearance requirements. The computer model illustrated that the thermal hot curve was utilized as the governing condition on TL-244, not the extreme ice condition which has the highest sags. Table 5 shows the expected sags under the various design conditions on TL-244.

Table 5: Comparison of Expected Sags (Ruling Span = 200m)

Weather Case	Ice Load (mm)	Wind Load (Pa)	Temp. (°C)	Sag (m)
Extreme Ice Load	31.75		-18	7.04
Ice Load	25.40		-18	6.29
Extreme Wind		885	-18	4.74
Combined Ice and Wind	12.70	383	-18	5.38
Everyday Condition			4	3.80
Cold (with Wind)		150	-18	3.18
Extreme Cold			-46	2.09
Thermal Curve			50	5.23

The model indicates that using the thermal curve there are no clearance violations at the design clearance of 6.4 meters, but as the ice load is increased to 31.75 millimetres, approximately 60 percent of the spans do not meet the required clearance at 6.4 meters. Figure 3 further illustrates this point, by showing the conductor sag in a typical span of TL-244. Both the thermal sag and the sag under different loads are shown with the minimum 5.5 meters of required clearance.

It is obvious that the current conductor sag condition for the existing AASC 'Butte' conductor is not sufficient to withstand the 31.75 millimetres ice condition. When the conductor is loaded with a 31.75 millimetres ice load, the conductor sags well below the required 5.5 meters ground clearance mark; in the case of span 114 the violation factor is 1.2, bringing the actual ground clearance to only 4.3 meters under an extreme ice event.

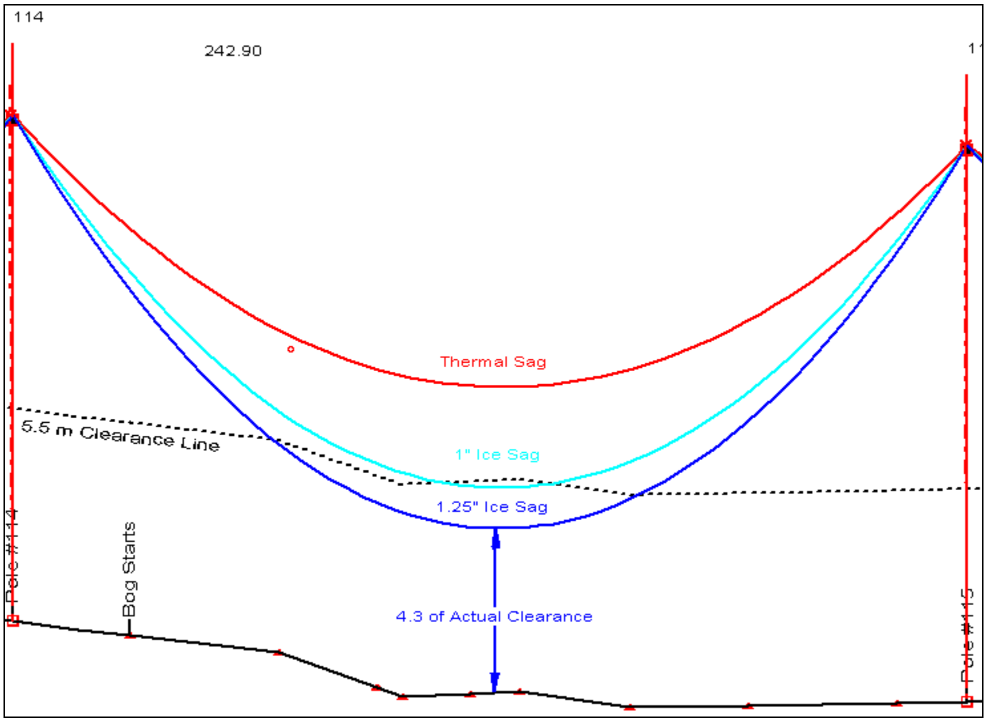


Figure 3: Ground Clearance for Span #114: Thermal Curve vs. Ice Loads

The 2008 engineering study checked the ground clearance along TL-244 for three loading conditions:

1. Thermal Load - The conductor at 50 degrees Celsius and 6.4 meters of required ground clearance. This represents the original design condition for TL-244.
2. Extreme Ice Load – The conductor loaded with 31.75 millimetres (1.25 inch) of ice and 5.5 meters of required ground clearance.[1]
3. Ice Load – The conductor loaded with 25.4 millimetres (one inch) of ice and 5.5 meters of required ground clearance. [1]

[1] 5.5 meters is the minimum vertical clearance for 138 kV Construction as per CSA Standard 22.3 No1-01 Table 2.

Table 6 provides a summary of the ground clearance violations for all spans in TL-244. The complete table of results is given in Appendix A. The study showed that only the ice loads provided any ground clearance violations at the 5.5 meters requirement.

Table 6 Summary of Ground Clearance Violations

Clearance	Clearance Margin		
Violation	**Thermal**	**1" Ice**	**1.25" Ice**
0 to 0.5 meters		1	21
0.5 to 1 meters			18
1 to 1.5 meters			1
TOTAL	0	1	40

For any proposed modifications, the 25.4 millimetres ice loading event was utilized instead of the original ice loading of 31.75 millimetres, which was deemed too restrictive. Under the 25.4 millimetres ice load, there was one clearance violation between Structures 114 and 115.

3.7.2 Insulator Swing Violations

CSA sets standards to ensure that the minimum required spacing between wooden pole structure and conductor is maintained to allow for safe climbing of the pole by line workers and to lower the number of outages that occur due to the conductor coming in contact with the wooden structures.

Table 4 illustrates the required clearance distances from the conductor to the pole based on the transmission line voltage. These swing angle clearances consider the frequency that each event will occur, which is why the everyday condition has the highest required clearance; the event could potentially take place everyday. Also, they are based on the voltage of the transmission line in which the higher the voltage the higher the required clearance. This ensures safe operation of the line.

The issue with TL-244's swing angle clearance is that when the line was upgraded from a 69 kV to 138 kV line the crossarms were left at the original 69 kV design size and not adjusted to match the standard 138 kV size.

Table 7 shows the difference between the crossarm size for the tangent transmission structure for both 69 kV and 138 kV voltages.

Table 7: Comparison of Crossarm Lengths for 69 kV and 138 kV Tangent Structures

Structure Type	**69 kV Crossarm**	**138 kV Crossarm**
	Length (meters)	Length (meters)
A, AX, AA, AW	6.7	8.9

It is evident from the table that the shorter 69 kV crossarm length will provide lower allowable swing angles than if the standard 138 kV crossarms were utilized. This is illustrated in Figure 4, which shows how the allowable swing angles are influenced by the size of the crossarm.

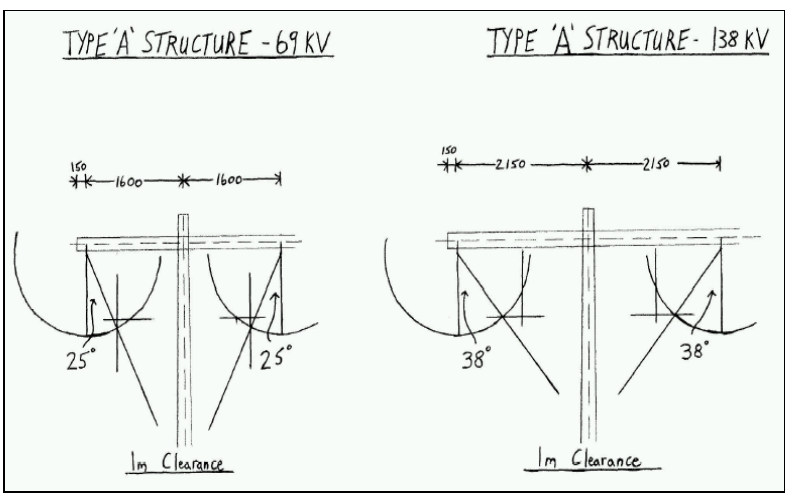


Figure 4: Comparison of Swing Angles for Type 'A' Tangent Structures on a 69 kV and 138 kV Line

From the two sketches in Figure 4 it is clear that the extra length on the 138 kV Type ‘A’ crossarm allows for a larger insulator swing. With the 69 kV crossarm, the maximum swing angle is 25 degrees based on the required 1.0m clearance for 138 kV during everyday weather conditions. This same angle will increase by 50% to 38 degrees with a 138 kV crossarm.

After analyzing all the 131 structures it was concluded that 21 structures had insulator strings which exceeded their maximum allowable swing. All of the structures were Type ‘A’ tangent structures. The complete results are shown in Appendix B.

3.7.3 Structural Violations

The engineering study analysed the complete wooden pole structure under all of the applicable weather conditions. In general, the structures performed very well, with the only violations being found on 25 of the crossarms. The most probable cause would be the additional weight added to the phases to decrease insulator swing during the upgrade to 138 kV, which would not have been taken into consideration during the initial design.

In total, all of the 118 tangent structures were fitted with extra counterweights, ranging from 45 to 90 kg per phase. 100 structures are equipped with 90 kg counterweights per phase, while the remaining structures are fitted with 45 kg of extra weight per phase. As expected, the extra weight will increase the expected design load by over 25 percent, which could potentially cause the crossarms to deteriorate faster than should be expected. Of the 131 structures which make up TL-244, 25 are in excess of 100 percent of their maximum allowable crossarm stress, under the extreme ice event.

Figure 5 is a PLS-POLE generated breakdown of the stresses applied to Structure No. 86 under the 31.75 millimetres ice load. Under this load case, the structure will experience the highest amount of stress on the crossarm. This is the typical result of all 25 structures which are over-stressed. The crossarm is utilized to 111 percent of its maximum allowable stress and is clearly showing the crossarm bending under the load. The picture on the right shows the actual structure and it clearly shows that even under the everyday condition there is some obvious bending in the crossarm.

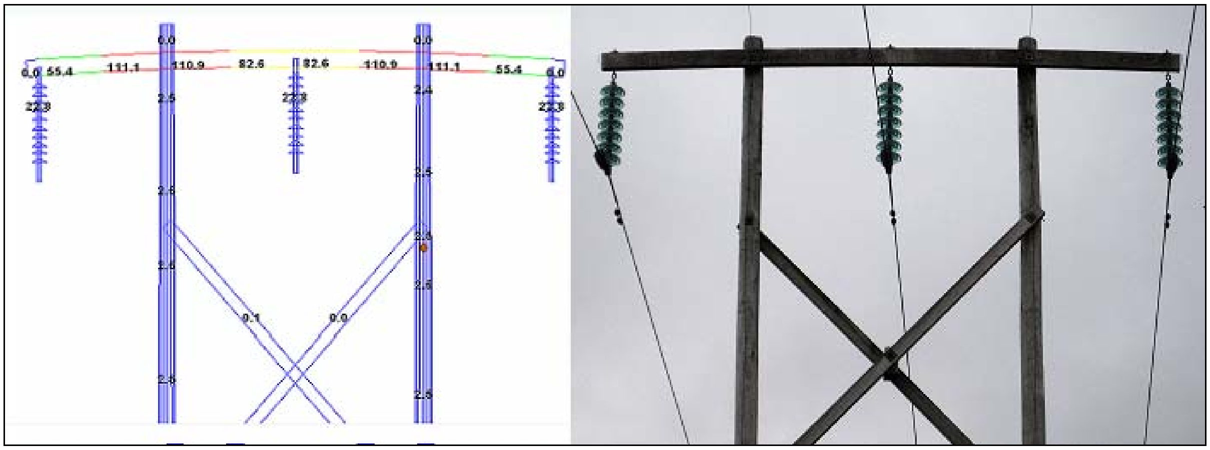


Figure 5: Typical Crossarm Loading under a 31.75 millimetres Ice Load

4 JUSTIFICATION

The engineering study has shown that under certain conditions, the energized conductors will come too close to the ground or structure and may cause an electrical flashover. This flashover may cause the conductor to burn off and/or pose a serious risk to the general public and employees of Hydro. To improve the operations performance of the line and to reduce the risk to the general public, it is necessary to correct the issues identified on TL-244.

In addition to the safety issue, the decreased insulator swing angles are a likely contributor to the high number of temporary outages experienced on the line. It is probable that during windy conditions, the conductor will momentarily infringe on the required electrical clearance thus causing a short, untraceable outage. Because of the shorter crossarms, TL-244 is at a higher risk for these events.

Finally, the crossarm replacements are justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists. See Section 4.10 for a high level comparison of the alternatives.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

A cost benefit analysis was not performed in this instance as there are no quantifiable financial benefits.

4.4 Legislative or Regulatory Requirements

There are no applicable legislative or regulatory requirements for this project.

4.5 Historical Information

There is no historical information associated with this project. This proposal is a multi-year project for the upgrades to be completed over two years.

4.6 Forecast Customer Growth

Customer load growth does not affect this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4.8 Losses during Construction

There are no anticipated energy losses during construction.

4.9 Status Quo

The status quo is not an acceptable alternative. Energized conductors that are too close to the ground or have insufficient electrical clearance pose a serious risk to the general public and Hydro personnel.

4.10 Alternatives

Although it is possible to completely reconfigure the entire line to meet the proper 138 kV design standard, the most economical means to complete this project is to isolate the specific problem structures and make minimal modifications as required:

- The ground clearance violation is minimal and it is proposed to survey the span to verify the violation and if possible the terrain will be leveled to improve the ground clearance. Other alternatives would be to install a mid-span structure to correct ground clearance issues ($40,000 to $50,000 per structure) or change the conductor to improve the clearance on that span only. This involves replacing the conductor and at least one or two structures. Depending on the specifics, this option will cost between $125,000 and $200,000 per span.
- The structures with marginal electrical clearance or structural violations will have their crossarms replaced with standard 138 kV crossarms to improve both the clearance and structural strength.

Rebuilding or reconfiguring the entire line to a standard 138 kV design would cost in excess of $30 million.

5 CONCLUSION

The following recommendations are broken down by category.

Ground Clearance Violations

For the span between Structures 114 and 115, with the low ground clearance under the 25.4 millimetres of ice, the most practical and economical solution is to attempt to mechanically level the terrain in the vicinity of the violation.

Crossarm Replacement

As previously mentioned, 41 structures currently either have swing clearance violations or exceed their structural capacity under the design ice load. The crossarms on these structures will be replaced with Hydro's standard 138 kV crossarm to improve the allowable swing clearance and structural strength. The proposed modifications are shown in Appendix C. Table 8 summarizes the structures that will be modified.

Table 8: Summary of Crossarm Replacements

Str No.	Str. Type	% of Max Structure Strength	% of Allowed Swing
3	A	103.8	112.7
4	A	105.0	86.5
5	A	98.2	114.3
6	A	100.4	83.3
7	A	94.0	113.8
10	A	101.8	107.4
13	A	105.9	87.6
22	A	90.6	100.9
25	A	94.9	111.8
30	A	91.3	105.6
32	A	97.3	111.3
35	A	85.6	109.0
36	A	79.5	110.5

Str No.	Str. Type	% of Max Structure Strength	% of Allowed Swing
45	A	102.3	106.2
49	A	102.7	87.2
54	A	102.3	84.6
55	A	81.2	123.9
57	A	87.7	115.3
59	A	102.6	85.1
62	A	101.0	84.4
64	A	103.5	83.3
65	A	83.6	116.9
67	A	91.5	103.0
77	A	78.9	102.1
78	A	102.9	111.4
79	A	101.2	111.1
82	A	103.1	84.7
86	A	111.2	83.8
87	A	108.5	88.6
88	A	100.5	89.5
100	A	96.2	115.6
102	A	108.6	85.3
103	A	101.9	90.0
104	A	105.2	83.1
110	A	103.3	89.3
111	A	102.1	86.2
113	A	107.2	84.6
114	A	103.2	93.8
123	A	101.5	92.4
126	A	84.7	106.2
127	A	82.5	111.3

Alternate Generation

The completion of the upgrades for TL-244 will involve de-energizing the line, resulting in no power supply north of Plum Point. Based on the available diesel generators on the northern peninsula enough power can be supplied to service St. Anthony and surrounding area with the exception of Bear Cove and vicinity. Therefore, alternate generation will need to be provided for the duration of the project to ensure Bear Cove is supplied with the 2.0 MW of electricity that it requires. In previous projects, Hydro has brought in diesel generators with the capacity to supply 2.0 MW of power each to supplement the shortage of power during prolonged construction outages; similar generators will be required for this project. It is anticipated that generation will be required for two weeks at a cost of $350,000.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 9.

Table 9: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	59.4	404.1	0.0	463.5
Labour	64.4	167.2	0.0	231.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	217.5	0.0	217.5
Other Direct Costs	5.2	43.3	0.0	48.5
O/H, AFUDC & Escln.	12.3	127.0	0.0	139.3
Contingency	0.0	96.1	0.0	96.1
TOTAL	**141.3**	**1,055.2**	**0.0**	**1,196.5**

5.2 Project Schedule

The anticipated project schedule is shown in Table 10. This project has been scheduled over two years, to fit within Hydro's overall capital plan, which attempts to balance the volume of engineering and construction that is required in any given year. In general, the engineering and material procurement will take place in 2010, with the construction scheduled in 2011.

Table 10: Project Schedule

Activity	Milestone
Project Initiation	Jan 2010
Complete Design Transmittal	Feb 2010
Detailed Engineering Design	Oct 2010
Procurement of Materials	Nov 2010
Develop Installation Specification	Dec 2010
Issue Tender and Award Job	Feb 2011
Material Delivery	May 2011
Develop Construction Package	May 2011
Contract Execution	Oct 2011
Commissioning	Sept 2011
Close Out and Documentation	Dec 2011

APPENDIX A

TL244 Ground Clearance Report

Summary of TL244 Ground Clearances

From	To	Clearance Margin		
Structure	Structure	Thermal	25.4 mm Ice	31.75 mm
1	2	0.00	0.02	0.04
2	3	4.33	2.18	1.29
3	4	0.00	0.00	0.00
4	5	0.00	0.00	0.00
5	6	2.39	0.53	-0.24
6	7	2.61	0.86	0.15
7	8	2.68	0.83	0.06
8	9	2.49	0.80	0.10
9	10	0.00	0.00	-0.21
10	11	2.06	0.12	-0.68
11	12	0.00	0.00	-0.58
12	13	3.97	1.95	1.10
13	14	2.25	0.39	-0.37
14	15	0.00	0.00	0.00
15	16	0.00	0.00	0.00
16	17	0.00	0.01	-1.04
17	18	3.73	1.82	0.97
18	19	1.74	0.05	-0.69
19	20	0.00	0.00	0.00
20	21	2.09	0.14	-0.52
21	22	0.00	0.00	0.00
22	23	3.16	2.31	1.94
23	24	4.79	3.54	2.99
24	25	0.00	0.00	0.00
25	26	2.21	0.26	-0.59
26	27	2.67	0.97	0.23
27	28	3.53	2.03	1.38
28	29	0.00	0.00	0.00
29	30	0.00	0.00	0.00
30	31	2.20	0.52	-0.21
31	32	3.75	2.31	1.59
32	33	0.00	0.00	0.00
33	34	2.72	1.13	0.43
34	35	2.52	1.06	0.42
35	36	1.98	0.62	0.02

From	To	Clearance Margin		
Structure	**Structure**	**Thermal**	**25.4 mm Ice**	**31.75 mm**
36	37	0.00	0.12	0.16
37	38	0.00	0.00	0.00
38	39	2.79	1.38	0.76
39	40	3.42	1.84	1.15
40	41	0.00	0.00	0.00
41	42	0.00	0.00	0.00
42	43	0.01	0.07	-0.51
43	44	3.68	2.01	1.28
44	45	2.34	0.76	0.07
45	46	2.09	0.02	-0.88
46	47	4.35	2.56	1.77
47	48	2.73	1.06	0.31
48	49	3.23	1.26	0.39
49	50	3.12	1.07	0.17
50	51	0.03	0.08	-0.04
51	52	0.00	0.00	0.00
52	53	4.39	2.34	1.45
53	54	2.63	0.68	-0.16
54	55	2.32	0.72	0.02
55	56	3.42	1.91	1.22
56	57	0.00	0.00	0.00
57	58	2.31	0.68	-0.03
58	59	0.00	0.11	0.18
59	60	0.00	0.00	-0.29
60	61	0.00	0.00	0.00
61	62	0.00	0.00	-0.30
62	63	0.00	0.00	-0.30
63	64	0.00	0.00	-0.59
64	65	0.00	0.00	-0.07
65	66	2.92	1.82	1.29
66	67	0.00	0.00	0.00
67	68	3.91	2.30	1.61
68	69	0.00	0.00	0.00
69	70	2.28	0.66	-0.04
70	71	2.53	1.19	0.61
71	72	0.00	0.00	0.00
72	73	0.00	0.00	0.00

From	To	Clearance Margin		
Structure	Structure	Thermal	25.4 mm Ice	31.75 mm
73	74	2.42	1.65	1.30
74	75	0.00	0.00	0.00
75	76	0.05	0.08	0.13
76	77	0.00	0.00	0.00
77	78	3.89	1.96	1.05
78	79	5.20	3.44	2.59
79	80	3.18	1.79	1.13
80	81	3.09	1.13	0.29
81	82	2.65	0.75	0.00
82	83	2.27	0.32	-0.52
83	84	0.00	0.00	0.00
84	85	2.40	0.35	-0.54
85	86	0.00	0.00	-0.36
86	87	2.30	0.10	-0.86
87	88	3.79	1.48	0.48
88	89	3.38	1.98	1.35
89	90	2.94	1.25	0.51
90	91	2.11	0.20	-0.38
91	92	2.47	0.78	0.02
92	93	0.00	0.00	0.00
93	94	0.00	0.08	0.12
94	95	0.00	0.00	0.00
95	96	0.01	0.05	0.05
96	97	0.00	0.00	0.00
97	98	2.25	0.35	-0.43
98	99	0.00	0.00	-0.34
99	100	0.00	0.00	0.00
100	101	4.27	2.39	1.60
101	102	3.66	1.74	0.88
102	103	2.19	0.06	-0.80
103	104	0.00	0.00	0.00
104	105	2.18	0.40	-0.33
105	106	3.26	1.16	0.29
106	107	0.00	0.05	0.11
107	108	0.00	0.00	0.00
108	109	3.21	1.41	0.67
109	110	3.02	0.98	0.14

From	To	Clearance Margin		
Structure	**Structure**	**Thermal**	**25.4 mm Ice**	**31.75 mm**
110	111	2.55	0.66	-0.11
111	112	0.00	0.00	-0.55
112	113	0.00	0.17	-0.31
13	114	2.23	0.17	-0.67
114	115	0.00	-0.20	-0.72
115	116	3.76	2.23	1.60
116	117	0.01	0.01	-0.19
117	118	0.05	0.05	0.05
118	119	2.46	0.79	0.11
119	120	0.01	0.03	0.06
120	121	0.00	0.00	-0.59
121	122	2.93	0.95	0.13
122	123	0.00	0.00	-0.44
123	124	2.34	0.11	-0.80
124	125	0.00	0.01	0.01
125	126	0.00	0.00	0.00
126	127	2.22	0.99	0.42
127	128	3.48	2.17	1.52
128	129	2.65	1.24	0.57
129	130	0.00	0.13	0.19
130	131	2.01	0.16	-0.69
Number of Violations		**0**	**1**	**40**

The shaded cells represent violations in ground clearance.

APPENDIX B

Structure Analysis Report

Summary of Structure Strength and Allowable Insulator Swing

Str No.	Str. Type	Pole Height (ft)	Pole Class	Station (m)	Line Angle (deg)	% of Max Structure Strength	% of Allowed Swing
1	E	55	2	63	14.68	99.9	
2	C	60	2	275	22.86	27.5	22
3	A	60	4	495		103.8	112.7
4	A	60	4	713		105	86.5
5	A	50	4	931		98.2	114.3
6	A	60	4	1137		100.4	83.3
7	A	50	4	1336		94	113.8
8	A	55	4	1544		91.6	91.7
9	A	55	4	1740		97.8	84.6
10	A	50	4	1945		101.8	107.4
11	A	55	4	2158		95.2	93.9
12	A	55	4	2372		95.6	94.4
13	A	60	4	2588		105.9	87.6
14	A	60	4	2795		85.2	81.1
15	A	60	4	3001		79.8	94.1
16	D	60	2	3205		36.2	
17	D	65	2	3475		41.6	
18	A	55	4	3685		97.7	88
19	A	55	4	3888		92.8	91.7
20	A	55	4	4093		93.9	92.6
21	A	55	4	4304		90	87.6
22	A	50	4	4476		90.6	100.9
23	A	60	4	4646		77	91.4
24	C	55	2	4812	26.09	26.2	16.2
25	A	50	4	5001		94.9	111.8
26	AW	55	4	5212		50.8	88.7
27	A	55	4	5412		93.5	84.4
28	A	55	4	5597		87.6	85.7
29	A	60	4	5779		83.7	87.9
30	A	50	4	5956		91.3	105.6
31	A	60	4	6152		86.1	79
32	A	50	4	6359		97.3	111.3
33	A	55	4	6548		86.6	90.4
34	A	55	4	6738		85.7	89.8

Str No.	Str. Type	Pole Height (ft)	Pole Class	Station (m)	Line Angle (deg)	% of Max Structure Strength	% of Allowed Swing
35	A	50	4	6921		85.6	109
36	A	50	4	7098		79.5	110.5
37	AX	50	4	7262		88.3	81.9
38	A	55	4	7455		85.3	91.7
39	A	55	4	7640		88.2	87.8
40	A	55	4	7831		89.7	84.8
41	A	55	4	8011		84.7	88
42	A	55	4	8195		96.8	89
43	A	55	4	8408		91.4	93.5
44	A	55	4	8604		92.9	87.6
45	A	50	4	8802		102.3	106.2
46	A	a5	4	9020		95.9	91.8
47	A	55	4	9223		90.3	94.2
48	A	60	4	9427		99.1	87.8
49	A	60	4	9641		102.7	87.2
50	A	55	4	9857		97.2	90.9
51	AW	55	4	10064		54.5	85.6
52	A	65	4	10285		99.3	92.4
53	A	60	4	10500		98.9	90.2
54	A	55	4	10711		102.3	84.6
55	A	50	4	10902		81.2	123.9
56	A	55	4	11093		86.6	91.4
57	A	50	4	11285		87.7	115.3
58	E	55	2	11477	23.24	69	
59	A	55	4	11689		102.6	85.1
60	A	60	4	11897		98	88.7
61	A	55	4	12106		94.5	90.7
62	A	55	4	12309		101	84.4
63	A	60	4	12519		99.7	90.3
64	A	55	4	12738		103.5	83.3
65	A	50	4	12937		83.6	116.9
66	A	55	4	13111		77.5	91.6
67	A	50	4	13283		91.5	103
68	A	55	4	13478		90.2	88.1
69	A	60	4	13668		90.9	88.1

Str No.	Str. Type	Pole Height (ft)	Pole Class	Station (m)	Line Angle (deg)	% of Max Structure Strength	% of Allowed Swing
70	A	55	4	13865		90.6	84.4
71	A	45	4	14041		83.3	79.7
72	A	55	4	14181		65.2	89.7
73	A	55	4	14333		73.2	82.9
74	B	55	2	14461	8.49	23	93.5
75	A	55	4	14627		75.2	88.1
76	A	45	4	14783		82.7	82.3
77	A	60	4	14949		78.9	102.1
78	A	50	4	15169		102.9	111.4
79	A	50	4	15382		101.2	111.1
80	A	70	4	15595		99.8	89.6
81	A	55	4	15806		99	88.2
82	A	60	4	16016		103.1	84.7
83	A	60	4	16227		97	93.6
84	A	55	4	16448		94.3	97.4
85	A	55	4	16663		99.3	88.8
86	A	60	4	16871		111.2	83.8
87	A	65	4	17095		108.5	88.6
88	A	60	4	17326		100.5	89.5
89	A	55	4	17508		89.5	87.6
90	A	55	4	17706		94.9	89.4
91	A	55	4	17916		93.5	94
92	A	45	4	18126		93.3	83.8
93	A	65	4	18282		72.1	85.3
94	A	55	4	18431		69.8	91.1
95	C	50	2	18588	-26.5	29.1	24.2
96	H	50	2	18793		38.4	
97	AW	55	4	19011		54.3	86.1
98	A	55	4	19220		96.9	88.7
99	A	55	4	19425		91.4	94.1
100	A	50	4	19632		96.2	115.6
101	A	55	4	19846		96.9	93.9
102	A	55	4	20066		108.6	85.3
103	A	55	4	20290		101.9	90
104	A	55	4	20487		105.2	83.1
105	A	60	4	20697		94	95.9
106	A	55	4	20916		94.5	90.2

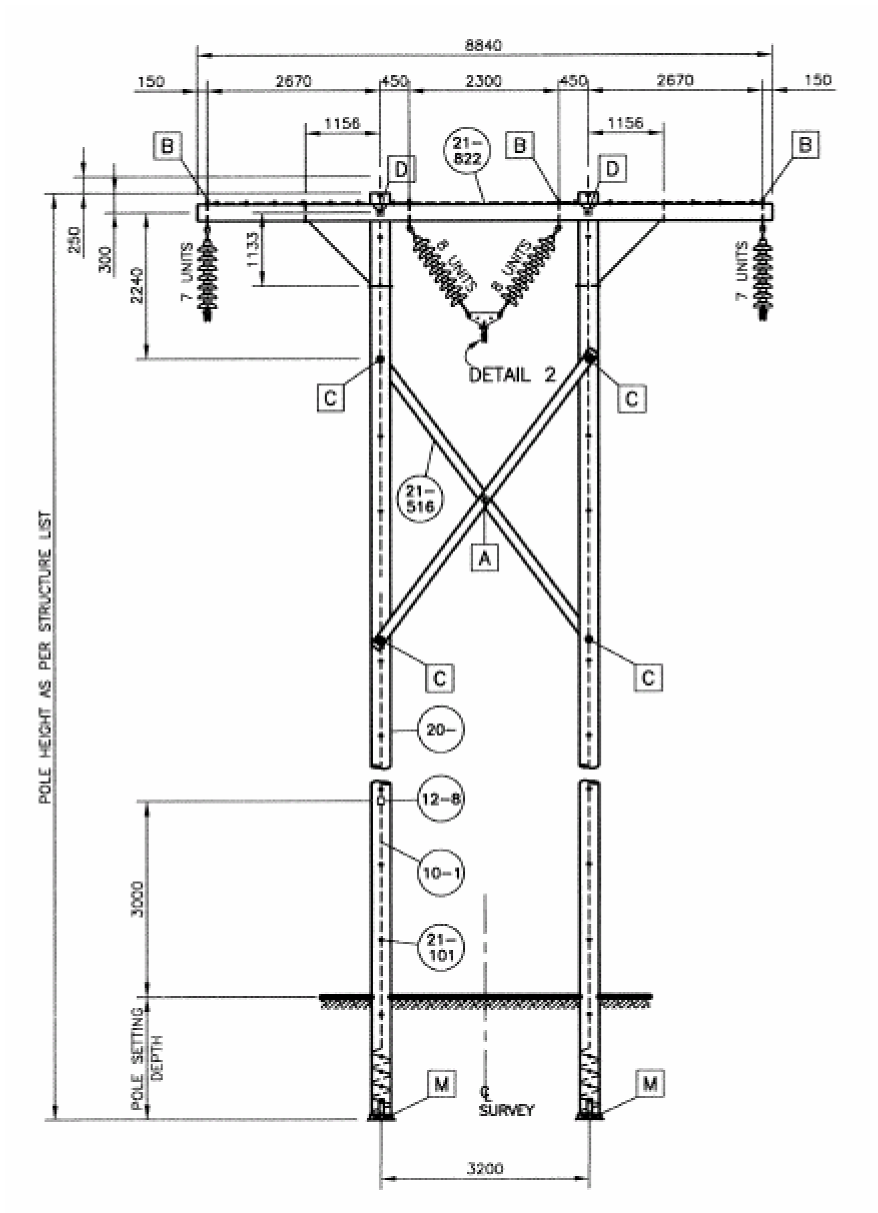
Str No.	Str. Type	Pole Height (ft)	Pole Class	Station (m)	Line Angle (deg)	% of Max Structure Strength	% of Allowed Swing
107	A	55	4	21107		96.2	84.4
108	A	55	4	21310		92.5	92.2
109	A	55	4	21517		97.3	90.4
110	A	60	4	21732		103.3	89.3
111	A	55	4	21939		102.1	86.2
112	A	55	4	22156		95.3	96.2
113	A	55	4	22376		107.2	84.6
114	A	55	4	22592		103.2	93.8
115	A	60	4	22835		97.5	92.3
116	A	55	4	23021		95.5	86.1
117	A	55	4	23233		92.4	90.4
118	A	55	4	23423		96	83.3
119	A	60	4	23623		90.6	89.5
120	C	65	2	23809	16	23.1	53.2
121	A	55	4	24024		98.8	92.1
122	AW	60	4	24238		61.4	84.4
123	A	55	4	24459		101.5	92.4
124	E	60	2	24682	68.36	80.8	
125	A	55	4	24861		79.9	91.9
126	A	50	4	25036		84.7	106.2
127	A	50	4	25211		82.5	111.3
128	A	55	4	25390		88.8	87.7
129	C	55	2	25566	24.06	24.7	13.9
130	A	60	4	25743		91.2	89.5
131	E	60	2	25950	82.95	85.1	

The shaded cells represent violations in either the structural strength or insulator swing of the structure.

APPENDIX C

Proposed Structural Modifications

Proposed Structural Modifications



A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER PEG Newfoundland and Labrador Trevor C. Andrews SIGNATURE July 31/09 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

POLE REPLACEMENTS – 2010

June 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Distribution systems typically consist of a substation coupled with a wood pole distribution line that directs power from the station to service drops throughout the community. This report will be focused on distribution lines located in the communities of Barachoix, English Harbour West, Fleur De Lys and Happy Valley that have been identified as requiring upgrades to the existing infrastructure.

The distribution lines referred to in this report were originally constructed over 40 years ago. The majority of line components were installed at the time of original construction and have far exceeded the estimated service life of 30 years. In addition, as a result of standardized inspection and testing procedure, it has become evident that line components are greatly deteriorated and may have remaining life spans of only one to five years before widespread failure occurs.

The majority of these poles identified for replacement due to deterioration are commonly known as blackjack poles. Blackjack poles are poles that were pressure treated with creosote for protection against moisture and insect damage. They were widely used for distribution construction during the 1960's and 1970's. Over time, the protective creosote coating tends to leech into the surrounding earth causing a potential for ground/water contamination. As a result of this, blackjack poles are no longer environmentally acceptable and are no longer used in the industry. In addition, industry experience has shown that blackjack poles pose a considerable risk to the safety of operations workers and the structural reliability of the distribution system. Blackjack poles are currently being replaced throughout the various Hydro distribution systems in the Province. The poles identified for replacement which are not blackjacks, have exceeded their economic and useful life spans and are considered to be a potential risk to the reliability of the existing distribution system.

Failure of such components will have a negative effect on the safety and reliability performance of the line as identified earlier in the report. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

2 PROJECT DESCRIPTION

This project is required to replace deteriorated poles on the following distribution systems:

- Barachoix Line 1 - 50 Poles
- English Harbour West Line 1 - 46 Poles
- Fleur De Lys Line 1 - 40 Poles
- Happy Valley Line 4 - 40 Poles

The work required to replace the specified poles will include, but is not limited to, the installation of new poles at the same locations, transfer of existing hardware and guys, structure framing and replacement of any deteriorated or damaged line hardware.

3 EXISTING SYSTEM

Barachoix – Line 1 (L1)

The Barachoix – L1 distribution line is a 25 kV three phase feeder that was originally constructed in 1969 to provide service to the communities of Furby's Cove, Hermitage, Sandyville and Seal Cove. The distribution line extends from the Barachoix Terminal Station to the Gaultois submarine cable crossing, to the community of Furby's Cove to the north and to Hermitage, Sandyville and Seal Cove to the south for a distance of 37 kilometers and serves approximately 500 customers. The line contains a high number of deteriorated poles that need replacement. The majority of these poles identified for replacement are blackjack poles. The remainder of the line will be inspected regularly to ensure its reliability.

English Harbour West – Line 1 (L1)

The English Harbour West – L1 distribution line is a 25 kV three phase feeder that was originally constructed in 1968 to provide service to the communities of Pool's Cove, St. Jacques, Belleoram, English Harbour West, Mose Ambrose, Boxey, Wreck Cove, and Coombs Cove. Since 2006, it also provides service to Rencontre East. The distribution line extends from the English Harbour West Terminal Station to Coomb's Cove, a distance of 115 kilometers and serves approximately 700 customers.

Fleur De Lys – Line 1 (L1)

The Fleur De Lys - L1 distribution line is a 25 kV three phase feeder that was originally constructed in 1966 to service the community of Fleur De Lys on the Baie Verte Peninsula. The distribution line extends from the Newfoundland Power Seal Cove Terminal Station to Fleur De Lys, a distance of 32 kilometers and serves approximately 200 customers. The line contains 40 deteriorated poles that need replacement. The majority of these poles identified for replacement are blackjack poles. The remainder of the line still appears to be satisfactory but will be inspected regularly to ensure its reliability.

Happy Valley – Line 4 (L4)

The Happy Valley – L4 distribution line is a 25 kV three phase feeder that was originally constructed between 1968 and 1975. The distribution line extends from the Hunt Street Substation to the Correctional Center and includes the trailer park and several residential streets. There are several single phase taps off to residential areas including a trailer court.

3.1 Age of Equipment or System

The Barachoix L1 Distribution line was constructed in 1969 and is 40 years old.

The English Harbour West L1 Distribution line was constructed in 1968 and is 41 years old.

The Fleur De Lys L1 Distribution line was constructed in 1966 and is 43 years old.

The Happy Valley L4 distribution line was constructed between 1968 and 1975 and the age of sections range between 34 and 41 years old.

The majority of components on each of these lines were installed at the time of original construction. In addition, minor upgrade/maintenance work has been conducted regularly, including the replacement of various poles, transformers and associated hardware as deemed necessary through regular field inspections.

3.2 Major Work and/or Upgrades

Table 1 shows the upgrades that have occurred since installation:

Table 1: Major Work and Upgrades

Year	Barachoix L1	English Harbour West L1	Fleur De Lys L1	Happy Valley L4
2008	$20,426			$ 4,258
2007	$275,980			$ 5,804
2005		$ 126,591		
2004	$19,676		$ 237,447	$ 2,000

Note: No major work was completed in 2006.

Barachoix – Line 1

The major work and upgrades for 2004 and 2008 include the replacement of various poles and transformers that have failed or have exceeded their useful life spans. The work undertaken in 2007 included the total replacement of a 20 km section of the line between Seal Cove and Pass Island.

English Harbour West – Line 1

The major work and upgrades in 2002 included the re-insulation of the entire line. The major work and upgrades in 2005 included the replacement of 35 deteriorated poles.

Fleur De Lys – Line 1

The major work and upgrades for 2004 included the replacement of all insulators on the Fleur De Lys L1 distribution system.

Happy Valley – Line 4

The major work and upgrades for 2004, 2007 and 2008 included replacement of various line components that were deteriorated or experienced failure.

3.3 Anticipated Useful life

The service life of a distribution line is 30 years.

3.4 Maintenance History

The five-year maintenance history for each of the lines is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
Barachoix – L1			
2008	6.6	2.8	9.4
2007	2.0	9.4	11.4
2006	0.5	1.3	1.8
2005	7.7	0.0	7.7
2004	11.4	8.4	19.8
English Harbour West – L1			
2008	1.1	3.1	4.2
2007	0.0	2.3	2.3
2006	0.0	0.0	0.0
2005	0.0	0.2	0.2
2004	0.0	2.1	2.1
Fleur De Lys – L1			
2008	2.6	0.0	2.6
2007	0.0	0.2	0.2
2006	3.2	0.8	4.0
2005	1.9	0.5	2.4
2004	6.4	3.3	9.7
Happy Valley – L4			
2008	3.8	0.0	3.8
2007	6.7	0.0	6.7
2006	4.3	0.0	4.3
2005	4.8	3.7	8.5
2004	0.9	2.2	3.1

Maintenance costs associated with these distribution lines include all work directly linked to preventative maintenance tasks such as line inspection, trouble calls and routine minor maintenance.

3.5 Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - (System Average Interruption Frequency Index) indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 3 lists the 2004 to 2008 SAIFI and SAIDI data, 2004 to 2008 corporate values, and the latest CEA five year average (2004 to 2008) for comparison. These statistics are not justification for this project.

Table 3: Outage Statistics - SAIFI SAIDI Data

Five Year Averages (2004 to 2008)				
Location	**All Causes**		**Defective Equipment**	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Barachoix – L1	4.84	12.79	0.77	0.72
English Harbour West – L1	4.98	12.14	0.41	0.68
Fleur De Lys – L1	5.45	8.71	0.27	0.88
Happy Valley – L4	10.52	7.77	1.05	1.00
Hydro Corporate	5.92	9.50	0.74	1.30
CEA	2.67	8.33	0.48	1.13

Although the outage statistics are not far outside Hydro's average statistics, the lines are deteriorated and should be replaced to avoid failure. The work should be conducted proactively to avoid a major failure resulting in an extended outage for the customers. To date, no major failures have occurred. The above statistics are based on the number of outages experienced by a line for numerous reasons, including planned maintenance, inspections and unforeseen failures. These statistics are not representative of failure only and are not meant to be a justification for the required work.

3.6 Industry Experience

Blackjack poles are no longer commonly used in the utility industry. Blackjack poles that are currently in use have surpassed their expected life span and are showing signs of major deterioration. Industry experience shows that it is common for blackjack poles to deteriorate from the inside out as a result of the thick layer of tar/creosote on the surface of the pole. The deterioration experienced on the inside of the pole causes a major reduction in strength of the structure. Utility lines comprised of blackjack poles will experience a false sense of security in that they may appear acceptable by visual inspection but the actual strength of the structure may be significantly reduced causing an increased risk of failure.

3.7 Maintenance or Support Arrangements

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed. The inspection schedule is determined through a Reliability Centered Maintenance Program initiated by Hydro and is dependant on a variety of factors including geographical location, line age, and customer usage. Inspection schedules may vary between lines depending on the existing circumstances. The deteriorated poles identified on each of these lines were classified as "B" (one to five years of remaining life) condition during the last inspection in 2006 and are scheduled to be replaced in 2010.

3.8 Vendor Recommendations

There are no specific vendor recommendations for this project.

3.9 Availability of Replacement Parts

Availability of replacement parts is not a consideration for this project.

3.10 Safety Performance

The poles identified as being deteriorated pose a considerable risk to the safety of operations personnel who may be performing climbing activities to conduct regular inspections or maintenance work. In addition, the failure of a structure may result in the cascading action of the line which would result in extended repair time and increased outage duration.

3.11 Environmental Performance

The following environmental issues have been identified:

- Blackjack poles (see Figures 1 and 2) are considered to be environmentally unacceptable due to the threat of ground/water contamination from the presence of the creosote coating on the surface of the pole. Hydro has implemented a policy and procedure to remove and discard all blackjack poles from the system. Hydro has established this initiative in compliance with applicable environmental regulatory authorities.

Figure 1: Typical Blackjack Wood Pole Structure

Figure 2: Typical Blackjack Pole

- Work and/or travel on bogs may be required to complete the project. Bogs are considered sensitive areas due to the high disturbance potential associated with this type of habitat. Mitigation may be required to complete work in these areas.

- The project may require work to be conducted near a protected water supply. Increased concerns with water quality in the province means careful planning must be undertaken before performing any work.

All work undertaken by Hydro would be assessed, monitored and regulated by the Hydro Environment Group. Hydro would work proactively with any regulating authorities to prevent and reduce any negative environmental affects on the surrounding environment. Environmental permits will be required to complete the proposed work

3.12 Operating Regime

Barachoix - Line 1 is in continuous operation providing service to 465 customers in the four communities serviced from the Barachoix Terminal Station.

English Harbour West - Line 1 is in continuous operation providing service to 716 customers in the nine communities serviced from the English Harbour West Terminal Station.

Fleur De Lys - Line 1 is in continuous operation providing service to 184 customers in the community of Fleur De Lys.

Happy Valley – Line 4 is in continuous operation providing service to 510 customers in the community of Happy Valley.

4 JUSTIFICATION

The distribution lines referred to in this report were originally constructed over 40 years ago. The majority of line components, still in operation, were installed at the time of original construction and have far exceeded their economic and useful life span.

As result of standardized inspection and testing procedure, it has become evident that line components are greatly deteriorated and may have a remaining ultimate life span of only one to five years before widespread failure occurs. Hydro performs inspections on all distribution line components classifying them using the following standardized grading system:

- Grade “A” Condition: Excess of 5 years of life remaining,
- Grade “B” Condition: 1 to 5 years of life remaining, and
- Grade “C” Condition: Less than 1 year of life remaining.

The deteriorated poles identified on each of these lines were classified as “B” condition during the last inspection in 2006 and are scheduled to be replaced in 2010.

The majority of the poles identified for replacement are blackjack poles, which no longer comply with Hydro standards. The poles identified as being deteriorated pose a considerable risk to the safety of operations personnel who may be performing climbing activities to conduct regular inspections or maintenance work. Industry experience has shown that they are considered unsafe and environmentally unfriendly by today’s standards.

Failure of such components will have a negative effect on the safety and reliability performance of the line as identified earlier in the report. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions. Depending on the extent of the damage caused by a failure, alternate generation may also be required to supply service to the communities while upgrades or rehabilitation is performed. The costs associated with alternative generation could be very costly and result in environmental concerns such as air emissions.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity since no new generation source is involved.

4.3 Cost Benefit Analysis

A cost benefit analysis calculation was not performed in this instance as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements associated with this project.

4.5 Historical Information

Blackjack poles were commonly used in the utility industry until concerns about ground/water surface contamination and the inability to actually assess the current structural condition of the pole emerged. As a result of these concerns, the use of blackjack poles was discontinued in the utility industry. Since the majority of these installed poles are nearing or have exceeded their useful lives, recent years have seen an increased replacement rate for the existing blackjacks with an approved substitute. Table 4 shows the history of pole replacement projects in the last five years.

Table 4: Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2009F	Replace Poles - L1 and L2 Jackson's Arm	433.7	
	Replace Poles - L1 Hampden	263.1	
2008	Replace Poles - South Brook	377.5	331.2
	Replace Poles - Bay D'Espoir	322.7	257.3
2007	Replace Poles - Barachoix L4	229.9	276.0
	Replace Poles - Farewell Head	355.0	295.3
	Replace Poles - St. Brendan's	159.1	175.4
2006	Replace Poles - L1 Bottom Waters	152.4	166.5
2005	Replace Poles - English Harbour West	167.9	126.6
	Install Midspan Poles - L6 Farewell Head	49.5	55.9
2004	Replace Poles - Bottom Waters	342.8	249.0
	Replace Poles - L1 St. Anthony	650.4	499.6

4.6 Forecast Customer Growth

There is no anticipated load growth on these systems for the next five years and therefore forecast customer growth will have no impact on this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4.8 Losses during Construction

There are no anticipated energy losses during construction.

Status Quo

The status quo is not an acceptable alternative for the following reasons:

- The majority of line components were installed at the time of original construction and have exceeded their economic lives of 30 years. They are heavily deteriorated with estimated life spans ranging between one and five years based on regular inspection.

- Failure to upgrade the existing feeder could increase the number of outages of varying durations to the customers it serves.

- Deteriorated/outdated equipment also poses considerable safety risk to Hydro operations personnel who maintain the lines, as well as individuals residing in and occupying the area.

4.10 Alternatives

There are no viable alternatives to replacing the deteriorated poles.

5 CONCLUSION

This project is required to ensure that a reliable energy supply is available for the customers serviced by each of these lines. Since the existing lines are over the age of 40 and current standardized methods of inspection have deemed the lines as being deteriorated, the lines have exceeded their economic and useful lives and are recommended for replacement.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 5.

Table 5: Budget Estimate (2010)

Project Cost:*($ x1,000)*	**Barachoix**	**English Harbour West**	**Fleur De Lys**	**Happy Valley**	**Total**
Material Supply	65.5	59.0	51.4	57.0	232.9
Labour	45.5	53.6	61.4	61.4	221.9
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	105.7	101.2	90.9	82.0	379.8
Other Direct Costs	10.3	12.1	19.6	19.6	61.6
O/H, AFUDC & Escln.	23.6	26.3	23.6	23.3	96.8
Contingency	22.7	22.6	22.3	22.0	89.6
TOTAL	**273.3**	**274.8**	**269.2**	**265.3**	**1082.6**

5.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Project Milestone	Barachoix L1	English Hr. West L1	Fleur De Lys L1	Happy Valley L4
Initiation	March 2010	March 2010	February 2010	March 2010
Design Complete	May 2010	May 2010	March 2010	May 2010
Equipment Ordered	April/May 2010	April/May 2010	April/May 2010	May 2010
Installation Commences	June 2010	June 2010	July 2010	July 2010
Installation Complete	July2010	July 2010	August 2010	August 2010
Project Closeout	August 2010	August 2010	September 2010	September 2010

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER D. A. RENDELL SIGNATURE 09/07/31 PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

CONSTRUCT TRANSMISSION LINE EQUIPMENT OFF-LOADING AREAS

May 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

This project is the third year of a seven year project in which Hydro proposes to construct approximately 200 transmission line equipment off-loading areas near secondary provincial highways where Hydro accesses its transmission lines. The original concentration for this project was along highways accessing the primary transmission lines of the island. Once construction was completed on the first round of off-loading areas, operations personnel immediately realized the benefits of having the off-loading areas and the project scope was expanded as similar problems were noted along highways accessing secondary lines along the Northern Peninsula. This project was originally for a five year period for the construction of 100 off-loading areas in the central region of Newfoundland. The scope of this project has been expanded to increase the total number of sites and to accelerate the rate at which off-loading areas are constructed so that operations personnel on the Northern Peninsula can sooner realize the benefits of the off-loading areas. This expanded scope adds additional sites in years three, four and five of the project and also extends the project life by an additional two years to allow for the construction of additional off-loading areas on the Northern Peninsula.

2 PROJECT DESCRIPTION

This project is required to construct equipment off-loading areas near secondary provincial highways at points where Hydro accesses its transmission lines. In 2010, 20 off-loading areas are proposed to be constructed in the central region of Newfoundland and 20 off-loading areas are proposed to be constructed along the Northern Peninsula Highway (Route 430). Issues of public and Hydro personnel safety have shown the need for designated areas to be constructed rather than using the highway for off-loading equipment.

3 EXISTING SYSTEM

Hydro's Transmission and Rural Operations is responsible for the maintenance of 56 transmission lines on the island portion of the province which have a combined length of 3,473 kilometers.[1] These transmission lines are constructed of wood, steel or aluminum, or some combination thereof, and range in age from three to 44 years. Approximately 1,608 kilometers of these transmission lines are 230 kV lines used to transmit electricity from the Bay d'Espoir Hydroelectric Generating Station through the Island Interconnected System. There are also 1,231 kilometers of 138 kV and 634 kilometers of 69 kV transmission lines on the island.

In order to provide reliable service to its customers, Hydro must be able to respond to maintenance issues and emergencies in a safe and efficient manner. Heavy equipment accessing transmission lines use government approved trails which originate along adjacent highways.

Secondary highways in this province are constructed to a standard which allows very narrow shoulders and steep embankments. Crews must also contend with increasing levels

[1] In the project proposal Construct Transmission Storage Ramps submitted as part of Hydro's 2009 Capital Budget Application, the number and the combined length of the transmission lines in the central region of Newfoundland was stated to be 46 transmission lines and 2,817 kilometers, which was based on the Transmission and Distribution Engineering inventory. The actual number of transmission lines is 44 and the actual combined length of the transmission lines is 2,761 kilometers. These numbers reflect the fact that two transmission lines carry lower voltages and are technically considered distribution lines. The central regional percentage of transmission lines included in the report (75%) was calculated based on the provincial total transmission line length of 3,791 kilometers (which includes Churchill Falls and two transmission lines being used as distribution lines) rather than the island total transmission line length of 3473 kilometers. This percentage was erroneously reported as being the percentage of the island total in last years report and should have been reported as being approximately 80%.

of both traffic and speed on secondary highways. Safety is further compromised in adverse weather conditions with reduced visibility. Flag persons and signage are often required to divert traffic or shut down traffic lanes altogether while off-loading equipment operations take place in a portion of one of the traffic lanes. Crews also have difficulty negotiating steep embankments while simultaneously attempting to stay clear of adjacent highway traffic and avoid damaging existing highway shouldering.

Current off-loading procedures are often an inefficient use of time, equipment and personnel. Once crews are finished their off-loading operations along secondary highways, they often have to park their work vehicles at distances up to three kilometers away to secure safe and legal parking. Crew members must then be shuttled back to the work area, thereby causing delays in the execution of transmission line work. The steep embankment slopes in some areas also cause delays to crews as they are often unable to negotiate their way down to trail level. Crews are forced to use alternate approved trails which are not located adjacent to the work area. Alternate approved trails are used to access the transmission lines and then the transmission line equipment is slowly traveled back along the transmission line to access the work area.

This project is required to build 15 new off-loading areas along the Jackson's Arm Highway, five new off-loading areas along the Burgeo Highway, and 20 new off-loading areas along the Northern Peninsula Highway (Route 430). Specific locations of proposed off-loading areas for construction in 2010 are shown on the maps in Appendix A. The off-loading areas will allow Hydro work crews to safely park away from existing traffic lanes and will facilitate transmission line equipment access to approved trails. The construction of new off-loading areas will consist of grubbing, excavating of unsuitable material, and supplying, placing and compacting of granular and Class A backfill. Supply and installation of culverts and signage will also be required based on site-specific conditions. A sketch of the off-loading ramp is provided in Appendix B.

The Department of Transportation and Works (DOTW) has approved Hydro's design of the transmission line equipment off-loading areas. However, individual off-loading areas are evaluated on a site by site basis and will be considered for secondary highways only. Individual site approval from the DOTW is based on the available stopping sight distance from both directions when approaching the off-loading area. Stopping sight distance is the distance from the point where a vehicle is first able to spot the off-loading area to the off-loading area itself. Only sites with adequate stopping sight distance in both directions will be approved. In highway zones with a posted speed limit of 90 kilometers per hour, a stopping sight distance of 300 meters will be maintained. Similarly, sites located in zones with posted speed limits of 80, 70 and 60 kilometers per hour will maintain stopping sight distances of 250, 200 and 160 meters respectively. Stopping sight distance is a function of speed; to react at higher speeds the driver needs a greater stopping distance and must therefore see the off loading area from a greater distance. This provides safe highway access for Hydro personnel and for any members of the public who use the ramps for an unauthorized purpose. The DOTW stopping sight distance standard applied to Hydro's off loading ramps is the same that is applied to any point of access to a highway. Sites selected for construction in 2009 have been reviewed in the field by DOTW and are currently in the permitting process.

Within the boundaries of Gros Morne National Park of Canada, jurisdiction for the construction and maintenance of highway accesses falls within the responsibility of Parks Canada. Hydro has presented this project to Parks Canada officials and they have approved in principal the construction of off-loading areas in the park. Off-loading areas will be evaluated and approved on a site by site basis in much the same manner as the DOTW does. Parks Canada has approved Hydro's design of the transmission line equipment off-loading areas.

<u>Seven Year Strategy</u>

2010 will be the third year in which Hydro proposes to construct approximately 200 off-loading areas on the island portion of the province. In the first year of the project, 25 off loading areas were constructed. Eleven were constructed along the Burgeo Highway between the Trans Canada Highway and the Burnt Pond Bridge. Fourteen were constructed along the Buchans Highway between the Trans Canada Highway and the Buchans dump site. The number of ramps constructed in 2008 was higher than the twenty sites proposed because the 2008 sites were primarily existing road access upgrades and sites which did not require large quantities of backfill and culvert, both of which are expensive items.

In 2009, the second year of the project, there are a total of 27 sites which are currently being considered for the construction of off-loading areas along the Burin Highway. Seven of these sites are existing highway accesses which do not require permits for upgrading. The remaining twenty are new highway accesses and are currently in the permitting process. Hydro does not expect all sites to pass the DOTW permitting process and not all sites approved by the DOTW will necessarily be constructed.

Sites are selected on a priority basis, with the highest hazard areas addressed first. Scheduling is optimized so that mobilization and construction are performed at least cost. Table 1 displays the number and locations of ramps to be constructed.

Table 1: Locations and Proposed Schedule for Off-Loading Areas

Highway	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Burin Peninsula		20		20	9		9
Bay d'Espoir					1		1
Buchans	14						
Springdale					1		1
Hampden					5		5
Jackson's Arm			15				
Howley					4		4
Burgeo	11		5				
Deer Lake-Rocky Harbour			20				

Highway	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Rocky Harbour - Bellburns				20			
Bellburns – Eddies Cove West					20		
Eddies Cove West – Flowers Cove						20	
Flowers Cove – St. Anthony							20
Total Sites	25	20	40	40	40	20	40

As this project is for the new construction of off-loading ramps, the following items related to the Existing System do not apply to this project:

- Age of Equipment;
- Anticipated Useful life;
- Major Work/Upgrades;
- Maintenance History;
- Outage Statistics;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacements Parts;
- Environmental Performance; and
- Operating Regime.

3.1 Safety Performance

A roll over accident on Friday, October 12, 2007 on the Trans Canada Highway (TCH) near the Hawke Hill access road is indicative of problems faced by Hydro work crews. A Go-Track unit was being loaded onto a low bed trailer by backing the unit onto the trailer deck. While the operator attempted to straighten the Go-Track with the trailer, the rear of the Go-Track starting sliding towards the ditch. The right track slid off the trailer to the road shoulder, which gave way slightly and with its own weight, the machine toppled onto its right side resting on the outriggers and boom in the ditch by the roadside. The operator remained in the machine but there were no injuries. The deck was clear and dry at the time of the incident. Direct and indirect costs to Hydro arising from this incident totaled $56,000. Figures 1 and 2 show pictures of this incident.

Figure 1: Go-Track unit resting on damaged outriggers and boom.

Figure 2: Low bed trailer parked close to the edge of the ditch to maintain clearance to the driving lane as Go-Track unit overhangs trailer deck on both sides when loaded. Note the tilt of the trailer and the shape of the tracks on the Go-Track unit.

This incident raises several issues. The shape of the D-Dent track used on the Go-Track leaves very little metal in contact with the bed of the trailer and in fact acts much like a ski when the vehicle is moving in the transverse direction. The width of the Go-Track is 3.05 meters. This dictates that the trailer must be parked as close to the edge of the shoulder's embankment as possible to avoid highway traffic. This arrangement causes the trailer to be tilted significantly in the direction of the ditch. This creates a significant risk of injury to workers and bystanders, as well as the possibility of environmental contamination. Safe loading operations on narrow shoulders require traffic to be stopped in adjacent traffic lanes including those on divided highways.

Shoulders on the TCH are designed to accommodate the full width of a typical parked vehicle. Despite the higher standards to which the TCH is built, shoulder width is still inadequate for the safe and efficient loading and unloading of transmission line equipment which is much wider than the typical vehicle traveling the TCH. The DOTW has to date rejected Hydro’s requests to build off loading ramps along the TCH.

4 JUSTIFICATION

This project is justified on the requirement to provide safety to Hydro work crews and the motoring public. This project will also provide efficient access to transmission lines by transmission line equipment crews during responses to emergencies and for regular maintenance. System reliability will also be improved in emergency situations.

Workplace safety and public safety are the predominant reasons for the construction of off-loading ramps. Hydro is committed to ensuring that our customers, employees, and the public are protected against the hazards of our facilities and operations. Transmission line equipment off-loading areas will facilitate the safe loading and unloading of equipment used to access government approved trails along secondary highways. The current procedure for the off-loading of transmission line equipment constitutes a hazardous operation with Hydro work crews working directly in active traffic lanes of highways with increasing levels of both traffic and speed. Hydro work crews have difficulty negotiating steep highway embankments while simultaneously attempting to stay out of adjacent highway traffic lanes. Safety is particularly compromised during adverse weather conditions such as fog, snow, rain, or sleet, which reduces visibility in high traffic areas. Construction of the off-loading areas will increase the level of safety associated with off-loading operations as the potential of vehicular incidents will be reduced, resulting in safer working conditions for our employees and less danger for the motoring public.

Current off-loading operations are time consuming processes which affect the efficiency of Hydro work crews during roadside off-loading and loading operations. When Hydro work crews access transmission lines their vehicles are parked at safe and legal parking areas which may not be close to the delivery points. During actual off-loading operations, partial or complete closure of a highway lane may be required which involves the use of signage, flag persons, or other precautionary measures, depending on the site-specific conditions. Eliminating the requirement for closed lanes on public roads, especially on highways, will reduce the danger created for the public. Furthermore, in some cases approved trails are currently inaccessible due to steep embankment slopes and delays are encountered when alternate approved trails must be used to get to the transmission lines. The new ramps will eliminate the need for lane closures and will facilitate easy access to approved trails for transmission line equipment, resulting in increased functionality and improved efficiency to Hydro work crews.

In addition to regular planned operations by maintenance crews, the off-loading ramps will be used during unplanned outage situations. The installation of these sites will permit faster mobilization and shorter response times during forced outage situations, thus reducing customer outage time.

4.1 Net Present Value

A net present value calculation was not performed as there are no viable alternatives.

4.2 Levelized Cost of Energy

The levelized cost of energy is a high level means to compare the costs of developing two or more alternative generating sources. Therefore, the levelized cost of energy is not applicable in this case.

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Legislative or Regulatory Requirements

Transmission line equipment off loading ramps are subject to approval by the DOTW for most highways in the province and by Parks Canada for highways inside the two national parks. The construction of the ramps must also meet with the approval of Hydro's internal environmental department.

4.5 Historical Information

2010 will be the third year of a seven year program to construct transmission line equipment off-loading areas on the island portion of the province. The approved budget for 2009 is $497,900. At the time of the writing of this report, preliminary work for 2009 has been initiated on the Burin Peninsula Highway. A total of 25 off loading areas were constructed on the Buchans and Burgeo Highways in 2008 at a cost of $305,300. Table 2 provides historical information for transmission line equipment off-loading area construction.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009	497.9		20		
2008	301.8	305.3	25	12.2	

4.6 Forecast Customer Growth

Customer load growth does not affect this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to the construction of transmission line equipment off-loading areas.

4.8 Losses during Construction

This project will have no effect on normal operations of generating facilities and will not cause any interruptions or system outages. Therefore, there will be no losses during construction.

4.9 Status Quo

If transmission line equipment off-loading areas are not constructed, the safety of both Hydro work crews and the traveling public will continue to be at risk during off-loading and loading operations in which heavy equipment is moved in active highway traffic lanes. Furthermore, access to transmission lines by Hydro work crews will continue to be impeded, decreasing productivity in the performance of maintenance and emergency repairs.

4.10 Alternatives

There are no viable alternatives available to the construction of transmission line equipment off-loading areas.

5 CONCLUSION

Transmission line equipment off-loading areas are needed to improve the safety of both Hydro work crews and the public. This project will allow Hydro's work crews to perform transmission line work more efficiently by providing a dedicated area for off-loading operations and parking. System reliability will also be improved in emergency situations as response times for mobilization will be reduced. This project demonstrates Hydro's continued commitment to employee and public safety.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 3.

Table 3: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	95.4	0.0	0.0	95.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	703.8	0.0	0.0	703.8
Other Direct Costs	21.2	0.0	0.0	21.2
O/H, AFUDC & Escln.	87.8	0.0	0.0	87.8
Contingency	82.0	0.0	0.0	82.0
TOTAL	**990.2**	**0.0**	**0.0**	**990.2**

5.2 Project Schedule

Table 4 provides the anticipated project schedule.

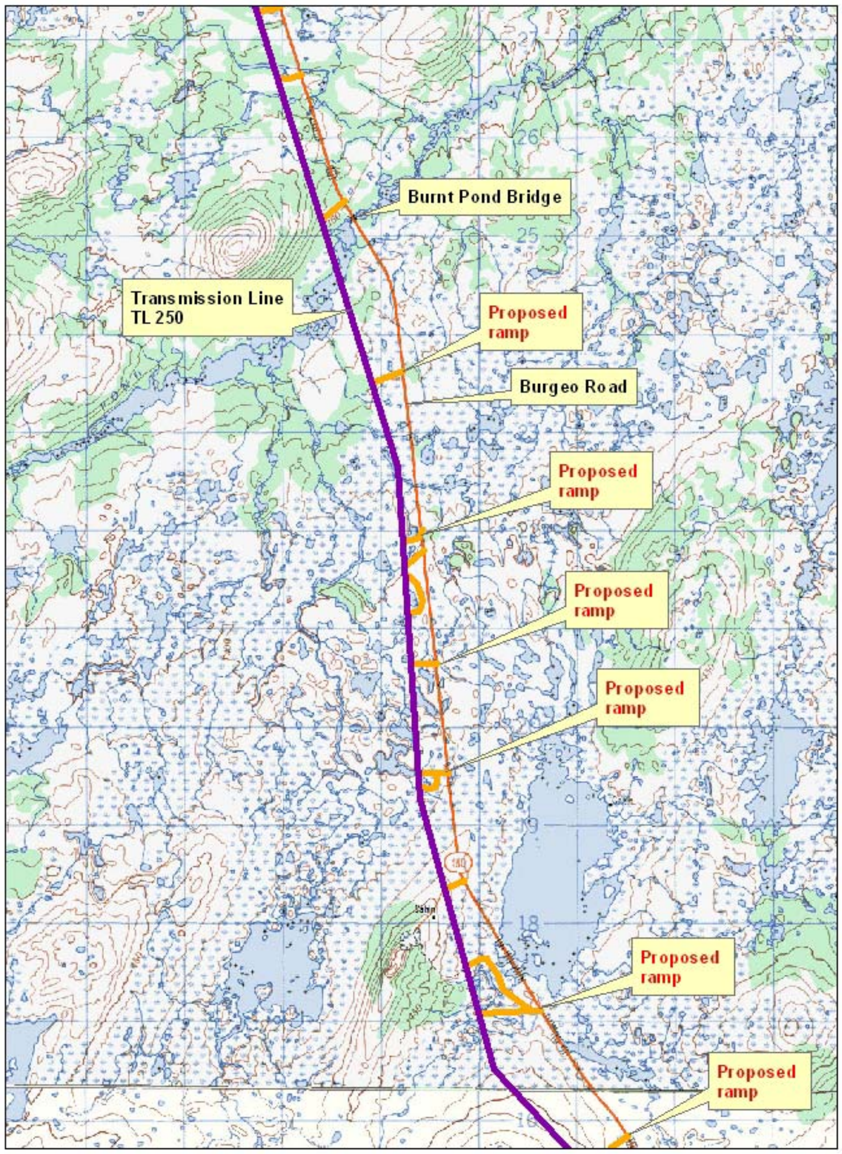
Table 4: Project Schedule

Activity	**Milestone**
Project Initiation	February 2010
Design and Planning	May 2010
Tendering	July 2010
Construct Transmission Line Equipment Off Loading Ramps	September 2010
Close Out and Documentation	November 2010

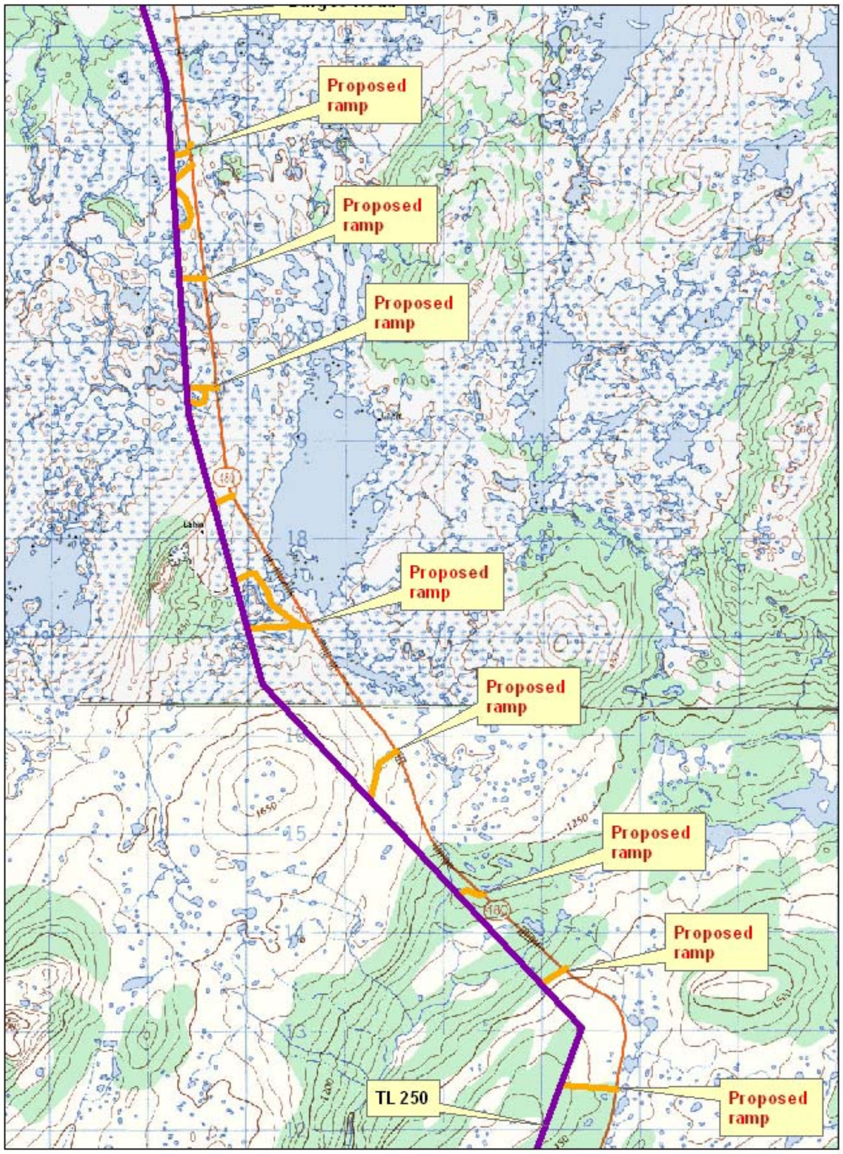
APPENDIX A

Maps Showing Specific Locations of Proposed Off-Loading Areas

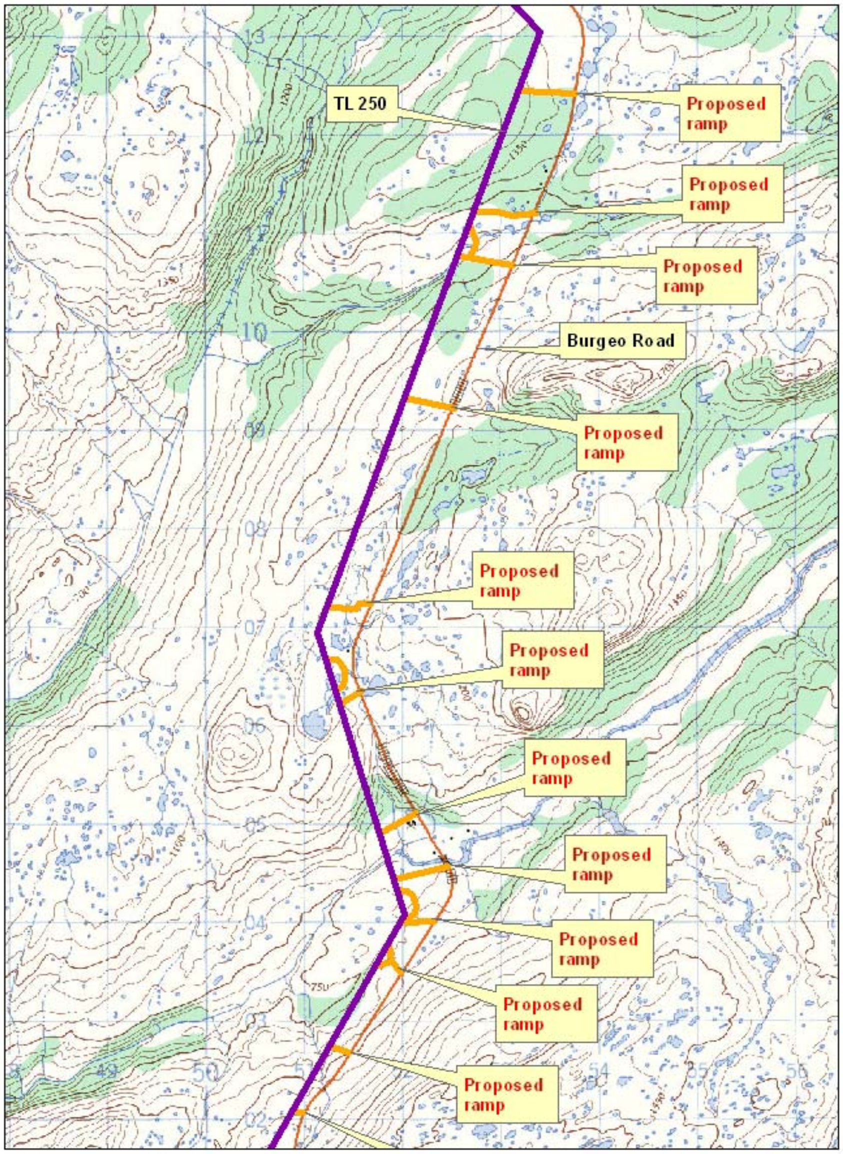
Central Newfoundland



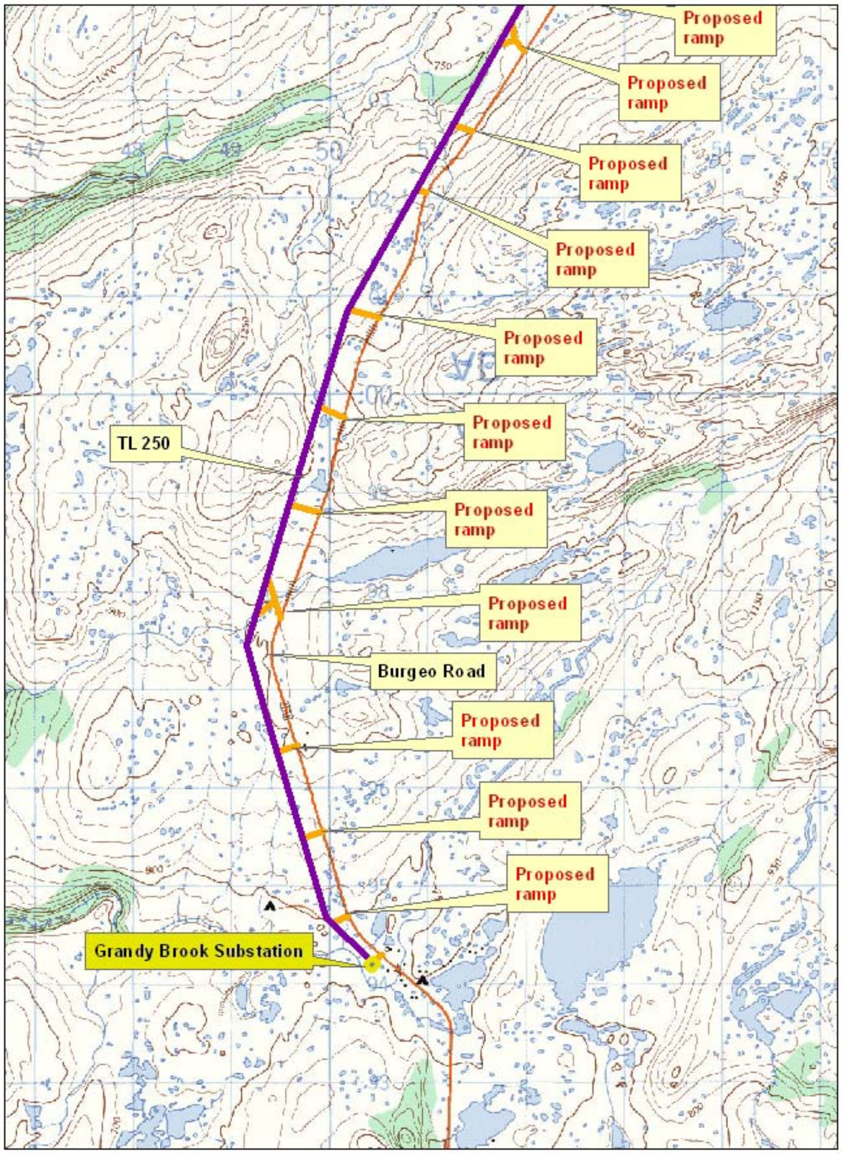
Transmission Line TL 250 along the Burgeo Highway



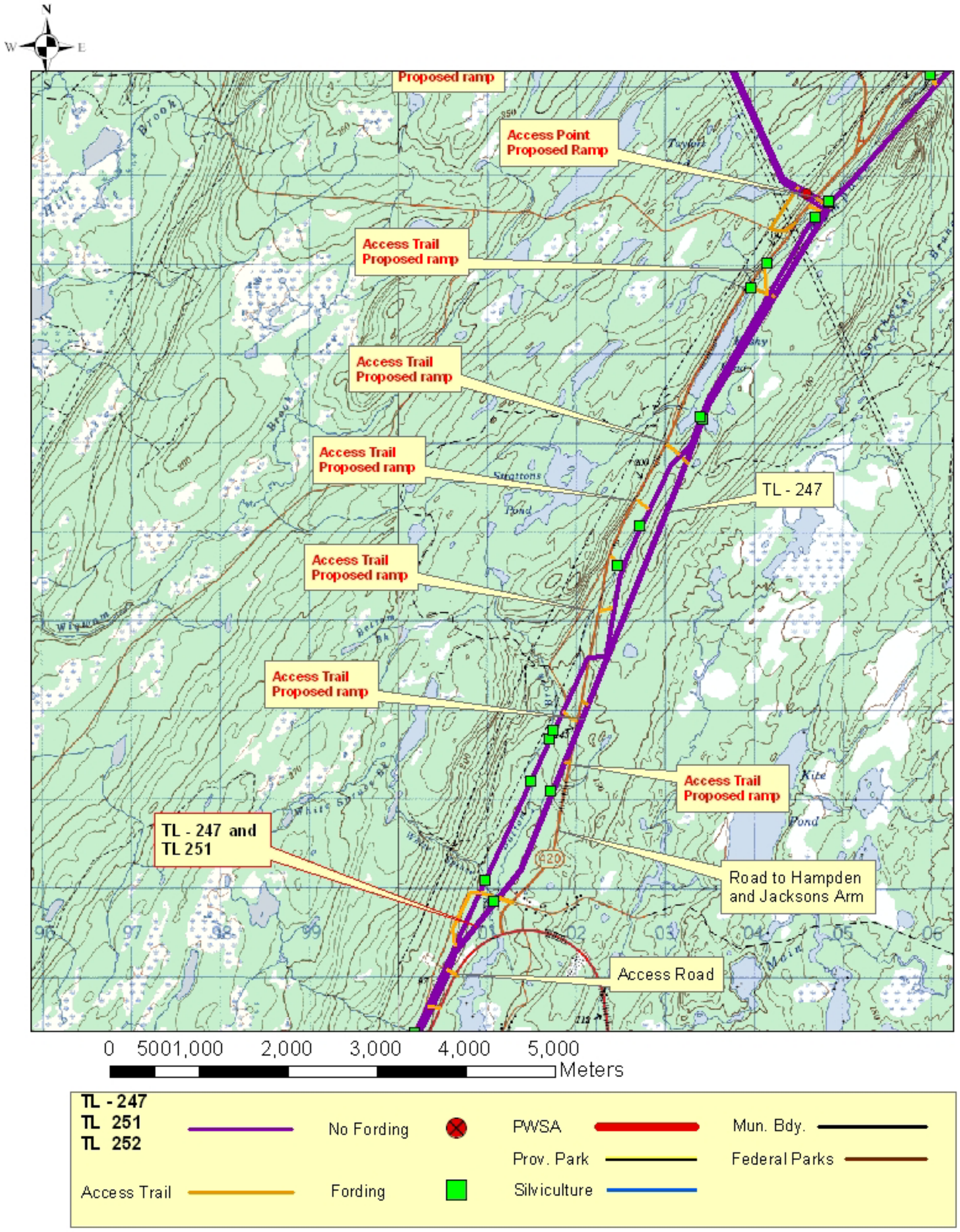
Transmission Line TL 250 along the Burgeo Highway



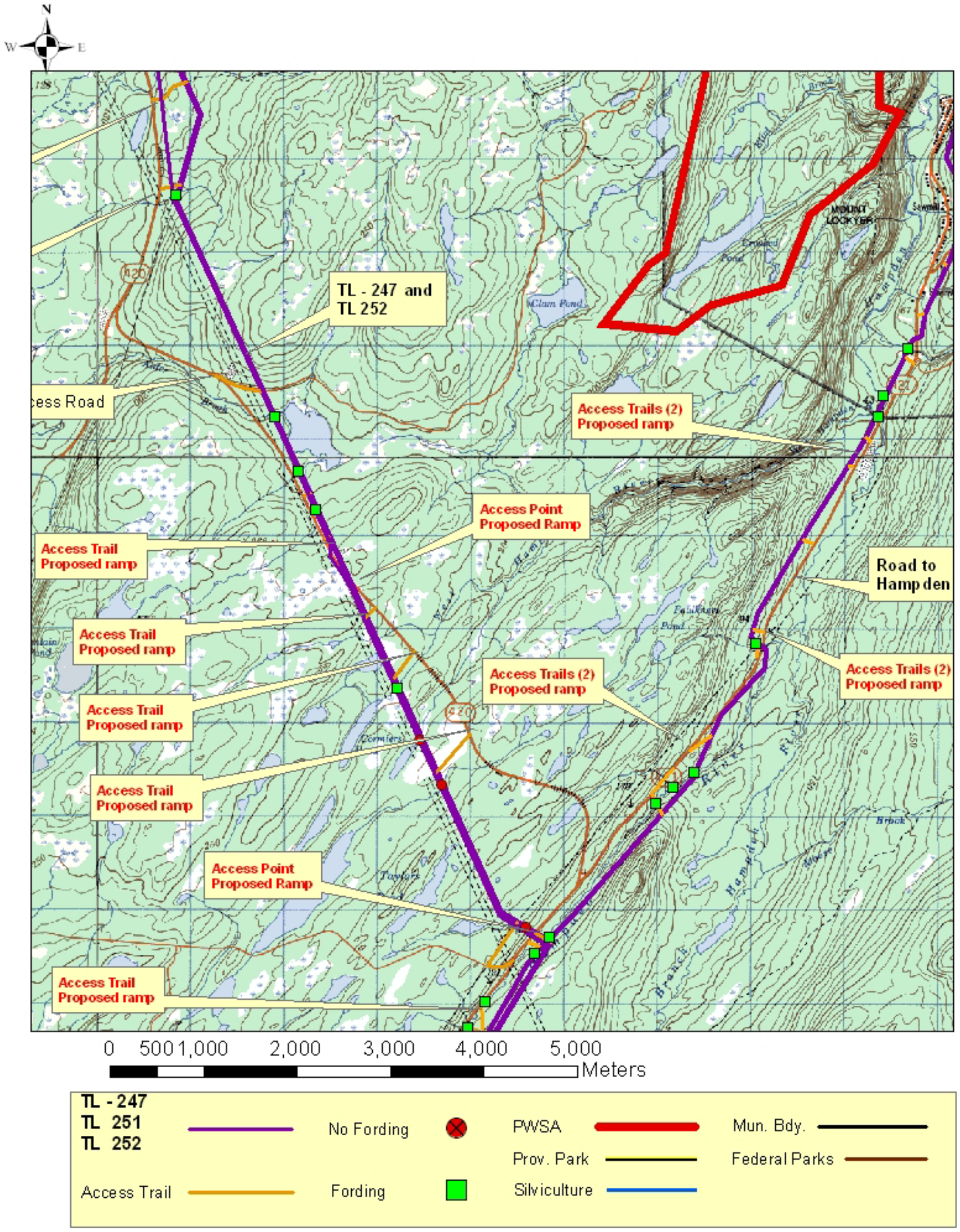
Transmission Line TL 250 along the Burgeo Highway



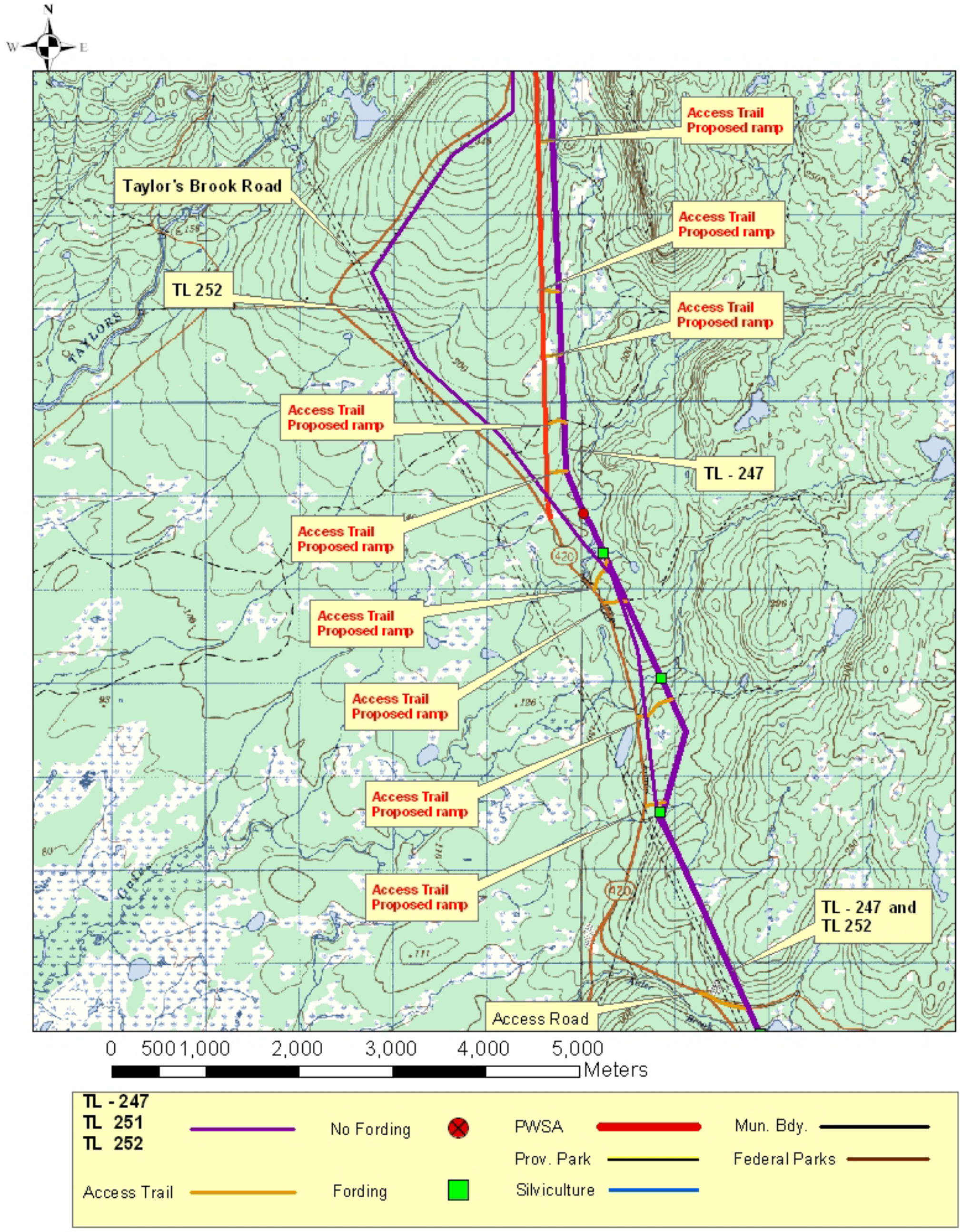
Transmission Line TL 250 along the Burgeo Highway



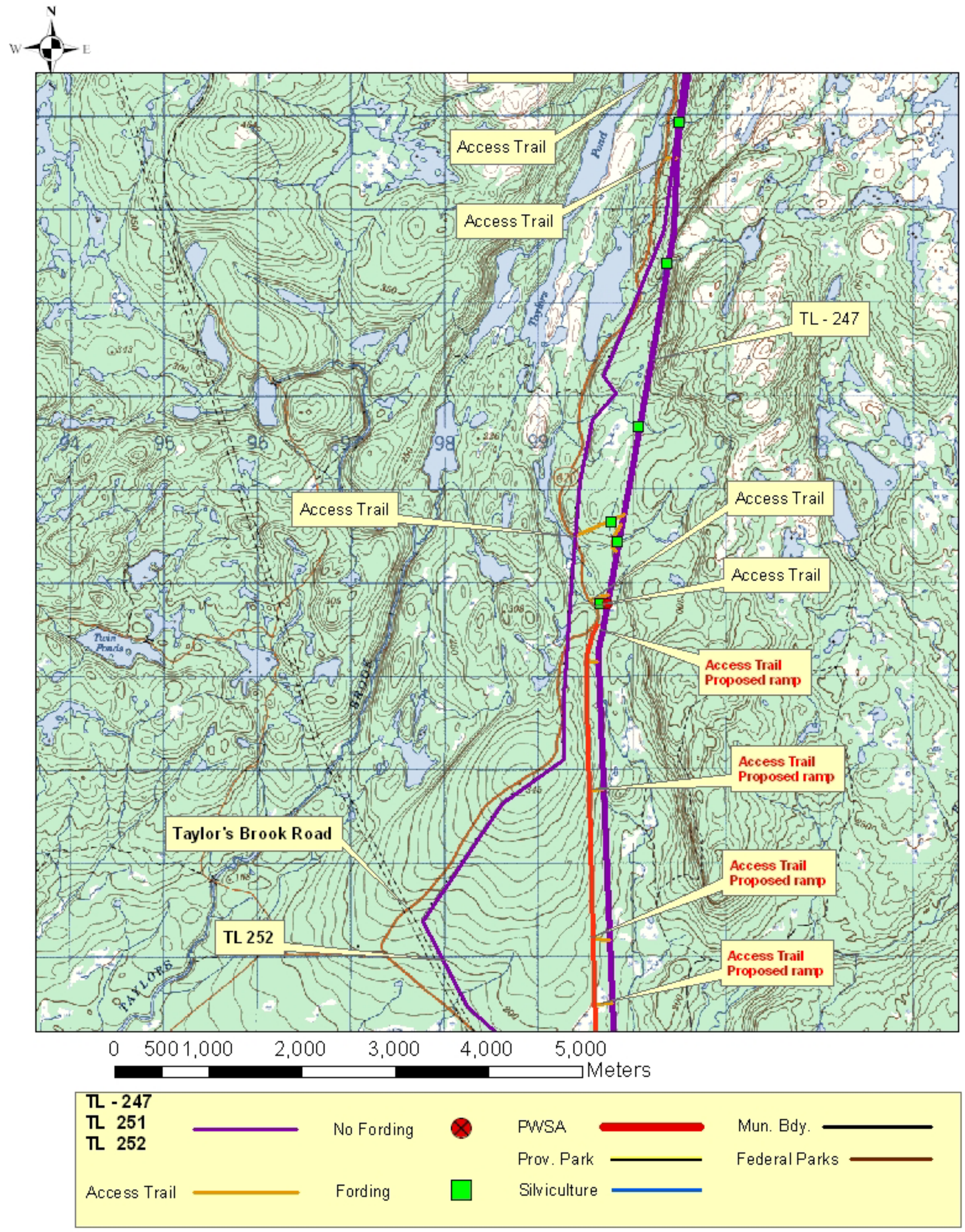
Transmission Lines TL 247 and TL 251 along the Jackson's Arm Highway



Transmission Lines TL 247 and TL 252 along the Jackson's Arm Highway

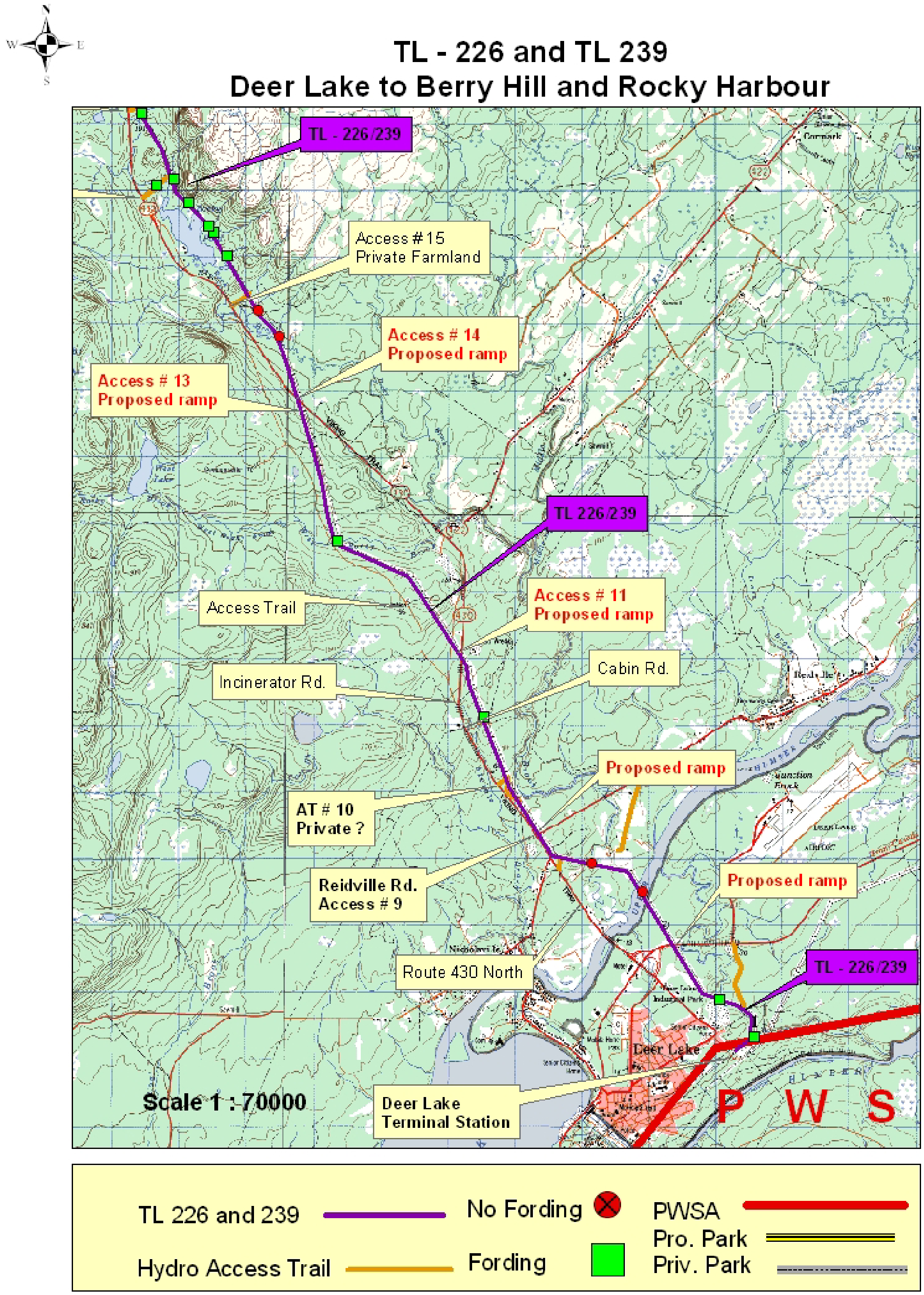


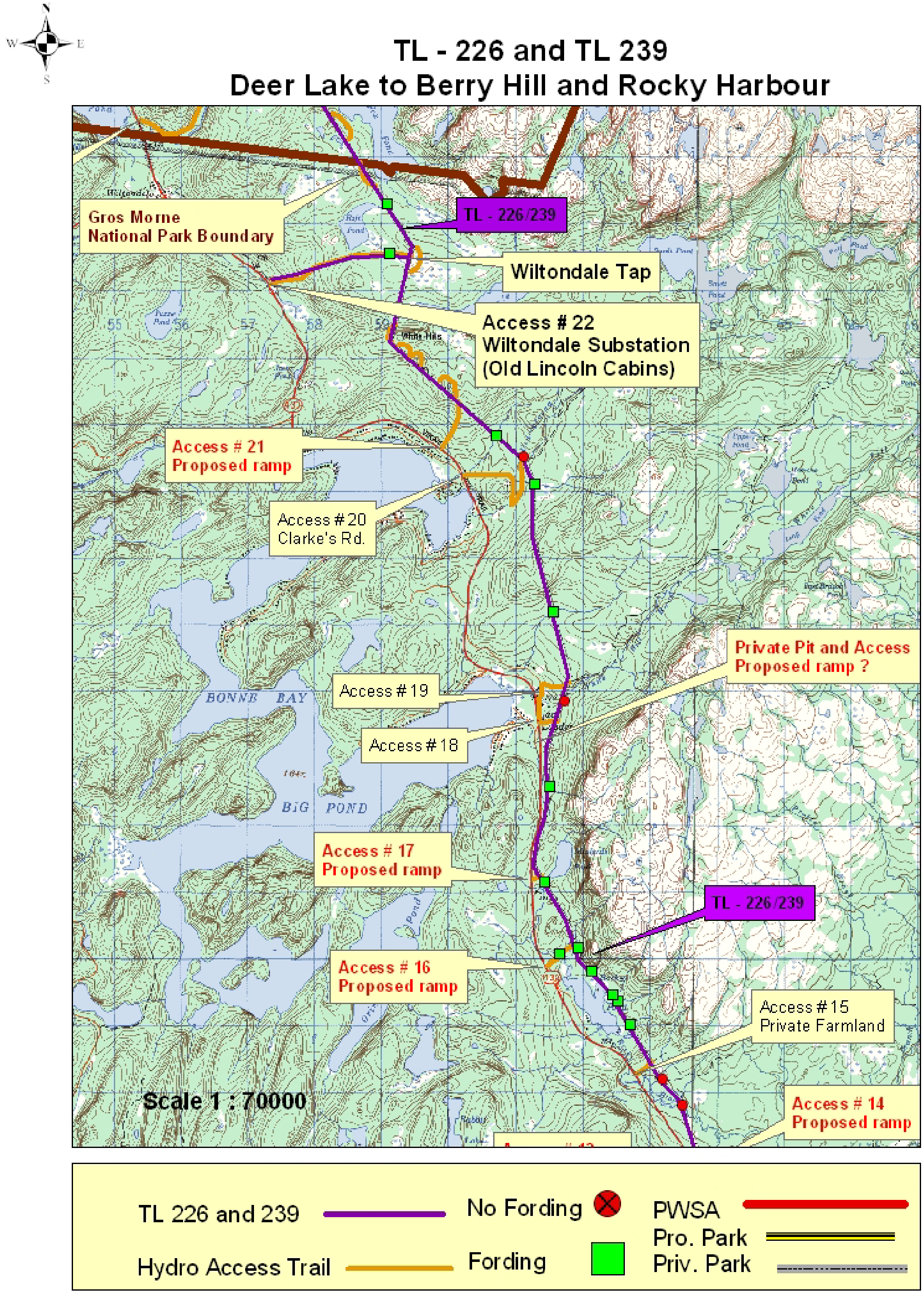
Transmission Lines TL 247 and TL 252 along the Jackson's Arm Highway

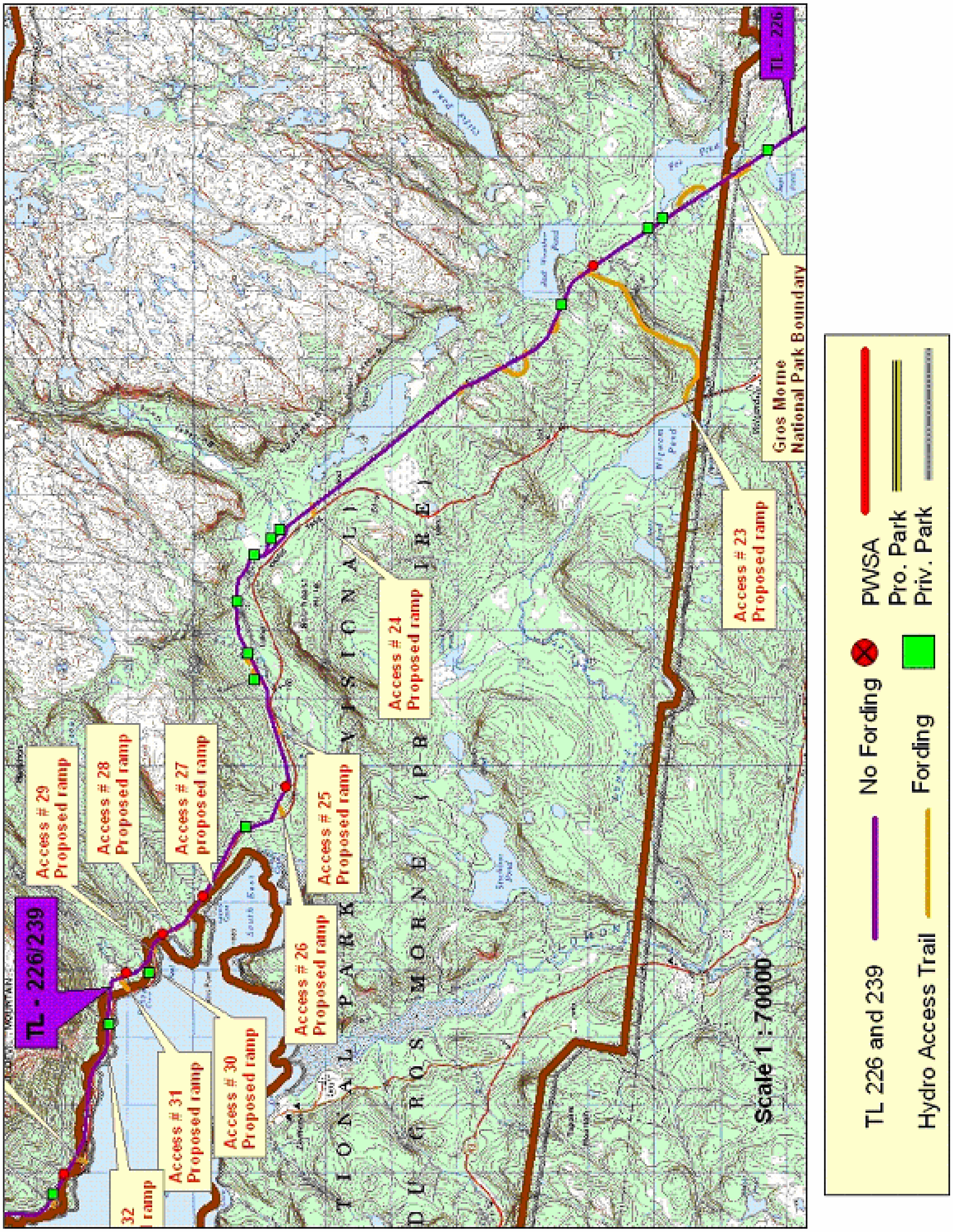


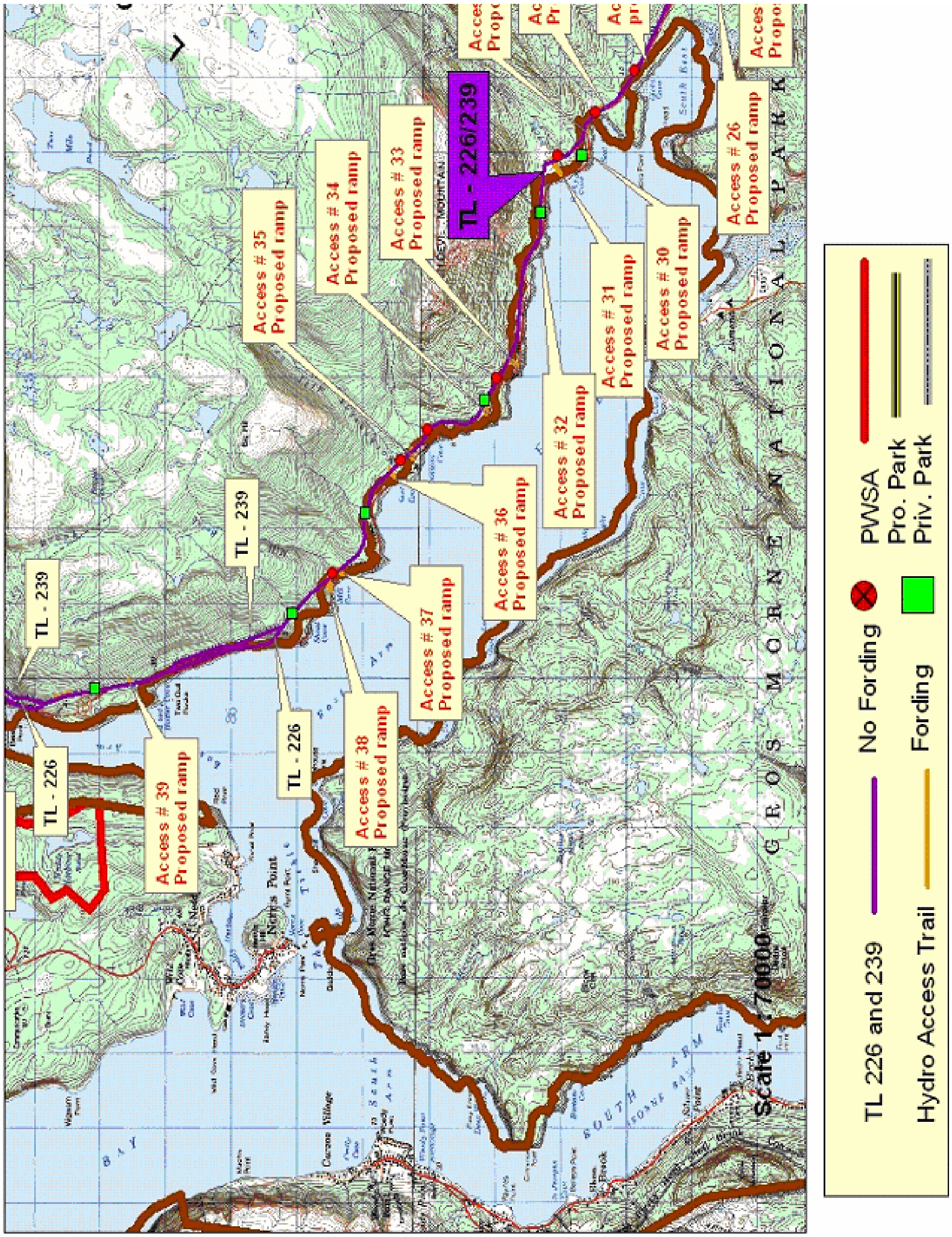
Transmission Lines TL 247 and TL 252 along the Jackson's Arm Highway

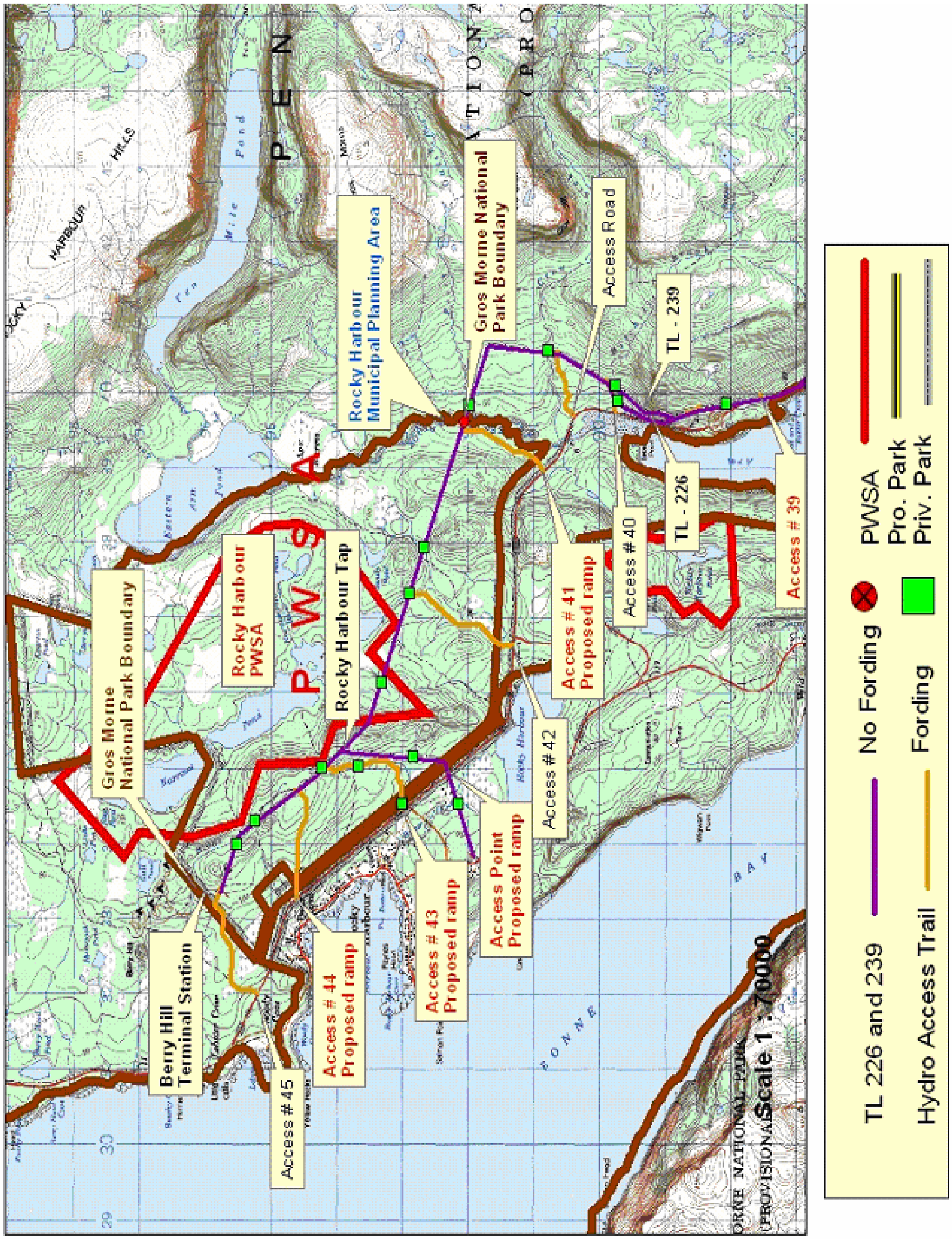
Northern Newfoundland




N
W
E
S
TL - 226 and TL 239
Deer Lake to Berry Hill and Rocky Harbour
Gros Morne
National Park Boundary
TL - 226/239
Wiltondale Tap
Access # 22
Wiltondale Substation
(Old Lincoln Cabins)
Access # 21
Proposed ramp
Access # 20
Clarke's Rd.
Private Pit and Access
Proposed ramp ?
Access # 19
Access # 18
BONNE BAY
BIG POND
Access # 17
Proposed ramp
TL - 226/239
Access # 16
Proposed ramp
Access # 15
Private Farmland
Scale 1 : 70000
Access # 14
Proposed ramp
TL 226 and 239
Hydro Access Trail
No Fording
Fording
PWSA
Pro. Park
Priv. Park

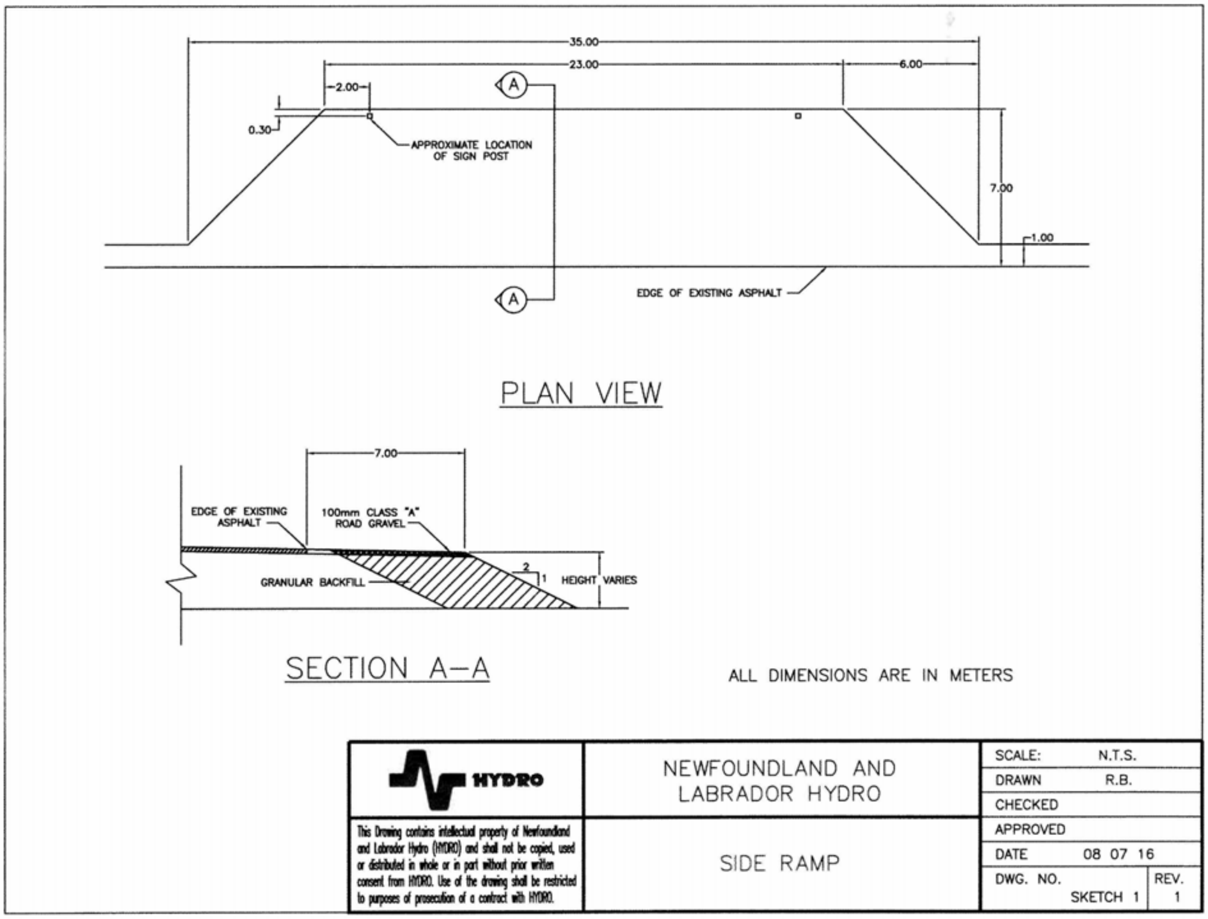

TL - 226/239
TL - 226
Access # 23 Proposed ramp
Access # 24 Proposed ramp
Access # 25 Proposed ramp
Access # 26 Proposed ramp
Access # 27 proposed ramp
Access # 28 Proposed ramp
Access # 29 Proposed ramp
Access # 30 Proposed ramp
Access # 31 Proposed ramp
32
ramp
Gros Morne National Park Boundary
Scale 1 : 70000
TL 226 and 239
No Fording
PWSA
Pro. Park
Priv. Park
Hydro Access Trail
Fording


TL - 239
TL - 226
Access # 39 Proposed ramp
TL - 226
TL - 239
Access # 38 Proposed ramp
Access # 37 Proposed ramp
Access # 36 Proposed ramp
Access # 35 Proposed ramp
Access # 34 Proposed ramp
Access # 33 Proposed ramp
Access # 32 Proposed ramp
Access # 31 Proposed ramp
Access # 30 Proposed ramp
Access # 26 Proposed ramp
TL - 226/239
GROS MORNE NATIONAL PARK
Scale 1:70000
TL 226 and 239
Hydro Access Trail
No Fording
Fording
PWSA
Pro. Park
Priv. Park


Rocky Harbour Municipal Planning Area
Gros Morne National Park Boundary
Access Road
TL - 239
TL - 226
Access # 39
Access # 40
Access # 41 Proposed ramp
Access # 42
Rocky Harbour Tap
Rocky Harbour PWSA
Gros Morne National Park Boundary
Access Point Proposed ramp
Access # 43 Proposed ramp
Access # 44 Proposed ramp
Access # 45
Berry Hill Terminal Station
Scale 1 : 70000
TL 226 and 239
Hydro Access Trail
No Fording
Fording
PWSA
Pro. Park
Priv. Park

APPENDIX B

Off-Loading Ramps Specifications


35.00
23.00
6.00
2.00
0.30
A
APPROXIMATE LOCATION OF SIGN POST
7.00
1.00
EDGE OF EXISTING ASPHALT
A
PLAN VIEW
7.00
EDGE OF EXISTING ASPHALT
100mm CLASS "A" ROAD GRAVEL
GRANULAR BACKFILL
2
1
HEIGHT VARIES
SECTION A–A
ALL DIMENSIONS ARE IN METERS
HYDRO
NEWFOUNDLAND AND LABRADOR HYDRO
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied, used or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.
SIDE RAMP
SCALE: N.T.S.
DRAWN R.B.
CHECKED
APPROVED
DATE 08 07 16
DWG. NO. SKETCH 1
REV. 1

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER DAVID W. HICKS SIGNATURE July 31 2009 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

UPGRADE POWER TRANSFORMERS

July 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

Table of Contents (cont'd.)

1 INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro's) Power Transformer Upgrading project is required to either extend the life of existing power transformers or replace units meeting the replacement criteria outlined in Section 2 of this report. Many transformers have been in service for more than 30 years (see Section 3.1). As they age, they are approaching the at-risk phase of their life cycle.

Hydro has 54 terminal stations in the Island Interconnected System and three in the Labrador Interconnected System. The terminal stations contain a total of 114 power transformers. Table 1 provides the number of transformers for each transformer rating.

Table 1
Transformer Rating

Transformer Rating (kV)	# of Transformers
230/138	13
230/69	4
230/66	14
230/46	9
230/16	4
230/13.8	14
230/6.9	1
138/69	2
138/66	5
138/25	7
138/13.8	2
138/12.5	2
69/25	8
69/13.8	1
69/12.5	1
69/4.16	5
66/25	4
66/13.8	2
66/12.5	7
66/7.2	2
66/6.9	3
66/4.16	1
66/0.6	3

Power transformers serve a very critical function to the power system. At the generating stations, transformers are referred to as step up transformers. They step up the voltage for power transmission from the generation source voltage to the line voltage. The voltage is stepped up to reduce the current and thereby reduce the transmission losses. At a terminal or substation, step down power transformers are used to convert the voltage down to distribution voltage levels suitable for delivery to end users. Figure 1 shows a picture of the power transformer T3 at Massey Drive.

The basic components of a power transformer are the steel tank, bushings, core, windings, clamping assembly and insulation system (oil and cellulose paper). The tank houses all the components of the transformer while the bushing acts as an interface between the internal winding conductors and the outside high voltage network. The purpose of the core and windings is to provide the voltage conversion. The transformer oil acts to insulate the windings from ground potential and also provides cooling. The cellulose paper is used to insulate the windings against turn to turn faults and the clamping assembly is required to secure the winding during short circuit magnetic forces.

The aging of the transformer is essentially aging of the insulation system. This aging process reduces both the mechanical and dielectric strength of the transformer. When older transformers are subjected to faults the chance of survival is less relative to that of newer units. Also, as load is increased on a power transformer the operating temperature is increased which, over time, negatively impacts the cellulose paper strength. The winding insulation can be weakened to the point where it can no longer sustain the mechanical stresses of a fault.

Figure 1: Power Transformer T3 at Massey Drive

2 PROJECT DESCRIPTION

With the power transformer being a critical and a high-cost capital asset, Hydro, like many North American utilities, has been working to maximize the life of its service units. In recent years, there has been a significant effort by Hydro to deal with power transformer problems resulting from their age and/or condition. Such problems include:

- Quality of transformer oil;
- Condition of coolers (radiators);
- Condition of on load tap changers;
- Leaking transformer bushings;
- Failure of protective devices such as gas relays, winding temperature devices and oil level equipment; and
- Leaking transformer gaskets.

The main objective for this project is to take a strategic approach to address all transformer issues collectively as opposed to individual projects. The intention is to utilize known information from the six problem areas stated above to execute a transformer upgrade or a complete replacement.

A transformer replacement will be based on the following criteria:

- Degree of Polymerization (DP) of cellulose insulation paper less than 400[1] (see table in Appendix C). Using a transformer oil sample, specialized laboratories can perform what is known as a Furan Analysis of the oil. As the cellulose paper insulation ages, furanic compounds are released into the oil. Based on the level of furanic compound, a 'DP'

[1] Hydro has chosen 400 as the target to allow adequate time to plan a replacement before the threshold of 200 is met.

number is inferred. New transformers have a DP number of more than 1000. While transformers near the end of their service life show DP numbers of 200 or less.

- Significant combustible gas generation in the transformer oil indicates an internal fault is developing. The gas generation rate is regularly recorded by performing a Dissolved Gas Analysis (DGA) from an oil sample.

Currently, there are no units that meet these criteria. However, it can be seen from Appendix C, Transformer T7 at Bay d'Espoir was showing DP levels below 400 in 2005, and this unit will be retested in 2009 and is planned to be replaced in 2012.

It is typically more cost effective and reliable to replace power transformers in a planned mode rather than a reactive mode. Hydro will replace transformers as the DP number becomes less than 400 within a three to five-year window. This will provide the necessary lead time to purchase and schedule the installation during the most appropriate system outage window. Currently, the lead and delivery time for power transformers is 18 to 24 months after receipt of order.

3 EXISTING SYSTEM

This project is required to upgrade or replace aging power transformers currently in service for Hydro.

3.1 Age of Equipment or System

Figure 2 shows the age distribution for Hydro's transformers rated 66 kV and greater. Currently, 55 percent of Hydro's transformer fleet is more the 30 years of age, and 11 units are 43 years old.

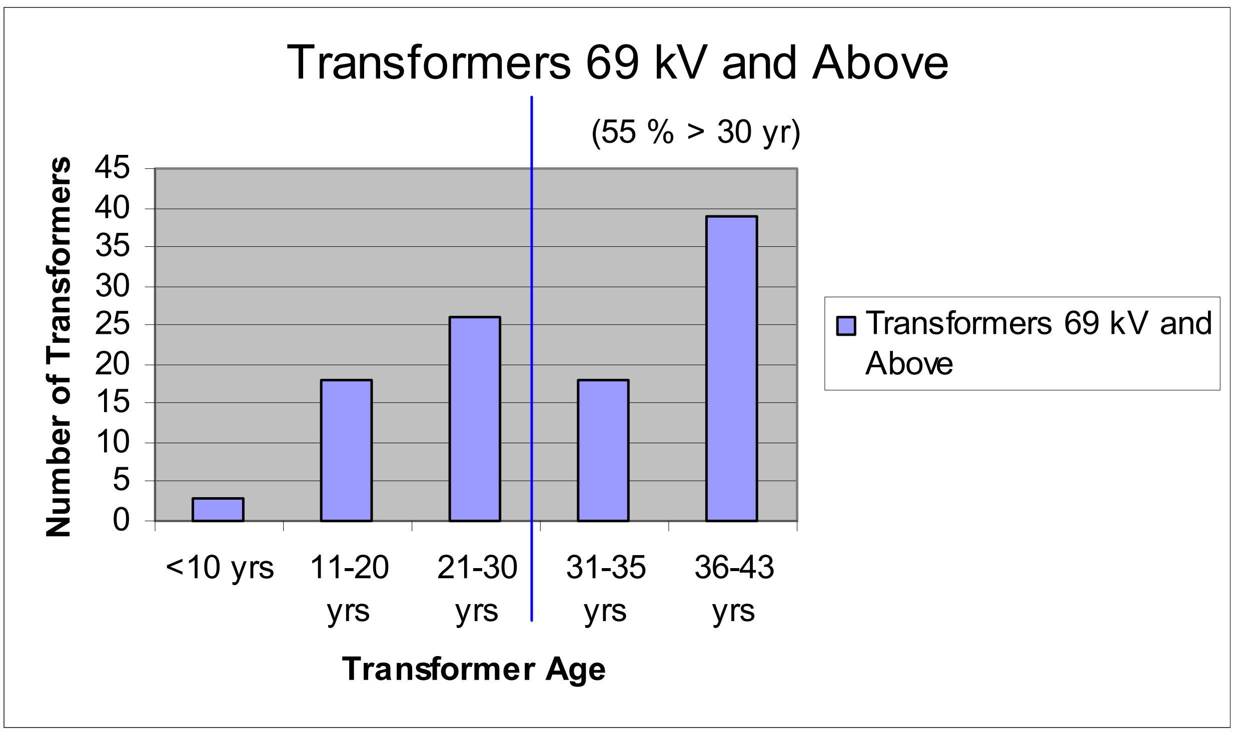


Figure 2: Transformer Age Distribution (66 kV and above)

3.2 Major Work or Upgrades

There have been no major capital upgrades to the power transformer fleet. Work has been confined to regular maintenance and inspections, with minor operational type repairs as discussed below.

3.2.1 Quality of Oil

As a transformer ages sludge begins building up on the windings inside the power transformer tank. This is a result of the chemical reaction between oxygen, oil and a small amount of moisture. As the chemical process takes place, oxygen inhibiter is depleted and acidity of the oil begins to rise. This results in the color of the oil being darker and the electrical insulating properties of the oil being lowered. If this process were left without intervention, the acidity would attack the cellulose insulating paper causing it to be brittle. If the insulating paper becomes weakened, there is a very high probability for failure due to failure of the mechanical strength of the paper. Transformers in this condition will have a low DP number.

After tracking oil quality data for a number of years, the acidity on several units was discovered to be outside the Institute of Electrical and Electronic Engineers (IEEE) Standard 637 oil quality guideline and Hydro decided to reclaim power transformer oil. This reclaiming process is able to bring aged oil back to within oil quality parameters similar to new oil. Figure 3 shows the visual change in oil color as it is reclaimed from start to finish, with the darkest being the start and the clearest being the end of the process. Table 2 outlines the work completed in this area to date. It is also important to note that in 2005 an in-house transformer ranking tool was developed (see Appendix D) to prioritize units for reclamation based upon selectable oil quality values and criticality within the Island Interconnected System.

Figure 3: Reclaimed Oil – Start (left) to Finish (right)

Table 2
List of oil reclamation work completed in recent years

Year	Major Work/Upgrade	Comments
2008	Reclaimed Transformer T1 and T2 at Holyrood.	Completed work with in-house staff using Hydro's Fluidex Reclamation unit
2007	Reclaimed Transformer T2 at Grand Falls and T2 at Cat Arm	Completed work with in-house staff using Hydro's Fluidex Reclamation unit
2006	Reclaimed Transformer T1 at Grand Falls	Completed work with in-house staff using new Fluidex technology oil Reclamation unit
2004	Reclaimed Transformer T1 at Upper Salmon and T2 at Bay d'Espoir	External contractor reclaimed power transformer using fuller earth technique at a cost of $90,000
2003	Reclaimed Transformers T1, T3 and T7 at Bay d'Espoir	ABB reclaimed 3 power transformers, at a cost of $200,000 using a Fluidex technology.

3.2.2 Work Completed on Radiators

Historically radiators were manufactured from painted carbon steel and Newfoundland and Labrador's environmental conditions have resulted in corrosion causing damage beyond repair. In some cases, this damage has lead to oil leaks. Figure 4 shows radiators being replaced at Bottom Waters. Table 3 shows a list of work completed with transformer radiators in recent years.

Figure 4: Radiators Being Replaced at Bottom Waters

Table 3
List of Work Completed With Transformer Radiators in Recent Years

Year	Major Work/Upgrade	Comments
2008	Removed and replaced radiators on T1 at Farewell Head	Leaking radiators were removed and replaced with new.
2007	Remove four radiators from Transformer T1 at Stephenville.	Radiators were leaking and after reviewing the load profile it was decided to remove four of 16 radiators.
2007	Replaced radiators on T1 transformer at Bottom Waters	Radiators were leaking and had to be replaced on an unbudgeted job.
2007	Completed a condition assessment for all power transformers in the TRO Central Region	See table in Appendix A showing ranking and proposed schedule for replacement.
2007	Purchased five radiators for T2 at Holyrood.	Due to a delivery problem the radiators were to be installed in 2008.
2006	Replaced radiators on transformer UST2 at Holyrood.	Radiators were leaking.
2005	Purchased new radiators for 230 kV Spare Unit Transformer for Holyrood.	Placed in storage to prevent corrosion.

3.2.3 Work Completed With On Load Tap Changers

In 2006, Hydro implemented a new maintenance philosophy for on load tap changers. On load tap changers are required to change the position of the winding inside the transformer to maintain acceptable customer voltages. To do this, moving components, which wear over time, are required. To measure this wear, an oil sample is taken to analyze the oil quality and particle count. This is a non-intrusive method to determine the condition of the internal parts of the tap changer. Sampling in 2006 revealed the poorest on load tap changer was on Transformer T3 at Massey Drive in Corner Brook. The manufacturer representative was brought to the site in 2007 and the tap changer was removed and overhauled. Figures 5 and 6 show the condition of the on load tap changer prior to and after refurbishment. The next steps are to follow the recommendations as outlined in the table in Appendix B.

Figure 5: Before Overhaul

Figure 6: After Overhaul

3.2.4 Bushing Replacements

In recent years, bushings have been replaced mainly due to leaks and poor Doble (high voltage insulation test) readings. In future, besides replacing leaking units, Hydro will also have to replace units to ensure all bushings containing PCBs are removed from service by 2025. Table 4 contains a listing of transformer bushing replacements in recent years.

Table 4
List of Transformer Bushing Replacements in Recent Years

Year	Major Work/Upgrade	Comments
2008	Replaced two 69 kV bushings on GT1 at Buchans	Replaced two bushing due to leaks. Cost per unit was $3,500.
2007	Replaced three Low Voltage (15 kV) high current bushings on T1 at Bay d'Espoir	Replaced units due to bushing leaks. Cost per unit was $15,000.
2007	Replaced one Low Voltage (15 kV) high current bushing on T1 at Upper Salmon	Replaced unit due to bushing leaks. Cost was $25,000. The cost was elevated due to problems going back online (Gas relay operation).
2006	Replaced three 15 kV bushings for T1 at Paradise River.	Replaced units due to leaks. Cost was $11,000.
2006	Replaced three 69 kV bushings for T2 at Western Avalon.	Replaced units due to leaks. Cost was $5,300.
2006	Replaced one 230 kV and one 15 kV bushing for T1 at Massie Drive	Replaced units due to leaks. Cost was $24,000.
2005	Replaced one 15 kV bushing for T4 at Hardwoods	Replaced unit due to bushing leaks. Cost was $7,000.
2004	Replaced one 230 kV and one 15 kV bushing for T3 at Hardwoods	Replaced units due to bushing leaks. Cost was $15,000.
2004	Replaced one 230 kV bushing for T1 at Buchans	Replaced unit due to bushing leaks. Cost was $31,000 ($16,000 was required to provide portable generation to facilitate this work).
2002	Replaced a total of six Low Voltage (15 kV) high current bushings on T2 and T6 at Bay d'Espoir	Replaced units due to bushing leaks. Cost was $60,000.

Note: The cost for bushings outlined above is from units taken from inventory. Units purchased at today's prices will be significantly higher.

3.2.5 Protective Device Replacements

As a result of maintenance checks and alarms, there has been a requirement to replace transformer protection devices such as gas relays, winding temperature relays, oil temperature relays and oil level devices. Table 5 lists replacements of protective devices completed in recent years.

Table 5
List of Replacements of Protective Devices Completed In Recent Years

Year	Major Work/Upgrade	Comments
2008	There were six gas relays, four relay/winding temperature relays, and one fault pressure device replaced.	Total cost was $39,000
2007	There were nine gas relays, five winding/oil temperature relays replaced.	Total cost was $49,000.
2006	There were four gas relays, four winding/oil temperature relays, and one oil level gauge replaced.	Total cost was $28,000.
2005	There were four gas relays, three winding/oil temperature relays, and one oil level gauge replaced.	Total cost was $25,500.
2004 or earlier	There were four gas relays, nine winding/oil temperature relays, and one oil level gauge replaced.	Each gas relay cost $3,500, winding/oil temperature relays cost $3,500 and each oil level device cost $1,000. Total cost was $46,500

3.2.6 Transformer Leaks

Oil leaks have been experienced on many transformers and are a result of several failure modes such as:

- Leaking bushings and bushing gaskets;
- Leaking valves;
- Leaking winding and oil temperature relays;
- Leaking gas relays;
- Leaking explosion relief devices;
- Leaking manhole and access covers;
- Leaking radiator gaskets and O-rings; and
- Leaking main tank top cover gaskets.

The majority of leaks are the result of failed gaskets which seal attached components to the transformer main tank. Experience indicates the gasket material is failing randomly throughout the transformer fleet and in some cases there are multiple occurrences on the same units. Repairs can be made to a transformer and the next inspection may reveal a leak on the same transformer in another location. The failure rate is accelerated by the age of the transformer and the thermal cycling experienced by the unit.

Depending on the location of the leak, the cost of repairs and required outage time can be quite extensive. Extended outages to these power transformers jeopardize the integrity of the power system and compromise the quality of service to customers. In each case, oil must be removed from the main tank to a level below the leak. This involves pumping and storing oil, installing nitrogen gas supply to protect the exposed internal components and then filtering the oil on refill. If oil has to be removed to a level below the core and windings it is required to put a vacuum on the unit for 24 to 48 hours prior to filling. When oil is moved inside a transformer, a minimum dwell time of 24 hours is required to allow the oil to stabilize and release any trapped air prior to energizing. Each time a transformer is exposed to the atmosphere there is an increased risk of moisture contamination which could result in shortened life or premature failure.

A typical gasket upgrading cost will be in the order of $65,000 due to the equipment and labor required to process oil.

Some transformers are also leaking around the top cover gasket. Replacement of the gasket would involve removal of all bushings, piping, current transformers, protective devices and oil. The top cover which is approximately 10 feet x 15 feet x 1/2 inch thick would have to be removed and a new gasket prepared and installed. This is an extensive job that would involve boom trucks, cranes and a five-man crew for at least six weeks.

Currently, other options are being pursued such as welding a channel around the top perimeter of the transformer completely encompassing the gasket cover. Transformer oil would eventually fill the void created by the new channel thus eliminating any further leaks to the environment. This option will require further engineering analysis to help determine if this approach will be acceptable.

3.3 Anticipated Useful life

According to Electric Power Research Institute (EPRI), the average age of in-service power transformers is 37 years. Failures of power transformers are typically random; however, probability of failure increases with age. The "bathtub" curve in Figure 7 shows a typical percent failure rate versus age curve for power transformers. Based upon this curve, half of Hydro's in-service transformers are on the tip up part of the curve where the probability of failure is increasing with time.

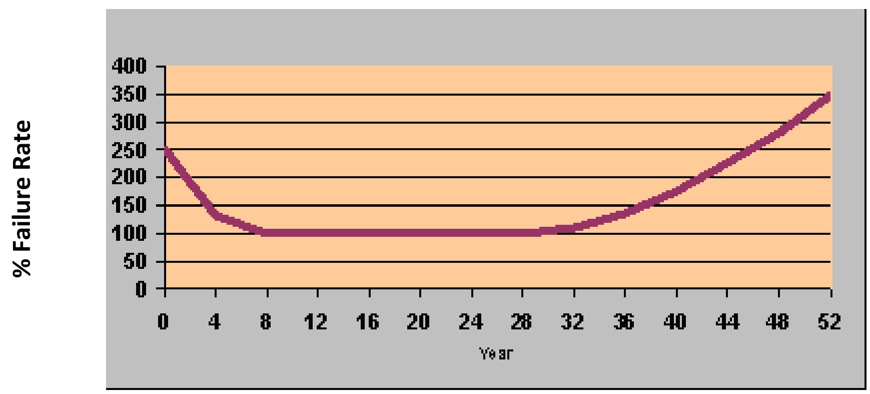


Figure 7: Power Transformers Failure Rate vs. Age

The Hartford Steam Boiler Institute states that the average life of a utility transformer today is 18 years. This is significantly lower than what has been documented by EPRI. Hydro is of the opinion the older designed units have longer life and if proper intervention is completed on the aged units, transformer life will be extended for an additional ten to 15 years.

3.4 Maintenance History

A five year maintenance history is shown in Table 6.

Table 6
Annual Maintenance Cost for Power Transformers in the Last Five Years

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	19	300	319
2007	46	242	288
2006	27	133	160
2005	29	254	283
2004	38	323	361

3.5 Outage Statistics

Table 7 lists the latest available statistics for the five-year averages for the performance of power transformers. A comparison is made between Hydro's five-year performance to the latest CEA five-year average (2001-2005). There have been 13 forced outages in the past five years but none were due to internal transformer failures. CEA averages for 2006 are not available from CEA yet and the NLH 2008 averages have not been compiled yet.

Table 7
Listing of Power Transformer Performance

	Frequency[1] (per a)	Unavailability[2] (%)
NLH (2003-2007)		
230 kV Transformers	0.02	0.015
138 kV Transformers	0.06	0.003
66 kV Transformers	0.03	0.001

	Frequency[1] (per a)	Unavailability[2] (%)
CEA (2002-2006)		
230 kV Transformers	0.07	0.104
138 kV Transformers	0.09	0.171
66 kV Transformers	0.06	0.086

[1] Frequency (per a) is the number of failures per year.
[2] Unavailability is the percent of time per year the unit is unavailable.

As stated previously, there have been no specific outages to the power system recorded as a result of power transformer failures. However, with the aging fleet, the risk of failure is high. Risk is evaluated by considering the probability of failure in light of the consequence of the event. With the transformer fleet aging, there is no doubt the probability of failure is increasing thus increasing the risk. The consequences can have very serious impacts to the power system. For example, in January of 2006 Hydro experienced a problem with frazzle ice at Upper Salmon while at the same time there were problems with the generating equipment at Holyrood. This event resulted in public notifications to conserve power during this period as Hydro was approaching its maximum available capacity. For this event, Hydro was able to resolve the issue at Upper Salmon in short order. If the same conditions were to exist at Holyrood and the Upper Salmon transformer were to fail, Hydro's ability to supply the province's demand would be difficult until a new power transformer could be procured (12 to 18 months).

Another event occurred on February 14, 2008 in which one unit at Holyrood was already offline due to boiler tube problems when another unit at Holyrood tripped. The trip was a result of water in the cabinet of Unit Service Transformer 3 (UST3). This resulted in the remaining available capacity approaching the system demand. The fact that the temperature was relatively warm for the time of year (- 2 ^{o}C) improved Hydro's ability to supply the lower than normal demand. If the event occurred one day before or two days after (with temperatures approaching -20 ^{o}C) the system demand would have been much higher resulting in load shedding or rolling blackouts within the province.

Both events illustrate the criticality of power transformers in providing reliable service to the people of the province. It is important to note that an outage resulting from a failure of a power transformer would have a severe impact on the power system due to the long lead time for procurement.

3.6 Industry Experience

Many utilities in North America are in a similar position as Hydro in that they have aging infrastructure and are diligently seeking for the most economic and reliable solution to this problem as it requires significant investment. There are many documented papers from various transformer owners on the subject of aging transformer infrastructure and various methods to deal with this issue. The majority have considered using condition assessment tools, either internally or through an outside vendor, to help with the decision to either upgrade or replace power transformers.

3.7 Maintenance or Support Arrangements

Routine maintenance as well as specialized power transformer work is completed using internal resources. Routine maintenance includes a visual inspection every three months for problems such as leaks, gauges not operating correctly, and other deficiencies. Every year, oil samples are taken and an Oil Quality and Dissolved Gas Analysis is performed to provide an input into the condition assessment tool. This condition assessment tool considers the criticality of the unit and provides an overall Transformer Priority Score (TPS) which is then ranked from highest to lowest. The transformer with the highest score is the unit that will be considered for oil reclamation during the next maintenance season (see Appendix D).

Transformers with on load tap changers have oil samples taken every three years to perform a Tap Changer Activity Signature Analysis (TASA) to help determine the condition of the tap changer. This is a special service offered by an oil analysis laboratory (TJH2b) which enables

Hydro to develop a ranking of the condition for each of the on load tap changers. Any future work for tap changers will require a support arrangement from the manufacturer.

In 2005, a Furan Analysis was completed on all power transformers 66 kV and above with re-sampling planned for every four years to help trend the aging process. The next data set will be available for review in 2009. More frequent sampling will be performed based upon lab results as per Appendix C.

On a six-year cycle, the transformer is taken offline and put through electrical testing with protective devices verified, fan controls checked, windings insulation tested (Doble), and winding resistance verified.

3.8 Vendor Recommendations

There are vendors such as ATI Weidman and ABB who are marketing condition assessment techniques for power transformers to provide customers with a list of ‘weak’ units that are recommended for refurbishment or replacement. As presented in this report, Hydro has been tracking the problem areas and has developed in-house ranking tools to help determine where the investment should be directed. With in-house expertise there is no need to engage outside help for the condition assessment component of this work.

3.9 Availability of Replacement Parts

The most critical power transformer assets are the generator step up transformers. Currently, there is a spare on order that can replace any of the seven generating units at Bay d’Espoir or the unit at Upper Salmon. However, the spare unit has a maximum rating of 100 MVA which is only two thirds the rating of T7 at Bay d’Espoir. This is particularly important as unit T7 is showing its paper strength to be weak and the probability of failure is high relative to the other units. The ability to acquire the necessary capital to replace this unit also becomes more critical as the associated generator is a 172 MVA unit and is the most efficient unit on the system.

For all transformers on the Hydro system, there is an emergency plan in place to address transformer failures on the system. However, this plan only deals with the first contingency and does not consider the possibility of other system problems occurring at the same time. As a result, if Hydro considered running units to failure without consideration for condition assessment it could be upwards of 18 months to acquire a replacement and the power system will be operating in a restricted mode. This restricted mode would limit flexibility of outages for maintenance of other system equipment and increase Hydro's risk of not being able to supply system demands.

3.10 Safety Performance

This is a reliability based project. If this project is not initiated there is a higher risk of transformer failure and possibly extended power outages within the province which will negatively impact public safety.

3.11 Environmental Performance

Hydro is an ISO 14001 certified company and as a result has several Environmental Management Programs in place. One of these programs is the reporting of spills and leaks.

One of the main sources of leaks is power transformers. Transformers contain Voltesso 35 oil which acts as an electrical insulation medium as well as a coolant. As transformers go through thermal cycling oil leaks are discovered due to component or gasket system failure. Some leaks are significant such as those discovered on the unit transformers at Bay d'Espoir, thus supporting the need for future investment.

Another environmental management program in place at Hydro is the reduction of polychlorinated bipheyls (PCBs) used as an insulating oil in transformers. Environment Canada requires that sealed equipment such as transformer bushings containing PCBs must be removed from service by 2025. Based upon preliminary review of the age and manufacturer of equipment, it is possible Hydro will be required to replace a significant number of bushings in power transformers to meet the PCB free deadline of 2025. A detailed PCB reduction plan for sealed equipment is being developed in 2009 and will form the basis for future investment in transformer bushings.

3.12 Operating Regime

Power transformers are placed in locations in the power system as generator step up units or used in terminal stations to convert to lower voltage levels to enable power to be distributed to customers.

If the step up power transformer is not available, it effectively results in having a generator unit offline. In the case of the step down power transformers, the unavailability of the unit, in radial applications, will result in communities without power. In cases where transformers are in parallel, transformer failures can result in load reduction to customers or customer outages.

4 JUSTIFICATION

As stated earlier in this report, 55 percent of Hydro's power transformers are greater than 30 years of age. In recent years, Hydro has been trying to address the six problem areas stated in Section 2 on an individual project basis. With significant investment required to address these concerns it was decided to look at an overall transformer upgrading program and this project was created to permit a planned and orderly upgrade of the power transformer fleet.

In looking at refurbishment, Hydro's condition assessment tool (which evaluates oil quality parameters such as acidity, interfacial tension, dielectric breakdown, dissolved gas parameters and criticality) provides a ranking of the worst to the best units. This is the ranking Hydro uses to determine which transformers will have their oil reclaimed next. For example, the ranking from 2008 to determine the reclamation work for 2009 is shown in Appendix D. It can be seen that the next unit to be completed is T1 at the Cat Arm Hydro Generating Station. To continue with this work into the future, a $140,000 allocation is required in each of the next five years.

Ranking tools have also been developed to rank the condition of radiators as well as tap changers. In the case of radiators, corrosion has resulted in radiator leaks in recent years. As outlined in Appendix A transformers T6 and T8 at Holyrood and T11 at Bay D'Espoir are the next highest priorities for replacement assuming all work for 2009 is completed. To continue with the radiator replacement portion of this program there is $77,000 identified in the budget estimate for this work in each of the next five years.

For tap changers, a review of the maintenance philosophy was completed in 2006 and the best approach was to perform condition based monitoring using tap changer oil samples. This approach is more scientific in that oil samples are sent to a certified lab where they provide a ranking based upon oil quality and particle counts within the oil. As can be seen from the ranking outlined in Appendix B there are transformers ranked as condition 3 and will require work in the near future. The plan for tap changers is to upgrade one tap changer in each year until all units showing condition 3 or higher are completed, and as a result $58,000 has been budgeted in each year for this work.

Other investments are required to address leaking bushings as well as those that are identified as having PCB levels greater than 2 ppm. Environment Canada has communicated to utilities that all PCB sealed equipment such as transformer bushings must be removed from service by 2025. To accomplish this, Hydro is finalizing a survey started in 2008 to better understand the number involved and the investment required. However, preliminary information gained from the 2008 survey is showing approximately 800 oil filled bushings that have been manufactured before 1985. Projecting these numbers over 15 years will require 54 bushings changed per year. As bushings come out of service, testing will be performed to help determine if given manufacturers, for given vintages, used non PCB oil (< 2ppm) and it is anticipated the actual number required to be removed will be less than 800. However, based upon this information it is prudent to increase the budget for the next five years from six bushings and $140,000 to 12 bushings and $280,000. As more information from testing becomes available, this number will need to be adjusted accordingly.

Besides bushings, there are also critical protective devices and wiring that has been causing problems in recent years. As is shown in Table 5 of Section 3.2.5, annual costs for this work has ranged from $25,500 to $49,000 and it is not expected to decline. As a result, this project has included $48,000 per year to address these issues.

4.1 Net Present Value

A net present value calculation was not performed in this instance as the justification is based upon condition assessment techniques directed towards reliability and upgrades on a priority basis.

4.2 Levelized Cost of Energy

The capital expenditures for this project will not affect the levelized cost of energy for the system.

4.3 Cost Benefit Analysis

A cost benefit analysis is not required for this project proposal, as the project is required for reliability and safety issues.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements other than those mentioned in Section 3.11 on Environmental Performance.

4.5 Historical Information

This proposal is the second year of the power transformer upgrade program which started in 2009. The upgrades are planned and executed based on the condition assessments of the transformers. The appendices of this report contain tables indicating which upgrades will be completed in each year. The work planned for 2009 involves radiator replacements at Stephenville and Holyrood; Bushing replacements at Bay d'Espoir; Tap changer upgrades at Oxen Pond and Harwoods and oil reclamation at Hinds Lake and Cat Arm. The forecasted costs for work in each year of the program have not changed from the 2009 submission other than the costs for bushing replacements. This cost item increased due to the fact that more bushing are required to be replaced because all PCB contaminated equipment must be removed from service by 2025.

4.6 Forecast Customer Growth

This project is not required due to forecasted customer growth but required to maintain reliability with refurbishment or replacement of the aging transformer fleet.

4.7 Energy Efficiency Benefits

There are no issues related to energy efficiencies associated with this project.

4.8 Losses during Construction

The upgrade of each transformer will be coordinated with the normal outage plans for the transmission system. These outage plans are designed around the system load requirements. Therefore, there are no production or revenue losses resulting from this project.

4.9 Status Quo

The status quo is not an option. With the current age of the power transformer fleet, failures can be expected if intervention or life extension measures are not considered.

4.10 Alternatives

There are only two solutions to the problems described with power transformers. These are to upgrade the transformers as proposed or replace them. The operation and maintenance costs of either alternative are generally the same. The upgrade option was chosen because it has the least cost and is the simplest solution to the problems.

5 CONCLUSION

The approach being proposed is to continually identify the “weak system units” and replace or refurbish critical assets on the system before they remove themselves from service. With this approach taken over multiple years, investment will be directed to the highest risk units.

As a result of the condition assessments completed to date there is only one transformer targeted to be replaced. Unit T7 at Bay d’Espoir is currently scheduled for engineering work and ordering in 2012 with expected delivery and installation in 2013.

For the remaining units, the upgrade option will be executed with a concentration in various areas annually. Where possible, more than one activity will be completed on a given transformer, however individual work activity priority will always be given to the units with the poorest ranking from the condition assessment of oil quality, radiator condition or tap changer oil condition results.

Table 8 summarizes the work plan for transformer upgrading planned for the next five years.

Table 8
Power Transformer Work Plan Summary 2010 to 2014

	2010 ($000)	**2011 ($000)**	**2012 ($000)**	**2013 ($000)**	**2014 ($000)**
Oil Reclamation	140	140	140	140	140
Radiator Upgrades	77	77	77	77	77
Tap Changer Upgrades	58	58	58	58	58
Bushing Replacements	280	280	280	280	280
Protective Device Upgrades	48	48	48	48	48
Upgrade Gasket System	65	65	65	65	65
Transformer Replacement	0	30	25	2900	0
Contingency and Escalation	148	164	177	1010	216
Total	**816**	**862**	**870**	**4578**	**884**

5.1 Project Schedule

The anticipated project schedule for each year is shown in Table 9.

Table 9
Project Schedule for Each Year

Activity	Milestone
Initial Planning and Equipment Ordering Tendering (Radiators, Bushings, and Protective Devices)	February
Equipment Delivery	July
Equipment Installations and Commissioning	November
Project In Service	November
Project Completion and Close Out	December

APPENDIX A

Transformer Radiator Ranking Summary 2009

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
HRD	SST1-2		1.5	1969, 8 rads, sweating with oil stains on the ground	2009
SVL	T1		2.5	1975 14 rads original, severe swelling and blistering. Leaking rads removed	2009
HRD	T6	230	2.5	1966, 3 rads, significant rust, swelling and blistering, 1 of 3 rads rated @6	2010
HRD	T8	230	2.5	1988, 4 rads, all very rusty	2010
BDE	T11	69	2.5	1970, original, significant swelling and blistering on 2, 2 @ 2-3, 7@5	2010
HRD	T7	230	3	1969, 3 rads, significant rust, swelling and blistering, 1 of 3 rads rated @7	2011
HWD	T1	230	3.5	1972, 6 rads, significant-serious rust on 2, original, have been painted	2011
BDE	T10	230	3.5	1976, 4 rads original, all blistering and rusted,	2011
HWD	T2	230	3.5	1978, 12 rads, original, have been painted, scaling and blistering	2012
WAV	T5	230	3.5	1989,4 rads, rusted and swelling, 2 rads drain pipes rusted severely	2012
BDE	T2	230	4	1966, 20 rads, evidence of rust and scaling, rads have been sand blasted and painted	2013
HWD	T3	230	4	1968, 6 rads, have been painted, scaling and blistering	2013
HRD	T2	230	4	1989, 10 rads, 5 new galvanized no paint, 5 original rated @ 3	2014
BDE	T3	230	4.5	1967, 20 rads, some rust on surface, rads appear to have been sand blasted and painted.	2014
BDE	T5	230	4.5	1968, 18 rads, some flaking and blistering,	2014
BUC	T1	230	5	1967, 17 rads, original carbon steel. Painted, some rust and blistering	2015
GBK	T1	138	5	1987, 1 rad original painted, surface rust and some blistering	2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
HRD	T10	230	5	1990, 3 rads, original, swelling and flaking,	>2015
CRV	T1	69	5	1976, 4 rads original, painted, minor rust between fins, rads welded on	>2015
DLS	T1	138	5.5	1989, 5 rads original, significant surface rust, not severe, paint would extend life,	>2015
BUC	Spare	230	6	1973, 7 rads, original carbon steel. Painted, some surface rust	>2015
HRD	SST3-4		6	1978, 3 rads, some scaling and swelling, 1 damaged fin (potential leak)	>2015
DLK	T1	138	6	1980, 6 rads, original carbon steel, have been painted, minor to moderate rust	>2015
GFC	T1	230	6	1966, 13 rads, original carbon steel. Painted, some surface rust and minor blistering	>2015
DLK	T2	230	6	1983, 6 rads original carbon steel, minor surface rust	>2015
BBK	T3	230	6	1987, 3 rads original, surface rust	>2015
BDE	T6	230	6	1969, 18 rads, some flaking and blistering	>2015
HRD	UST3		6	1978, 3 rads, 1 rad blistered significantly. Belongs to plant. One (1) Blistered rad replaced in 2007.1@10 2@6	>2015
SVL	T3		6.5	1975, 12 rads have been painted moderate surface rust	>2015
BUC	GT1		7	1966, 3 rads, original carbon steel. Painted, no rust, good shape	>2015
WAV	GT1		7	1966, 3 rads, welded, good shape, have been painted	>2015
BDE	SPARE	25	7	1966, 17 rads original, welded on, some rust, transformer requires painting, very rusty on top of low side junction box (600V)	>2015
BBK	T2	138	7	1967, 8 rads (4 new galvanized, 4 original @ 7)	>2015
BUC	T2		7	1983, 6 rads, original carbon steel. Painted, no rust, good shape	>2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
GFC	T2	230	7	1966, 13 rads, original carbon steel. Painted, minor rust, no blistering	>2015
HLK	T2	138	7	1980, 10 rads, original, minor rust a minor swelling	>2015
WAV	T3	230	7	1967, 3 rads, minor rust, have been painted	>2015
WAV	T4	230	7	1966, 3 rads, minor rust and flaking, have been painted	>2015
OPD	GT1	69	7.5	1966, 3 rads welded, painted, in fair-good shape	>2015
SVL	GT1	69	7.5	1975, 3 rads original, minor rust	>2015
BDE	T1	230	7.5	1966, 20 rads, appears to have 8 new rads, all others appear to have been sand blasted and painted	>2015
CBC	T1	230	7.5	1972, 10 rads, original, painted and some minor rust on end 3, PAINTING REQUIRED ON LOW SIDE JUNCTION BOX	>2015
HLK	T1	138	7.5	1980, 10 rads, original, minor rust	>2015
LHR	T1	230	7.5	1968, 4 rads original have been painted, 4 have been removed from other end, minor rust, TRANSFORMER RUSTY AND NEEDS PAINT,	>2015
SOK	T1	138	7.5	Good shape original, painted carbon steel	>2015
BDE	T12	230	7.5	1988, 3 rads original, very little rust, OIL LEAK ON TAP CHANGER	>2015
CBC	T2	230	7.5	1972, 10 rads, original, painted and some minor rust on end 3, PAINTING REQUIRED ON LOW SIDE JUNCTION BOX	>2015
BDE	T4	230	7.5	1968, 11 rads, original	>2015
BDE	T7	230	7.5	1977, 12 rads original, no significant rust	>2015
EHW	T1	69	8	1993, 8 original rads painted galvanized, paint scaling no corrosion	>2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
OPD	T1	230	8	1967, 16 rads, one missing (should be 17) no visible rust, primer showing, painting will extend life, original?	>2015
STB	T1	230	8	1977, 5 rads, original carbon steel. Painted, no rust, good shape	>2015
WAV	T1	230	8	1966, 3 rads, good shape, original, minor rust, have been painted	>2015
MDR	T2		8	1970, 6 rads original, carbon steel, painted, good shape	>2015
STB	T2	230	8	1976, 5 rads, original carbon steel. Painted, no rust, good shape	>2015
WAV	T2	230	8	1973, 3 rads, minor rust, original, have been painted	>2015
HRD	T3	230	8	1969, 5 rads (Forced oil coolers) made by Unifin 1992, good condition	>2015
HRD	T5	230	8	1969, rads have been painted, original, good shape, maybe galvanized	>2015
BBK	T1	230	8.5	1967, 3 rads, original rads and have been painted	>2015
SSD	T1	230	8.5	1977, 5 rads have been painted with good shape	>2015
HLY	T2	138	8.5	1981, 4 rads original, very little rust, good shape	>2015
HRD	T9	13.8	8.5	1970, 8 rads, painted, good shape, no visible rust. Belongs to plant	>2015
CBF	T1		9	1966, 16 rads, good shape, minor rust, **TRF TO BE REPLACED IN 2007**	>2015
MDR	T1	230	9	1998, 6 rads original galvanized, good shape, no rust	>2015
BCX	T1		9	1993, Rads original, Painted Galvanize, paint scaling no rust.	>2015
CBF	T2	66	9	rebuilt 2002, 16 rads, original from 1966, indoors, good shape	>2015
OPD	T2	230	9	1986, 3 rads, real good shape, minor touch up paint required at a couple of spots	>2015
MDR	T3	230	9	1981, 9 rads, galvanized, good shape, no rust	>2015

Table A1: Transformer Radiator Ranking Summary

LOC	DESIG	KV	Rad Condition (1 = Leak 10 = New)	Comments	Target Year to replace
SSD	T4	230	9	1976, 5 rads have been painted with good shape	>2015
HWD	T5	66	9	1976, 10 rads, painted galvanized, minor touch up on brackets and rads	>2015
OPD	T3	230	9	1977, 11 rads, Good shape except for 1 which has oil stains on the bottom, unsure why, and some stain on the ground below, all rads appear to have been replaced and looks like they are painted galvanized	>2015
HRD	T1	230	9.5	1976, 20 rads, all new painted galvanized	>2015
HWD	T4		9.5	1992, 12 rads, painted galvanized, good shape, no rust, **CARBON DRAIN PIPES RUSTED AND SHOULD BE REPLACED**	>2015
HRD	UST1		9.5	1969, 10 rads, new galvanized. Belongs to plant.	>2015
HRD	UST2		9.5	1969, 10 rads, new galvanized. Belongs to plant.	>2015
BWT	T1		10	1990, 3 rads, leaking, very rusted and weeping/sweating, all rads replaced 2006-12-06	>2015

APPENDIX B

Transformer On Load Tap Changer Summary Ranking

TASA Rank	Action
1	Resample in 3 years
2	Resample in 3 years
3	Resample in 6 months and consider refurbishment
> 3	Resample immediately to confirm , plan refurbish tap changer if reanalysis gives a TASA Rank of 4 or 4*

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
Hardwoods	T1	GE	173307	3		February 2011	Refurbish 2009
Bottom Brook	T1 A	GE	183	2 *		February 2011	Refurbish in 2009, only GE Tap Changer not refurbished due to known failures with this type
Bottom Brook	T1 B	GE	183	2 *		February 2011	Refurbish in 2009, only GE Tap Changer not refurbished due to known failures with this type
Bottom Brook	T1 C	GE	183	2 *		February 2011	Refurbish in 2009, only GE Tap Changer not refurbished due to known failures with this type
Oxen Pond	T2	ASEA	54961	3		Aug, 2009	Refurbish 2010
Sunny Side	T1-A	GE	126316	2		Aug, 2009	Retest in 2009 Due to going from a 3 ranking to 2.
Sunny Side	T1-B	GE	126316	2		Aug, 2009	Retest in 2009 Due to going from a 3 ranking to 2.
Sunny Side	T1-C	GE	126316	2		Aug, 2009	Retest in 2009 Due to going

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
							from a 3 ranking to 2.
Stoney Brook	T1-Center	GE	280891	2		Aug, 2009	Retest in 2009 Due to going from a 3 ranking to 2.
Stoney Brook	T2-Center	GE	81216	2		Aug, 2009	Retest in 2009 Due to going from a 3 ranking to 2.
Stoney Brook	T2-Right	GE	81216	2		Aug, 2009	Retest in 2009 Due to going from a 3 ranking to 2.
Holyrood	T10	ABB	40107	2		February 2011	
Bay D'Espoir	T10	ABB (ASEA)	65429	2		February 2011	
Stoney Brook	T1-Left	GE	280891	2		February 2011	
Stoney Brook	T2-Left	GE	81216	2		February 2011	
Stephenville	T3-Right	Reinhaussen	5745	2		February 2011	
Holyrood	T6 # 1	ABB	13069	2		February 2011	
Holyrood	T6 # 2	ABB	13069	2		February 2011	
Holyrood	T6 # 3	ABB	13069	2		February 2011	
Bottom Brook	T3	Reinhaussen	53988	2		February 2011	Ranking changed (1 to 2)
Hardwoods	T2	Reinhaussen	162744	1		Aug, 2009	Retest in 2009 Due to going from a 3 ranking to 1.
Duck Pond	T1	ABB	2010	1		February 2011	
Stoney Brook	T1-Right	GE	280891	1		February 2011	Ranking changed from 2 to 1
Deer Lake	T1	Federal Pioneer		1		February 2011	
Doyles	T1	Federal Pioneer	22796	1		February 2011	

Table B1: Tap Changer Ranking Summary 2008

Location	Xfmr	Manufacturer	Operation Counter	TJH2B Ranking	Lab Test Number	Retest Date	Comment(s)
West Avalon	T1	GE	73282	1		February 2011	
Buchans	T1	Reinhaussen	72505	1		February 2011	
Massey Drive	T1	Reinhaussen	22629	1		February 2011	
Oxen Pond	T1	Reinhaussen	10281	1		February 2011	
Bay D'Espoir	T12	Federal Pioneer	41991	1		February 2011	
Massey Drive	T2	GE	52667	1		February 2011	
Deer Lake	T2 A	Reinhaussen	35210	1		February 2011	
Deer Lake	T2 B	Reinhaussen	35210	1		February 2011	
Deer Lake	T2 C	Reinhaussen	35210	1		February 2011	
Hardwoods	T3	GE	43845	1		February 2011	
Oxen Pond	T3	Reinhaussen	146785	1		February 2011	
Stephenville	T3-Centre	Reinhaussen	5745	1		February 2011	
Stephenville	T3-Left	Reinhaussen	5745	1		February 2011	
Hardwoods	T4	Reinhaussen	17408	1		February 2011	
Holyrood	T7 # 1	ABB	9516	1		February 2011	
Holyrood	T7 # 2	ABB	9516	1		February 2011	
Holyrood	T7 # 3	ABB	9516	1		February 2011	
Massie Drive	T3	Reinhaussen	59398	1		February 2011	Refurbished 2007
Holyrood	T8	Reinhaussen	18002	1		February 2011	Refurbished 2008
Holyrood	T5	ASEA	94355	1		February 2011	Refurbished 2008

APPENDIX C

Transformer Furan Analysis Results Degree of Polymerization

Color Code	Activity	Criteria
	In Schedule to Replace within 3-5 years	≤ 400 DP
	Annual Furan Analysis	400 > 649 DP
	Continue with 4 yr Furan Analysis	> 650 DP

(Note: Criteria Developed in 2008)

Table C1: Transformer DP Ranking

Location	Serial #	Estimated DP
BAY D'ESPOIR- T7	288926	370-472
Corner Brook-T2	230814-B	426-518 (Prior to 2002 Rewind)
Corner Brook-T1	230815	429-512 (Prior to being replaced in 2007)
Upper Salmon-T1	289479	503-736
PRVTS-T1	T-60753	510-634
HRD-T2	61-00-69225	597-779
BAY D'ESPOIR-T2	293267	647-652
HRD-T1	303236	673-810
WAVTS-T2	288178	699-812
CAT ARM-T1	6311669	721-755
WAVTS-T1	286101	739-872
HLK-T2	1-4228	770-801
HLK-T1	1-4227	788-816
CAT ARM-T2	6311670	793
HUD-T2	284305	825
HVY-T1	289067	840
QZT-T2	92-927	865
VAN-T1	A-3S-6397	867
Hudson Sub-NTL-T2	266877	924
Wabush Sub-T1	292003	927

Table C1: Transformer DP Ranking

Location	Serial #	Estimated DP
Wabush Sub-T2	292004	937
HVY-T2	289068	977
Hudson Sub-NTL-T1	2112781	999
CBF-T2	230814	1000
Bartlett Sub-T1	A-3S-6270	>1000
Bartlett Sub-T2	A-3S-6192	>1000
BAY D'ESPOIR- T1	293266	>1000
BAY D'ESPOIR- T3	293456	>1000
BAY D'ESPOIR- T7 after	288926	>1000
BAY D'ESPOIR-T2 after	293267	>1000
BBK-T1	286625	>1000
BBK-T3	61-00-68607	>1000
BRT-spare	1707401001	>1000
BUCHANS-T1	293315	>1000
HRD-T3	287198	>1000
HRDTS- spare	287199	>1000
HRL-T1	291212	>1000
Hudson Sub-T1	A-3S-6352	>1000
HUD-T1	WC5408037	>1000
HVY-T3	A32S0153	>1000
MDR-T1	18757-101-01	>1000
MDR-T2	287527	>1000
MDR-T3	A3S-5316	>1000
MRF-T1	T-60559	>1000
NTP-T1	300499	>1000
NTP-T2	2300500	>1000
NTS-T3	G47521	>1000
NTS-T4	G5372	>1000
OPDTS-T1	N293314	>1000

Table C1: Transformer DP Ranking

Location	Serial #	Estimated DP
OPDTS-T2	289703	>1000
OPDTS-T3	A-3S-7857	>1000
QZT-T1	A-3S-6447	>1000
SSDTS-T1	289147	>1000
SSDTS-T4	288838	>1000
STONEY BROOK-T1	288894	>1000
STONEY BROOK-T2	288839	>1000
Upper Salmon-T1 after	289479	>1000
Wabush Sub-T3	T606551	>1000
Wabush Sub-T4	T606552	>1000
Wabush Sub-T5	2306740	>1000
WAVTS-T3	286626	>1000
WAVTS-T4	286167	>1000
WAVTS-T5	61-00-69167	>1000
WTS-T2	292004	>1000

APPENDIX D

Transformer Priority Score and Ranking

		TRANSFORMER PRIORITY SCORE (TPS)									
		GSU (Vital)			Radial (CRITICAL)			All Other (IMPORTANT)			
Condition Factor		10	9	8	7	6	5	4	3	2	1
WORST	10	100	90	80	70	60	50	40	30	20	10
	9	90	81	72	63	54	45	36	27	18	9
	8	80	72	72	56	48	40	32	24	16	8
	7	70	63	56	49	42	35	28	21	14	7
	6	60	54	48	42	36	30	24	18	12	6
	5	50	45	40	35	30	25	20	15	10	5
	4	40	36	32	28	24	20	16	12	8	4
BEST	3	30	27	24	21	18	15	12	9	6	3
	2	20	18	16	14	12	10	8	6	4	2
	1	10	9	8	7	6	5	4	3	2	1

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T1	CATTS	7.43	8.67	64.43
T1	HLKTS	6.74	8.33	56.16
T1	HRDTS	5.74	9.67	55.47
T5	BDETS1	6.11	8.33	50.95
T4.	BDETS1	6.07	8.33	50.57
T1	PRVTS	6.99	7.00	48.92
T1	BUCTS	7.44	6.33	47.14
T2	STATS	6.61	7.00	46.30
T6	BDETS1	5.52	8.33	46.02
T1	USLTS	5.27	8.67	45.70
T2	HLKTS	5.43	8.33	45.27
T3	BDETS1	5.35	8.33	44.60
T3	HRDTS	4.67	9.33	43.58
T7	BDETS1	4.56	9.00	41.01
UST3	HRDTS	7.49	5.33	39.91
T3	MDRTS	7.06	5.33	37.61
T2	BDETS1	4.28	8.33	35.70
T1	STBTS	6.83	5.00	34.15
T2	CBFTS	5.35	6.33	33.88
React.R2	Plum Point	6.77	5.00	33.86
React.R1	Plum Point	6.42	5.00	32.10
T1	Bartlett	6.00	5.33	31.98
UST2	HRDTS	5.99	5.33	31.92
T7	HRDTS	7.83	4.00	31.32
SST	STA AirPort	6.20	5.00	31.02
Spare	HRDTS	3.28	9.33	30.64
T2	USLTS	4.22	7.00	29.51

Table D1: Transformer Priority Score Ranking				
Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T1	STBTS	5.43	5.33	28.95
SST1	CATTS	5.34	5.33	28.47
T3	WAVTS	7.07	4.00	28.27
T1	SSDTS	5.65	5.00	28.24
T1	Wabush	5.53	5.00	27.67
T1	DLKTS	5.53	5.00	27.67
T2 LTC	HVYTS	5.51	5.00	27.56
T3	OPDTS	6.34	4.33	27.48
T1	WAVTS	6.80	4.00	27.18
T1	OPDTS	6.73	4.00	26.91
T5	HRDTS	5.38	5.00	26.88
T10	BDETS1	4.81	5.33	25.62
T2	DLKTS	5.49	4.67	25.61
T2	BBKTS	4.74	5.33	25.26
T1	HVYTS	5.03	5.00	25.17
T10	HRDTS	5.01	5.00	25.06
T4	WAVTS	6.16	4.00	24.64
T3	SVLTS	4.85	5.00	24.26
T1	Parsons Pond	4.49	5.33	23.92
T6	HRDTS	5.98	4.00	23.91
T1	Triton	4.70	5.00	23.52
T2	Hawks Bay	4.34	5.33	23.14
T1	BBKTS	5.68	4.00	22.73
UST1	HRDTS	4.20	5.33	22.41
T12	BDETS1	4.14	5.33	22.05
T1	Muskrat Falls	4.41	5.00	22.05
T1	STATS	4.41	5.00	22.05
T1	RWC	4.40	5.00	21.99

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T2	STBTS	5.49	4.00	21.95
T1	Wiltondale	4.39	5.00	21.93
T2	Quartzite	4.09	5.33	21.80
T1	BDETS1	2.57	8.33	21.40
T1	SSDTS	4.27	5.00	21.36
T1	GCLTS	2.52	8.33	21.01
T1	Rocky HL	3.88	5.33	20.65
T1	STA AirPort	4.11	5.00	20.57
T5	HWDTS	2.66	7.67	20.40
T1	DPDTS	3.18	6.33	20.14
T4	Wabush	3.98	5.00	19.89
T3	HWDTS	4.88	4.00	19.50
T3	BBKTS	3.64	5.33	19.38
T4	SSDTS	4.84	4.00	19.36
T2	WAVTS	4.83	4.00	19.32
T3	Hawks Bay	3.80	5.00	18.98
T1	Burgeo	3.77	5.00	18.86
T1	Hudson	3.74	5.00	18.69
T1	Wabush	3.74	5.00	18.69
T1	Cow Head	3.50	5.33	18.66
T3	HVYTS	3.49	5.33	18.59
T2	RWC	3.56	5.00	17.78
T1	GBKTS	3.31	5.33	17.63
T2	GFTS	2.64	6.67	17.58
T1	Glenburnie	3.27	5.33	17.44
T2	MDRTS	4.27	4.00	17.09
T5	WAVTS	3.94	4.33	17.09
T2	Hudson	3.41	5.00	17.05

Table D1: Transformer Priority Score Ranking

Transformer	Location	Lab Analysis Score	Criticality Score	TPS Score
T1	MBKTS	3.17	5.33	16.90
T1	Quartzite	3.13	5.33	16.66
T2	Bartlett	3.32	5.00	16.59
T1	FGOTS	3.32	5.00	16.59
T1	CBCTS	2.76	6.00	16.57
T4	HWDTS	4.02	4.00	16.09
T1	MDRTS	3.22	5.00	16.08
T2	Daniels Hr	2.93	5.33	15.63
T1	La Scie	2.97	5.00	14.83
T8	HRDTS	3.70	4.00	14.82
SST-34	HRDTS	2.94	5.00	14.72
T1	JAMTS	2.92	5.00	14.60
T1	Peters Barrens	2.74	5.33	14.60
T1	BWTTS	2.68	5.33	14.29
T1	SVLTS	1.85	7.67	14.20
T2	CBCTS	2.53	5.33	13.51
SS1	USLTS	2.68	5.00	13.41
T2	BUCTS	2.51	5.33	13.39
T1	Hampden	2.57	5.00	12.84

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REPLACE OFF-ROAD TRACK VEHICLES

Whitbourne and Bishop's Falls

June 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates a fleet of heavy duty off-road track vehicles comprised of 26 track units and six mid-size excavators.

The heavy duty off-road fleet is strategically distributed across the transmission and distribution areas throughout the province and is utilized on a regular basis to support line maintenance staff engaged in the maintenance and repair of the transmission and distribution system.

2 PROJECT DESCRIPTION

This project proposes the replacement of a two passenger cargo carrying unit with dump capability stationed at the Whitbourne line maintenance depot and a crew cab cargo carrying unit stationed at the Bishop's Falls line maintenance depot. The existing units are moved throughout the Hydro system by line maintenance crews. They are used to transport the crew and their materials to work sites along the various rights of way. The dump capability facilitates using the units to transport material and backfill when the line work requires installation of tower footings, anchors or poles.

This proposal is to replace the units with similarly configured units, with the addition of a material handling boom on the crew cab unit. The boom will enhance the efficiency of the crew cab unit, by allowing it to also serve as a heavy lifting unit.

3 EXISTING SYSTEM

The project is required to replace Unit No. 7839 in Whitbourne and Unit No. 7735 in Bishop's Falls with similarly configured units.

3.1 Age of Equipment or System

Unit No. 7839 is 17 years old and Unit No. 7735 is 20 years old.

3.2 Major Work and/or Upgrades

There have been no major upgrades on these units.

3.3 Anticipated Useful life

The anticipated useful life for heavy-duty off-road track vehicles is 15 to 20 years.

3.4 Maintenance History

The maintenance history for Unit No. 7389 and Unit No. 7735 is shown in Tables 1 and 2.

Table 1: Five-Year Maintenance History Unit No. 7839

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	4.6	2.8	7.4
2007	0.8	15.3	16.1
2006	1.5	2.9	4.4
2005	1.5	13.0	14.5
2004	1.7	12.8	14.5

Table 2: Five-Year Maintenance History Unit No. 7735

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	2.2	5.5	7.7
2007	1.8	9.8	11.6
2006	2.4	24.9	27.3
2005	1.3	10.7	12.0
2004	1.2	4.7	5.9

3.5 Outage Statistics

As this project relates to the replacement of mobile equipment, there is no relevant data related to outage statistics.

3.6 Industry Experience

Heavy duty off-road equipment is a standard component of any electric utility maintenance fleet which has to maintain transmission or distribution lines in remote areas. The replacement criterion across the Canadian Utility Industry varies depending on location, exposure to harsh environmental conditions and the number of service hours for the equipment. While some variances exist, it is generally the case that this type of equipment is replaced in a 15 to 20-year time frame depending on its functionality and condition. The criterion utilized by Hydro is to consider units which are 15 years old, then evaluate maintenance costs and technological issues. Units which meet the age requirement and warrant replacement are then included in the proposals.

3.7 Maintenance or Support Arrangements

The Hydro fleet of off-road track vehicles is primarily maintained by in-house mechanical maintenance personnel. Outside maintenance garages are utilized when the required maintenance is within their expertise.

3.8 Vendor Recommendations

There are no vendor recommendations for this project.

3.9 Availability of Replacement Parts

Replacement parts are usually available for these units, however as they age and become more obsolete delays in sourcing replacement parts are common.

3.10 Safety Performance

As this project relates to the replacement of mobile equipment, there is no relevant data related to safety performance.

3.11 Environmental Performance

Replacement units are now certified Tier 3 for emission compliance. Tier 3 is a standard to regulate sulphur emissions from diesel engines. The regulations, promulgated in February 2005 by Environment Canada, introduced emission standards for model year 2006 and later diesel engines used in off-road applications.

3.12 Operating Regime

As this project relates to the replacement of mobile equipment, there is no relevant data related to operating regime.

4 JUSTIFICATION

Regulated Operations maintains 3,742 kilometers of transmission lines and 3,334 kilometers of distribution lines throughout the electrical system, much of which is located in remote areas inaccessible to wheeled vehicles. Heavy off-road track equipment is essential to the line crews in accessing these lines for inspections and to perform planned or emergency maintenance.

Hydro operates in many diverse locations across the province and it is critical to the ability to provide economical and reliable electricity that employees are provided with safe and reliable equipment.

This proposal provides for the normal replacement of two heavy duty off-road vehicles due to their ages and condition, and will provide the operators with more efficient and ergonomically designed units. Technological improvements in the cab design have reduced the noise and heat levels in the cab. Drive trains have improved from mechanical to hydrostatic. These units are now fully automatic and do not have manual transmission. Safety improvements include interlocks to prevent operation of the unit without the operator in the driver's seat. Failure to replace these units will lead to increasing down time and maintenance costs.

4.1 Levelized Cost of Energy

As this project relates to the replacement of mobile equipment, there is no relevant data related to levelized cost of energy.

4.2 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.3 Legislative or Regulatory Requirements

As this project relates to the replacement of mobile equipment, there is no relevant data related to legislative or regulatory requirements.

4.4 Historical Information

Table 3 shows the history of off-road track vehicle replacements for the past five years.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)[1]	Comments
2008	1150.3	749.3	3	249.8	2 Excavators with Backhoe and Grader
2007	491.0	443.0	2	221.5	1 Excavator and Muskeg with Boom
2006	680.0	555.0	4	138.8	3 Excavators, Muskeg and Crane
2005	797.6	652.6	1	652.6	Muskeg and Aerial Device
2004					None purchased

[1] The costs per unit vary depending on the type of unit purchased as well as whether there are attachments such as aerial devices, cranes or booms.

4.5 Forecast Customer Growth

As this project relates to the replacement of mobile equipment, there is no relevant data related to forecast customer growth.

4.6 Energy Efficiency Benefits

As this project relates to the replacement of mobile equipment, there is no relevant data related to energy efficiency benefits.

4.7 Losses During Construction

As this project relates to the replacement of mobile equipment, there is no relevant data related to losses during construction.

4.8 Status Quo

Failure to replace these units will lead to increasing downtime and maintenance costs and will result in employees being exposed to undesirable ergonomic conditions. Hydro employees maintain the electrical system and require dependable and safe vehicles for their work. Continued operation of these units could negatively affect response times for emergency outages or planned maintenance.

4.9 Alternatives

This type of equipment is essential to line maintenance activity and there are no known alternatives.

5 CONCLUSION

This proposal provides for the replacement of heavy duty off-road Unit Nos. 7839 and 7735 due to their age and condition and will provide the operators with more efficient and ergonomically designed units.

These heavy off-road vehicles will be strategically located at Whitbourne and Bishop's Falls and will be utilized on a regular basis to support our line maintenance staff engaged in the maintenance and repair of the transmission and distribution system.

Budget Estimate

Table 4 shows the budget estimate.

Table 4: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	580.0	0.0	0.0	580.0
Labour	2.0	0.0	0.0	2.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.0	0.0	0.0	6.0
O/H, AFUDC & Escln.	37.8	0.0	0.0	37.8
Contingency	58.8	0.0	0.0	58.8
TOTAL	**684.6**	**0.0**	**0.0**	**684.6**

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER R.N. SEYMOUR SIGNATURE PROVINCE OF NEWFOUNDLAND	Electrical
	Mechanical N.S.
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACE UNIT 2001 AND ENGINE 566

Francois

May 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Francois is a small community located on the south coast of Newfoundland. The community is accessible only by coastal ferry. Electricity in the community is supplied by a Newfoundland and Labrador Hydro (Hydro) owned and operated diesel generating plant (Figure 1). The diesel generating plant contains three diesel generating units rated at 136, 200, and 275 kW for a total installed capacity of 611 kW and a firm capacity of 336 kW. The diesel plant in this community serves 60 domestic and 16 general service customers with a forecast peak load of 298 kW to the year 2014, and gross peak production of approximately 909 MWh per year. The plant is manually operated by one full-time and one part-time operator, whereby an operator must start and stop (dispatch) the generating units to suit load conditions throughout the day.

Figure 1 Francois Diesel Plant

2 PROJECT DESCRIPTION

This project will replace Generating Unit 2001 and the diesel engine on Generating Unit 566 at the Francois Diesel Plant.

Generating Unit 566

Generating Unit 566 (Figure 2) is a 200 kW Mitsubishi model 6D22-TCS generating unit manufactured in 1996. The engine on this unit will be replaced with a complete new engine (model 6D24-TC). A complete set of critical spares will be also be purchased for emergency parts replacement. All other equipment can be reused.

The engine block on Unit 566 is pitted and requires replacement; however, a replacement block is not available. Pitting of the block causes a loss of integrity of sealing surfaces and promotes further erosion. It eventually allows transfer of coolant to the cylinders and the escape of hot exhaust gases around sealing surfaces. Loss of cylinder sealing is a failure condition under which an engine should not be operated or else more serious damage may occur. Unit 566 would normally be overhauled complete with a new engine block. As stated, a replacement block is not available.

Figure 2 Diesel Unit 566

Generating Unit 2001

Generating Unit 2001 (Figure 3) is a 136 kW Caterpillar model D3306 generating unit manufactured in 1981 which will be replaced with a 150 kW generating unit for improved dispatch flexibility. The unit replacement will include the installation of a new control panel meeting Hydro's current design standard. The existing exhaust stack and sound attenuated radiator will be reused.

Generating unit 2001 is 28 years old and has had four rebuilds. Under normal use, an overhaul will last for five to seven years (20,000 hours). In general, Hydro's prime power generating units do not exceed 30 years of service.

Figure 3 Diesel Unit 2001

3 EXISTING SYSTEM

3.1 Age of Equipment or System

Unit 2001 was installed in 1981 (28 years old) and Unit 566 was installed in 1996 (13 years old).

3.2 Major Work and/or Upgrades

Unit 2001 has had four overhauls since installation. The last overhaul was at 60,000 hours and the unit currently has 81,343 hours of operating time. This unit requires overhaul or replacement.

Unit 566 has had two overhauls since installation. The last overhaul was at 45,170 hours and the unit currently has 55,920 total operating hours. At the current rate of utilization (4,500 hours in 2008) it would be scheduled for overhaul in 2011.

3.3 Anticipated Useful life

Diesel generating units are depreciated over a 20-year period and an expected average service life of 25 years. Since 2002, eight generating units have been replaced which were between 21 and 30 years of age. Two exceptions, however, were the replacement of Mitsubishi generating units after nine years of service (see Section 3.6).

3.4 Maintenance History

Maintenance costs are not a factor in the replacement of this equipment. The five-year maintenance history for Generating Units 566 and 2001 is shown in the Tables 1 and 2.

Table 1: Five-Year Maintenance History for Unit 566

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	1.4	0.6	2.0
2007	0.5	5.5	6.0
2006	0.5	9.6	10.1
2005	0.8	0.0	0.8
2004	1.8	1.0	2.8

Table 2: Five-Year Maintenance History for Unit 2001

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.3	4.0	4.3
2007	0.3	6.1	6.4
2006	0.3	3.6	3.9
2005	0.9	5.0	5.9
2004	0.8	0.1	0.9

It must be noted that these costs do not include travel expenses or travel time. Service calls to Francois require one twelve hour day of travel in each direction.

3.5 Outage Statistics

Hydro does not currently maintain a diesel generating unit reliability database. It only records outages which have a customer impact. The customer impact is recorded as in the general category of loss of supply and includes outages in addition to those caused by the unit to be replaced. Outages are not a factor in the replacement of this equipment.

Table 3 lists the 2004 to 2008 average SAIFI and SAIDI data for Francois for all causes as compared to Loss of Supply outages. Loss of Supply outages applies to the loss of the diesel unit. Table 3 also lists the 2004 to 2008 corporate value and the latest CEA five year averages (2003 to 2007) for comparison.

Table 3: Francois 2004-2008 Average SAIFI and SAIDI Data

Five Year averages (2004 to 2008)

	All Causes		Loss of Supply	
SYSTEM	**SAIFI**	**SAIDI**	**SAIFI**	**SAIDI**
Francois	5.12	2.51	4.00	1.04
Central Isolated	5.06	4.38	3.62	0.96
Hydro Corporate	5.93	9.59	3.08	2.81
CEA Region 2 (2003-2007)	2.67	8.33	1.44	2.47

Newfoundland and Labrador Hydro tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration Index for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - (System Average Interruption Frequency Index) indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Loss of Supply is defined by the CEA as:

Customer interruptions due to problems in the bulk electricity supply system such as underfrequency load shedding, transmission system transients, or system frequency excursions.

During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle. In this case it applies to the loss of the diesel plant.

3.6 Industry Experience

Two Mitsubishi powered generating units were replaced by Hydro in 2005. Unit 564 in Port Hope Simpson was retired during a generation increase due to low reliability, high maintenance costs, and long delivery times for parts. Unit 569 in Hopedale was replaced following a bearing and crankshaft failure, at which time the high cost of parts and long delivery time were determined to be unacceptable for continued operation of the generating unit. Both units were nine years old at the time of replacement.

Unit 2001 is 28 years old. With the current utilization rate and overhauls at 20,000 hours, a fifth overhaul will extend its expected service life beyond 30 years. Hydro generally evaluates small prime power generating units near 30 years of service for replacement due to obsolescence. After 2009, this will be the oldest small (<500 kW) prime power generating unit in Hydro’s inventory. The Caterpillar model D3306 engine is reportedly common in industrial equipment, and is presently still supported by the manufacturer.

3.7 Maintenance or Support Arrangements

Maintenance on the generating units in Francois is performed by internal operations personnel from Bishop’s Falls. Maintenance consists of scheduled preventive maintenance, such as oil and filter changes, required corrective maintenance to repair failed components or correct operational problems, and scheduled overhauls.

3.8 Vendor Recommendations

The vendor for Mitsubishi equipment recommends replacement of the engine on Unit 566 rather than rebuilding.

3.9 Availability of Replacement Parts

Parts for Unit 566 are not stocked locally and, from past experience, are usually not available within North America. Replacement parts are available with lead times ranging from 6 to 12 weeks, frequently requiring special order from the manufacturer in Japan. A replacement block cannot be obtained.

The local Vendor of Caterpillar equipment reports that replacement parts are still readily available for unit 2001. It has been Hydro's experience that most parts are available within days. It is not possible to predict how long Caterpillar will continue to manufacture parts for these engines. Following an overhaul, unit 2001 should remain in service an additional 6 to 7 years. Availability of replacement parts for this period is not certain.

3.10 Safety Performance

There are no safety performance issues related to these generating unit replacements.

3.11 Environmental Performance

These replacements are not based on environmental performance, however, engine emissions improvements are expected when replacing older generating units. Emissions standards for diesel engines in Canada have been aligned with European Union and United States Environmental Protection Agency (EPA) standards. These agencies have been phasing in improved emissions standards since 1996. A lack of standards for stationary diesels makes it possible to still sell non-EPA equipment however, in recent years, only EPA compliant equipment has been offered by vendors. The class of equipment being replaced is expected to meet US EPA tier III standards. Based upon available data for the existing equipment and tier III allowable maximums, NOx emissions are expected to be reduced by approximately 74%, and particulate emissions are expected to be reduced by approximately 68% for Unit 2001. Improvements are dependent upon unit loading and specific equipment performance. There is no emissions information presently available on the replacement engine for Unit 566.

3.12 Operating Regime

The Francois Diesel Plant is the only source of power generation for the community, and it operates on a continuous basis. In keeping with Hydro's generation planning criteria, two of the three installed units must be available at all times to ensure that the electrical needs of the community are satisfied. The individual units are operated in the most efficient manner to meet the load in the community at any given time. Where such opportunities exist, the operation of the generating units is cycled to distribute operating hours among all three units throughout the year while maintaining optimum efficiencies.

The load profile in Francois, as illustrated in Figures 4 and 5, is such that Unit 2001 can only be utilized after 12 am and before 8 am throughout the winter and as well as early spring and late fall. That is, the load exceeds the operating range of the 136kW unit. Because the units are manually dispatched, this unit generally does not get used during half of the year due to the hours at which dispatch is possible. It is not until mid-May through to October that the load is within range of the 136kW unit during daytime hours and the unit can be dispatched. During the winter months, unit 566 is primarily used. During peak periods, unit 2001 can be dispatched in combination with 566 or unit 570 can be run by itself.

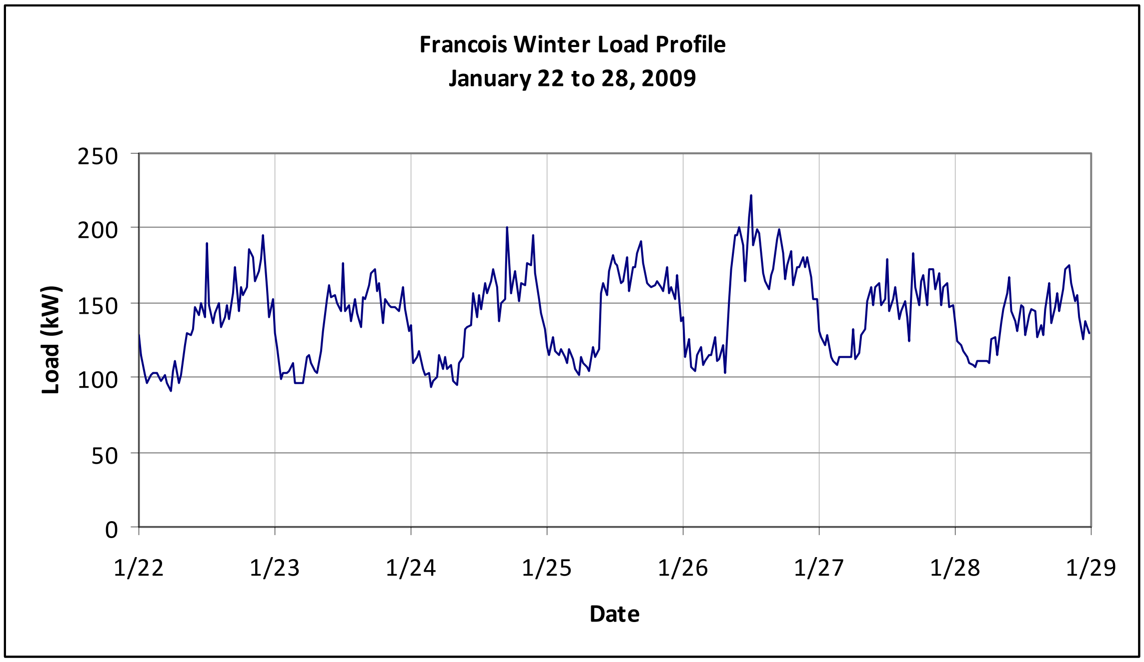


Figure 4 Francois Winter Load Profile

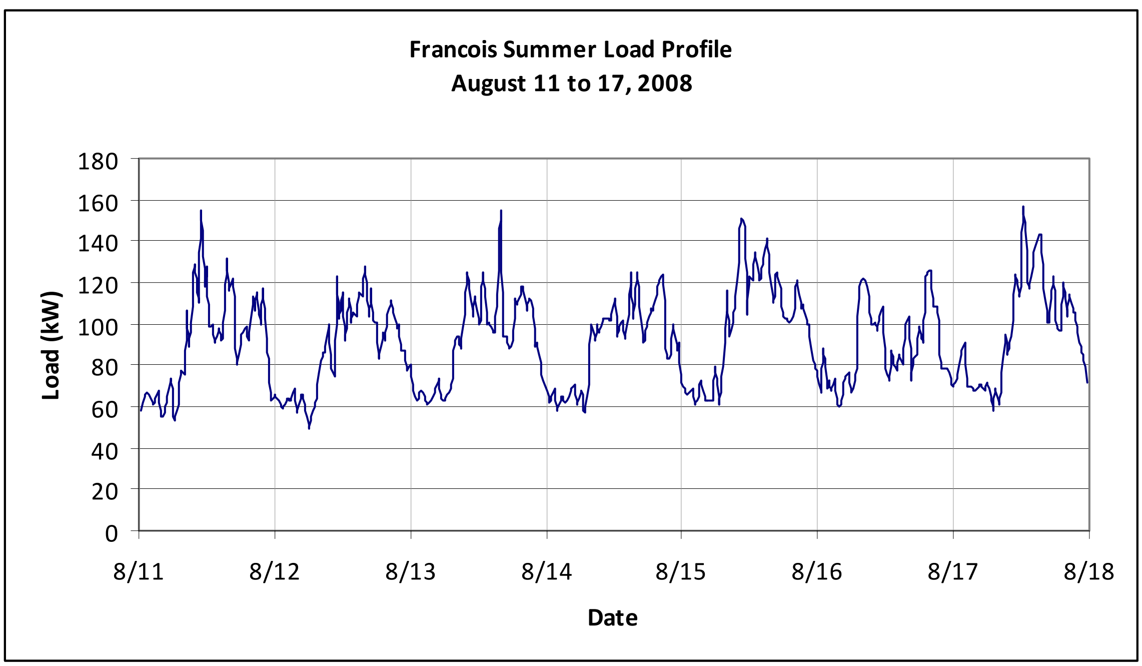


Figure 5 Francois Summer Load Profile

4 JUSTIFICATION

Replacement of the engine of Unit 566 and purchase of critical spares is justified on the requirement to provide reliable electrical service. Unit 566 requires engine replacement or overhaul. In the case of Mitsubishi equipment, the cost of a complete engine is approximately the same as a full set of rebuild parts. In addition, unacceptably long lead times for Mitsubishi parts delivery increases exposure to outages while operating on firm capacity. When purchasing new generating units, Hydro specifies that overhaul parts and minor parts (such as pistons, liners, gaskets, and bearings), be available within 48 hours and that major parts (such as blocks, crankshafts, and cylinder heads) be stocked in North America. Hydro has operated four Mitsubishi generating units and two remain in service. It has been Hydro's experience that parts must usually be shipped from Japan and require up to three months of lead time. This level of parts support is unacceptable to maintain isolated prime power generation assets. Therefore, it is necessary to stock critical spares for this equipment.

Replacement of Unit 2001 is justified based on age of equipment and efficiency improvements. Due to the age of unit 2001, it is considered impractical to rebuild the genset and continue to operate it beyond 30 years. Improved fuel efficiency of a modern genset will result in an estimated fuel savings of approximately 13,600 litres per year.

4.1 Net Present Value

Two net present value calculations have been performed.

The first analysis compares complete replacement of Unit 2001 with a rebuild of Unit 2001 in 2010 and replacement in 2016. The comparison is based over 20 years of operation, includes fuel and O&M costs, and assets are depreciated at 5% per annum. The results of this analysis are shown in Table 4.

Table 4: NPV Analysis 1 Results

FRS REPLACE GENSET 2001		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year 2029***		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
2010 GENSET REPLACEMENT	1,781,782	0
2010 OVERHAUL & 2016 REPLACEMENT	1,820,097	38,315

The second analysis compares complete replacement of Unit 566 with replacement of the engine only, combined with purchase of critical spares. In this case it is assumed that Unit 566 would be completely replaced in approximately 12 years (90,000 to 100,000 operating hours). This analysis is based over 20 years with a depreciation of 5% per annum. The results of this analysis are shown in Table 5.

Table 5: NPV Analysis 2

FRS - Replace Unit 566		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year 2029***		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Replace Unit 566	455,810	102,325
Replace 566 Engine Only	353,485	0

4.2 Levelized Cost of Energy

As this project does not involve new generation sources, a levelized cost of energy analysis is not applicable.

4.3 Cost Benefit Analysis

As there are no quantifiable benefits, a cost benefit analysis has not been performed.

4.4 Legislative or Regulatory Requirements

The justification of this project is not based on regulatory requirements.

4.5 Historical Information

Table 6 provides historical information on similar projects completed over the last three years.

Table 6: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2008	290	310	1	310	80 kW William's Hr.
2007	410	423	1	423	450 kW Rigolet, + new stack
2006	331	321	1	321	250 kW Black Tickle, No Radiator
2006	382	357	1	357	450 kW St. Lewis

In addition, two Mitsubishi generating units were replaced in 2005. See Section 3.6 Industry Experience for further detail.

4.6 Forecast Customer Growth

The justification for this project is not based on customer growth, however, customer growth has been considered in sizing replacement equipment. Table 7 presents the current peak load forecast for Francois from 2009 to 2014.

Table 7
Peak Load Forecast Francois

Year	Francois	
	Gross Peak (kW)	% of Firm Criterion
2009	294	88
2010	297	88
2011	297	88
2012	297	89
2013	298	89
2014	298	89

4.7 Energy Efficiency Benefits

Modern equipment provides improvements in fuel efficiency. When compared directly, the new equipment shows an improved fuel efficiency of 7% to 17% over the operating range of 100% down to 50% load. It is estimated that overall plant efficiency should improve by approximately 10% during the months when unit 2001 is primarily operated. The actual improvement is dependent both upon the condition of the existing equipment and the exact equipment purchased through the tender process.

4.8 Losses during Construction

No losses during construction are anticipated, since generating units will be replaced individually while existing units continue to generate power.

4.9 Status Quo

Unit 566 requires replacement of the engine block. A replacement engine block, however, is not available thus dictating a complete engine replacement. A temporary repair has been performed to address block pitting, however, eventual failure of the engine on Unit 566 is certain which will require further repair or replacement. If critical spares for Unit 566 are not stocked, the Francois Diesel Plant will be subject to greater than normal periods without reserve capacity due to long delivery times for parts.

Unit 2001 is due for overhaul or replacement. If overhauled it will require replacement in five to seven years, extending its service life beyond the practical limit of 30 years.

4.10 Alternatives

The alternative to engine replacement and stocking of critical spares for Unit 566 is a complete replacement of the generating unit. This would improve equipment reliability and address the issue of long delivery times for parts. The Francois Diesel Plant would not be exposed to extended periods of operation without reserve capacity.

The alternative to replacement of Unit 2001 is a rebuild of the engine. The current present value of this alternative over the 20 year evaluation period is approximately $38,000 greater than replacement.

5 CONCLUSION

This project is necessary to maintain reliability of generation in the community of Francois. The alternatives chosen were determined to be the least cost alternatives in keeping with Hydro's mandate to provide least cost electricity.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 8.

Table 8: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	80.0	201.8	0.0	281.7
Labour	62.6	105.3	0.0	167.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	5.0	0.0	5.0
Other Direct Costs	10.7	34.0	0.0	44.7
O/H, AFUDC & Escln.	15.2	54.0	0.0	69.2
Contingency	0.0	50.0	0.0	50.0
TOTAL	**168.4**	**450.1**	**0.0**	**618.5**

5.2 Project Schedule

The anticipated project schedule is shown in Table 9.

Table 9: Project Schedule

Activity	**Milestone**
Project Initiation	March 2010
Equipment Specification and Tender	June 2010
Detailed Design	Aug 2010
Unit 566 Engine Replacement	September 2010
Construction	July 2011
Commissioning	Aug 2011
Project Close-Out	Sept 2011

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REGISTERED PROFESSIONAL ENGINEER HOWARD D. RICHARDS SIGNATURE 2009/07/31 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACE RECLOSER CONTROL PANELS

May 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates distribution systems throughout Newfoundland and Labrador. In 2008, Hydro supplied approximately 36,000 metered customers. A key component of the distribution systems is the distribution automatic recloser. It is the primary fault protective device on distribution feeders.

A distribution recloser is set to detect faults on the feeders and to open if a fault occurs. The feeder is put back in service by the recloser and if the fault has been cleared, the feeder will stay in service, minimizing the outage to customers.

This project is to replace aging and weathered distribution recloser control panels on distribution feeders to ensure fault protection reliability is not compromised. Photos of a severely rusted recloser control panel are shown in Figures 1 and 2.

Figure 1: Shoal Cove N Recloser Control Cabinet

Figure 2: Shoal Cove N Recloser Control Cabinet

2 PROJECT DESCRIPTION

The Recloser Control Panel Replacement Project is intended to be a five year project to replace 36 aging reclosers control panels. This project will commence in 2010 with the replacement of 16 recloser control panels as listed in Table 1. The existing control panels are housed in steel enclosures which have deteriorated due to the extreme environment. To prevent future deterioration of the new panels due to weather the Recloser Control Panel Replacement Project uses rack mounted control panels inside control buildings where applicable and control panels located inside stainless steel enclosures where no building exists. The new recloser control panel will also have remote control capability should a future telecommunications network be established at these sites. In 2010, nine rack mounted panels and seven pole mounted control panels will be installed. For a complete list of the reclosers to be replaced between 2010 and 2014 see Appendix A.

These reclosers have been identified for replacement on the basis that these reclosers are located in three distinct areas of the province and fall under separate operating regions. Reclosers which fall under Transmission and Rural Operations (TRO) Central have been replaced over the past two years and the reclosers to be replaced in 2010 will account for six of the last eight to be replaced, the remainder to be replaced in 2011. These reclosers have been chosen based on their age and location in a highly corrosive coastal environment. TRO Labrador has identified only five units which will be replaced 2010. These units are to be replaced based on age as all of these units are 35 years old. TRO Northern is starting its recloser replacement in 2010 and has identified these five reclosers for replacement based on known salt contamination of the area, number of recloser operations and distribution line length. The existing control panel enclosures, as listed in Table 1, will be replaced in 2010, pole mounted units shall be replaced with stainless steel enclosures while rack mounted units will be mounted inside the available control building and need no further enclosure.

Table 1: 2010 Recloser Control Panel Replacements

Location	Type	Recloser ID	Age at Replacement
Happy Valley-Goose Bay	Rack Mounted	HV1-R1	35
Happy Valley-Goose Bay	Rack Mounted	HV7-R1	35
Happy Valley-Goose Bay	Rack Mounted	HV8-R1	35
Happy Valley-Goose Bay	Rack Mounted	HV10-R1	35
Happy Valley-Goose Bay	Rack Mounted	HV16-R1	35
Shoal Cove N	Pole Mounted	BC6-R2	35
Jackson's Arm	Pole Mounted	JA1-R1	32
Jackson's Arm	Pole Mounted	JA2-R1	32
Hampden	Pole Mounted	HA1-R1	32
South Brook	Pole Mounted	SB7-R2	32
English Harbour West	Pole Mounted	EH1-R2	31
Plum Point	Rack Mounted	PP1-R1	29
Plum Point	Rack Mounted	PP2-R1	29
Bear Cove	Rack Mounted	BC4-R1	26
Bear Cove	Rack Mounted	BC6-R1	26
English Harbour West	Pole Mounted	EH1-R1	22

3 EXISTING SYSTEM

The existing Cooper Recloser control panels are housed in a painted steel design which has been exposed to an extreme environment, including a highly corrosive coastal environment for many of the recloser locations. Within the last several years many of these recloser control panels have deteriorated beyond repair which can cause the failure of internal components.

3.1 Age of Equipment or System

Refer to Table 1 for a listing of the age of the assets being replaced.

3.2 Major Work and/or Upgrades

Table 2 lists the major upgrades that were performed on those reclosers being replaced in 2010. Refer to Appendix B for a complete listing of the major upgrades that were performed on reclosers scheduled to be replaced between 2010 and2014.

Table 2: Major Work/Upgrades

Date	Recloser	Major Work/Upgrade	Cost
06/10/23	English Hr West Recloser EH1-R1 (Asset #41812)	Recloser Control Panel Removed for Repair (severe rust)	$1,296
06/03/12	Hampden Recloser HA1-R1 (Asset #41781)	Replace/Replace Control Cabinet	$2,086
04/11/29	Bear Cove Recloser BC4-R1 (Asset #106300)	Changed output card	*

*Cost not noted on Emergency Work Order

3.3 Anticipated Useful life

The asset type has an estimated service life of 20 years.

3.4 Maintenance History

Table 3 shows the five-year maintenance history for the reclosers being replaced in 2010. Refer to Appendix C for the five-year maintenance history for all reclosers to be replaced under the program.

Table 3: Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009 to date	Happy Valley Recloser HV7-R1 (Asset #45998)	0.1	0.0	0.1
	Total 2009	**0.1**	**0.0**	**0.1**
2008	Happy Valley Recloser HV1-R1 (Asset #45996)	0.0	1.1	1.1
2008	Jackson's Arm Recloser JA1-R1 (Asset #41780)	1.7	0.0	1.7
2008	Jackson's Arm Recloser JA2-R1 (Asset #41782)	1.9	0.0	1.9
2008	Plum Point Recloser PP2-R1 (Asset #58177)	0.4	1.5	1.9
2008	Bear Cove Recloser BC4-R1 (Asset #106300)	0.5	1.2	1.7
	Total 2008	**4.5**	**3.8**	**8.3**
2007	Happy Valley Recloser HV1-R1 (Asset #45996)	0.0	0.2	0.2
2007	Happy Valley Recloser HV7-R1 (Asset #45998)	0.3	1.1	1.4
2007	Hampden Recloser HA1-R1 (Asset #41781)	1.2	0.0	1.2
2007	English Hr West Recloser EH1-R2 (Asset #41779)	0.0	1.1	1.1
2007	English Hr West Recloser EH1-R1 (Asset #41812)	2.2	0.0	2.2
2007	Happy Valley Recloser HV16-R1 (Asset #46004)	0.0	0.3	0.3
	Total 2007	**3.7**	**2.7**	**6.4**
2006	Shoal Cove North Recloser BC6-R2 (Asset #80026)	0.0	0.1	0.1
2006	Happy Valley Recloser HV1-R1 (Asset #45996)	0.2	0.0	0.2
2006	Happy Valley Recloser HV7-R1 (Asset #45998)	0.2	0.0	0.2
2006	South Brook Recloser SB7-R2 (Asset #41771)	1.6	0.0	1.6

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2006	Jackson's Arm Recloser JA1-R1 (Asset #41780)	0.0	0.1	0.1
2006	Hampden Recloser HA1-R1 (Asset #41781)	0.0	2.1	2.1
2006	English Hr West Recloser EH1-R2 (Asset #41779)	0.0	0.4	0.4
2006	Plum Point Recloser PP1-R1 (Asset #58176)	0.2	0.0	0.2
2006	Plum Point Recloser PP2-R1 (Asset #58177)	0.0	0.3	0.3
2006	Bear Cove Recloser BC6-R1 (Asset #105809)	0.0	0.1	0.1
2006	English Hr West Recloser EH1-R1 (Asset #41812)	0.0	0.5	0.5
	Total 2006	**2.2**	**3.6**	**5.8**
2005	Happy Valley Recloser HV7-R1 (Asset #45998)	0.0	1.3	1.3
2005	Happy Valley Recloser HV16-R1 (Asset #46004)	0.0	0.5	0.5
2005	Hampden Recloser HA1-R1 (Asset #41781)	0.0	0.9	0.9
2005	Plum Point Recloser PP1-R1 (Asset #58176)	0.0	0.8	0.8
2005	Bear Cove Recloser BC6-R1 (Asset #105809)	0.0	5.8	5.8
	Total 2005	**0.0**	**9.3**	**9.3**
2004	Happy Valley Recloser HV10-R1 (Asset #46002)	0.0	0.2	0.2
2004	Jackson's Arm Recloser JA1-R1 (Asset #41780)	1.1	0.0	1.1
2004	Hampden Recloser HA1-R1 (Asset #41781)	1.6	0.0	1.6
2004	English Hr West Recloser EH1-R2 (Asset #41779)	0.2	0.0	0.2
2004	Plum Point Recloser PP2-R1 (Asset #58177)	0.0	0.5	0.5
2004	Bear Cove Recloser BC4-R1 (Asset #106300)	1.2	0.2	1.4
2004	Bear Cove Recloser BC6-R1 (Asset #105809)	0.0	0.6	0.6
	Total 2004	**4.1**	**1.5**	**5.6**

3.5 Outage Statistics

Newfoundland and Labrador Hydro (Hydro) tracks all distribution system outages using industry standard indexes, SAIFI and SAIDI which are explained as follows:

SAIDI- indicates the System Average Interruption Duration for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - Indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 4 lists the 2004 to 2008 average SAIFI and SAIDI data by feeder and distribution system where the recloser panels are proposed to be replaced in 2010. The table also lists the 2004 to 2008 corporate value and the latest CEA five year average (2003-2007) for comparison. Refer to Appendix D for a summary of distribution system outage statistics for all reclosers to be replaced under the program.

Table 4: Outage Statistics

System	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Central Interconnected	3.85	9.74	0.49	1.29
Northern Interconnected	5.02	8.86	0.52	1.10
Labrador Interconnected	8.41	9.54	0.79	0.75
Bear Cove System	6.18	12.46	1.08	1.52
Bear Cove Feeder 4	4.68	8.86	0.70	1.43
Bear Cove Feeder 6	6.77	13.88	1.24	1.55
English Harbour West Feeder 1	4.98	12.14	0.41	0.68
Hampden Feeder 1	3.60	9.71	0.47	1.51
Happy Valley System	10.42	8.76	0.92	0.93
Happy Valley Feeder 1	10.10	7.20	0.70	0.64
Happy Valley Feeder 10	9.98	6.99	1.03	1.04
Happy Valley Feeder 16	11.00	16.31	0.62	1.29

System	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Happy Valley Feeder 7	12.63	15.37	1.16	2.02
Happy Valley Feeder 8	8.99	6.55	0.45	0.37
Jackson's Arm System	4.20	15.11	0.44	3.08
Jackson's Arm Feeder 1	3.54	12.02	0.02	0.17
Jackson's Arm Feeder 2	4.64	17.15	0.70	5.02
Plum Point System	4.34	5.99	0.90	1.15
Plum Point Feeder 1	5.25	7.92	1.23	1.83
Plum Point Feeder 2	3.61	4.43	0.63	0.61
South Brook System	3.10	7.67	0.36	0.92
South Brook Feeder 7	2.27	6.52	0.66	1.39
Hydro Corporate	**5.92**	**9.50**	**0.74**	**1.30**
CEA Region 2	**2.67**	**8.33**	**0.48**	**1.13**

Hydro's present system for collecting outage information does not record equipment failures by distribution equipment components such as recloser panels. Outages due to recloser control panels along with other defective equipment would be included in the general defective equipment category. The data provided in the table lists the outage statistics for all causes and defective equipment.

Defective Equipment is defined by the CEA as:
Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

It does not include planned outages to repair defective equipment.

3.6 Industry Experience

The stainless steel enclosure for the control panel or the rack mounted control panel is recommended for installations subject to severe weather or salt contamination.

3.7 Maintenance or Support Arrangements

There are no maintenance or support agreements with the manufacturers. Hydro Operations staff performs preventive maintenance on an annual basis for each distribution recloser which includes function testing for verification of settings as approved by Engineering Services. There has also been increased corrective maintenance for these recloser control panels because of severe rusting of the metal enclosure and subsequent failure of interior electronics due to moisture ingress.

3.8 Vendor Recommendations

The vendor of the distribution reclosers has advised Hydro that the solution to the severe rust contamination on the recloser control panels is replacement with the latest digital control which is available in a stainless steel panel enclosure, as well as in rack mount configuration. The vendor has also confirmed that the existing recloser itself does not require change out and that only its sensing current transformers (CT) require replacement in order to be compatible with the accuracy of the new digital control.

3.9 Availability of Replacement Parts

Hydro has been advised by the vendor that circuit boards and plug-in cards have delivery times of 12-20 weeks, as can be seen below in an excerpt of a vendor email:

> ”The existing F3 controls are from 1960's technologies. As many of these devices still exist at Utilities all over the world, Cooper had strategically found new components suppliers in the 80's, had stock-piled required boards and components to support the devices. I am still amazed that we can still obtain parts, as many of the old original manufacturers have long since moved on to more current technologies. I would expect within the next 5-10 years that we may have great difficulty obtaining replacement parts for these old devices. The replacement parts business could be terminated at any time - although Cooper does not have any set time at present. To the best of my knowledge,

> most of the control boards are still available, but on a 12-20 week delivery basis."

3.10 Safety Performance

During a fault, electrical energy enters the earth; these electronic reclosers sense the fault condition and break the electrical path feeding the fault. This quickly limits the electrical energy entering the earth greatly reducing the electrocution hazard.

3.11 Environmental Performance

This multi-year project does not have any environmental impact.

3.12 Operating Regime

All distribution reclosers listed for upgrade are in continuous operating mode.

4 JUSTIFICATION

Recloser control panels have deteriorated beyond repair. Once the integrity of the control panel has been compromised the ingress of moisture and contaminants does occur, affecting the internal electronic components which can result in mis-operation of the recloser and power outages to Hydro customers.

The distribution recloser is a key protective device for detection of various types of system faults and the automatic restoration of power when these line faults are only temporary in nature. It also enables isolation of the faulted line section should the system fault be permanent. Therefore, the operating integrity of this key protective device must not be compromised by the failure of an internal electronic component due to severe rusting of the recloser control panel.

The replacement recloser control cabinet shall be stainless steel construction, which is now the standard design requirement for new installations in order to protect against severe salt contamination.

4.1 Net Present Value

A net present value calculation was not performed in this instance, as only one viable alternative exists.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

A cost benefit analysis is not required as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements with this project.

4.5 Historical Information

The Recloser Control Panel Replacement Project is a five year project to replace 36 reclosers. Eight recloser control panel replacements were completed in 2008 under this program for reclosers at the Change Islands Substation (CH2-R1 and CH3-R1), Fogo Island Substation (FO4-R1, FO5-R1, and FO6-R1), and the Bottom Waters Terminal Station (BW1-R1, BW2-R1 and BW3-R1). Recloser control panel replacements for reclosers at the Burgeo Substation (BU2-R1, BU3-R1 and BU4-R1) and at the Bottom Waters Terminal Station (BW2-R3 and BW4-R1) have commenced in 2009 under this program. Table 5 contains the historical information for these replacements.

Table 5: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	132.4		5		Project in progress
2008	222.5	133.9	8	16.74	Completed with approved change order[1]

[1] A change order to revise the 2008 budget was issued as the cost for the recloser controls were less than originally estimated and several of the recloser structure modifications were not required as originally anticipated. The amount of field work by operations crews was also significantly reduced by retrofitting each recloser and pre-commissioning it with its new electronic controls in the Hydro terminals maintenance repair facility at Bishop’s Falls, thereby reducing operations crews overtime and travel time. The total reduction on the change order was $88,961.

4.6 Forecast Customer Growth

Customer load growth does not affect this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits with this type of project.

4.8 Losses During Construction

There will be planned power outages with this project involving those reclosers that require CT replacements and will have to be temporarily removed from service.

4.9 Status Quo

Maintaining the status quo will result in increased distribution recloser operations and customer outages.

4.10 Alternatives

There is no viable alternative to replacement of the control panels for the distribution reclosers listed in Appendix A. Severe control enclosure rusting already exists and has caused internal component failures. Many of the original electronic components for these control panels are no longer available.

5 CONCLUSION

Replacing each panel with a more modern digital control panel with stainless steel enclosure or rack mounted panels located in a control building is the only option. The first two years of the recloser control panel replacement project for Transmission and Rural Operations has commenced as per Section 4.5.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 6.

Table 6: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	217.9	0.0	0.0	217.9
Labour	239.1	0.0	0.0	239.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	69.1	0.0	0.0	69.1
O/H, AFUDC & Escln.	24.4	0.0	0.0	24.4
Contingency	52.6	0.0	0.0	52.6
TOTAL	**603.1**	**0.0**	**0.0**	**603.1**

5.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	**Milestone**
Project Initiation, Design & Equipment Ordering	April 2010
Field Construction/Installations	October 2010
Commissioning (after installation)	October 2009
In Service	October 2010
Project Completion and Close Out	November 2010

These Milestones will be replicated for 2011, 2012, 2013, and 2014.

APPENDIX A

Age of Assets

Location	Recloser ID	Asset #	Year Installed
L'Anse au Loup	LL2-R1	95688	1968
Mary's Harbour	MH1-R1	80037	1970
Port Hope- Simpson	PH1-R1	80031	1970
Hawke's Bay	HB3-R1	58178	1971
Shoal Cove N	BC6-R2	80026	1975
L'Anse au Loup	LL1-R1	99933	1975
Cooks Harbour	CH7-R1	80051	1975
St. Anthony	SA1-R3	80042	1975
Happy Valley	HV1-R1	45996	1975
Happy Valley	HV7-R1	45998	1975
Happy Valley	HV8-R1	278417	1975
Happy Valley	HV10-R1	46002	1975
Happy Valley	HV16-R1	46004	1975
South Brook	SB7-R2	41771	1978
Jackson's Arm	JA1-R1	41780	1978
Jackson's Arm	JA2-R1	41782	1978
Hampden	HA1-R1	41781	1978
English Hr West	EH1-R2	41779	1979
Barachoix	BA1-R1	41774	1979
Barachoix	BA4-R1	41806	1979
St. Anthony	SA2-R1	107289	1980
Cow Head	CH1-R1	58187	1981
Daniels Harbour	DH1-R1	58184	1981
Glenburnie	GL2-R1	58181	1981
Plum Point	PP2-R1	58177	1981
Plum Point	PP1-R1	58176	1981
Roddickton	RO1-R3	107301	1981
Bear Cove	BC4-R1	106300	1984
Bear Cove	BC6-R1	105809	1984
Roddickton	R04-R1	106298	1984
Roddickton	RO1-R2	103587	1985
Roddickton	RO3-R2	106299	1985
St. Anthony	SA3-R1	99273	1985
St. Anthony	SA1-R1	97367	1986
English Hr West	EH1-R1	41812	1988
Parsons Pond	PP1-R1	159132	1999

APPENDIX B

Major Upgrades

Major Work/Upgrades

Date	Recloser	Major Work/Upgrade	Cost
08/09/18	Parson's Pond Recloser PP1-R1 (Asset #159132)	Replace power cable	$463
06/10/23	English Hr West Recloser EH1-R1 (Asset #41812)	Recloser Control Panel Removed for Repair (severe rust)	$1,296
06/03/12	Hampden Recloser HA1-R1 (Asset #41781)	Replace/Replace Control Cabinet	$2,086
06/03/02	Hawke's Bay Recloser HB3-R1 (Asset #41781)	Recloser Control Panel Repaired	$2,086
06/03/02	St. Anthony Recloser SA3-R1 (Asset #99273)	Recloser Control Panel Repaired	$2,086
05/12/19	St. Anthony Recloser SA3-R1 (Asset #99273)	Recloser Control Panel Failure To Trip	$806
05/05/02	Glenburnie Recloser GL2-R1 (Asset #58181)	Replace CT	$407
04/11/29	Bear Cove Recloser BC4-R1 (Asset #106300)	Changed output card	*
04/08/20	L'Anse au Loup Recloser LL2-R1 (Asset #95688)	Install Sequence Coordination Accessory	$904
04/07/21	Roddickton Recloser RO4-R1 (Asset #106298)	Install Sequence Coordination Accessory	$830

*Cost not noted on Emergency Work Order

APPENDIX C

5 Year Maintenance History

Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	Happy Valley Recloser HV7-R1 (Asset #45998)	0.1	0.0	0.1
2009	Barachoix Recloser BA4-R1 (Asset #41806)	1.3	0.0	1.3
2009	Glenburnie Recloser GL2-R1 (Asset #58181)	0.0	0.1	0.1
	Total 2009	**1.4**	**0.1**	**1.5**
2008	Happy Valley Recloser HV1-R1 (Asset #45996)	0.0	1.1	1.1
2008	Jackson's Arm Recloser JA1-R1 (Asset #41780)	1.7	0.0	1.7
2008	Jackson's Arm Recloser JA2-R1 (Asset #41782)	1.9	0.0	1.9
2008	Barachoix Recloser BA1-R1 (Asset #41774)	0.6	0.0	0.6
2008	Cow Head Recloser CH1-R1 (Asset #58187)	0.3	0.0	0.3
2008	Daniels Harbour Recloser DH1-R1 (Asset #58184)	0.0	0.4	0.4
2008	Plum Point Recloser PP2-R1 (Asset #58177)	0.4	1.5	1.9
2008	Bear Cove Recloser BC4-R1 (Asset #106300)	0.5	1.2	1.7
2008	Roddickton Recloser RO4-R1 (Asset #106298)	0.0	0.1	0.1
2008	St. Anthony Recloser SA3-R1 (Asset #99273)	0.5	1.2	1.7
2008	Parson's Pond Recloser PP1-R1 (Asset #159132)	0.0	0.8	0.8
	Total 2008	**5.9**	**6.3**	**12.2**
2007	L'Anse au Loup Recloser LL2-R1 (Asset #95688)	0.9	0.0	0.9
2007	Port Hope Simpson Recloser PH1-R1 (Asset #80031)	0.4	0.3	0.7
2007	Hawke's Bay Recloser HB3-R1 (Asset #41781)	0.0	1.2	1.2
2007	L'Anse au Loup Recloser LL1-R1 (Asset #99933)	0.7	0.0	0.7

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	Cooks Harbour Recloser CH7-R1 (Asset #80051)	0.0	0.2	0.2
2007	Happy Valley Recloser HV1-R1 (Asset #45996)	0.0	0.2	0.2
2007	Happy Valley Recloser HV7-R1 (Asset #45998)	0.3	1.1	1.4
2007	Hampden Recloser HA1-R1 (Asset #41781)	1.2	0.0	1.2
2007	English Hr West Recloser EH1-R2 (Asset #41779)	0.0	1.1	1.1
2007	St. Anthony Recloser SA2-R1 (Asset #107289)	0.0	0.7	0.7
2007	Daniels Harbour Recloser DH1-R1 (Asset #58184)	0.4	0.0	0.4
2007	Glenburnie Recloser GL2-R1 (Asset #58181)	0.4	1.1	1.5
2007	St. Anthony Recloser SA3-R1 (Asset #99273)	0.0	1.4	1.4
2007	English Hr West Recloser EH1-R1 (Asset #41812)	2.2	0.0	2.2
2007	Happy Valley Recloser HV16-R1 (Asset #46004)	0.0	0.3	0.3
	Total 2007	**6.5**	**7.6**	**14.1**
2006	Port Hope Simpson Recloser PH1-R1 (Asset #80031)	0.4	0.0	0.4
2006	Hawke’s Bay Recloser HB3-R1 (Asset #41781)	0.0	2.0	2.0
2006	Shoal Cove North Recloser BC6-R2 (Asset #80026)	0.0	0.1	0.1
2006	St. Anthony Recloser SA1-R3 (Asset #80026)	0.0	0.1	0.1
2006	Happy Valley Recloser HV1-R1 (Asset #45996)	0.2	0.0	0.2
2006	Happy Valley Recloser HV7-R1 (Asset #45998)	0.2	0.0	0.2
2006	South Brook Recloser SB7-R2 (Asset #41771)	1.6	0.0	1.6
2006	Jackson’s Arm Recloser JA1-R1 (Asset #41780)	0.0	0.1	0.1
2006	Hampden Recloser HA1-R1 (Asset #41781)	0.0	2.1	2.1

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2006	English Hr West Recloser EH1-R2 (Asset #41779)	0.0	0.4	0.4
2006	Barachoix Recloser BA1-R1 (Asset #41774)	0.0	0.8	0.8
2006	Glenburnie Recloser GL2-R1 (Asset #58181)	0.0	0.6	0.6
2006	Plum Point Recloser PP1-R1 (Asset #58176)	0.2	0.0	0.2
2006	Plum Point Recloser PP2-R1 (Asset #58177)	0.0	0.3	0.3
2006	Roddickton Recloser RO1-R2 (Asset #103587)	0.3	0.0	0.3
2006	Bear Cove Recloser BC6-R1 (Asset #105809)	0.0	0.1	0.1
2006	Roddickton Recloser RO4-R1 (Asset #106298)	0.3	0.8	1.1
2006	Roddickton Recloser RO1-R3 (Asset #107301)	0.0	0.2	0.2
2006	St. Anthony Recloser SA1-R1 (Asset #97367)	0.0	5.1	5.1
2006	English Hr West Recloser EH1-R1 (Asset #41812)	0.0	0.5	0.5
	Total 2006	**3.2**	**13.2**	**16.4**
2005	L'Anse au Loup Recloser LL2-R1 (Asset #95688)	0.0	0.1	0.1
2005	Hawke's Bay Recloser HB3-R1 (Asset #41781)	0.0	1.0	1.0
2005	Cooks Harbour Recloser CH7-R1 (Asset #80051)	0.5	0.0	0.5
2005	Happy Valley Recloser HV7-R1 (Asset #45998)	0.0	1.3	1.3
2005	Happy Valley Recloser HV16-R1 (Asset #46004)	0.0	0.5	0.5
2005	Hampden Recloser HA1-R1 (Asset #41781)	0.0	0.9	0.9
2005	Barachoix Recloser BA4-R1 (Asset #41806)	0.8	0.0	0.8
2005	Cow Head Recloser CH1-R1 (Asset #58187)	0.3	0.0	0.3
2005	Daniels Harbour Recloser DH1-R1 (Asset #58184)	0.4	0.0	0.4

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2005	Glenburnie Recloser GL2-R1 (Asset #58181)	0.0	0.4	0.4
2005	Plum Point Recloser PP1-R1 (Asset #58176)	0.0	0.8	0.8
2005	Bear Cove Recloser BC6-R1 (Asset #105809)	0.0	5.8	5.8
2005	Roddickton Recloser RO3-R2 (Asset #106299)	0.2	0.0	0.2
2005	Parson's Pond Recloser PP1-R1 (Asset #159132)	0.6	0.0	0.6
	Total 2005	**2.8**	**10.8**	**13.6**
2004	L'Anse au Loup Recloser LL2-R1 (Asset #95688)	0.3	2.1	2.4
2004	Hawke's Bay Recloser HB3-R1 (Asset #41781)	0.0	1.6	1.6
2004	L'Anse au Loup Recloser LL1-R1 (Asset #99933)	0.5	1.1	1.6
2004	Cooks Harbour Recloser CH7-R1 (Asset #80051)	0.0	0.1	0.1
2004	Happy Valley Recloser HV10-R1 (Asset #46002)	0.0	0.2	0.2
2004	Jackson's Arm Recloser JA1-R1 (Asset #41780)	1.1	0.0	1.1
2004	Hampden Recloser HA1-R1 (Asset #41781)	1.6	0.0	1.6
2004	English Hr West Recloser EH1-R2 (Asset #41779)	0.2	0.0	0.2
2004	Barachoix Recloser BA1-R1 (Asset #41774)	1.6	0.0	1.6
2004	St. Anthony Recloser SA2-R1 (Asset #107289)	0.5	0.0	0.5
2004	Cow Head Recloser CH1-R1 (Asset #58187)	2.6	0.1	2.7
2004	Glenburnie Recloser GL2-R1 (Asset #58181)	0.4	0.0	0.4
2004	Plum Point Recloser PP2-R1 (Asset #58177)	0.0	0.5	0.5
2004	Roddickton Recloser RO1-R3 (Asset #107301)	0.0	0.2	0.2
2004	Bear Cove Recloser BC4-R1 (Asset #106300)	1.2	0.2	1.4

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2004	Bear Cove Recloser BC6-R1 (Asset #105809)	0.0	0.6	0.6
2004	Roddickton Recloser RO4-R1 (Asset #106298)	0.0	0.8	0.8
2004	St. Anthony Recloser SA1-R1 (Asset #97367)	0.4	0.0	0.4
2004	St. Anthony Recloser SA3-R1 (Asset #99273)	0.4	0.0	0.4
	Total 2004	**10.8**	**7.5**	**18.3**

APPENDIX D

Distribution System Outage Statistics

The table lists the 2004 to 2008 average SAIFI and SAIDI data by feeder and distribution system where the recloser panels are proposed to be replaced. The table also lists the 2004 to 2008 corporate value and the latest CEA five year average (2003-2007) for comparison.

System	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Central Interconnected	3.85	9.74	0.49	1.29
Northern Interconnected	5.02	8.86	0.52	1.10
Labrador Interconnected	8.41	9.54	0.79	0.75
Barachoix System	4.84	12.79	0.75	0.69
Barachoix Feeder 1	4.02	11.86	0.21	0.20
Barachoix Feeder 4	5.48	13.24	0.21	0.32
Bear Cove System	6.18	12.46	1.08	1.52
Bear Cove Feeder 4	4.68	8.86	0.70	1.43
Bear Cove Feeder 6	6.77	13.88	1.24	1.55
Bottom Waters System	4.30	11.16	0.63	1.56
Bottom Waters Feeder 2	1.72	4.77	0.44	1.57
Bottom Waters Feeder 4	3.00	7.65	0.62	1.84
Burgeo System	3.26	5.60	0.08	0.09
Burgeo Feeder 2	3.34	5.66	0.21	0.22
Burgeo Feeder 3	3.13	5.42	0.00	0.00
Burgeo Feeder 4	3.24	5.85	0.00	0.00
Cow Head Feeder 1	2.90	6.02	0.29	0.36
Daniels Harbour Feeder 1	2.93	5.26	0.01	0.01
English Harbour West Feeder 1	4.98	12.14	0.41	0.68
Glenbernie Feeder 2	4.48	11.13	0.43	0.66
Hampden Feeder 1	3.60	9.71	0.47	1.51
Happy Valley System	10.42	8.76	0.92	0.93
Happy Valley Feeder 1	10.10	7.20	0.70	0.64
Happy Valley Feeder 10	9.98	6.99	1.03	1.04
Happy Valley Feeder 16	11.00	16.31	0.62	1.29
Happy Valley Feeder 7	12.63	15.37	1.16	2.02
Happy Valley Feeder 8	8.99	6.55	0.45	0.37
Hawke's Bay System	5.87	6.81	0.26	0.24
Jackson's Arm System	4.20	15.11	0.44	3.08
Jackson's Arm Feeder 1	3.54	12.02	0.02	0.17

System	All Causes		Defective Equipment	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
Jackson's Arm Feeder 2	4.64	17.15	0.70	5.02
Parson's Pond Feeder 1	3.14	5.41	0.01	0.01
Plum Point System	4.34	5.99	0.90	1.15
Plum Point Feeder 1	5.25	7.92	1.23	1.83
Plum Point Feeder 2	3.61	4.43	0.63	0.61
Roddickton System	6.43	10.71	0.23	0.17
Roddickton Feeder 1	6.95	10.48	0.26	0.21
Roddickton Feeder 2	3.85	5.43	0.00	0.00
Roddickton Feeder 3	4.50	6.09	0.01	0.03
Roddickton Feeder 4	7.87	19.08	0.41	0.25
South Brook System	3.10	7.67	0.36	0.92
South Brook Feeder 7	2.27	6.52	0.66	1.39
St. Anthony System	6.49	11.79	0.63	1.83
St. Anthony Feeder 1	5.08	8.00	0.22	0.03
St. Anthony Feeder 2	5.06	4.90	0.60	0.51
St. Anthony Feeder 3	6.05	6.86	0.00	0.00
Hydro Corporate	5.92	9.50	0.74	1.30
CEA Region 2	2.67	8.33	0.48	1.13

Hydro's present system for collecting outage information does not record equipment failures by distribution equipment components such as recloser panels. Outages due to recloser control panels along with other defective equipment would be included in the general defective equipment category. The data provided in the table lists the outage statistics for all causes and defective equipment.

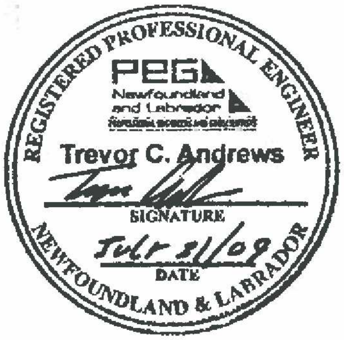
Defective Equipment is defined by the CEA as:

> *Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.*

It does not include planned outages to repair defective equipment.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES



Electrical
Mechanical
Civil
Protection & Control
Transmission & Distribution
Telecontrol
System Planning

VOLTAGE CONVERSION - GAULTOIS

May 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

The Gaultois distribution system was originally constructed in 1970 and is connected to the Island Interconnected System by submarine cables. The distribution system consists of a 25 kV power transformer coupled with a 4.16 kV distribution feeder that supplies continuous power to the community. The distribution system is the primary source of power for the community. An assessment of the system performed by Newfoundland and Labrador Hydro (Hydro) operations indicates that it has become deteriorated.

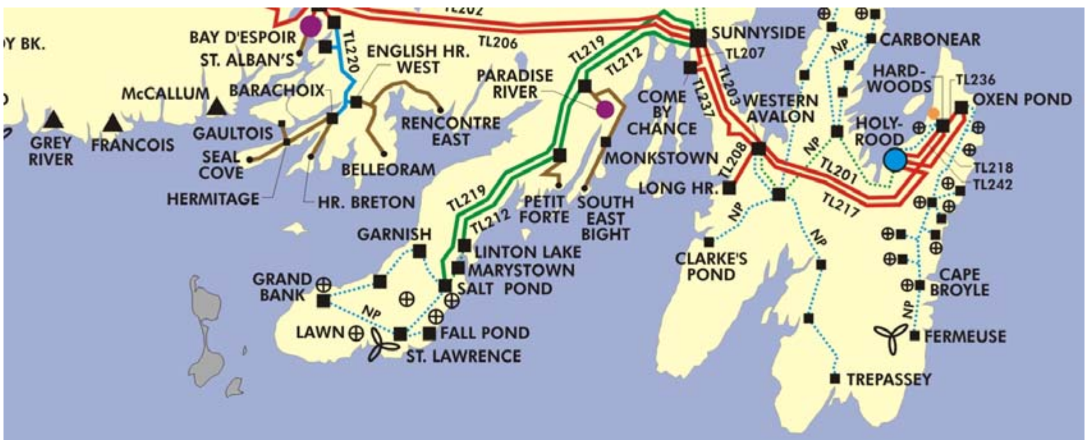


Figure 1: Map showing geographic location of Gaultious.

2 PROJECT DESCRIPTION

The existing distribution line will be upgraded to a 25 kV feeder which will be supplied directly by the existing submarine cable link from the Island Interconnected System. The existing substation will be decommissioned and removed.

This project will include all work required to complete the voltage conversion on the existing Gaultois distribution system from 4.16 kV to 25 kV.

The scope of this project will include the following items:

- Replacement of deteriorated structures (wood poles) – as identified for replacement;
- Replacement of 22 distribution transformers with dual voltage units – to enhance reliability by no longer requiring an outage while performing routine maintenance.
- Replacement of 205 insulators – re- insulation required for voltage increase to 25 kV;
- Replacement of 35 porcelain cutouts (See section 3.10 for details)
- Replacement of deteriorated conductor (Approximately 1.0 circuit kilometer);
- Removal of the existing power transformer and other station components as they will no longer be required with the 25 kV voltage conversion
- Replacement of the chain link fence around substation area.

This will be a two year project with the design undertaken in July 2010 and construction in 2011.

3 EXISTING SYSTEM

The existing distribution system was constructed in 1970. The distribution line extends from an existing 25 kV substation in the southern end of Gaultois to the northerly end of the community, a distance of approximately 1.5 kilometers and serving approximately 125 customers. The system contains a number of components that have become deteriorated and pose either a safety or environmental risk. The deteriorated components include but are not limited to the following items:

- Substation structures (wood poles);
- Substation chain link fence;
- Distribution transformers;
- Conductor.

Other components such as the porcelain insulators, cutouts and the power transformer will be replaced or removed to meet the requirements of the 25 kV voltage conversion.

3.1 Age of Equipment or System

Since the Gaultois distribution system was constructed in 1970, it has been in operation as the primary source of distribution for 39 years.

3.2 Major Work and/or Upgrades

There have been no major upgrades on the Gaultois distribution system since the original installation. Table 1 lists the upgrades that have occurred on the submarine cable since installation:

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2008	Replace submarine cable terminators	Actual Cost $31,827
2008	Submarine cable armour remediation	Actual Cost $68,342

The upgrades listed in Table 1 above are for the submarine cable only and do not include any work on the rest of the distribution system.

3.3 Anticipated Useful life

The service life for both the substation and distribution line is 30 years.

3.4 Maintenance History

The five-year maintenance history for the Gaultois Distribution line is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Total Maintenance	Comments
2008	$955.55	Minor Maintenance
2007	$9,576.78	Replace Bushings in Power Transformer
2006	$177.03	Minor Maintenance
2005	$354.06	Minor Maintenance
2004	$1,907.64	Minor Maintenance

Maintenance costs associated with the Gaultois distribution system includes all work directly linked to preventative maintenance tasks such as line inspection, trouble calls and routine minor maintenance.

3.5 Outage Statistics

Hydro tracks all distribution system outages using industry standard indexes, SAIFI, and SAIDI which are explained as follows:

SAIDI- is the System Average Interruption Duration Index for customers served per year and indicates the average length of time a customer is without power in the respective distribution system per year.

SAIFI - is the System Average Interruption Index and indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 3 lists the 2004 to 2008 SAIFI and SAIDI data for Gaultois - Line 2, 2004 to 2008 corporate values, and the latest CEA five year average (2004 to 2008) for comparison.

Table 3: SAIFI SAIDI Five Year Averages

Five Year Averages (2004 to 2008)				
	All Causes		Defective Equipment	
	SAIFI	SAIDI	SAIFI	SAIDI
Gaultois Line 2	4.22	14.04	0.41	0.47
Hydro Corporate	5.92	9.50	0.74	1.30
CEA	2.67	8.33	0.48	1.13

3.6 Industry Experience

Industry experience shows that the majority of infrastructure exceeding its useful life with no major upgrades since original installation has become severely deteriorated and should be replaced based on priority. The level of priority for all sites will be dependant upon the importance of the site as a main distribution feeder and the results of regular inspections. Using a standardized inspection/grading system within the utility industry, the line components proposed for replacement have been identified as close to the end of their useful lives. Hydro performs inspections on all distribution line components classifying them using the following standardized grading system:

- Grade "A" Condition: Excess of 5 years of life remaining,
- Grade "B" Condition: 1 to 5 years of life remaining, and
- Grade "C" Condition: Less than 1 year of life remaining.

3.7 Maintenance or Support Arrangements

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by regulated operations personnel and any corrective maintenance required is reported, scheduled and completed. The inspection schedule is determined through a Reliability Centered Maintenance Program initiated by Hydro and is dependant on a variety of factors including geographical location, line age, and customer usage. Inspection schedules may vary between lines depending on the existing circumstances. The deteriorated components identified on this line were classified as "B" condition during the last inspection in 2006 and are scheduled to be replaced in 2010.

3.8 Vendor Recommendations

There are no specific vendor recommendations for this project.

3.9 Availability of Replacement Parts

Replacement parts are readily available.

3.10 Safety Performance

The following safety issues have been identified:

- The poles and cross arms are deteriorated and pose a risk to the safety of operations personnel who may be performing climbing activities to conduct regular inspections or maintenance work.

- The porcelain cutouts have experienced numerous failures when being opened and closed. Damaged cutouts may result in equipment becoming energized and pose an electrical contact threat for operation crews. Due to these safety concerns, the porcelain cutouts no longer comply with current Hydro standards and are in the process of being replaced with new polymer cutouts.

- The chain link fence is damaged, severely rusted and requires replacement.

- The existing conductor is deteriorated (weak and brittle) and susceptible to breakage over time. A conductor failure would result in outages and may result in injury or damage to persons and property that it comes into contact with.

3.11 Environmental Performance

The following environmental issues have been identified:

- A portion of the poles used during the original construction of the distribution system were blackjacks. Blackjack poles are treated on the surface with a coating of tar/creosote to prevent decay of the material and were commonly used in the past by the utility industry. Blackjack poles are environmentally unacceptable due to the threat of ground/water contamination from the presence of the creosote coating on the surface of the pole. Hydro is currently in the process of removing and discarding all blackjack poles from the system. Hydro has established this initiative in compliance with applicable environmental regulatory authorities such as the Department of Environment and the Department of Fisheries.

All work undertaken in this area will be assessed, monitored and regulated by the Hydro Environment Group. All applicable environmental permits will be obtained prior to the completion of the proposed work.

3.12 Operating Regime

The Gaultois distribution system is in continuous operation providing power to approximately 125 customers in the community.

4 JUSTIFICATION

The existing distribution system was constructed in 1970. The distribution line extends from an existing 25 kV substation in the southern end of Gaultois to the northerly end of the community, a distance of approximately 1.5 kilometers and serving approximately 125 customers. The majority of line components were installed at the time of original construction and have exceeded their economic lives of 30 years. In addition, as a result of standardized inspection and testing, it has become evident that line components are deteriorated and may have a remaining life span of only one to five years before widespread failure occurs.

Failure of such components will have a negative effect on the safety and reliability performance of the line as identified earlier in the report. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions. The level of difficulty in restoring power to customers may also be impacted by the affect of isolation of the community due to its geographical location. Depending on the extent of the damage caused by a failure, alternate generation may also be required to supply service to the communities while upgrades are or rehabilitation is performed. The costs associated with alternative generation could be costly and result in environmental concerns such as air emissions.

It has also been recognized that some of the existing line components are no longer at a standard used by Hydro for line applications.

The deteriorated components include but are not limited to the following items:

- Substation structures (wood poles);
- Substation chain link fence;
- Distribution transformers;
- Conductor.

Other components such as the porcelain insulators, cutouts and the power transformer will be replaced or removed to meet the requirements of the 25 kV voltage conversion.

4.1 Net Present Value

The cumulative net present value of converting the Gaultois distribution system to 25 kV is \$472,731. Please refer to Section 4.3 for details.

4.2 Levelized Cost of Energy

This project will have no effect on the levelized cost of electricity.

4.3 Cost Benefit Analysis

A cost benefit analysis was conducted for this project and included the following two options:

Option 1: Gaultois Substation refurbished and the distribution line re-conductored with 4/0 AASC.

Option 2: Gaultois system converted to 25 kV and the distribution line re-conductored with 1/0 AASC.

The two options were assessed with different conductors due to the fact that the conductor selected for each option is the most efficient and economical for that particular scenario.

As a result of the cost benefit analysis (see Table 4), it is evident that the voltage conversion is the most economic and viable option. The analysis was based on factors including capital costs, operating costs and cost benefits based on current conditions.

Table 4: Cost Benefit Analysis

Gaultious Alternative Comparison *Cumulative Net Present Value* *To The Year* 2039		
Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Alt. #1 SubStation Replacement - 4/0 Conductor	588,406	115,675
Alt. #2 - Voltage Conversion with 1/0 Conductor	472,731	0

4.4 Legislative or Regulatory Requirements

There are no known legislative or regulatory requirements associated with this project. Also, see Section 3.11 Environmental Performances.

4.5 Historical Information

There are no costs for similar projects that can be compared to this project.

4.6 Forecast Customer Growth

There is no anticipated load growth on the Gaultois distribution system over the next five years.

4.7 Energy Efficiency Benefits

There are energy efficiency benefits that can be attributed to this project. By converting to a higher voltage and re-conductoring the primary line to a larger size, the losses saved as a result of the upgrades is estimated to be 43,540 kWh per year. The savings have a value of about $77,247 over the 30 year life of the asset.

4.8 Losses During Construction

There are no anticipated energy losses during construction.

4.9 Status Quo

The status quo is not an acceptable alternative for the following reasons:

- The majority of line components were installed at the time of original construction and have far exceeded their economic lives of 30 years. They are heavily deteriorated with an estimated life span ranging between one and five years based on regular inspection.

- Failure to upgrade the existing system could increase the number of outages of varying durations to the customers it serves.

- Deteriorated/outdated equipment also poses considerable safety risk to Hydro operations personnel who maintain the lines, as well as individuals residing in and occupying the area.

4.10 Alternatives

Please see Section 4.3 for a discussion of the alternatives. The voltage conversion of the existing system is the most viable option as determined by the cost benefit analysis.

5 CONCLUSION

This project is required to ensure a reliable energy supply is available for the approximately 125 customers served by the Gaultois distribution system.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 5.

Table 5: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	53.0	100.0	0.0	153.0
Labour	16.0	48.3	0.0	64.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	245.6	0.0	245.6
Other Direct Costs	6.0	14.8	0.0	20.8
O/H, AFUDC & Escln.	7.0	53.6	0.0	60.6
Contingency	0.0	48.4	0.0	48.4
TOTAL	**82.0**	**510.7**	**0.0**	**592.7**

5.2 Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	Milestone
Initiation	July 2010
Design Complete	September 2010
Equipment Ordered	October 2010
Installation Commences	June 2011
Installation Complete	August 2011
Project Closeout	November 2011

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REPLACE LIGHT DUTY MOBILE EQUIPMENT – 2010

April 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates a fleet of light duty mobile equipment comprised of approximately 120 snowmobiles, 70 All terrain vehicles, 120 trailers, 10 forklifts and 25 miscellaneous attachments (for lawn mowers/backhoes/salt spreaders/snow plows, etc).

The mobile equipment fleet is strategically distributed across our operating areas throughout the Province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

The Transportation section of Hydro maintains a close liaison with other Canadian Utilities through participation on the Canadian Utility Fleet Council and has established mobile equipment replacement guidelines, which consider the age and operating conditions for the equipment.

2 PROJECT DESCRIPTION

This project proposes the replacement of 18 snowmobiles, 15 All Terrain Vehicles, 7 heavy-duty trailers and 10 light-duty trailers in accordance with the established replacement criteria as follows:

- Snowmobiles/All Terrain Vehicles: Line crews 3-5 years
- Snowmobiles/All Terrain Vehicles: Other 5-7 years
- Light-Duty Trailer 6-8 years
- Heavy-Duty Trailer 12-15 years

3 EXISTING SYSTEM

As this project is for the replacement of light-duty mobile equipment, there is no relevant information for the following:

- Outage Statistics;
- Safety Performance;
- Environmental Performance; and
- Operating Regime.

3.1 Age of Equipment or System

Please see Appendix A for a detailed listing of the mobile equipment being replaced under this proposal, which includes age at retirement and projected kilometers.

3.2 Major Work and/or Upgrades

There have been no major upgrades since purchase.

3.3 Anticipated Useful life

The estimated service life for All Terrain Vehicles, snowmobiles, trailers and attachments is as follows:

- Snowmobiles/All Terrain Vehicles: Line crews 3-5 years
- Snowmobiles/All Terrain Vehicles: Other 5-7 years
- Trailers: Light-Duty 6-8 years
- Trailers: Heavy-Duty 12-15 years

3.4 Maintenance History

Hydro does not maintain maintenance records for this type of equipment to this level of detail.

3.5 Industry Experience

Light mobile equipment replacement scheduling varies dependant on location, exposure to harsh environmental conditions, and the severity of the service use for the equipment.

3.6 Maintenance or Support Arrangements

The Hydro fleet of light duty mobile equipment is maintained by external service garages.

3.7 Vendor Recommendations

There are no vendor recommendations in regards to this project.

3.8 Availability of Replacement Parts

Replacements parts are usually available for all of the equipment being replaced in this proposal.

4 JUSTIFICATION

Hydro operates in many diverse locations across the province, and it is critical that our employees are provided with safe and reliable equipment in order to provide economical and reliable electricity.

As this proposal provides for the normal replacement of mobile equipment in accordance with established criteria, there is no relevant information related to:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Cost Benefit Analysis

As this project relates to the replacement of mobile equipment, a cost benefit analysis has not been performed.

4.3 Historical Information

Table 1 provides a history of light-duty mobile equipment purchases.

Table 1: Mobile Equipment Less than $5,000

Year	Units Purchased					Budget ($000)	Actual ($000)
	All Terrain Vehicle's	Snowmobiles	Trailers	Forklifts	Attachments		
2009 (F)	15	26	14	1	0	561.2	
2008	20	24	9	1	2	522.2	454.4
2007	15	19	0	0	0	241.0	243.5
2006	15	17	4	0	0	249.2	243.3
2005	11	15	5	0	1	230.8	244.8

4.4 Status Quo

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Our employees are expected to maintain the electrical system 24 hours, 7 days a week and require dependable and safe vehicles for their work. As equipment ages, it experiences increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

4.5 Alternatives

Purchase of this equipment is the only viable option.

5 CONCLUSION

This project provides for the normal replacement of light-duty mobile equipment which is at the end of its useful life and is no longer dependable. Purchase of this equipment is the only viable option to support the maintenance of Hydro's assets.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	478.0	0.0	0.0	478.0
Labour	2.0	0.0	0.0	2.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	25.6	0.0	0.0	25.6
Contingency	48.0	0.0	0.0	48.0
TOTAL	**553.6**	**0.0**	**0.0**	**553.6**

5.2 Project Schedule

This project is scheduled to be completed by December 31, 2010.

APPENDIX A

Replace Light Duty Mobile Equipment

Unit	2010 Mobile Equipment Type	Age at retirement	Rep	Replacement Criteria			Maint. Life to date $
				AGE	KMS	Condition	
V7001	All Terrain Vehicle	5.2	5	X			9,239
V7022	All Terrain Vehicle	5.1	5	X			3,161
V7023	All Terrain Vehicle	5.1	5	X			2,114
V7027	All Terrain Vehicle	4.9	4	X			400
V7028	All Terrain Vehicle	4.9	4	X			968
V7029	All Terrain Vehicle	4.9	4	X			290
V7049	All Terrain Vehicle	4.2	4	X			1,123
V7050	All Terrain Vehicle	4.2	4	X			949
V7051	All Terrain Vehicle	9.9	4	X			2,605
V7052	All Terrain Vehicle	4.2	4	X			179
V7053	All Terrain Vehicle	4.5	4	X			1,751
V7056	All Terrain Vehicle	4.2	4	X			642
V7057	All Terrain Vehicle	4.2	4	X			447
V7061	All Terrain Vehicle	4.5	4	X			1,141
V7062	All Terrain Vehicle	4.5	4	X			1,479
V8763	Heavy Duty Trailer	21.2	12	X			3,846
V8809	Heavy Duty Trailer	27.2	12	X			12,192
V8810	Heavy Duty Trailer	14.2	12	X			11,625
V8813	Heavy Duty Trailer	14.2	12	X			6,692
V8814	Heavy Duty Trailer	13.2	12	X			42,526
V8818	Heavy Duty Trailer	13.2	12	X			76,757
V8819	Heavy Duty Trailer	13.2	12	X			23,060
V8685	Light Duty Trailer	14.6	6	X			1,000
V8735	Light Duty Trailer	30.6	10	X			792
V8795	Light Duty Trailer	16.6	10	X			505
V8817	Light Duty Trailer	30.2	10	X			2,764
V8833	Light Duty Trailer	12.2	10	X			1,000
V8835	Light Duty Trailer	12.6	6	X			2,100
V8852	Light Duty Trailer	9.0	6	X			2,180
V8853	Light Duty Trailer	9.1	6	X			8,271

Unit	2010 Mobile Equipment Type	Age at retirement	Rep	Replacement Criteria			Maint. Life to date $
				AGE	KMS	Condition	
V8860	Light Duty Trailer	8.2	6	X			12,577
V8861	Light Duty Trailer	6.8	6	X			9,374
V7005	Snowmobile	5.1	5	X			135
V7006	Snowmobile	5.1	5	X			35
V7007	Snowmobile	5.1	5	X			253
V7008	Snowmobile	4.6	4	X			683
V7009	Snowmobile	4.6	4	X			262
V7014	Snowmobile	5.1	5	X			299
V7031	Snowmobile	4.4	4	X			1,378
V7033	Snowmobile	4.4	4	X			2,401
V7034	Snowmobile	4.4	4	X			2,100
V7039	Snowmobile	4.4	4	X			1,900
V7041	Snowmobile	4.5	4	X			59
V7043	Snowmobile	4.5	4	X			1,596
V7044	Snowmobile	4.4	4	X			1,556
V7045	Snowmobile	4.4	4	X			726
V7047	Snowmobile	4.4	4	X			567
V7639	Snowmobile	6.1	5	X			166
V7654	Snowmobile	6.1	5	X			2,084
V7655	Snowmobile	6.1	5	X			539

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REPLACE VEHICLES AND AERIAL DEVICES

Hydro System 2010

April 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) operates a fleet of vehicles comprised of approximately 200 light duty vehicles (cars, pick-ups and vans) and 65 heavy duty trucks (aerial devices, material handlers and boom trucks).

The vehicle fleet is strategically distributed across Hydro's operating areas throughout the Province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

The Transportation section of Hydro maintains a close liaison with other Canadian Utilities through participation on the Canadian Utility Fleet Council and has established vehicle replacement guidelines, which consider the operating regime for the vehicles, as well as average replacement criteria used by other Canadian Utilities.

2 PROJECT DESCRIPTION

This project proposes the replacement of 42 light duty vehicles and eight heavy duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers as follows:

- Light duty vehicles 5-7 years or 150,000 kms
- Heavy duty vehicles 7-10 years or 200,000 kms

3 EXISTING SYSTEM

As this project is for the replacement of vehicles and aerial devices there is no relevant information related to the following:

- Outage Statistics;
- Safety Performance; and
- Operating Regime.

3.1 Age of Equipment or System

Please see Appendix A for a detailed listing of the vehicles being replaced under this proposal, which includes the age at retirement and projected kilometers.

3.2 Major Work and/or Upgrades

There have been no major upgrades since purchase.

3.3 Anticipated Useful life

The anticipated useful life for light duty vehicles is six years and for heavy duty vehicles it is eight years.

3.4 Maintenance History

Please see Appendix A for the life to date maintenance costs for vehicles being replaced under this proposal.

3.5 Industry Experience

Vehicle replacement criteria across the Canadian Utility Industry varies dependant on location, exposure to harsh environmental conditions and the severity of the service hours for the vehicle. While some variances exist, it is generally the case that vehicles are replaced in accordance with the replacement criteria utilized by Hydro (see Section 2).

Hydro's Transportation section maintains a database of the vehicle fleet which tracks individual unit history including acquisition date, kilometers and maintenance history. The Fleet Specialist updates this information on an ongoing basis and uses current data to determine annual vehicle replacements.

Prior to the preparation of the capital budget proposal, a review of the latest version of the database is performed to select the units which meet the replacement criteria for age or kilometers, and to verify those which should be included in the capital budget proposal based on their maintenance history or ongoing maintenance issues.

3.6 Maintenance or Support Arrangements

The Hydro fleet of vehicles is primarily maintained by external service garages. In-house mechanical maintenance personnel are used to maintain the specialized utility equipment such as our aerial devices, booms and heavy off-road tracked equipment.

3.7 Vendor Recommendations

There are no vendor recommendations in regards to this project.

3.8 Availability of Replacement Parts

Replacements parts are usually available for all of the vehicles being replaced in this proposal.

3.9 Environmental Performance

A fuel consumption analysis is completed on all light-duty vehicles that have a fuel consumption rating to ensure we get fuel efficient vehicles. The fuel cost is calculated on a 55% Hwy / 45% city fuel rating for 75,000 kms. The total cost is factored into the upfront cost of the vehicle and the tender is awarded to the lowest total cost bid.

4 JUSTIFICATION

Hydro operates in many diverse locations across the province, and it is critical that employees are provided with safe and reliable vehicles in order to provide least-cost and reliable electricity to customers.

As this proposal provides for the normal replacement of on-road vehicles in accordance with established criteria, there is no relevant information related to the following:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

4.1 Net Present Value

A net present value calculation was not performed in this instance as only one viable alternative exists.

4.2 Cost Benefit Analysis

The light duty vehicles are subjected to a lease or purchase cost/benefit analysis during the tender process to determine the least cost alternative. The cost benefit analysis is most accurate if done in the year of replacement, as this allows us to factor in current year fleet incentives offered by the manufacturers. This proposal provides the funding to purchase the required vehicles. Should the subsequent cost/benefit analysis dictate, then costs will be adjusted to reflect the lease option.

4.3 Historical Information

Table 1 provides the purchase history for vehicle and aerial device purchases.

Table 1: Vehicle and Aerial Device Purchases 2005 - 2009				
Year	**Units Purchased**		**Budget ($000)**	**Actuals ($000)**
	Vehicles	**Aerial Device**		
2009 (F)	33	6	2,156	
2008	33	5	1,826	1,557
2007	23	9	2,686	2,218
2006	27	4	1,732	1,571
2005	27	1	868	768

4.4 Status Quo

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Hydro employees maintain the electrical system 24 hours a day, 7 days a week and require dependable and safe vehicles for their work. As vehicles age, they experience increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

4.5 Alternatives

Replacement of these vehicles and aerial devices is the only viable option.

5 CONCLUSION

This project provides for the normal replacement of light-duty and heavy-duty vehicles which are at the end of their useful lives and are no longer dependable.

5.1 Budget Estimate

The budget estimate for this project is shown in Table 2.

Table 2: Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	2,034.5	0.0	0.0	2,034.5
Labour	6.0	0.0	0.0	6.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.0	0.0	0.0	6.0
O/H, AFUDC & Escln.	109.2	0.0	0.0	109.2
Contingency	0.0	0.0	0.0	0.0
TOTAL	**2,155.7**	**0.0**	**0.0**	**2,155.7**

5.2 Project Schedule

The project is scheduled to be completed by June 2011.

APPENDIX A

Replace Vehicles and Aerial Devices Hydro System 2010

Unit	Vehicle Type	Age at Retirement	Proje kMs	Replace ent Criteria			Maint Life-to-Date $
				AGE	KMS	Condition	
V1056	Mini Van	7.0	156,843	X	X		11,994
V1062	Car	6.0	149,275	X			5,632
V1063	Car	6.1	166,880	X	X		7,698
V1091	Car	8.0	168,133	X	X		10,479
V1098	Mini Van	7.3	191,091	X	X		28,604
V1281	Mini Van	5.2	165,244	X	X		8,305
V1284	Car	5.1	216,817	X	X		9,384
V1286	Car	5.1	90,803	X		ENG HRS	6,447
V1290	Car	5.2	145,617	X	X		8,292
V1309	Car	3.3	92,769	X			2,165
V2102	Pick Up	9.1	116,403	X		ENG HRS	6,247
V2120	Utility Veh	9.1	219,728	X	X		38,247
V2125	Pick Up	7.7	61,850	X		ENG HRS	6,641
V2132	Pick Up	7.7	139,835	X	X		23,103
V2137	Pick Up	7.7	137,988	X		ENG HRS	22,726
V2150	Pick Up	7.1	173,335	X	X		11,630
V2151	Pick Up	7.1	213,893	X	X		10,235
V2156	Pick Up	6.8	144,861	X			22,076
V2162	Pick Up	7.0	180,829	X	X		31,989
V2163	Pick Up	7.0	191,130	X	X		7,828
V2172	Pick Up	6.0	160,915	X	X		10,409
V2175	Van	6.0	216,866	X	X		8,344
V2176	Pick Up	6.0	214,129	X	X		9,672
V2177	Pick Up	6.0	196,313	X	X		12,072
V2180	Pick Up	6.0	164,840	X	X		6,232
V2293	Pick Up	9.9	123,626	X		BODY	11,103
V2569	Pick Up	5.2	175,182	X	X		23,831
V2570	Pick Up	5.2	227,258	X	X		14,984
V2571	Pick Up	5.2	160,586	X	X		5,016
V2572	Pick Up	5.2	183,921	X	X		16,044
V2573	Pick Up	5.2	176,468	X	X		11,676
V2574	Pick Up	5.2	163,356	X	X		20,955
V2575	Pick Up	5.2	174,461	X	X		15,329

Unit	Vehicle Type	Age at Retirement	Projected kMs	Replacement Criteria			Maint Life-to-Date $
				AGE	KMS	Condition	
V2576	Pick Up	5.3	142,606	X	X		12,363
V2577	Pick Up	5.3	237,497	X	X		13,780
V2578	Pick Up	5.3	205,640	X	X		12,850
V2579	Pick Up	5.2	125,307	X			10,403
V2580	Pick Up	5.2	149,562	X			8,400
V2582	Pick Up	5.1	200,094	X	X		17,670
V2583	Pick Up	4.2	153,533		X		8,235
V2589	Pick Up	4.0	227,480		X		$11,513
V2594	Pick Up	4.0	179,407				13,363
V4460	Boom Truck	10.6	152,728	X		MAINT	117,561
V4463	Boom Truck	9.7	159,451	X		BODY	58,732
V4466	Boom Truck	9.7	145,771	X			81,570
V4467	Boom Truck	9.6	215,366	X	X		73,187
V4476	Line Body	7.5	212,034	X			56,103
V4479	Aerial Device	8.0	301,065	X	X	MAINT	101,779
V4489	Aerial Device	7.1	198,501	X		BOOM	66,410
V4494	Material Handler	6.0	243,791	X	X	MAINT	104,577

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

STATIONARY BATTERY AND CHARGER REPLACEMENT PROGRAM

March 2009

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro's) Stationary Battery Replacement Program (the Program) is an ongoing program to replace stationary battery systems which are required for equipment located in generating and terminal stations and at telecommunications sites throughout Hydro's operating area.

Hydro has 39 generation sites including hydraulic, thermal and diesel, 54 high-voltage (66 kV and above) terminal stations and 14 telecommunications microwave sites. Stationary batteries are located in all of these sites, and are used to provide power to telecommunications, protection and control, and switching equipment during times of AC power loss, enabling Hydro to continue operating the stations, either locally or by remote control from the Energy Control Centre (ECC).

Two types of stationary batteries are in use today. The flooded-cell battery shown in Figure 1 is the most common type. It consists of a series of individual cells connected together to supply the required voltage, either 48V or 125V DC, depending on the application. Each cell has rectangular plates of lead-calcium alloy bathed in a sulfuric acid electrolyte. The battery is large, heavy, and unwieldy; however, it has the advantage of high reliability and a typical service life of 18-20 years. If an individual cell fails, the battery continues to operate, although at diminished capacity. This type of battery has three disadvantages. Flooded-cell batteries emit small amounts of hydrogen gas during charging, and therefore require battery room ventilation. The battery also requires regular maintenance to ensure the battery electrolyte does not deplete during operation, and a jar container may fail causing potentially dangerous spills of sulfuric acid.

Figure 1 - Flooded-cell battery (Stephenville)

In an effort to develop a smaller battery with less maintenance and less exposure to dangerous chemicals, manufacturers introduced a new type of battery, known as Valve Regulated Lead Acid (VRLA) or “maintenance-free”, shown in Figure 2. These batteries hold the electrolyte suspended in a gel or paste and utilize a sealed container which reduces the chance of spill and prevents hydrogen escaping to the atmosphere. Unfortunately, once in operation they soon demonstrated several significant disadvantages. In practice, VRLA batteries have only seven to ten years of service life, which is approximately half of the flooded-cell battery service life. The batteries can experience a condition known as “thermal runaway” which is overheating that could lead to an explosion. As well, when a cell fails, it fails with an open circuit, meaning that the failure of one cell can cause the whole bank to fail. For these reasons, many users are moving back to flooded-cell batteries.

Figure 2 - VRLA battery (Hinds Lake)

There are two applications for stationary batteries – telecommunications and station service. The voltage of telecommunications batteries is usually 48V DC. These batteries typically have higher standby capacity (in terms of hours the battery can supply the load) than is required for station service batteries for two reasons. First, they often carry telecommunications for not only the site itself, but other sites as well, so they have a higher standby time requirement. Second, the station service equipment operates intermittently, whereas the telecommunications equipment draws power continuously. Station service batteries operate protection, control and switching equipment in the station, and are typically 125V DC.

Because they operate at a different voltage and on direct rather than alternating current, batteries are equipped with a charging system or charger. The charger converts AC to DC for the battery and attached equipment. Chargers normally last longer than the batteries and, therefore, are not always replaced when the batteries are replaced.

2 PROJECT DESCRIPTION

The batteries being replaced under the Program for 2010 are both VRLA and flooded-cells, and are shown in Table 1. The chargers being replaced are shown in Table 2.

Table 1
2010 Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Berry Hill (BHL)	Flooded	48V	1990	C&D
Deer Lake (DLK)	Flooded	48V	1990	GNB
Hinds Lake (HLK)	Flooded	48V	1990	GNB
Peters Barren (PBN)	Flooded	48V	1990	C&D
Howley (HLY)	VRLA	48V	2000	Yuasa
Happy Valley (HVP)	VRLA	48V	2000	Yuasa

Table 2
2010 Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Berry Hill (BHL)	48V	50A	1990	Saft Nife
Peters Barren (PBN)	48V	50A	1990	Saft Nife
Massey Drive (MDR TS CHG 1)	125V	20A	1985	Cigentic
Massey Drive (MDR TS CHG 2)	125V	20A	1985	Cigentic
Paradise River (PDR)	125V	50A	1988	Staticon
Cat Arm (CAT CHG 1)	125V	60A	1985	CTS
Cat Arm (CAT CHG 2)	125V	60A	1985	CTS
Cat Arm (CAT CHG 3)	125V	60A	1985	CTS
Snook's Arm (SNK)	125V	3A	1990	Saft Nife

The batteries and chargers being replaced under the Program for the years 2010 – 2014, inclusive, are shown in Appendix A – Five Year Battery Replacement Schedule. This plan is subject to modification if conditions warrant the early replacement of a system, or if a system is showing deterioration different from originally expected.

3 EXISTING SYSTEM

The battery banks throughout Hydro's system are inspected regularly, depending on age and condition, to determine if there is a need for replacement.

Batteries are typically inspected annually and tested as required. More frequent monitoring and testing may be performed if deterioration is noticed.

Flooded-cell and VRLA batteries have an average life of 18 to 20 years and seven to ten years, respectively. Replacement is based on a combination of age and condition. As batteries age, they rapidly deteriorate and will no longer provide sufficient power in the event of an outage.

3.1 Age of Equipment or System

The original installation dates shown in Tables 1 & 2 convey the ages of the various battery banks and chargers being replaced.

3.2 Major Work and/or Upgrades

There has been no major work or upgrades on any of the batteries or chargers being replaced under this project.

3.3 Anticipated Useful life

Flooded-cell batteries have a typical service life of 18 to 20 years. VRLA batteries have a typical service life of seven to ten years.

For calculating depreciation expense all battery banks and chargers are assumed to have an economic life of 15 years.

3.4 Maintenance History

Battery maintenance varies with the age, location and type of battery. Generally speaking, if batteries are in a location where they are being observed regularly, such as a staffed generating station, they may not be tested as regularly as those in locations that are not visited frequently. Visual observation of batteries can offer information regarding their condition.

Regular maintenance included visual inspection, measurement of cell voltage, measurement of electrolyte specific gravity, and replacement of evaporated electrolyte with distilled water.

Conductance testing is a recent testing method and this type of testing is intended to supplement traditional capacity testing, which is the most accurate test of a battery's condition. In a capacity test, the battery is removed from service and connected to a load that is designed to discharge the battery over eight hours. This test of the so-called eight hour rate assesses the actual capacity of the battery. The battery cells are observed during the test for rapid loss of voltage to determine if they have deteriorated. The battery is deemed to have failed the test if it demonstrates less than 80 percent of rated capacity[1].

Because the capacity test takes a significant amount of time and requires a disruption of service, it is difficult to conduct regularly. A suitable proxy for discharge testing is conductance testing, during which the conductance or ability of the battery's individual cells to conduct current is measured. Hydro personnel periodically test batteries using a conductance tester. By comparing results over time, deterioration of the battery can be tracked. Ideally, batteries are tested shortly after installation and this baseline is used to track changes in the battery's condition. However, many batteries currently being replaced

[1] Institute of Electrical and Electronics Engineers (IEEE) Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead-Acid Batteries for Stationary Applications, Section 7.

have been in service longer than Hydro has been testing batteries, so baseline test results are not available. As well, some manufacturers publish reference values that are useful for comparing test results; however these results are not available for all batteries. As a result, some judgment must be used.

Chargers are not generally tested. They are replaced as they reach the end of their useful lives or when maintenance becomes an issue.

Each battery being replaced will be discussed individually, where test results are available.

3.4.1 Deer Lake (DLK) 48V Battery

The DLK 48V battery has experienced significant degradation. Tests in 2007 concluded that conductance has decreased by an average of 17 percent for all cells, indicating a need for immediate replacement.

3.4.2 Hinds Lake (HLK) 48V Battery

The HLK 48V battery has experienced significant degradation. Tests in 2008 concluded that conductance has decreased by an average of 19 percent for all cells, indicating a need for immediate replacement.

3.4.3 Howley (HLY) 48V Battery

The HLY 48V battery has experienced significant degradation. Tests in 2008 concluded that conductance has decreased by an average of 22 percent for all cells, indicating a need for immediate replacement.

3.4.4 Happy Valley (HVY) 48V Battery

The HVY 48V battery has experienced significant degradation. Tests in 2008 concluded that conductance has decreased by an average of 18 percent for all cells, indicating a need for immediate replacement

The batteries at Berry Hill and Peters Barren do not have available test results. Replacement is based on age and operating experience.

3.5 Outage Statistics

Battery chargers are typically installed in a redundant configuration, in order to minimize outages. Batteries that fail must be replaced immediately. There are no recorded outages for any of the equipment being replaced under this program.

3.6 Industry Experience

Battery life is highly variable and can depend on many factors. High temperature, slightly elevated charging voltage, and the number, duration and depth of discharges can all affect the service life of a battery. Industry users have experienced battery life for VRLA batteries of as little as 24 months[2] and as long as 25 years for flooded cell batteries that are rarely used and maintained under ideal conditions[3]. Hydro has had to replace batteries with as little as five years of use and has kept batteries in service for well over 20 years in some cases. Testing and monitoring of batteries is critical to ensuring that they are available when required.

[2] "Eliminate VRLA Battery Failures in Telecom Outside Plants and Maximize In-Service Life", B. Williams, *Battcon 2000 Proceedings*, 2000.

[3] "Myths and Misconceptions: Exploring the Myths of Battery Life, a User's Perspective", M.S. Clark, *Battcon 2006 Proceedings*, 2006.

3.7 Maintenance or Support Arrangements

Most batteries and chargers are maintained by Hydro personnel. Depending on the location, the battery may be inspected and/or tested bi-annually or annually. The exception is uninterruptible power source (UPS) backup batteries at Hydro Place and Holyrood. Because of the specialized application, these batteries are maintained by the manufacturer. Annual inspection and maintenance is performed on these batteries.

3.8 Vendor Recommendations

Most vendors refer to the standards published by the Institute of Electrical and Electronics Engineers (IEEE) for battery testing and replacement.

3.9 Availability of Replacement Parts

Many, although not all, battery manufacturers have relatively consistent product lines and replacement of individual cells is available for batteries. When a cell fails prematurely, it is normal to replace it and keep the remainder of the string. However, when the battery reaches the end of its useful life, replacement of individual cells is not recommended. At this point, more frequent inspection, as well as the overhead costs associated with ordering and installing individual cells and the likelihood that multiple cell replacements will be required at different points in time, will offset any cost saving associated with extending the life of the battery for what will likely be only a few years.

3.10 Safety Performance

Aging batteries can on occasion present a safety hazard since cells are more likely to rupture, especially if plate distortion is present. This phenomenon is often observed in aging batteries but rupture is not common. As well, aging cells occasionally develop cracks which may leak. Hydro personnel are equipped with personal protective equipment and spill remediation kits should electrolyte spillage occur.

3.11 Environmental Performance

Because of the presence of sulfuric acid and lead, precautions must be taken in the handling and disposal of batteries. Transportation of Dangerous Goods (TDG) regulations apply to the transport of batteries. Training is provided to Hydro personnel and contractors to ensure that the risk to the environment is minimized.

3.12 Operating Regime

Battery banks and chargers are stand-by equipment and are used to provide power to telecommunications, protection and control, and switching equipment during times of AC power loss, enabling Hydro to still operate terminal stations and microwave sites, either locally or by remote control from the Energy Control Centre. These systems are the last line of defense during power outages, and therefore high reliability and sufficient backup time must be provided. These systems must be available 24 hours per day, every day. Replacement after failure is unacceptable, since a power outage at the station will prolong customer outages.

4 JUSTIFICATION

Flooded-cell batteries have an average service life of 18-20 years. VRLA batteries have an average service life of seven to ten years. Replacement is based on a combination of age and condition. As batteries age, they rapidly deteriorate and will no longer provide sufficient power in the event of an outage. IEEE Standards 450 and 1188 recommend replacement of a battery at the earliest possible opportunity if the capacity has fallen to 80 percent or less of its rated capacity.

Based on age alone, the batteries being replaced have either reached or are nearing the end of their useful lives. Testing of the batteries demonstrates the need for timely replacement.

Hydro's Battery Replacement Program ensures that batteries are replaced before they fail. Batteries are key components of the infrastructure that is required to support the reliable operation of the power grid. Hydro's battery replacement program ensures that battery life is maximized while at the same time ensuring that reliable operation is maintained.

4.1 Net Present Value

A cost benefit analysis, rather than net present value analysis has been performed (see Section 4.3).

4.2 Levelized Cost of Energy

As the batteries and chargers are not related to generating units, the levelized cost of energy is not applicable.

4.3 Cost Benefit Analysis

A cost benefit analysis demonstrates that flooded-cell batteries are the most cost-effective option.

In performing this analysis, the following assumptions were made:

1. The labour cost for engineering, installation and maintenance of a flooded-cell or VRLA battery is the same;
2. A VRLA battery must be replaced after 10 years;
3. A flooded-cell battery must be replaced after 20 years; and
4. Chargers for VRLA and flooded-cell batteries are the same cost, and are replaced at the same time.

Twenty years of data was analyzed to capture the life of one flooded cell and two VRLA batteries.

Table 3
Battery Banks and Chargers Replacement

Alternative Comparison Cumulative Net Present Value to the Year 2029		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Flooded Cell Battery	44,907	0
VRLA Battery	62,374	17,467

4.4 Legislative or Regulatory Requirements

IEEE Standards 450 and 1188 recommend replacement of a battery at the earliest possible opportunity if the capacity has fallen to 80 percent of its rated capacity. Note that these are neither legislative nor regulatory requirements, but are industry accepted standards.

4.5 Historical Information

Historical information for the Stationary Battery and Charger Replacement Program is shown in Table 4.

Table 4
Five-Year Battery Chargers Capital Budget and Expenditures History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Battery Bank Units	Cost per Bank Unit ($000)	Charger Units	Cost per Charger Unit ($000)
2009F	728.6		11		11	
2008	430.4	473.4	8	43.7	4	30.9
2007	628.3	416.2	7	49.5	5	13.9
2006	564.9	585.1	14	34.9	11	8.8
2005	529.7	479.9	14	34.3	2	No Data

The difference in unit costs from year-to-year results from the various sizes of units that are required for each site.

4.6 Forecast Customer Growth

Batteries and chargers are not impacted by forecast customer growth.

4.7 Energy Efficiency Benefits

There are no projected energy efficiency benefits related to the replacement of batteries and chargers.

4.8 Losses during Construction

Installation of batteries and chargers will not require customer outages. When a battery is being replaced, a temporary battery is used to provide backup in case there is an AC power outage. When chargers are being replaced, the battery supplies the load. In either case, customers are not affected.

4.9 Status Quo

Prolonged power outages would result from terminal stations and microwave sites being without backup power when AC power is unavailable from battery banks.

4.10 Alternatives

Acceptable alternatives to stationary batteries do not exist. Stationary batteries are a critical component of, and are integral to, the design of station control and telecommunications equipment.

Because of their short life, when replacing VRLA batteries, flooded cell batteries are substituted whenever possible. Space limitations sometimes dictate that VRLA batteries must be used.

5 CONCLUSION

Stationary batteries are a critical component of the equipment required to control the power grid. In order to ensure that the grid can be controlled during times of disruption, Hydro will replace aging batteries and chargers on a continual basis to ensure that reliability of the overall system is maintained.

5.1 Budget Estimate

The estimate for 2010 is slightly lower than in 2009, owing to a decrease in the number of systems being replaced, but offset by an increase in material and contract costs. It is anticipated that lower amounts will be required in future years. The 2010 estimate is shown in Table 5.

Table 5
Budget Estimate

Project Cost:*($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	216.5	0.0	0.0	216.5
Labour	184.8	0.0	0.0	184.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	126.0	0.0	0.0	126.0
Other Direct Costs	48.3	0.0	0.0	48.3
O/H, AFUDC & Escln.	83.6	0.0	0.0	83.6
Contingency	57.6	0.0	0.0	57.6
TOTAL	**716.8**	**0.0**	**0.0**	**716.8**

5.2 Project Schedule

The anticipated project schedule summarized in Table 6.

Table 6
Project Schedule

Activity	Milestone
Project Initiation	January 2010
Design Complete	April 2010
Commissioning Complete	October 2010
Project Closed	November 2010

5.3 Future Plans

Work to be proposed in future years for replacement of batteries and chargers is described in Appendix A – Five Year Battery Replacement Schedule. This plan is subject to modification if conditions warrant the early replacement of a system, or if a system is showing deterioration different from originally expected.

APPENDIX A

Five Year Battery Replacement Schedule

2010

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Berry Hill (BHL)	Flooded	48V	1990	C&D
Deer Lake (DLK)	Flooded	48V	1990	GNB
Hinds Lake (HLK)	Flooded	48V	1990	GNB
Peters Barren (PBN)	Flooded	48V	1990	C&D
Howley (HLY)	VRLA	48V	2000	Yuasa
Happy Valley (HVY)	VRLA	48V	2000	Yuasa

Battery Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Berry Hill (BHL)	48V	50A	1990	Saft Nife
Peters Barren (PBN)	48V	50A	1990	Saft Nife
Massey Drive (MDR TS CHG 1)	125V	20A	1985	Cigentic
Massey Drive (MDR TS CHG 2)	125V	20A	1985	Cigentic
Paradise River (PRV)	125V	50A	1988	Staticon
Cat Arm (CAT CHG 1)	125V	60A	1985	CTS
Cat Arm (CAT CHG 2)	125V	60A	1985	CTS
Cat Arm (CAT CHG 3)	125V	60A	1985	CTS
Snook's Arm (SNK)	125V	3A	1990	Saft Nife

2011

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Long Harbour (LHR)	Flooded	125V	1991	Exide C
Lake Melville (LMR)	VRLA	48V	2001	C&D

Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Bottom Brook (BBK)	125V	12A	1991	Saft Nife
Buchans (BUC CHG 1)	125V	30A	1990	Saft Nife
Buchans (BUC CHG 2)	125V	30A	1990	Saft Nife
Doyles (DLS)	125V	12A	1991	Saft Nife
Indian River (IRV CHG 1)	125V	40A	1992	Staticon
Indian River (IRV CHG 2)	125V	40A	1992	Staticon

2012

Battery Replacements

Location	Type	Voltage	Install Date	Manufacturer
Bay d'Espoir Plant (BDE PH2)	Flooded	125V	1992	Exide

Charger Replacements

Location	Battery Voltage	Capacity	Install Date	Manufacturer
Bottom Waters (BWT)	125V	10A	1990	Saft Nife
Springdale (SPL TS CHG 1)	125V	30A	1992	Saft Nife
Springdale (SPL TS CHG 2)	125V	30A	1992	Saft Nife

2013

Battery Replacements

None are required on account of previous battery bank replacements.

Charger Replacements

None are required on account of previous charger system replacements.

2014

Battery Replacements

None are required on account of previous battery bank replacements.

Charger Replacements

None are required on account of previous charger system replacements.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CORPORATE APPLICATION ENVIRONMENT

Upgrade Microsoft Products

June 2009

newfoundland labrador hydro

a nalcor energy company

Table of Contents

1 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) currently deploys a standard desktop that includes a number of Microsoft products. The applications included are:

- Microsoft Office XP Professional:
  - Microsoft Word
  - Microsoft Excel
  - Microsoft PowerPoint
  - Microsoft Access
- Microsoft Operating system (Windows XP)
- Microsoft Visio (limited distribution)
- Microsoft Tools and applications to ensure efficient operation of the personal computers (PC) in Hydro.

Microsoft software must be regularly upgraded to address functional or vendor obsolescence and to maintain the benefits of vendor advancements in system functionality. Software must be upgraded to obtain continued vendor support, to improve software compatibility, to improve security, to improve ease of use and provide a stable application environment for Hydro's key business functions. Out-dated and non-maintained software would lead to breakdowns in business functions that would ultimately yield higher costs.

2 PROJECT DESCRIPTION

This project consists of the purchase of Microsoft software under a Microsoft Enterprise Agreement. Information technology software must be current and effective and provided in a stable environment to allow efficient functioning of Hydro's core business.

The Microsoft Enterprise Agreement covers the purchase of Microsoft software and provides access to the latest versions of each software product purchased under this agreement.

Through the Microsoft Enterprise Agreement, Hydro achieves an overall cost savings. This is a fixed, annual price agreement based on the number of desktops. Under this agreement, Hydro distributes its purchasing costs for these licenses over three years. The budget estimate for this project is shown in Table 2.

3 EXISTING SYSTEM

The current versions of software deployed from Microsoft were purchased in 2003. Table 1 shows the current release of software and the version that the software will be upgraded to. The current software is in what Microsoft calls extended support which allows for security fixes but no functionality improvements.

Table 1
Existing Software

Product	Installed Version	Future Version
Microsoft Desktop Operating System	Windows XP Pro	Windows 7
Microsoft Access	Access 2002	Office Pro 2007
Microsoft Word	MS Word 2002	Office Pro 2007
Microsoft Excel	MS Excel 2002	Office Pro 2007
Microsoft Power Point	MS Power PT 2002	Office Pro 2007
Visio Pro	Visio 2000	Visio 2003
Visio Pro	Visio 2002	Visio 2003
SQL Enterprise Edition Per proc	MS SQL 2000	SQL Ent. 2008
SQL Standard Edition Per Proc	MS SQL 2000	SQL Std. 2008
System Management Server (SMS)	SMS 2003	SCCM 2007
SMS Server CAL's	SMS 2003	SCCM 2007 CAL's
SharePoint Ent CAL		Sharepoint Ent. CAL's
Sharepoint Server		Sharepoint Server 2007

Age of Equipment or System

The current Microsoft application base has been in use at Hydro since 2003. It was released from Microsoft in 2001. Two newer versions of this software have been released since Hydro installed it in 2003.

3.2 Major Work or Upgrades

There have been no major upgrades since the implementation of the Microsoft applications.

3.3 Anticipated Useful life

The anticipated useful life of an application is approximately seven years or until support of the software is no longer available. However, if incompatibilities with other software arise, an upgrade to newer versions of the products may be required.

3.4 Maintenance History

There is no maintenance history associated with the Microsoft Applications with the exception of monthly security upgrades to prevent vulnerabilities.

3.5 Outage Statistics

There are no outage statistics related to this project.

3.6 Industry Experience

There is no known industry experience available with regards to application versioning, although as a result of being behind the mainstream in versioning, collaboration can be affected.

3.7 Maintenance or Support Arrangements

The current software is in what Microsoft calls extended support which allows for security fixes but no functionality improvements. The proposed Enterprise Agreement itself will be the support and maintenance agreement for those products included in the agreement.

3.8 Vendor Recommendations

There are no relevant vendor recommendations with respect to this project.

3.9 Availability of Replacement Parts

Availability of replacement parts is not a consideration for this project.

3.10 Safety Performance

There is no specific safety issues related to this project.

3.11 Environmental Performance

Environmental non-compliance is not an issue for this project.

3.12 Operating Regime

The Hydro application environment is a continuous duty asset.

4 JUSTIFICATION

The Microsoft Enterprise Agreement is the least cost option to ensuring access to current Microsoft software products.

Microsoft software must be regularly upgraded to address functional or vendor obsolescence and to maintain the benefits of vendor advancements in system functionality. Software must be upgraded to provide continued vendor support, to improve software compatibility, to improve security, to improve ease of use and provide a stable application environment for Hydro's key business functions. Out-dated and non-maintained software would lead to breakdowns in business functions that would ultimately yield higher costs.

4.1 Net Present Value

While net present value is not applicable to this project, see the Alternatives section below for a discussion of the costs of alternatives.

4.2 Levelized Cost of Energy

Levelized cost of energy is not applicable to this project.

4.3 Cost Benefit Analysis

A cost benefit analysis is not applicable to this project, as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

4.5 Historical Information

This is not a recurring project, historical information is not available.

4.6 Forecast Customer Growth

Customer load growth does not affect this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to this project.

4.8 Losses during Construction

There will be no energy system outages as a result of this project.

4.9 Status Quo

The current Microsoft application base is approximately six years old. The applications in use are operating with the functionality and programming technology of that period. Out-dated and non-maintained software would lead to breakdowns in business functions that could ultimately yield higher costs.

4.10 Alternatives

Hydro investigated three alternatives for the purchase of the Microsoft standard suite of office tools which is used across the company for word processing, presentations and basic data manipulation (Office Word, Excel, Access, Powerpoint) along with the underlying back office systems (SQL Server, Systems Management Server).

The three alternatives identified were:

- Do nothing now and pay for new licenses to upgrade in the future. The select agreement cost per personal computer is $566.63 or $1,699.89 over three years. Three year costs for material supply would be $2,209,850.80.

- Purchase a Microsoft Select Agreement with Software Assurance for each installation of the software. This provides Hydro with ownership of the latest releases of the identified software. These licenses have to be purchased individually as needed. The annual cost per personal computer is $521.35 or $1,564.05 over three years. Three year costs for material supply would be $2,033,265.80.

- Purchase a Microsoft Enterprise Agreement. This provides Hydro with ownership of the latest releases of the identified software. These licenses are paid for annually per personal computer. Costs are spread out over the three-year period. The annual cost per personal computer is $417.12 or $1,251.35 over three years. Three year costs for material supply would be $1,626,748.56.

All other costs per personal computer would remain the same at $477,000 or $367.46 per personal computer and the number of computers being upgraded under each alternative is the same.

5 CONCLUSION

The Microsoft suite of products must be kept up to date with current software releases and to take advantage of new system functions. Software must be upgraded to improve software compatibility and to improve ease of applications for all users across the company.

5.1 Budget Estimate

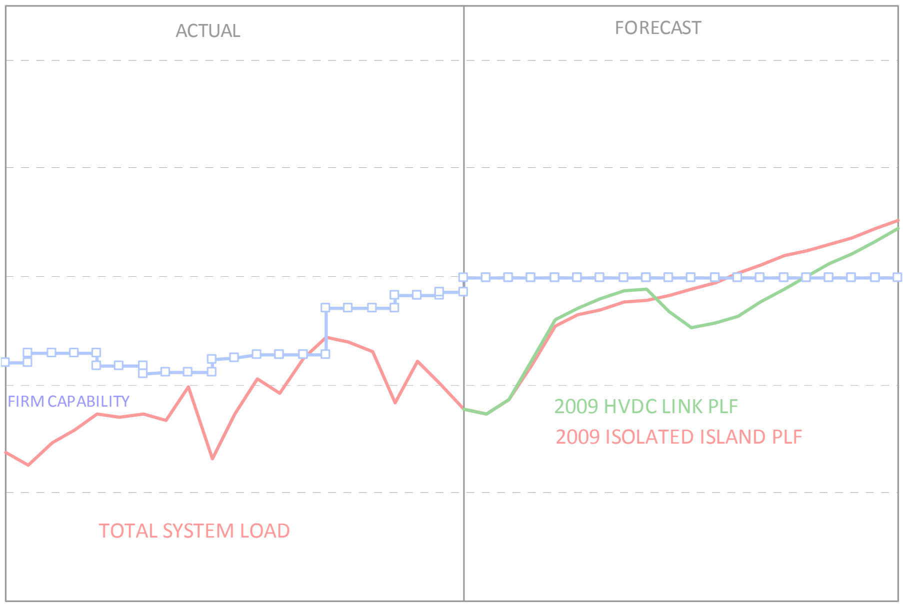
The budget for this project is to be split into three equal payments over the three years of the Enterprise Agreement. The budget estimate is shown in Table 2.

Table 2
Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**2012**	**BEYOND**	**TOTAL**
Material Supply	542.3	542.3	542.3	0.0	1,626.9
Labour	120.0	40.2	30.2	0.0	190.4
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	22.9	34.3	48.3	0.0	105.5
Contingency	66.2	58.3	57.3	0.0	181.8
Sub Total	**751.4**	**675.1**	**678.1**	**0.0**	**2,104.6**
Cost Recovery	(225.4)	(202.5)	(203.4)	(0.0)	(634.4)
TOTAL	**526.0**	**472.6**	**474.7**	**0.0**	**1,473.2**

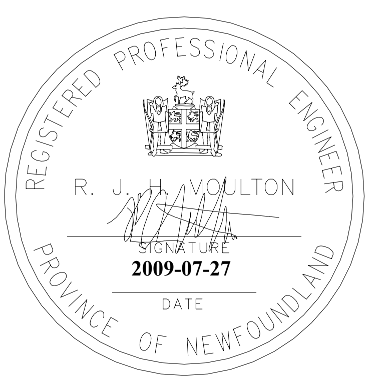
5.2 Project Schedule

This project is expected to start in January 2010 with the purchase of the Enterprise Agreement. Under this agreement, Hydro distributes its purchasing costs for these licenses over three years 2010, 2011, 2012.



GENERATION PLANNING ISSUES
2009 MID YEAR

System Planning Department
July 2009



newfoundland labrador
hydro
a nalcor energy company

Executive Summary

This report provides an overview of the Island Interconnected System (the System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly and thus cost-effective process.

The Province's Energy Plan outlines specific measures to address environmental concerns related to the Holyrood Thermal Generating Station (HTGS). The long-term plan is to replace the energy provided by the plant with electricity from the lower Churchill development through a High Voltage Direct Current (HVdc) transmission link from Labrador to the island. In the event the Lower Churchill Project does not proceed, scrubbers and precipitators will be installed at the plant. This requires Newfoundland and Labrador Hydro (Hydro) to maintain two planning load forecasts and two preliminary generation expansion plans; one for the HVdc link and one for the Isolated Island scenario. Based on an examination of the System's existing plus committed capability, in light of the 2009 Planning Load Forecasts (PLF) and the generation planning criteria, under both scenarios, capacity (Loss of Load Hours (LOLH)) deficits start in 2015. There are no energy deficits in either case until post-2018. If a third wind project is brought in-service in 2013, generation additions for the Isolated Island scenario could be postponed until 2016.

In order to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, under an Isolated Island scenario, the addition of an RFP process necessitates a decision to proceed in late 2011 to meet an in-service date of fall 2016. This is due to the need to complete the RFP evaluation and subsequent Board of Commissioners of Public Utilities (Board) review and have a final decision by mid-2013

It should be noted that while Hydro is closely monitoring potential emissions reductions regulations, the analysis presented does not model potential costs or credits under an environmental mitigation strategy such as a cap-and-trade system.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;
- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.

Table of Contents

1.0 Introduction

This report provides an overview of the Island Interconnected System (the System) generation capability, the timing of the next requirement for additional generation supply, the resources available to meet that requirement, and identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

This report used to be completed at year end, but it was decided to change to a mid year report, to coincide with the submission to the Board of the Capital Budget Application and the Twenty-Year Capital Plan.

In September 2007, the Provincial Government released its Energy Plan. The Energy Plan directed Hydro to evaluate two options to deal with environmental concerns at the Holyrood Thermal Generating Station (HTGS). Option A was to replace HTGS produced electricity with electricity from the Lower Churchill River development via a High Voltage Direct Current (HVdc) transmission link to the Island. Option B was to install scrubbers and electrostatic precipitators to control emissions at the HTGS and maximize the use of wind, small hydro and energy efficiency programs to reduce the reliance on HTGS produced electricity. These two options require significantly different strategies to effectively implement and require the development of two separate, preliminary, generation expansion plans to manage the near-term until a decision can be made on which option will be pursued for future development.

This report addresses the timing of the next requirement, in light of the most recent load forecast, for additional generation supply under both options and the resources available to meet that requirement. The report also identifies any issues that need to be addressed to ensure that a decision on the preferred source can be made through an orderly process.

2.0 Load Forecast

This review utilizes the 2009 long-term Planning Load Forecast (PLF) as prepared in the spring of 2009. Long-term load forecasts for the Province are derived using Hydro's own electricity demand models and are driven by corresponding Provincial economic forecasts that are regularly prepared for Hydro by the Department of Finance, Government of Newfoundland and Labrador. For this analysis, Hydro has included the lower Churchill River generation and transmission investments as an alternative to the isolated Island future while recognizing that these developments have yet to be technically committed through project sanction. Some key assumptions respecting incremental economic activity for both generation supply futures are:

- Single Island newsprint operation at Corner Brook producing 330,000 metric tonnes of newsprint per year;
- Single Island oil refining operation at Come by Chance producing at 115,000 barrels per day;
- Commercial production at the Vale Inco NL nickel processing facility on the Island in 2013[1];
- Teck Resources Limited mining operations at Duck Pond continuing through 2013[2].

In terms of high-level economic indicators, growth rate summaries for the HVdc link and Isolated Island scenarios are presented in Table 2-1. As indicated in the table, there are modest longer-term economic differences associated with the two generation supply alternatives.

[1] Amended 2002 Development Agreement, Vale Inco and the Government of Newfoundland and Labrador
[2] Teck Cominco 2007 Annual Report.

Table 2-1

Provincial Economic Indicators – 2009 PLF				
		2008-2013	**2008-2018**	**2008-2028**
Adjusted Real GDP at Market Prices* (% Per Year)	HVdc Link	2.1%	1.0%	0.8%
	Isolated Island	1.3%	0.9%	0.8%
Real Disposable Income (% Per Year)	HVdc Link	2.7%	1.5%	1.2%
	Isolated Island	2.1%	1.4%	1.2%
Average Housing Starts (Number Per Year)	HVdc Link	2,710	2,525	2,170
	Isolated Island	2,700	2,510	2,160
End of Period Population ('000s)	HVdc Link	518	516	509
	Isolated Island	515	511	507
*Adjusted GDP excludes income that will be earned by the non-resident owners of Provincial resource developments to better reflect growth in economic activity that generates income for local residents.				

Hydro carries out generation planning for the total system and that includes the power and energy supplied by Hydro's customer-owned-generation resources in addition to Hydro's bulk and retail electricity supply, including power purchases. The projected electricity growth rates for the System under both the HVdc Link and Isolated Island cases are presented in Table 2-2. An important source of load growth for the utility sector on the Island continues to be the unwavering preference for electric water heating systems space and ever-increasing preference for electric space heating across residential and commercial customers. For Hydro's industrial customers, single newsprint mill and oil refinery operations are maintained, the Teck Resources mine is expected to operate through 2013 and the Vale Inco NL nickel processing facility is now scheduled to be in commercial production in 2013.

Table 2-2

Electricity Load Growth Summary – 2009 PLF				
		2008-2013	**2008-2018**	**2008-2028**
Utility[1]	HVdc link	1.9%	1.1%	1.1%
	Isolated Island	1.8%	1.3%	1.1%
Industrial[2]	HVdc link	0.0%	0.1%	0.1%
	Isolated Island	0.0%	0.1%	0.1%
Total	HVdc link	1.4%	0.8%	0.8%
	Isolated Island	1.3%	1.0%	0.9%

1. Utility load is the summation of Newfoundland Power and Hydro Rural.
2. Industrial load is the summation of Corner Brook Pulp and Paper, AbitibiBowater[3], North Atlantic Refining, Teck Resources and Vale Inco NL.

Table 2-3 provides a summary of the 2009 PLF projections for electric power and energy for the System for the period 2009 to 2018. Similar long-term projections are also prepared for the Labrador Interconnected System and for Hydro's Isolated Diesel Systems to derive a Provincial electricity load forecast. Appendix A contains the longer term PLF that was used to complete the generation expansion analysis.

[3] AbitibiBowater ceased production at its Grand Falls newsprint mill in February 2009.

Table 2-3

Electricity Load Summary – 2009 PLF						
HVdc Link	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand[3] (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2009	1,326	5,985	286	1,603	1,592	7,781
2010	1,351	6,100	196	1,435	1,534	7,727
2011	1,376	6,210	236	1,456	1,568	7,858
2012	1,400	6,348	274	1,679	1,604	8,223
2013	1,417	6,417	282	1,984	1,673	8,601
2014	1,437	6,501	275	2,009	1,686	8,710
2015	1,450	6,588	275	2,009	1,699	8,798
2016	1,469	6,660	275	2,009	1,718	8,871
2017	1,485	6,669	275	2,009	1,733	8,881
2018	1,488	6,473	275	2,009	1,737	8,682
Isolated Island	Utility[1]		Industrial[1]		Total System[2]	
	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)	Maximum Demand (MW)	Firm Energy (GWh)
2009	1,326	5,985	286	1,603	1,592	7,781
2010	1,351	6,100	196	1,435	1,534	7,727
2011	1,376	6,210	236	1,456	1,568	7,858
2012	1,399	6,300	274	1,679	1,603	8,174
2013	1,416	6,366	282	1,984	1,672	8,550
2014	1,431	6,431	275	2,009	1,680	8,640
2015	1,443	6,481	275	2,009	1,691	8,691
2016	1,453	6,562	275	2,009	1,702	8,772
2017	1,471	6,574	275	2,009	1,719	8,784
2018	1,477	6,613	275	2,009	1,726	8,824

Note: 1. Utility and Industrial demands are non-coincident peak demands.
2. Total System is the total Island Interconnected System and includes losses. Demands are coincident peak demands.
3. Maximum demand in 2009 includes AbitibiBowater paper mill.

3.0 System Capability

Hydro is the primary supplier of system capability to the Island Interconnected System, accounting for 78 percent of its net capacity and 77 percent of its firm energy. Capability is also supplied by customer generation from Newfoundland Power Inc., and Corner Brook Pulp and Paper Limited (Kruger Inc.) Hydro also has contracts with two Non-Utility Generators (NUGs) for the supply of power and energy as well as contracts with two wind power projects that became operational in late 2008 and early 2009. Hydro also receives energy from the expropriated assets at Star Lake and on the Exploits River.

Hydroelectric generation accounts for 64 percent of the System's existing net capacity and firm energy capability. The remaining net capacity comes from wind farms and thermal resources. The thermal resources are made up of conventional steam, combustion turbine and diesel generation plants. Of the existing thermal capacity, approximately 71 percent is located at the HTGS and is fired using No. 6 fuel oil. The remaining capacity is located at sites throughout the Island. A complete breakdown of the System's existing capability is provided in Table 3-1.

Table 3-1

Island Interconnected System Capability – As of June 2009			
	Net Capacity [MW]	Energy [GWh]	
		Firm	Average
Newfoundland & Labrador Hydro			
Bay d'Espoir	592.0	2,272	2,648
Upper Salmon	84.0	492	567
Hinds Lake	75.0	290[4]	339[5]
Cat Arm	127.0	678	682
Granite Canal	40.0	191[4]	220[5]
Paradise River	8.0	33	36
Snook's, Venam's & Roddickton Mini Hydros	1.3	5	7
Total Hydraulic	927.3	3,961	4,499
Holyrood	465.5	2,996	2,996
Combustion Turbine	118.0	-	-
Hawke's Bay & St. Anthony Diesel	14.7	-	-
Total Thermal	598.2	2,996	2,996
Total NL Hydro	**1,525.5**	**6,957**	**7,478**
Newfoundland Power Inc.			
Hydraulic	96.6	324	428
Combustion Turbine	36.5	-	-
Diesel	7.0	-	-
Total	140.1	324	428
Corner Brook Pulp and Paper Ltd.			
Hydraulic	121.4	793	864
Star Lake and Exploits Generation			
Hydraulic	105.8	634	749
Non-Utility Generators			
Corner Brook Cogen	15.0	100	100
Rattle Brook	4.0	13	16
St. Lawrence Wind	27.0	92	104
Fermeuse Wind	27.0	75	84
Total	66.3	317	220
Total Island Interconnected System	**1,965.8**	**8,988**	**9,756**

[4] Firm Energy numbers for Hinds Lake and Granite Canal were reversed in the previous report.

4.0 Planning Criteria

Hydro has established criteria related to the appropriate reliability, at the generation level, for the System that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more that 2.8 hours per year[6].

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[7].

5.0 Identification of Need

Table 5-1 presents an examination of the HVdc link and Isolated Island load forecasts compared to the planning criteria. It does not incorporate Hydro's preliminary expansion plan to show uncommitted generation additions. In 2006, firm system capability was updated to reflect a 115 GWh increase in Hydro's hydroelectric-plant capability. This change was the result

[5] Average Energy numbers for Hinds Lake and Granite Canal were reversed in the previous report.
[6] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.
[7] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (HTGS) is based on energy capability adjusted for maintenance and forced outages.

of a hydrology adjustment and the use of an integrated system model which determines a more realistic firm system capability. Previously, firm system capability was calculated using the summation of individual firm values provided by the design consultants of each facility.

Table 5-1 illustrates when supply capacity and firm capability will be outpaced by forecasted electricity demand under the two different expansion scenarios being considered. The table shows that under both the HVdc link and Isolated Island scenarios, capacity (LOLH) deficits start in 2015 but that there are no energy deficits in either case until post-2018. Since the closure of the pulp and paper mills in Stephenville and Grand Falls, capacity deficits now precede energy deficits indicating that the system is now capacity, rather than energy, constrained.

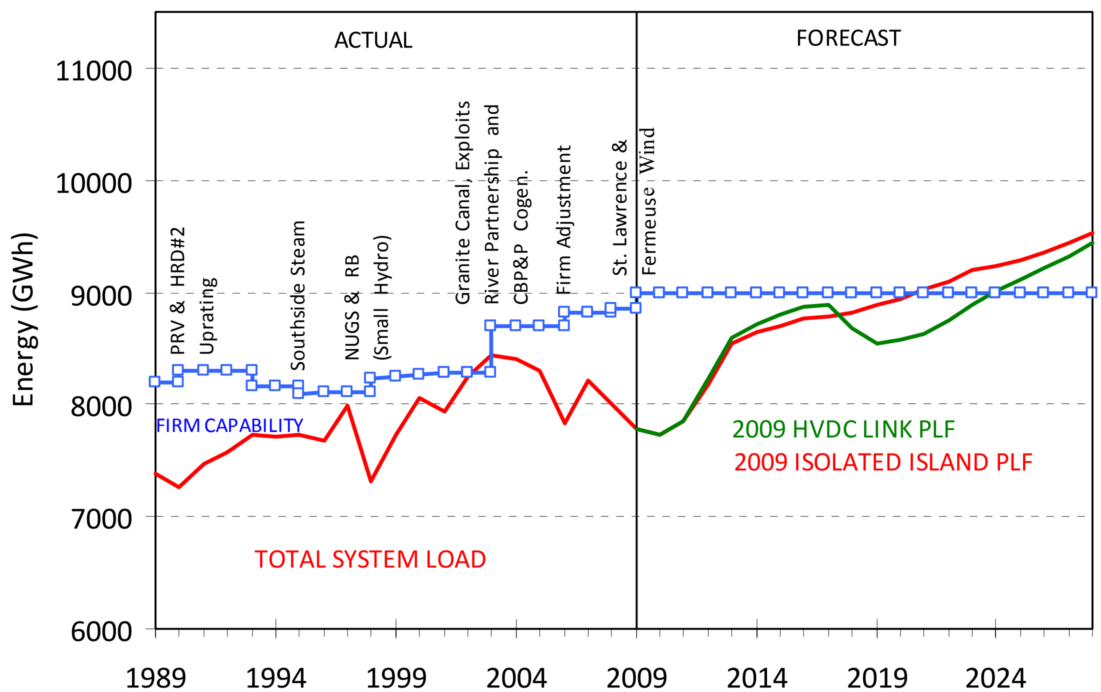
It should be noted that the capacity deficits trigger the need for the next generation source by 2015 under the current planning criteria. Under the expansion scenario ultimately pursued, this need may be met by different sources as explained in the Preliminary Generation Expansion Analysis section (Section 7).

Table 5-1 – Load Forecasts Compared to Planning Criteria

Year	Load Forecasts: Maximum Demand [MW]		Load Forecasts: Firm Energy [GWh]		Existing System		LOLH [hr/yr]		Energy Balance [GWh]	
	HVdc Link	Isolated Island	HVdc Link	Isolated Island	Installed Net Capacity [MW]	Firm Capability [GWh]	HVdc Link	Isolated Island	HVdc Link	Isolated Island
2009	1,592	1,592	7,781	7,781	1,966	8,849	0.40	0.40	1,068	1,068
2010	1,534	1,534	7,727	7,727	1,966	8,988	0.12	0.12	1261	1261
2011	1,568	1,568	7,858	7,858	1,966	8,988	0.25	0.25	1130	1130
2012	1,604	1,603	8,223	8,174	1,966	8,988	0.57	0.54	765	814
2013	1,673	1,672	8,601	8,550	1,966	8,988	2.02	1.91	387	438
2014	1,686	1,680	8,710	8,640	1,966	8,988	2.62	2.40	278	348
2015	1,699	1,691	8,798	8,691	1,966	8,988	3.32	3.09	190	297
2016	1,718	1,702	8,871	8,772	1,966	8,988	4.34	3.71	117	216
2017	1,733	1,719	8,881	8,784	1,966	8,988	5.24	4.65	107	204
2018	1,737	1,726	8,682	8,824	1,966	8,988	4.63	5.18	306	164

Figure 5-1 presents a graphical representation of historical and forecasted load and system capability for the HVdc link and Isolated Island scenarios. It is a visual representation of the energy balance shown in Table 5-1.

Figure 5-1
Island Interconnected System Capability vs. Load Forecast



6.0 Near-Term Resource Options

This section presents a summary of identified near-term generation expansion options. It represents Hydro's current portfolio of alternatives that may be considered to fulfill future generation expansion requirements. Included is a brief project description as well as discussion surrounding project schedules; the basis for capital cost estimates; issues of bringing an alternative into service; and other issues related to generation expansion analysis.

6.1 Island Pond

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 172 GWh and 186 GWh, respectively.

The development would include the construction of a three kilometre diversion canal between Meelpaeg Reservoir and Island Pond, which would raise the water level in Island Pond to that of the Meelpaeg Reservoir. Also, approximately 3.4 kilometres of channel improvements would be constructed in the area. At the south end of Island Pond, a 750 metre long forebay would pass water to the 23 metre high earth dam, and then onto the intake and powerhouse finally discharging it into Crooked Lake via a 550 metre long tailrace. The electricity would be produced by one 36 MW Kaplan turbine and generator assembly.

The facility would be connected to TL263, a nearby 230 kV transmission line connecting the Granite Canal Generating Station with the Upper Salmon Generating Station.

Schedule and Cost Estimate Basis

To ensure that Hydro is in a position to properly evaluate Island Pond, an outside consultant was commissioned to prepare a final-feasibility level study and estimate. The final report, *Studies for Island Pond Hydroelectric Project*, was presented to Hydro in December 2006. The report prepared a construction ready update report including an updated capital cost estimate and construction schedule. In the absence of any further work beyond what was identified, the overall schedule is estimated to be approximately 42 months from the project release date to the in-service date.

6.2 Portland Creek

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 99 GWh and 142 GWh, respectively.

The project requires: a 320 metre long diversion canal; three concrete dams; a 2,900 metre penstock; a 27 kilometre 66 kV transmission line from the project site to Peter's Barren Terminal Station; and the construction of access roads. The electricity would be produced by two 11.5 MW Pelton turbine and generator assemblies.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Portland Creek is based on a January 2007 feasibility study, *Feasibility Study for: Portland Creek Hydroelectric Project*, prepared for Hydro by outside consultants. The proposed construction schedule indicates a construction period of 32 months from the project release date to the in-service date. The main activities that dictate the schedule are the construction of access roads and the procurement of the turbine and generator units.

6.3 Round Pond

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 108 GWh and 139 GWh, respectively.

Schedule and Cost Estimate Basis

The current schedule and capital cost estimate for Round Pond is based on the 1988 feasibility study, *Round Pond Hydroelectric Development*, prepared for Hydro by outside consultants, and the associated 1989 Summary Report based on the same. In the absence of any further work beyond what was identified in this study, the overall program for the Round Pond development is estimated to be completed in 33 months, including detailed engineering design. The period for site works includes two winter seasons during which construction activities can be expected to be curtailed. Work on transmission line, telecontrol and terminal equipment would be incorporated in this schedule.

6.4 Wind Generation Projects

The Island of Newfoundland has a world-class wind resource with many sites exhibiting excellent potential for wind-power development. Despite this, there are a number of operational constraints that limit the amount of additional non-dispatchable generation that can be accepted into the System. In January 2007, Hydro signed its first power purchase agreement (PPA) for 27 MW of wind power located at St. Lawrence and in December 2007 it signed a second PPA for another 27 MW of wind power located at Fermeuse. These projects have both begun to generate power into the Island grid. Pending further review and eventual operating experience and with the loss of the load associated with the shutdown of the Grand Falls Pulp and Paper Mill in late 2008, it was decided to postpone a RFP for a third wind farm, as the potential for spill, due to the additional non-dispatchable generation, makes the project economically unattractive (see Section 9.1 Intermittent and Non-Dispatchable Resources).

Any future wind farm would potentially consist of a number of interconnected wind turbines, each ranging in size from 1.8 to 3.0 MW (or larger, as the technology becomes available), tied to a single delivery point on the System's transmission network. For example, a 25 MW wind farm could consist of eight turbines and, depending on the location's wind resource, produce an estimated annual firm and average energy capability of approximately 70 and 110 GWh, respectfully.

Hydro would not develop wind-based projects strictly to address capacity deficits due to the inability to selectively dispatch turbines during periods of high demand. However, these projects do carry some inherent capacity value based on their positive influence on the LOLH calculation and could possibly defer the need for other new generation sources.

Schedule and Cost Estimate Basis

Wind projects typically require at least six to eight months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 18 months. The overall project schedule is approximately 30 months from the project release date to the in-service date. Additional time may be required, depending on market conditions, to secure turbine delivery.

6.5 Combined Cycle Plant

The combined cycle facility, also known as a combined-cycle combustion turbine (CCCT) facility, consists of a combustion turbine fired on light oil, a heat recovery steam generator, and a steam turbine generator.

Two alternative sites are being considered and estimates have been prepared based on two different power ratings at each site. One alternative calls for a proposed combined-cycle plant to be located at the existing HTGS to take advantage of the operational and capital cost savings associated with sharing existing facilities. The other alternative is to develop a greenfield site at a location that has yet to be determined. The greenfield alternative may be preferred due to environmental constraints that may be placed on any new developments at Holyrood and reduce the risk of loss of multiple generation sources in the event of major events.

In either alternative, the power ratings being considered are either a 125 MW or a 170 MW (net) CCCT facility. The annual firm energy capability is estimated at 986 GWh for the 125 MW option and 1,340 GWh for the 170 MW option.

Schedule and Cost Estimate Basis

It is expected that a combined-cycle plant would require an Environmental Preview Report (EPR) with the guidelines for its preparation similar to the 1997 review of the proposed Holyrood Combined Cycle Plant. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for each power rating of the Holyrood Combined Cycle Plant is based on the *Combined Cycle Plant Study Update, Supplementary Report* which was completed in 2001, with a review by Hydro’s Mechanical Engineering Department in 2009.

6.6 Holyrood Thermal Generating Station Unit IV

HTGS Unit IV is a 142.5 MW (net) conventional steam unit fired on heavy oil and is based on similar technology as the three existing HTGS units. The unit would be located at the HTGS adjacent to the existing units. The annual firm energy capability is estimated at 936 GWh.

Schedule and Cost Estimate Basis

It is expected that the HTGS Unit IV project would require, at a minimum, an EPR with the guidelines for its preparation similar to that of a 1997 review of the proposed project. The overall project schedule is estimated to be approximately 51 months from the project release date to the in-service date.

Sensitivity analysis has demonstrated that the capital cost of the proposed HTGS Unit IV project would have to drop considerably compared with the combined-cycle option given that environmental mitigation requirements, which would be required for this facility, will increase the cost of such a facility. It is highly unlikely that this option would be competitive with a combined-cycle option. Therefore, Hydro will continue to include the proposed HTGS Unit IV project in its portfolio of alternatives but the cost estimate should be updated, in detail, when the appropriate sensitivity analysis identifies the project as a potential near-term addition.

6.7 Combustion Turbine Units

These nominal 50 MW (net), simple-cycle combustion turbines (CT) would be located either adjacent to similar existing units at Hydro's Hardwoods and Stephenville Terminal Stations or at greenfield locations. They are fired on light oil and due to their modest efficiency relative to a CCCT plant, they are primarily deployed for peaking and voltage support functions but, if required, can be utilized provide an annual firm energy capability of 394 GWh each.

Schedule and Cost Estimate Basis

It is anticipated an EPR would be required for each proposed CT project. The overall project schedule is estimated to be at least 36 months from the project release date to the in-service date.

The capital cost estimate for these units was reviewed and updated in 2009, by Hydro's Mechanical Engineering Department. Approximately 90 percent of the direct cost is for the gas turbine package and due to recent fluctuations in demand for gas turbines; prices remain volatile. Hydro should continue to monitor turbine prices to determine when a further in-depth review of the capital cost estimates becomes necessary.

6.8 High Voltage Direct Current (HVdc) Link

As part of the potential development of the lower Churchill River (Lower Churchill Project), a HVdc link would be constructed to the Island to replace power and energy required from the HTGS and to help meet the future energy requirements of the Island. The schedule and capital cost estimate for this project is currently under development.

7.0 Preliminary Generation Expansion Analysis

To provide an indication of the timing and scale of future resource additions required over the load forecast horizon, Hydro uses *Ventyx Strategist®* software to analyse and plan the generation requirements of the System for a given load forecast. *Strategist®* is an integrated, strategic planning computer model that performs, amongst other functions, generation system reliability analysis, projection of costs simulation and generation expansion planning analysis.

The expansion scenarios presented are considered preliminary and they have not been submitted for approval by the Board. In the Province's Energy Plan, Hydro has been directed to pursue one of two options for dealing with environmental concerns related to the HTGS. The first option is based on replacing the HTGS with energy from the Lower Churchill River development via a HVdc link to the Island. The second option is based on an isolated System and is similar to present day operations but the HTGS environmental concerns of sulphur dioxide (SO_2) and particulate emissions will be addressed via the addition of scrubbers and electrostatic precipitators. The scrubbers and electrostatic precipitators will not address greenhouse gas issues. These two options have been named for the purposes of this report as the HVdc link scenario and the Isolated Island scenario.

These expansion plan scenarios represent Hydro's preferred path, utilizing resources from the identified portfolio.

The generation expansion analysis uses an 8.00 percent discount rate with all costs modeled in current (as spent) Canadian dollars, and the results discounted to the base year of 2009. Other key economic parameters necessary to quantify the long-term costs of alternate generation expansion plans are summarized in Appendix B.

Based on the study assumptions outlined previously, the least-cost[8] generation expansion plan, under the two scenarios, is shown below in Table 7-1 and graphically in Figures 7-1 and 7-2.

7.1 High-Voltage Direct Current Link Scenario

Under the HVdc link scenario, no additional generation sources are required until the HVdc link is put in-service. The HVdc link would be put in-service in 2015 and this would provide Hydro's system capability requirements well beyond the horizon of this expansion analysis.

[8] For Hydro, the term "least-cost" refers to the lowest Cumulative Present Worth (CPW) of all capital and operating costs associated with a particular incremental supply source (or portfolio of resources) over its useful economic life, versus competing alternatives or portfolios. CPW concerns itself only with the expenditure side of the financial equation. The lower the CPW, the lower the revenue requirement for the utility and hence, the lower the electricity rates will be. By contrast, the term Net Present Value (NPV) typically refers to a present value taking into account both the expenditure and revenue side of the financial equation, where capital and operating expenditures are negative and revenue is positive. The alternative with the higher NPV has the greater return for the investor.

However, the existing 50 MW CTs at Hardwoods and Stephenville would be retired in 2022, and a new 50 MW CT would be constructed in that year, to replace them.

7.2 Isolated Island Scenario

Under the Isolated Island scenario, the third wind project is planned for 2013, at the same time the additional load from the Vale Inco NL facility is forecast to come on to the grid, enabling the grid to absorb more non-dispatchable generation. Wind is considered due to the benefits of fuel displacement and emissions reductions at the HTGS. The final decision on whether or not to proceed with a wind project will require some deeper analysis to determine the optimal timing, and size of a potential project.

The next supply options in the least-cost generation expansion scenario are the indigenous hydroelectric plants of Island Pond in 2016, Portland Creek in 2019, and Round Pond in 2021 followed by a 170 MW CCCT plant in 2023 and a 50 MW CT in 2026. The CCCT plant is indicative of the most economic thermal plant for supplying base load, which the Island would require in the long-term for firm capability as an isolated system.

For the Isolated Island scenario, further additions of thermal-electric plants can be expected post 2027. Many of Hydro's assets are nearing their expected end-of-life and it is important to point out that under both expansion plans, the 54 MW combustion turbines located at Hardwoods and Stephenville are scheduled to retire during the study period.

While the expansion plans are indicative of the scale of future requirements, any final decision on resource additions will be made at an appropriate time in the future following a full review. These, and other issues, are discussed further in the following section.

Table 7-1

2009 Generation Expansion Plans (Preliminary)		
Year	**HVdc Link Scenario Hydro's Alternatives (Capacity/Firm Capability)**	**Isolated Island Scenario Hydro's Alternatives (Capacity/Firm Capability)**
2009		
2010		
2011		
2012		
2013		Wind Farm (25 MW/77 GWh)
2014		
2015	HVdc link (800 MW)	
2016		Island Pond (36MW/172 GWh)
2017		
2018		
2019		Portland Creek (23 MW/99 GWh)
2020		
2021		Round Pond (18 MW/108 GWh)
2022	CT (50 MW/394.2 GWh) HWD CT & SVL CT Retired	
2023		CCCT (170 MW/1,340 GWh) SVL CT Retired
2024		HWD CT Retired
2025		
2026		CT (50 MW/394.2 GWh)
2027		
2028		

Note: The HVdc link expansion plan satisfies Hydro's generation planning criteria well beyond the 2028 planning horizon. However, the Isolated Island expansion plan will require further additions as HTGS units are retired beginning in 2032 (estimated).

Figure 7-1
Preliminary HVDC Link Expansion Plan vs. Load Forecast

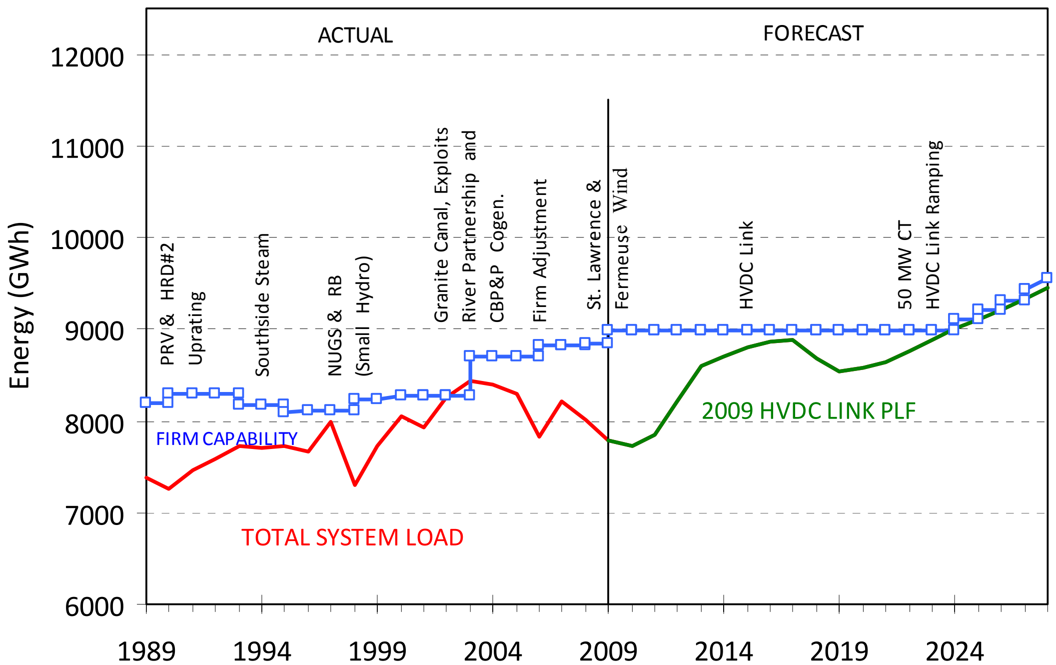
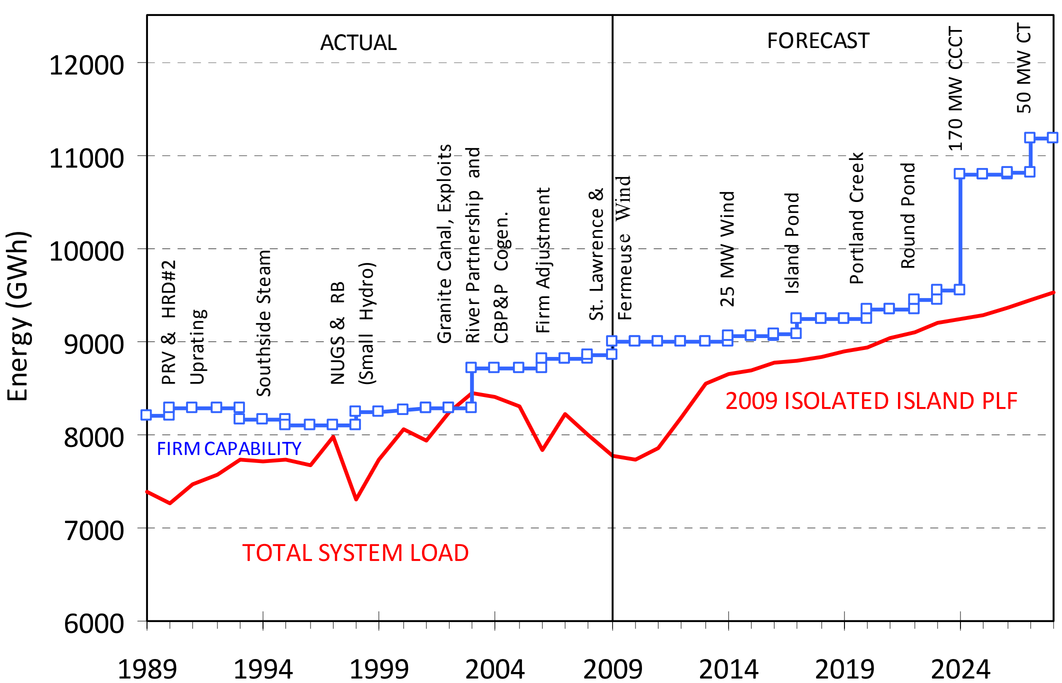


Figure 7-2
Preliminary Isolated Island Expansion Plan vs. Load Forecast



8.0 Timing of Next Decision

8.1 Request for Proposals

In addition to those resources included in Hydro's own portfolio of near term alternatives, any number of alternatives may be brought forward under a general request for generation proposals (RFP). As with the 1997 RFP, alternatives submitted under a general RFP can range from various forms of conventional technologies to alternate technologies such as wind power.

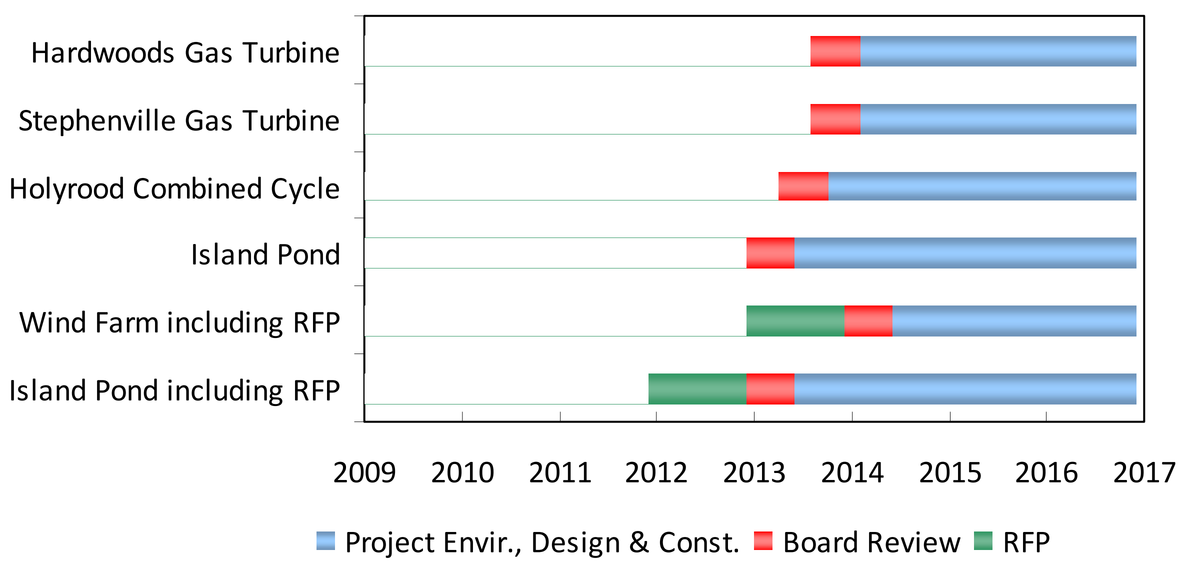
In addition to the time required to bring a project through the normal environmental and construction schedules, additional lead time is required to implement an RFP process. Based on Hydro's 1997 experience, the minimum amount of time required to issue and evaluate proposals through an RFP process is approximately seven months. This was accomplished only through having a high priority placed on the process by the Leadership Team, the commitment of key personnel from various departments and the assistance of consultants from outside Hydro. Due to the urgency to have a final report on generation expansion alternatives ready by mid-June 1997, the RFP, issued in mid-January, gave proponents only approximately three months to submit proposals. Many proponents expressed concern about the short time allotted to prepare proposals and it was evident that if more time had been provided, there may have been more submissions. Ideally, the RFP process requires approximately 15 months to complete, as was the case for Hydro's first RFP for small hydro non-utility generators in 1992. An RFP process with a 12 month schedule from issue through to completion of the project evaluations is a reasonable compromise between the accelerated schedule of the 1997 RFP and the much longer 1992 RFP schedule.

8.2 Newfoundland and Labrador Board of Commissioners of Public Utilities

Prior to 1996, Hydro was not required to seek approval from the Board for its capital program. However, with the 1996 amendments to the Hydro Corporation Act, Hydro, in the absence of a Government exemption, must seek Board approval before committing to a new generation project whether owned or contracted. Given that this process has yet to be tried, approval is estimated to take as long as six months depending on the level of interest shown and the number of interveners requesting standing at the hearings. Based on the level of interest shown at recent Board hearings and as expressed in the 1997 RFP, it is expected that there would be significant interest in a hearing for a new generation source.

Assuming an additional 25 MW wind project is brought in-service by 2013, for fuel displacement at Holyrood, additional generation will be required by the fall of 2016. Based on the requirement for additional generation by the fall of 2016 under an Isolated Island scenario, the following bar chart illustrates the lead times, including that required for a Board review, for each of the near term alternatives to achieve in-service by that time.

Figure 8-1 - Project Lead Times



The addition of an RFP process necessitates a decision to proceed in late 2011 to meet an in-service date of fall 2016. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by mid-2013 to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio.

9.0 Other Issues

9.1 Intermittent and Non-Dispatchable Resources

Based on the Island's existing plus committed generating capacity, approximately 397 MW, or 20 percent of net capacity can be characterized as non-dispatchable generation. While energy production from these resources is predictable over the long term, the generation may not be available when needed. The concern with this type of generation comes on two fronts; first in the availability of the generation to meet higher loads; and second on occasions of light load when the non-dispatchable capacity can no longer be absorbed into the system without adverse technical and economic impacts.

From a generation planning point of view, when assessing the adequacy of system resources to meet peak demands, the characteristics of non-dispatchable generation are incorporated into the unit models. Therefore, on a go-forward basis, new non-dispatchable resources are appropriately evaluated in generation capacity planning analyses.

However, long-term generation planning may not necessarily capture the short-term operational constraints of intermittent and non-dispatchable resources, particularly those related to the ability of the system to absorb the capacity under light load periods. As more and more intermittent and non-dispatchable capacity is added to the system, there comes a point at which the ability to maintain stability and acceptable voltages throughout the system is compromised. As well, there is an increased risk of spilling during high inflow periods as hydraulic production is reduced to accept non-dispatchable production.

In advance of any future RFP that would likely feature non-dispatchable resources such as small hydro and wind energy, it is necessary to determine what limitations on non-dispatchable resources are appropriate. While this has been studied a number of times, changes in available generation and load, such as the Grand Falls paper mill ceasing operations, necessitates a revisting of the analysis. In this light it is recommended that System Planning, in cooperation with Generation Operations, continue to conduct studies to identify the amount of non-dispatchable capacity that may be added without adversely affecting the operation of the system. Changes in these areas may affect proposals in an RFP process in the context of the type of proposal and price.

9.2 Environmental Considerations

Known environmental costs, such as environmental mitigation and monitoring measures that may be identified under the Environmental Assessment Act, and the current Provincial Government 25,000 tonnes per year limitation on SO_2 emissions from the HTGS, have traditionally been included in generation planning studies. In 2007, the Provincial Energy Plan communicated that Hydro would deal with environmental emissions concerns at the HTGS either by pursuing the development of the lower Churchill River and a HVdc link to the Island, or install capital intensive environmental mitigation technologies in the form of scrubbers and electrostatic precipitators to control emissions at the HTGS.

In 2006, Hydro began burning 1 percent sulphur No. 6 fuel oil for the HTGS. While there can be additional purchase costs for 1 percent sulphur over 2 percent sulphur fuel oil, this improvement in fuel grade has reduced SO_2 and other emissions by about 50 percent. In early 2009, Hydro further switched to 0.7 percent sulphur fuel, which may reduce SO_2 emissions by a further 30 percent.

There remains considerable potential for other Government-led environmental initiatives (such as the Clean Air Act, cap-and-trade systems, carbon taxes, etc.) that can impact utility decision-making. While it is impossible to predict the exact nature of future emissions controls or other environmental programs, and their resulting costs, it is necessary to be aware of the issue.

The most prominent environmental issue currently under consideration is greenhouse gases and their impact on global warming. Carbon dioxide (CO_2) is the primary greenhouse gas and Hydro, by virtue of its Holyrood thermal operations, is a principal emitter in the Province at an average of 0.97 million tonnes per year[9]. In the absence of a transmission link from Labrador to the Island, the long-term incremental energy supply for the Island is very likely to be thermal-based and thus this issue could have a significant impact on production costing and future generation planning decisions.

For example, under a cap-and-trade system, the amount of effluent, such as CO_2, Hydro could be permitted to emit could potentially be capped by a regulator at a certain level. To exceed this level, credits could perhaps be purchased from a market-based system at a price set by the market. Conversely, surplus credits for effluent not emitted under the cap level might be traded on the market to generate revenue. This type of system could have significant impacts on Hydro's production costing and the cost of electricity, especially under the Isolated Island scenario.

Other emissions that may come under further regulation include nitrogen oxides (NO_x) and particulate.

Hydro maintains a base of knowledge to be able to provide a qualitative level of analysis on the potential consequences of environmental initiatives such as this on resource decisions. As well, Hydro is closely monitoring national and international activity in this area.

[9] Based on the 5-year average of 970,459 tonnes per year of CO_2 from 2004 through 2008.

9.3 Holyrood Thermal Generating Station End-of-Life

Units 1 and 2 of the HTGS were commissioned in 1971 and Unit 3 was commissioned in 1979. Under an Isolated Island future, the energy these units will be required to produce will be approaching their firm capability. Under a HVdc link future, these units will be required, as a minimum, to function as synchronous condensers to provide System voltage support as well as to provide a backup supply for some period after the HVdc link comes inservice. Due to the age of these assets, significant capital investments may be required to ensure that they are capable of operating reliably until their anticipated end of life. Typically, as thermal plants age they are derated to account for their decreasing reliability caused by increasing failure rates of aging components. Under an Isolated Island scenario, Hydro cannot derate these units without adding additional generation sources. Hydro must determine what is required for the HTGS to function until its anticipated end of life under both expansion scenarios and to facilitate this, the Board has approved a Condition Assessment of the facility, which will begin during 2009.

9.4 Energy Conservation

In November 2008, Hydro filed a request to defer costs incurred in 2009 associated with the new programs outlined in the Five Year Conservation and Demand Management (CDM) Plan submitted to the Board in June 2008. This request provided updated program concept information and energy savings were estimated at 70 GWh per year in 2013. Also in November, Hydro and Newfoundland Power launched the takeCHARGE program, a joint utility energy conservation program providing tips and information as well as rebates and community programming to help consumers save. The launch of the program brand and website was the first step in bringing the programs outlined in the Five Year CDM Plan to market. In early June 2009, the residential rebate programs were launched addressing home heating savings. A commercial lighting rebate program was also launched at the end of June and a large Industrial program is scheduled in the fall. This collaborative approach is ensuring positive steps towards the creation of a culture of conservation. In all likelihood, the energy conserved will not delay the need for additional generation; however, Hydro should continue to assess its impact on the PLF and expansion plans.

10.0 Conclusion

Based on an examination of the System's existing plus committed capability, in light of the 2009 PLF and the generation planning criteria, the Island system can expect capacity deficits starting in 2015 under both the HVdc link and Isolated Island scenarios but no energy deficits until post-2018. If a third wind project is brought in-service in 2013, generation additions for the Isolated Island scenario could be postponed until 2016.

Due to the direction given to Hydro under the Provincial Government's Energy Plan, two generation expansion plans are to be maintained until a sanction decision on the Lower Churchill Project can be reached. These two expansion plans differ based on the inclusion of a HVdc link as an available alternative to meet the System's energy requirements. The decision for sanctioning for the Lower Churchill Project is scheduled for 2010 and at that time, the expansion scenario that Hydro will ultimately pursue will be known. Until that time, it would be desirable to avoid committing to one generation expansion plan over another; however, Hydro must be prepared to react to protect the reliability of energy supply for the Provincial market. If a revised forecast indicates that a decision is required prior to the Lower Churchill Project sanctioning, a detailed study on how best to proceed will have to be prepared to ensure that the most appropriate decision can be undertaken in an orderly process.

In order to meet the deficits noted in 2015/2016, Hydro has identified two possible sources. The preferred source depends whether or not the Lower Churchill Project and the HVdc link are sanctioned. Assuming that the Project and link are sanctioned, the HVdc link will meet the capacity and energy requirements of the Island for many years to come and nothing is required before the HVdc link. However, if the Project and link are not sanctioned, Hydro will likely require the construction of the 36 MW Island Pond hydroelectric plant to meet its capacity requirements. It is likely that the remaining hydroelectric facilities of Portland Creek and Round Pond would also be constructed for their capacity and energy benefits along with their economic and environmental benefits associated with the displacement of fuel required to produce energy at the HTGS. In order to protect the in-service date for the Island Pond alternative, which has been identified as the preferred next source of generation from Hydro's portfolio, the addition of an RFP process for other supplies necessitates a decision to proceed in late 2011 to meet an in-service date of fall 2016. This is due to the need to complete the RFP evaluation and subsequent Board review and have a final decision by mid-2013

The impact of energy conservation measures resulting from the *Five-Year Energy Conservation Plan* will need to be evaluated to determine what, if any impact, it has on the decision for the next source. At this time, it is expected that the principal benefits will be the economic and environmental benefits of the reduced reliance on HTGS produced electricity and that the timing for the next decision will be unaffected.

From a system planning point of view, the key issues for Hydro to deal with in the near term are:

- HVdc Transmission Link – Hydro must be prepared for events that may delay the proposed Lower Churchill Project or if the project is not sanctioned;
- HTGS End-of-Life – Hydro must determine what is required to ensure the HTGS can be operated reliably under both a HVdc link future and an Isolated Island future. For the latter case, other future generation sources should be considered;
- Government Emissions Reductions Initiatives – Hydro must remain vigilant in considering the impact that Government emissions reductions initiatives could have on production costing and future generation planning studies;
- Environmental impact considerations – Hydro must begin to consider the potential impact of delays in project scheduling for all new generation sources due to increased environmental assessments in the form of Environmental Impact Studies;

- Fuel displacement – Hydro must continue to pursue and develop projects and incorporate energy conservation activities that are technically and economically feasible to displace fuel at the HTGS;
- Industrial expansion and contraction – Hydro must continue to assess, as updated information is provided, the impacts of industrial activity both positive and negative on the System's capacity and firm energy balance;
- Resource Inventory – Hydro must ensure that it maintains a current inventory of resource options with sufficient study as to provide confidence in overall project concept, costs and schedules.

Appendix A

Table A-1
2009 Planning Load Forecasts

	2009 PLF HVdc Link Case		2009 PLF Isolated Island Case	
Year	Maximum Demand [MW]	Firm Energy [GWh]	Maximum Demand [MW]	Firm Energy [GWh]
2009	1,592	7,781	1,592	7,781
2010	1,534	7,727	1,534	7,727
2011	1,568	7,858	1,568	7,858
2012	1,604	8,223	1,603	8,174
2013	1,673	8,601	1,672	8,550
2014	1,686	8,710	1,680	8,640
2015	1,699	8,798	1,691	8,691
2016	1,718	8,871	1,702	8,772
2017	1,733	8,881	1,719	8,784
2018	1,737	8,682	1,726	8,824
2019	1,712	8,534	1,734	8,887
2020	1,693	8,579	1,745	8,936
2021	1,702	8,636	1,756	9,027
2022	1,713	8,757	1,773	9,100
2023	1,732	8,883	1,785	9,199
2024	1,751	9,005	1,801	9,233
2025	1,770	9,113	1,809	9,290
2026	1,787	9,211	1,819	9,362
2027	1,803	9,326	1,831	9,444
2028	1,820	9,445	1,844	9,525

Appendix B

Table B-1

Fuel Forecast

Year	Residual 0.7%S (6.287 MBTU/BBL) [$/BBL]	Diesel (5.825 MBTU/BBL) [$/litre]
2009	60.50	0.530
2010	73.30	0.620
2011	88.10	0.725
2012	87.90	0.720
2013	90.60	0.740
2014	93.50	0.770
2015	95.40	0.815
2016	101.50	0.860
2017	107.00	0.900
2018	111.80	0.940
2019	119.20	1.000
2020	126.10	1.060
2021	128.60	1.080
2022	131.10	1.100
2023	133.80	1.125
2024	136.40	1.145
2025	139.20	1.170
2026	141.90	1.190
2027	144.80	1.215
2028	147.70	1.240

Source: Investment Evaluation, Nalcor and Market Analysis Section, System Planning, Hydro, June 2009

Table B-2

Escalation Rates

Year	General Inflation		Construction			Operation & Maintenance	
	GDP	Canadian CPI	Hydro & Thermal Plant	Transmission Line	Transformer Station	More Materials Less Labour	More Labour Less Materials
2009	1.0%	1.8%	1.4%	-0.2%	0.9%	2.2%	2.8%
2010	1.9%	1.9%	0.5%	2.3%	1.3%	2.2%	2.8%
2011	1.9%	1.9%	1.7%	2.0%	1.0%	2.2%	2.8%
2012	1.9%	1.9%	2.3%	3.4%	2.0%	2.2%	2.8%
2013	2.0%	2.0%	3.0%	3.5%	2.8%	2.2%	2.8%
2014	2.0%	2.0%	3.1%	3.5%	3.1%	2.2%	2.8%
2015	2.0%	2.0%	2.0%	1.9%	2.4%	2.2%	2.8%
2016	2.0%	2.0%	1.5%	1.7%	1.7%	2.2%	2.8%
2017	2.0%	2.0%	2.7%	2.6%	2.0%	2.2%	2.8%
Post 2018	2.0%	2.0%	2.7%	2.8%	2.2%	2.2%	2.8%

Source: Investment Evaluation, Nalcor and Market Analysis Section, System Planning, Hydro, January 2009