AN APPLICATION TO THE
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2010 CAPITAL BUDGET APPLICATION

VOLUME I

August 2009

newfoundland labrador hydro
a nalcor energy company

newfoundland labrador
hydro
a nalcor energy company

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August 3, 2009

BY HAND

Board of Commissioners
Of Public Utilities
P.O. Box 21040
St. John's, NL
A1A 5B2

ATTENTION: Cheryl Blundon - Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2010 Capital Budget Application

Please find enclosed ten copies of Hydro's 2010 Capital Budget Application, in two volumes, filed in accordance with the Capital Budget Application Guidelines issued by the Board in October of 2007 and in accordance with the guidelines and conditions for capital budget proposals as outlined by the Board in Order No. P.U. 7 (2002 – 2003).

Under this Application, Hydro is seeking approval of $52.8 million in capital expenditures and one lease in excess of $5,000. Also, Hydro is seeking approval of its 2008 rate base in the amount of $1,489,786,000.

Volume I of the filing contains an Overview of Hydro's proposed 2010 Capital Budget and its 2010 Capital Plan. The Capital Plan contains a five-year plan filed in compliance with Order No. P.U. 7 (2007) and as well contains a 20-year plan that contains other information required by the Board such as information as to the Holyrood Thermal Generating Station and as to the province's Energy Plan.

Section A of the Application sets out the high level summary of the 2010 budget by the following categories: Generation, Transmission and Rural Operations and General Properties.

Section B contains the detailed project justifications for each period over $500,000 and contains an Overview section as well as detailed explanations. Also contained in Section B are the Multi-Year Projects.

Section C sets out the projects over $200,000 but less than $500,000; Section D contains the projects over $50,000 and less than $200,000. Section E contains the classification of the capital project proposals. Section F contains a proposed lease, while Section G sets out the Schedule of Capital Expenditures for the period 2005 – 2014. Section H to the Application contains the status report for the 2009 capital program to June 30.

Section I to this Application is a report on the ten-year plan of maintenance expenditures for the Holyrood Generating Station required to be filed by Order No. P.U. 14 (2004). Section J sets out the 2008 rate base for Hydro.

Volume II of the Application contains the reports associated with capital project proposals over $500,000. This volume also includes Hydro's report, *Generation Planning Issues, 2009 Mid Year Update*. This report provides the information the Board requested under its letter dated August 5, 2008 pertaining to the Integrated Resource Planning.

We trust that you will find the enclosed to be in order and satisfactory. Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly

Newfoundland and Labrador Hydro

Wayne Chamberlain Jr.

Wayne Chamberlain,
General Counsel and Corporate Secretary

Encl.

cc: Mr. Peter Alteen
Newfoundland Power

Mr. Tom Johnson, Consumer Advocate
O'Dea Earle

Mr. Joseph Hutchings, Q.C.
Poole Althouse

Mr. Paul Coxworthy
Stewart McKelvey Stirling Scales

Table of Contents
Volume I

TAB

Table of Contents
Volume I
(cont'd.)

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2010 capital budget pursuant to s.41(1) of the Act; (2) its 2010 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2010 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2008.

TO: The Board of Commissioners of Public Utilities ("the Board")

THE APPLICATION of Newfoundland and Labrador Hydro ("Hydro") ("the Applicant") states that:

1. Hydro is a corporation continued and existing under the Hydro *Corporation Act, 2007,* is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Section A to this Application is Hydro's proposed 2010 Capital Budget in the amount of approximately $52.8 million prepared in accordance with the guidelines and conditions outlined in Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines issued October 29, 2007.

3. Section B to this Application is a list of the proposed 2010 Construction Projects and Capital Purchases for $500,000 and over, prepared in

accordance with Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines.

4. Section C to this Application is a list of the proposed 2010 Construction Projects and Capital Purchases for $200,000 and over, but less than $500,000, prepared in accordance with Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines.

5. Section D to this Application is a list of the proposed 2010 Construction Projects and Capital Purchases in excess of $50,000 but less than $200,000 prepared in accordance with Order No. P.U. 7 (2002-2003) and the Capital Budget Application Guidelines.

6. Section E to this Application summarizes Hydro's proposed 2010 capital projects by definitions, by classification and by materiality as required by the Capital Budget Application Guidelines.

7. Section F contains no new leases proposed for 2010 in excess of $5,000 per year.

8. Section G to this Application is a Schedule of Hydro's Capital Expenditures for the period 2005 to 2014.

9. Section H to this Application is a report on the status of the 2009 capital expenditures including those approved by Orders No. P.U. 36 (2008), projects under $50,000 not included in these Orders, and the 2008 capital expenditures carried forward to 2009.

10. Section I to this Application is a report on the ten year Plan of Maintenance Expenditures for the Holyrood Generating Station required to be filed by Order No. P.U. 14 (2004).

11. Section J to this Application shows Hydro's actual average rate base for 2008 of $1,489,786,000.

12. Volume II to this Application contains the supplementary reports referred to in various capital budget proposals.

13. The proposed capital expenditures for 2010 as set out in this Application are required to allow Hydro to continue to provide service and facilities for its customers which are reasonably safe, adequate and reliable as required by Section 37 of the Act.

14. The Applicant has estimated the total of contributions in aid of construction for 2010 to be approximately $300,000. The information contained in the 2010 Capital Budget (Section A) takes into account this estimate of the contributions in aid of construction to be received from customers. All contributions to be recovered from customers shall be calculated in accordance with the relevant policies as approved by the Board.

15. Communications with respect to this Application should be forwarded to Geoffrey P. Young, Senior Legal Counsel, P.O. Box 12400, St. John's, Newfoundland and Labrador, A1B 4K7, Telephone: (709) 737-1277, Fax: (709) 737-1782.

16. The Applicant requests that the Board make an Order as follows:

(1) Approving Hydro’s 2010 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2010 Capital Purchases and Construction Projects in excess of $50,000 as set out in Sections B, C, and D hereto, and its leases as set in Section F, pursuant to section 41 (3) of the Act;

(3) Approving the proposed estimated contributions in aid of construction as set out in paragraph 11 hereof for 2010 as required by section 41 (5) of the Act, with all such contributions to be calculated in accordance with the policies approved by the Board; and

(4) Fixing and determining Hydro’s average rate base for 2008 in the amount of $1,489,786,000 pursuant to section 78 of the Act.

DATED at St. John’s, Newfoundland, this day of August, 2009.

NEWFOUNDLAND AND LABRADOR HYDRO

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Todd S. Newhook
Legal Counsel

Newfoundland and Labrador Hydro,
500 Columbus Drive, P.O. Box 12400
St. John's, Newfoundland, A1B 4K7
Telephone: (709) 737-1715
Facsimile: (709) 737-1782

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2010 capital budget pursuant to s.41(1) of the Act; (2) its 2010 capital purchases, and construction projects in excess of $50,000 pursuant to s.41 (3) (a) of the Act; (3) its leases in excess of $5,000 pursuant to s. 41 (3) (b) of the Act; and (4) its estimated contributions in aid of construction for 2010 pursuant to s.41 (5) of the Act and for an Order pursuant to s. 78 of the Act fixing and determining its average rate base for 2008.

AFFIDAVIT

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

1. I am Vice-President, Engineering Services, on behalf of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.

2. I have read and understand the foregoing Application.

3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John’s in the)
Province of Newfoundland and)
Labrador)
this ____ day of ________ 2009,)
before me:)

___________________________________ ______________________

Barrister – Newfoundland and Labrador John Mallam

INTRODUCTION

Hydro is required to provide reliable service to its customers, through the provisions of the Hydro Corporation Act, the Electrical Power Control Act, 1994, and the Public Utilities Act. The provision of a safe, reliable, least cost supply of electricity requires that Hydro continuously renew, expand and modify its generation, transmission and distribution assets, and the assets that support those systems. Hydro must also address changing environmental and other regulatory requirements, challenges which often require the acquisition of new assets or improvement to existing assets. Hydro's long term planning initiatives are complicated by the expected approval of the Lower Churchill Project and by the closure of the paper mill at Grand Falls. The latter event, which has reduced the demand for power and has made additional hydroelectric energy available to the system, coupled with the completion of two 25 MW wind power facilities (St Lawrence and Fermeuse) has enabled a deferral of the selection of the next energy source to 2011[1]. This Overview will discuss the projects proposed for 2010. Discussion of the 5 and 20 year plans are contained in the section entitled "2010 Capital Plan".

2010 PLAN CONSIDERATIONS

Maintaining Hydro's systems in reliable operating condition is accomplished through a combination of routine maintenance of existing assets, replacement of assets which have reached the end of their useful lives and are worn beyond the point of economic repair, or by replacement of assets with ones which will result in lower life cycle costs or improved operational characteristics.

The majority of Hydro's most important assets are approximately forty years old. This is true of Hydro's largest hydro installation at Bay d'Espoir, the Holyrood Thermal Generating Station, and much of Hydro's transmission and distribution systems. In addition, many other generation assets, such as the Stephenville Gas Turbine, Hardwoods Gas Turbine and Hinds Lake Generating Station are more than 30 years old.

Many of the capital proposals contained in this, and previous capital budget applications, resulted from the age of Hydro's assets, which reached the end of their useful lives and require replacement. The quantity and value of these routine sustaining capital proposals can be expected to continue to be a major factor as the assets age, become obsolete and are no longer supported by manufacturers affecting reliability and customer service. In other cases, the introduction of newer, more efficient technologies justifies the replacement of old equipment.

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[1] See Generation Planning Report in Volume II, Tab 25

The age of Hydro's assets also has implications for efficient operating methods and safety. Some of Hydro's generating plants were constructed at a time when most systems and auxiliary equipment were manually operated. Today, most equipment is automated or remotely controlled, which permits the operators to spend more time focused on maximizing efficiency and equipment monitoring. Many older safety standards are not adequate under current legislation or generally accepted standards, and the modification of facilities is required to eliminate or minimize risk of injury to employees, contractors and the general public. This application contains proposals to improve the safety of Hydro's workplaces and to implement automation or remote control of equipment to facilitate the efficient operation of assets.

During 2007, Hydro initiated an internal review of its major assets to develop a long term asset refurbishment and replacement plan. This process resulted in the production of a 20-Year Capital Plan which identifies the major capital expenditures which will be required to maintain the existing assets in safe, reliable operating condition to serve our customers. The plan contains significant peaks in 2011 and 2012, which were not present in the plan filed last year as part of the 2009 Capital Budget Application. These peaks were caused by two projects; the conversion of the operating voltage of the Labrador City distribution system and the construction of a new diesel plant at Charlottetown. The former project is required to upgrade an old distribution system which has reached its capacity limit, the magnitude and cost of which was not known when the five year plan was prepared in 2008. The latter project is required to address a large increase in demand resulting from the expansion of a fish plant on the Charlottetown system, of which Hydro was not made aware of until the fall of 2008. The plan was adjusted to accommodate these two projects and the revised total cost of the five year plan is close to the value for the same period indicated last year. The plan is a living document which will be reviewed and revised annually as new information about the condition of our assets and the operating demands placed on them becomes available. General revisions will be made annually and major revisions will be made periodically when warranted by changing conditions and new information.

Consideration in the development of a capital proposal is given to:

- Load growth
- Maintenance history
- Condition assessment
- Performance assessment

- Legislative requirements
- Reliability improvement
- Cost efficiencies
- Operating experience
- Asset Maintenance Strategy
- Discussions between Regulated Operations and Engineering Services
- Familiarity with equipment
- Operating and Maintenance cost, and
- Professional judgment.

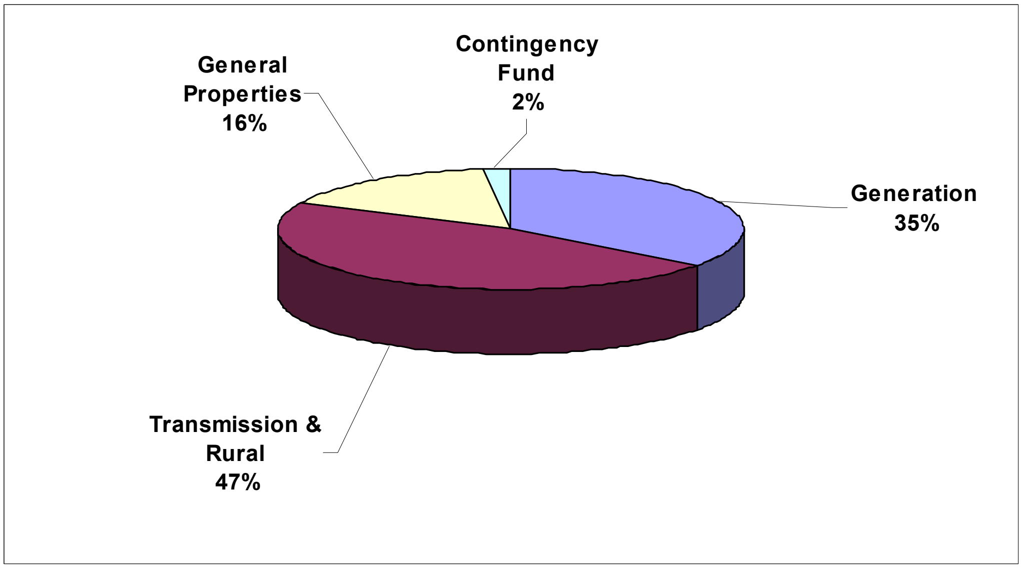
There are three broad categories of replacement criteria:

- Time and condition based, such as diesel generators (100,000 hours of operation) and vehicles (combination of years and operating hours for some classes);
- Condition based, such as transmission line wood poles and turbine bushings and seals; and
- Technical assessment based, where an evaluation of reliability, performance, condition, costs and other factors result in a capital proposal.

In summary, this Application contains a capital plan in which the overriding consideration is least cost, reliable generation, transmission and distribution of electricity while maintaining and enhancing safety and environmental performance. Assets are operated and maintained to deliver the least life cycle cost.

Chart 1 shows the breakdown of the 2010 Capital Budget by major classification. The classifications, other than the contingency fund, which represents only 2 percent of the 2010 budget, are then discussed further.

Chart 1. 2010 Capital Budget - Summary

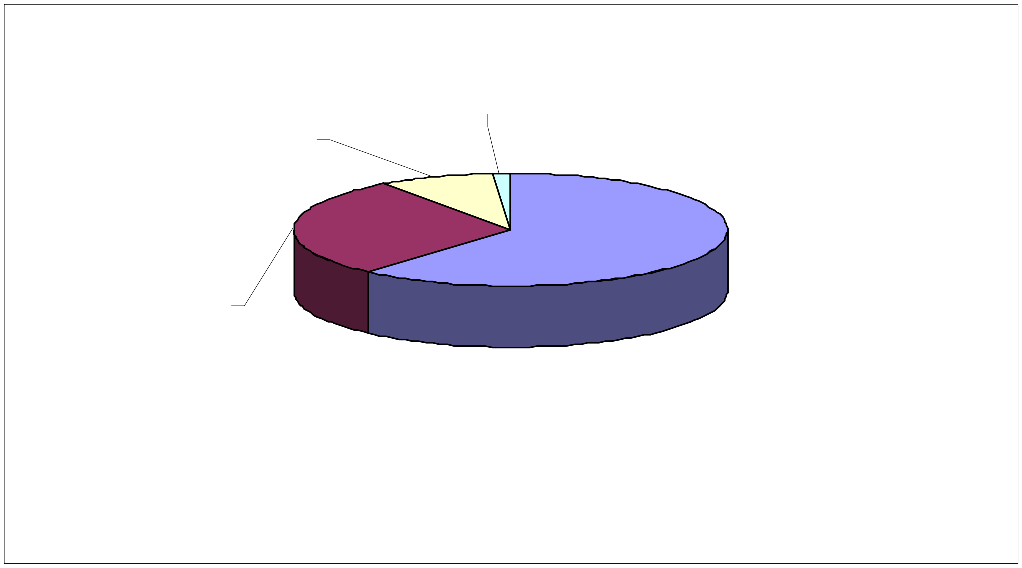


GENERATION ASSETS

On the Island Interconnected System, power and energy are provided by Hydro through a mix of hydroelectric and fossil-fired generation, as well as some power purchases. This production, along with the transmission system, is managed by Hydro's Energy Control Centre to ensure economic and reliable dispatch of available resources. At the end of 2008, Hydro's Island Interconnected production facilities consisted of 15 generating stations varying in size from 360 kW to 592 MW, with a total 1,592 MW of net capacity. Additionally, tools and equipment are required for the operating and maintenance of these generation assets.

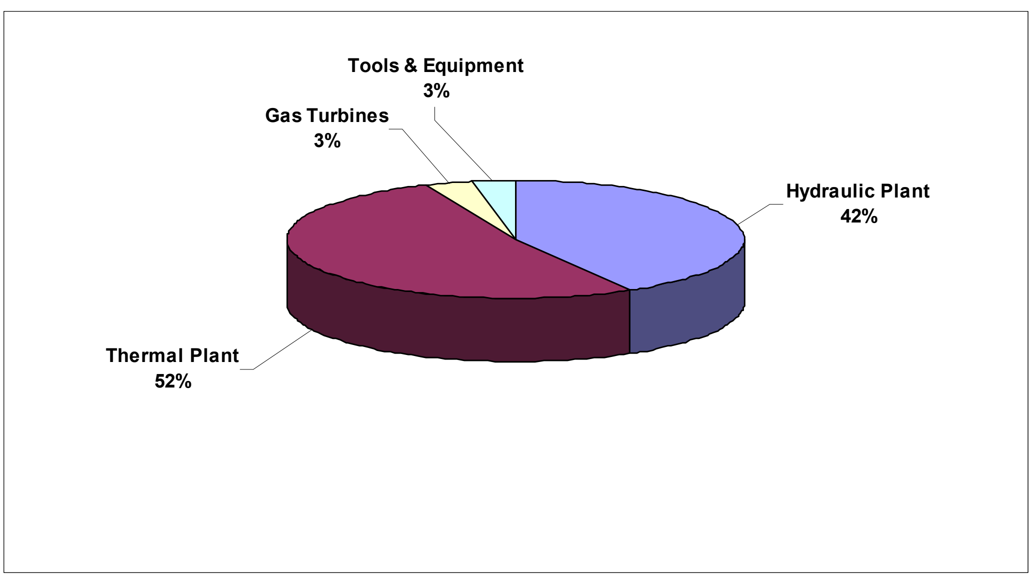
The division of the 2010 Capital Budget for Island Interconnected generation among Hydraulic Plant, Thermal Plant, Gas Turbines and Tools and Equipment expenditures is shown in Chart 2.

Chart 2: 2010 Capital Budget – Generation



The five-year (2004 to 2008) average[2] is shown in Chart 3. For 2010, thermal plant represents 29 percent of the Island Interconnected generation budget, compared with 52 percent over the past five years. In past years thermal plant projects have represented the majority of expenditures on generation assets but in 2010 the focus will shift to hydro plants, which is indicative of their age, which is among the oldest of Hydro's assets.

Chart 3: Five-year average Capital Budget - Generation (2004 - 2008)



[2] Last year's five-year average was also 2004 to 2008 because it included the 2008 Forecast. These five-year averages are based on the 2004 to 2008 Actual Expenditures.

Hydraulic Plant

Hydro's hydraulic generating plants range from five to more than 40 years of age. Capital expenditures are required to ensure reliability and to maximize the potential useful operating lives of assets, of which many components are coming to the end of their expected service lives. This application includes a proposal for the replacement of a stator winding at Bay d'Espoir. Units 1-4 were equipped with asphalt windings, a design which originated decades earlier and was the industry norm but which began to be superseded in the 1970s by longer lasting and more reliable insulation systems. Hydro has detected deterioration of these stator windings and has included the replacement of all four asphalt stator windings in the early years of the 20 year plan, to ensure the reliability of these generators.

Thermal Plant

Holyrood Thermal Generating Station Units 1 and 2 are now 40 years old while Unit 3 is 29 years old. The generally accepted life expectancy for thermal plants is 30 years, although the expected service life of Holyrood assets has been extended to 2020. Holyrood remains critical to the reliable supply of power to the Island Interconnected System, as it serves the base load of the system and will be required to do so in the short to medium term. The long term operational plan for this facility has been uncertain, as Hydro has investigated the feasibility of developing the Lower Churchill River and importing electricity from Labrador to the Island, which would eliminate the need for energy production from Holyrood. Should that project proceed, Holyrood will remain a critically important facility prior to completion of the Lower Churchill Project. Following completion of the Lower Churchill project, the Holyrood plant will continue to be an essential component of the Provincial electrical grid as a synchronous condensing facility. Additionally, the plant will function as a standby facility during the early years of operation of the Lower Churchill generating plant and direct current link between Labrador and Newfoundland. The implications of the Lower Churchill project are discussed in detail in the report entitled "Generation Planning Issues 2009 Mid Year Update", located in Volume II of this submission.

The challenges faced by Hydro are complex because circumstances require that Holyrood must operate in a manner quite different than the norm for thermal plants. Conventional practice is that a thermal plant is base loaded throughout its career until it reaches maturity and then the plant is operated as a peaking or standby facility in its final years, thus operating at a very low capacity factor, often less than 10 percent. This thermal plant has passed the age at which other utilities have performed condition assessment and life extension studies and have either retired the facilities or have initiated life extension projects. However, until the Lower Churchill Project is completed and power is brought to the Island Interconnected System via a HVDC link, the Holyrood plant must continue to operate at, or near, its historical average capacity factor of 40 percent to 50 percent annually and much higher through the critical winter period. The closure of the paper mill at Grand Falls will reduce demand on Holyrood until the nickel processing plant being constructed at Long Harbour begins commissioning and operation in 2011. The capital projects contained in this application are necessary to replace assets which are at the end of their useful lives, and which must be replaced to maintain reliability through to the completion of the HVDC link to the Lower Churchill development. The Holyrood Projects for 2009 are listed below:

<u>Replacement Projects, required to maintain reliability and meet standards to at least the completion of the infeed from Lower Churchill:</u>

- Replace programmable logic controllers
- Refurbish fuel storage facility
- Replace pumphouse motor control centers

<u>Upgrade projects:</u>

- Install Unit 1 condensate drains and high pressure heater trip – Recommended by insurer to protect turbine
- Install warm air makeup access – Eliminate safety hazard and facilitate access for maintenance

Gas Turbines

Hydro's gas turbine plants at Stephenville, Hardwoods and Holyrood are more than thirty years old. The generally accepted life expectancy for gas turbine plants is between twenty-five and thirty years. A complicating factor in Hydro’s case is that the manufacturer of the power turbine, one of the key components, went out of business years ago, eliminating the availability of factory technical support and spare parts. Also, the manufacturer of the gas engines (jet engines), another key component, has declared it obsolete and has stated that it intends to cease providing technical support and spare parts.

During 2007, Hydro engaged a consultant to perform a condition assessment of the Hardwoods and Stephenville gas turbines. Their findings and recommendations were used to prepare plans for refurbishment of these facilities to ensure that they can operate reliably and that their useful service lives can be extended as long as can be financially justified. This application contains a proposal to begin refurbish the Hardwoods Gas Turbine over several years.

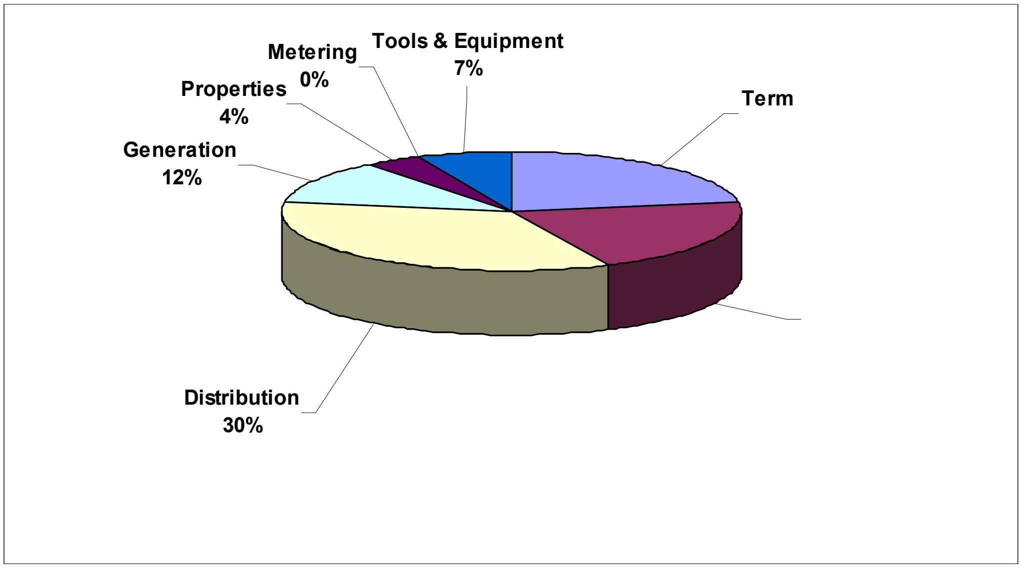
TRANSMISSION AND RURAL OPERATIONS ASSETS

Hydro owns and operates thermal generation with 39 MW of net capacity on the Labrador Interconnected system and owns and operates diesel generation assets with 20 MW of firm and 29 MW of net capacity in 21 isolated rural systems. On the Island Interconnected System, Hydro owns and operates 3,473 kilometers of transmission lines and 54 high voltage terminal stations operating at voltages of 230, 138 and 69/66 kV. On the Labrador Interconnected system, Hydro owns and maintains 269 km of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. In addition, Hydro owns and operates approximately 3,334 km of distribution lines, principally in rural Newfoundland and Labrador.

Hydro's Transmission and Rural Operations assets are aging, and require annual capital expenditures to maintain reliable service, to comply with environmental guidelines, and to ensure the safety of employees, contractors, and the general public.

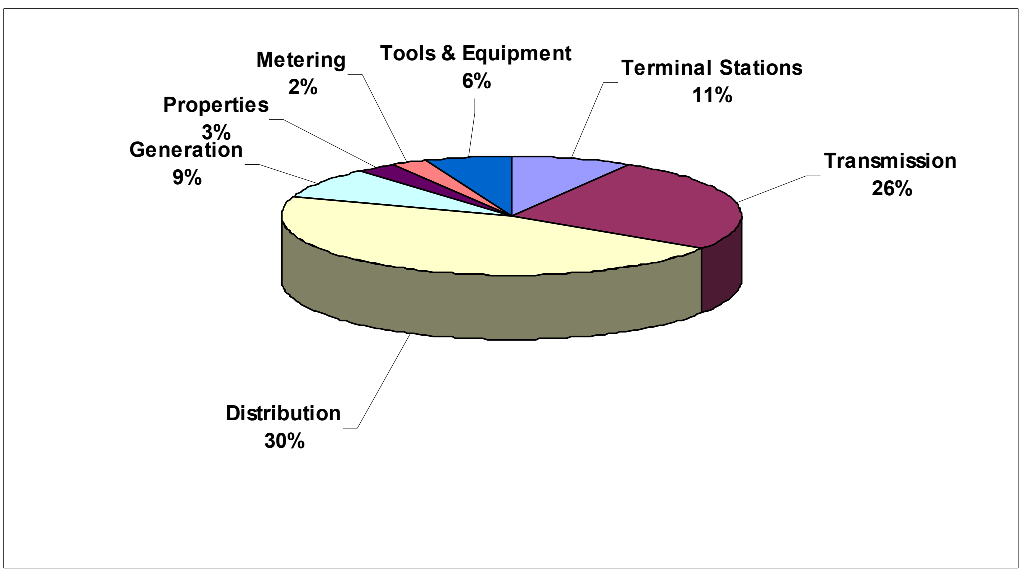
The division of the 2010 Capital Budget for Transmission and Rural Operations is shown in Chart 4. These breakdowns are generally consistent with the five-year (2004-2008) average as shown in Chart 5 below.

Chart 4: 2010 Capital Budget - Transmission and Rural Operations



Note: Metering is 0.1% so it appears as 0% in the Chart.

Chart 5: Five-year average Capital Budget – Transmission and Rural Operations (2004 - 2008)



Terminal Stations and Transmission

Many of Hydro's transmission lines were constructed in the 1960's and with expected useful lives in the 40-year range, annual reconstruction and general upgrades are needed to ensure that Hydro can continue to provide our customers with reliable electrical service. Regular capital replacement and upgrading is required to ensure that the maximum useful economic life is extracted from these assets to ensure the supply of reliable, least cost energy to our customers.

The terminal station and transmission proposals for 2010 are:

- Constructing new terminal stations in Labrador City to permit increasing the distribution voltage to 25 kV;
- Upgrading aging power transformers;
- Replacing failing insulators at various locations;
- Upgrading ageing circuit breakers;
- Replacing ageing disconnect switches and transformers at various locations; and
- Performing grounding upgrades

Distribution and Diesel Generation

The 21 remote electrical systems along the coasts of Labrador and the Island are served by diesel generation. Providing service to customers in these communities requires that the fuel storage, diesel generating units and distribution systems all be kept in safe, reliable and environmentally responsible working order. This application includes projects specifically directed towards meeting these requirements, such as replacing diesel generator units at McCallum and Francois.

Hydro also provides service to residential and general service customers on the Island Interconnected System. Hydro has included projects in this application that are intended to ensure that distribution lines and equipment that require replacement due to age are replaced prior to failure, thereby reducing the probability of interrupting service to our customers, such as replacing insulators and poles.

Aside from projects that are designed to ensure reliable service, this application also includes projects to provide distribution upgrades and service extensions to new customers throughout Hydro's service area.

The number of outages in the Labrador West area of the Labrador Interconnected System created concern about the suitability of this distribution system to serve the needs of the customers. This application contains a proposal to rebuild the distribution system at a higher voltage to restore reliability and to permit growth in the area.

GENERAL PROPERTIES ASSETS

The General Properties category includes projects related to Hydro's Information Systems, where technology is strategically deployed in a wide variety of business applications. This section of the application also includes proposals for security enhancements, vehicle replacements and telecommunications export replacements which are all necessary for the provision of reliable and cost effective service to customers.

Chart 6 shows the breakdown of the General Properties Capital Budget. The Information Systems 2010 Capital Budget is 17 percent less than the five-year average (shown in Chart 7), which is indicative of the maturation of Hydro's information technology and an increasing trend to replacement rather than major upgrades.

Chart 6: 2010 Capital Budget - General Properties

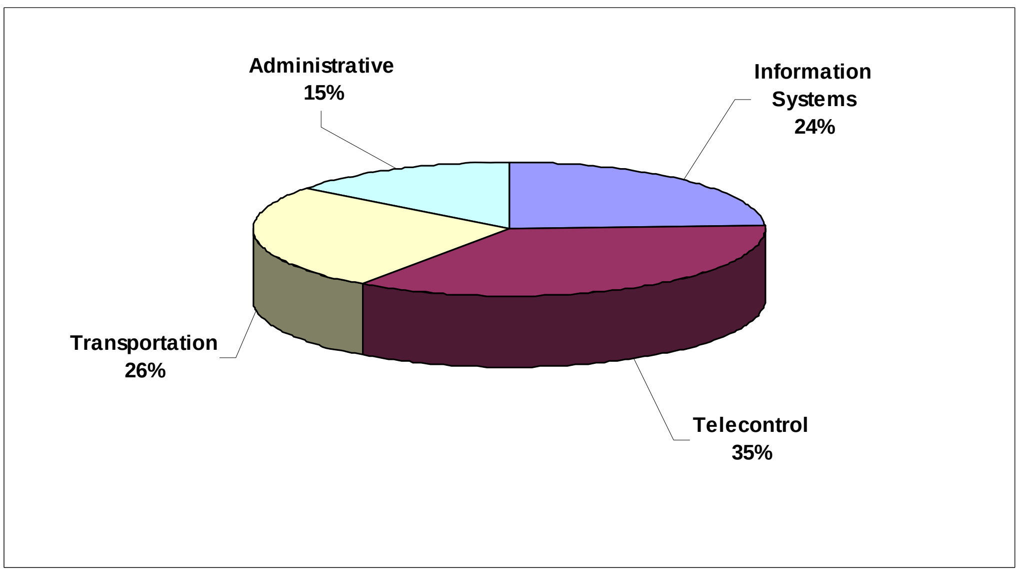
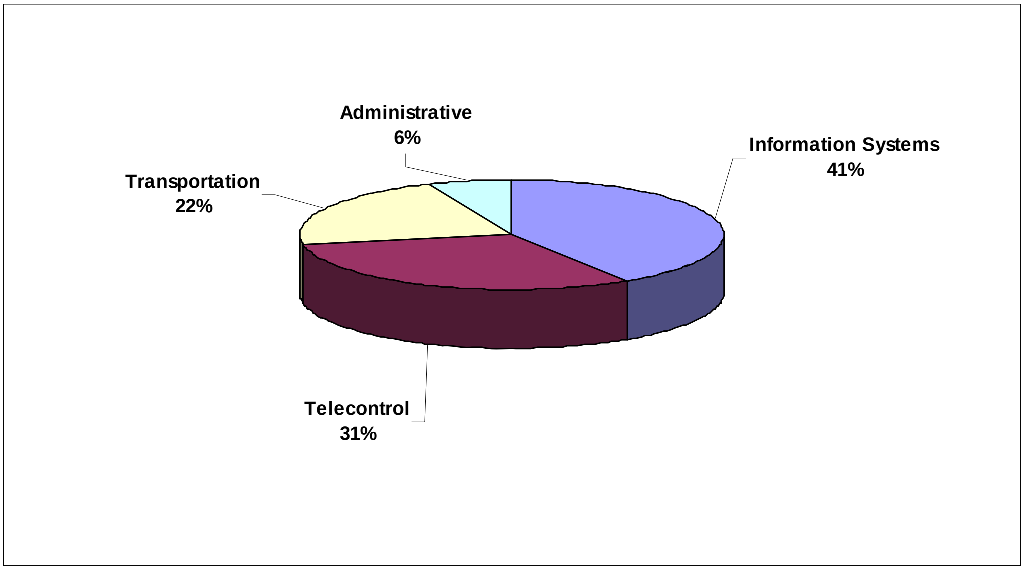


Chart 7: Five-Year Capital Budget - General Properties (2004 – 2008)



Information Systems

The Information Systems proposals include ongoing capital expenditures and are directed towards maintaining Hydro's computing capacity and associated infrastructure ensuring that it remains current and reliable. Projects include upgrades to the software applications used throughout the Hydro system, the replacement of desktop and laptop computers, and the replacement of peripheral computer equipment.

Telecontrol

Operating an integrated electrical system requires reliable communication systems across Hydro's province-wide facilities and among its employees, many of whom work in remote locations. The 2010 capital budget proposals in this category include infrastructure replacements and, in some cases, ongoing replacement or refurbishment programs, for such items as:

- Remote Terminal Units at Multiple Sites;
- Replacing battery banks and battery chargers; and
- Radomes at Multiple Sites.

In summary, Hydro's Capital Budget Application for 2010 contains various projects designed to provide cost effective and reliable power and energy to the residents and businesses of the province while ensuring employee and public safety and enabling Hydro to fulfill its environmental obligations.

A Report to the
Board of Commissioners of Public Utilities

2010 CAPITAL PLAN

newfoundland labrador hydro
a nalcor energy company

Table of Contents

Introduction

In Board Order No. P.U. 30 (2007), Hydro was directed to file a five-year capital expenditure plan. The Board indicated the plan should focus on strategic spending priorities beginning with the current year of the Application. As well, the capital expenditure plan should identify shifts in spending priorities over the five-year period, the circumstances contributing to these shifts, and alternative approaches under consideration. Additionally, the Board requested a separate section concerning Holyrood, including the impacts of the Provincial Energy Plan, an impact statement concerning alternative development scenarios reflecting how decisions associated with each scenario might influence the physical plant, the environmental, operational and management imperatives, as well as forecast maintenance and capital requirements for the ensuing five-years. Each individual project at the Holyrood plant contained in the annual capital budget submission could then be reconciled, justified and costed in respect of one or more development scenario. Hydro developed and filed a five and twenty-year plan with the 2009 Capital Budget Application. This report updates the 2009 Capital Plan.

Hydro has a responsibility to provide safe, reliable, and least-cost service to meet the needs of its customers. Providing a reliable supply of electrical energy depends on maintaining assets in sound condition. Utility assets are kept in reliable working condition by routine maintenance and replacement when necessary. Asset additions are determined through analysis of long term requirements to address future demands for power and energy, and transmission and distribution additions are also identified.

The 1960's saw a vast expansion in assets to fulfill the mandate of the Newfoundland and Labrador Power Commission, Hydro's predecessor, which was to electrify the province. This period of growth means that important assets are now over 40 years old and either have reached, or will soon reach, the end of their expected service lives. This includes components of the Bay d'Espoir Generating Station, the Holyrood Thermal Generating Station and much of Hydro's transmission and distribution systems. Hydro has a responsibility to maintain this infrastructure to a level that continues to allow Newfoundlanders and Labradorians to live in a modern society, dependent on electricity for home and business use.

In 2007, the Government of Newfoundland and Labrador released its Energy Plan which outlines the importance of maintaining a reliable electricity supply. Replacing and maintaining assets is a vital component to sustaining and improving existing systems. It also indicates that the preferred solution to the Province's long term electrical energy needs is the construction of the Lower Churchill Project and delivery of electricity to the Island via high voltage direct current (HVDC) transmission.

Twenty-Year Plan

Hydro's planning horizon for asset additions extends to twenty years in the future, depending on the asset, and these additions are planned for construction on a just-in-time basis. The generation plan is discussed in a report entitled "Generation Planning Issues 2009 Mid Year", located in Volume II of this submission. This 20-Year Capital Plan does not include additional generation capacity to address future energy requirements of the interconnected electrical systems, nor does it include proposals for Fuel Conservation and Demand Management (CDM). The plan does contain some additional generation capacity for isolated diesel generation systems. CDM may include other capital plans intended to reduce demand and energy needs that, aside from reducing fuel requirements, may impact generation additions. Asset replacements are planned based on condition assessments, maintenance and operating cost reviews, changing technology, expected lives of equipment and knowledge of individual assets. Table 1 summarizes Hydro's service life for major asset classes.

Table 1 - Asset Service Life[1]

Asset Type	Typical Useful Life
Thermal Power Plant	25 and 30 years
Hydroelectric Power Plant	25, 50, 75, and 100 years
Gas Turbine Plant	15 to 30 years
Diesel Plant	20-years
Transmission Line	40 and 50 years
Terminal Station	40 years
Transformer	40 years
Distribution System	30 years

Table 2 indicates when some of Hydro's major assets were placed in service.

Table 2 - Age of Selected Hydro Assets

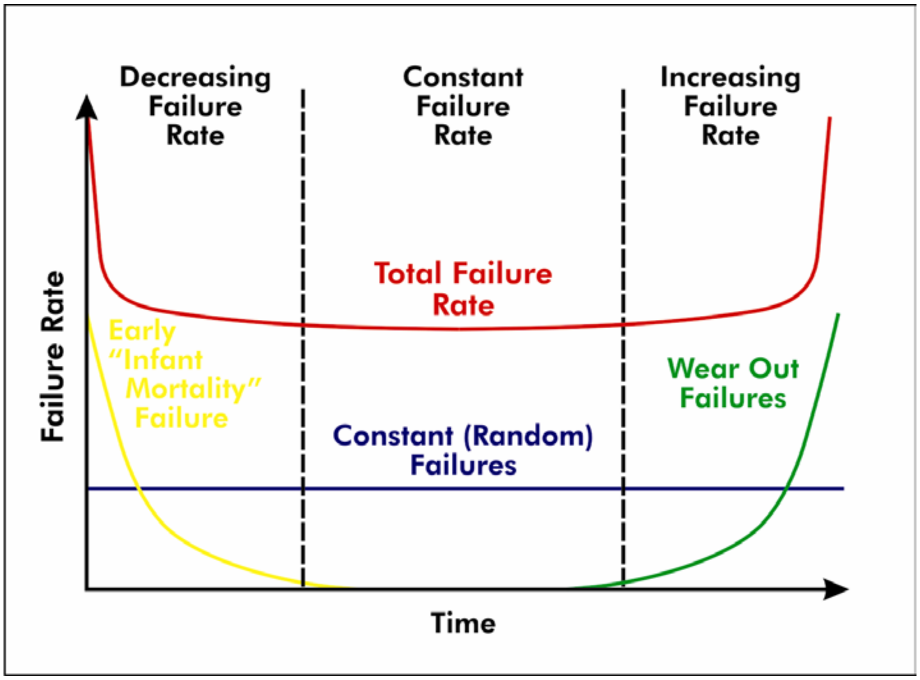
Facility	Year Commissioned
Bay d'Espoir Stage 1	1967
Bay D'Espoir Stage 2	1969
Bay D'Espoir Stage 3	1977
Holyrood Generating Station Stage 1	1970
Holyrood Generating Station Stage 2	1980
Stephenville Gas Turbine	1976
Hardwoods Gas Turbine	1977
Hinds Lake	1980
Upper Salmon	1983
Cat Arm	1985
Paradise River	1989
Granite Canal	2003
Transmission lines (numerous)	Beginning 1967

[1] Detailed service life data last filed with the Board in response to Request for Information IC-142 NLH as part of Hydro's 2006 General Rate Application.

Terminal Stations (numerous)	Beginning 1967

The reliability of most equipment over its lifespan follows a generally accepted trend, known as the bathtub curve, as illustrated in the following diagram:

Chart 1 – Equipment Lifespan



Total Failure Rate, which in its graphic form is known as a "bathtub" curve because of its shape, the sum of three individual types of failures:

1. Random failures, which are failures caused by a variety of reasons with unpredictable frequency.
2. Infant mortality failures, which occur during the first years of operation and are generally attributed to design, application, material or manufacturing defects or improper operation. These are "break in" failures.
3. Wear out failures, which, as the term implies, occur as the asset, or some of its components, reach the end of their service lives and break down.

The above tables and diagram indicate that many of Hydro's major assets have reached, or are about to reach, maturity, at which time steps must be taken to ensure that reliable service is maintained. These steps can include refurbishment and partial or total replacement. Over recent years many projects were implemented to refurbish or replace mature assets or asset components, and the number of these projects will increase significantly if Hydro is to continue to provide a reliable supply of electricity to its customers. Hydro manages its assets to provide reliable least cost electricity to its customers. The methodology for managing assets is currently being updated, and will be submitted to the Board in the near future.

The 20-year plan is a living document and will be revised frequently as new information about the condition of Hydro's assets becomes available, as asset management strategies evolve, and as demands and priorities change within asset classes. Cost estimates will require revision over time as changes occur in the costs of commodities, equipment and services. As each project nears its implementation year, the need for that particular project will be reassessed, its priority in relation to other potential projects will be evaluated, the preferred implementation year will be determined and its cost will be estimated to a greater degree of accuracy. Some more complex projects will require studies several years in advance of implementation to fully define and justify the project and to identify and evaluate alternatives.

The 20-year capital plan contains few projects which are new assets. The "Generation Planning Issues 2009 Mid Year" report, located in Volume II, tab xx. describes the two long term expansion scenarios: an interconnected scenario based upon importation of electricity from the Lower Churchill Project; and an isolated Island scenario in which future energy requirements are derived from an assortment of renewable and non-renewable assets. Major load additions, such as further Industrial Customer development, have not been considered. For the sake of clarity and simplicity, none of these generation expansion scenarios is included in the 20-year Capital Plan; it addresses existing assets only with a few exceptions, such as terminal station additions which will be required whether or not an HVDC infeed or refinery is constructed, and capacity additions at isolated diesel plants as well as distribution system expansion.

Hydro anticipates that its 2010 – 2014 capital expenditures to maintain the existing systems will rise to an average of $61.2 million over the next five-years and to an average of $58.9 million, expressed in

2009 dollars, over the next 20-years,. Expenditures for new generation and transmission assets are not included in these estimates.

This plan will be reviewed and revised annually, therefore, significant changes can be expected in the scope, timing and cost of individual projects, as well as the overall magnitude of future capital plans, as the plan develops and more information about the condition of assets becomes available. As the plan unfolds, Hydro will, to the greatest extent possible, schedule projects to achieve a relatively constant magnitude of annual sustaining capital expenditures. However, peaks will be inevitable as some projects involve significant individual expenditures which cannot be spread over several years.

Strategic Spending Priorities

The strategic priorities are:

1. Mandatory Issues:
   - Ensuring the safety of Hydro personnel, its contractors, and the general public;
   - Compliance with legislative and regulatory requirements;
   - Dealing with environmental risks.
2. Meeting projected load growth;
3. Achieving cost efficiencies;
4. Asset Maintenance Philosophy initiated in 2007
   - Maintaining reliability by addressing issues identified by:
     - Operating experience
     - Maintenance history
     - Condition assessment
     - Performance assessment
     - Familiarity with equipment
     - Operating and maintenance cost
     - Professional judgment
     - Asset Maintenance Strategy
     - Discussion between Regulated Operations and Engineering Services
   - Obtaining reliability improvement.

Asset Management Philosophy

Hydro's Asset Management Philosophy is a multi-pronged approach to formally documenting, reviewing and revising asset maintenance tactics in the short, medium and long term. Progress on the more detailed approach, which started with Holyrood Thermal Generating Station Assets and Gas Turbines, has been reported to the Board in Hydro's Quarterly report under the heading Asset Maintenance Strategy. The second, more high-level approach began in the last quarter of 2008. This second phase has resulted in an Asset Management Framework, the documentation of which is currently being prepared. This will be, as dated previously, submitted to the Board in the near future.

Five-Year Plan

The detailed five-year plan is presented in Appendix A.

The five-year plan indicates an increasing trend in expenditures as noted in the 2009 Capital Budget Application, required to address Hydro's maturing infrastructure and the need to replace assets, or components, to maintain reliable service. The plan contains significant peaks in 2011 and 2012, caused by two projects; the conversion of the operating voltage of the Labrador City distribution system and the construction of a new diesel plant at Charlottetown. The former project is required to upgrade an old distribution system which has reached its capacity limit, the magnitude and cost of which was not known when the five year plan was prepared in 2008. The latter project is required to address a large increase in demand resulting from the expansion of a fish plant on the Charlottetown system, of which Hydro was not made aware of until the fall of 2008. The very significant cost of these two projects resulted in a reprioritization of projects within the five and twenty year plans to maintain the total cost of the five year plan close to the value for the same period indicated in the 2009 Capital Budget Application. The total cost of the five year plan is less than 5% higher than indicated last year for 2010 to 2014, despite the inclusion of these two large projects. The trend of increasing capital expenditures will continue as Hydro addresses aging infrastructure which will require significant annual expenditures to reliably enable electrical energy to be produced, transmitted and distributed. An additional influence on the magnitude of the plan is the rapidly fluctuating equipment cost which has been changing much faster than the Consumer Price Index in recent years. Raw materials, such as copper, iron and alloy steels required for the production of the equipment have fluctuated greatly in price, making it difficult to accurately estimate the cost of some projects. The return to near historic prices for materials such as copper early in 2009 was short lived and their prices have escalated markedly since then.

Generation

The requirement to invest sustaining capital in generation facilities is increasing as many of the generating plants reach or surpass their normally expected service lives. Primary drivers for these projects are the realization of end of service lives for equipment, reductions in reliability or performance and considerations for safety.

Hydraulic

Reliability maintenance is the primary five-year priority for Hydro's five-year capital plan. In recent years, Hydro has detected deterioration in the condition of the stator windings of Units 1 through 4 in the Bay d'Espoir Generating Station. These four units, the oldest of the six installed in that plant, were equipped with asphalt insulated windings, the standard insulation system of that time. Deterioration increases risk of failure. Hydro proposes to begin replacing these windings in 2010 to ensure that these generators can continue to operate reliably. Continuing in 2009, Hydro proposes to replace cooling water systems at the Bay d'Espoir Generating Station, replacing critical piping systems which have become corroded with age. Other projects include the replacement or upgrading of control systems, fire alarm systems and cooling water pumps.

Holyrood Thermal Generating Station

Expenditures at the Holyrood Thermal Generating Station are discussed in detail later in this document.

Gas Turbines

Maintaining reliability of existing assets is also the priority for Hydro's gas turbines, which provide emergency and peaking power and function as synchronous condensers to help control voltage on the Island Interconnected system. In the past, capital expenditures at Hydro's gas turbine generating plants have been relatively insignificant, but this is changing due to their age. The two principal gas turbine plants, Hardwoods and Stephenville, have exceeded their design lives and are in need of major refurbishment to ensure their availability and reliability in the coming years. Hydro began the process this year with a $450,000 project for Hardwoods and proposes to continue the process over the next three years, replacing worn out and obsolete equipment to ensure that this plant will continue operate reliably for many years to come. A similar process is proposed for the Stephenville Gas Turbine, with expenditures beginning in 2012. Hydro's newest gas turbine plant located at Happy Valley was constructed in 1992. This plant has had only minor upgrades and is not expected to require any significant capital expenditures until 2013.

Terminal Stations

Increasing load and maintaining reliability are the principal drivers for terminal station expenditures over the next five years. The largest single project will be the construction of two new terminal stations in Labrador City. The distribution system is old and is loaded to capacity, requiring the construction of the two stations and the reconfiguration of the distribution system to maintain reliability, ensure acceptable voltage levels in response to load growth. This $10 million terminal station project was proposed and approved in 2009 as a two year project but it anticipated that when the study and planning for the distribution system modifications are completed this year it will be rescheduled as a three-year project to coincide with the reconfiguration of the distribution system. The distribution system will be discussed later in this document. Increased demand is also driving the requirement for an additional transformer at the Oxen Pond Terminal Station in St. John's. This project will cost $4 million in 2012 and 2013.

Aging equipment is a major concern and is considered when reviewing short and long term plans. The five-year plan contains expenditures to replace instrument transformers and to upgrade power transformers, many of which are over 40 years old. Hydro also proposes upgrading its aging mobile substation and disconnect switches, in an effort to maintain reliability as equipment reaches the end of its useful life.

Transmission

Reliability maintenance is the primary driver for transmission investment. The wood pole line management program leads the expenditures in this category, enabling Hydro to realize the maximum useful life from these transmission systems. The program is based on periodic assessment of the wooden transmission poles and facilitates their replacement before failure, while extracting the maximum possible reliable life from each pole. Other projects over the next five years are the replacement of insulators, upgrading of access trails and upgrading TL-244 (Plum Point to Bear Cove, Northern Peninsula).

Safety of Hydro personnel, contractors, and the public is also a factor in the five-year plan for Transmission. Hydro will continue its program of constructing highway offloading ramps, which will eliminate a serious safety risk to Hydro employees and the public while offloading heavy equipment required for maintaining transmission lines.

Distribution

New customer additions and reliability maintenance are the strategic areas addressed by the five-year capital plan for distribution assets. This equipment is subject to the same aging and wear as the generation and transmission assets and must be replaced periodically to ensure reliable service. The largest distribution project for the next five years will be the reconfiguration of the Labrador City distribution system. As was mentioned in the previous section of this document on Terminal Stations, the distribution system is Aging and is loaded to capacity, requiring its reconfiguration to maintain reliability, ensure acceptable voltage levels and to respond to load growth. The principal feature of the reconfiguration will be the increase of the distribution system voltage to 25 kV, enabling more energy to be distributed throughout the City while maintaining acceptable voltage levels. A project was proposed and approved in 2009 to perform preliminary engineering and develop a detailed cost estimate for this conversion project. This work is in progress and a report with cost estimates will be submitted to the Public Utilities Board by the end of August, 2009. The majority of other expenditures for the next five years will consist of service extensions and upgrades to distribution systems, at a combined total projected cost of $26 million. Other significant projects include the major upgrading of whole feeders or lines, such as at Glenburnie and Plum Point and replacing the submarine cable from Pilley's Island to Long Island.

Rural Generation

Aging infrastructure replacement to ensure reliability is required for rural generation. Hydro's diesel generating sets have the shortest lives of all its generating assets, requiring replacement after 100,000 hours of operation. During the next five years Hydro plans to replace generating sets in Francois (2011), McCallum (2010), and Little Bay Islands (2014). Replacement of generating sets at Norman Bay, Paradise River and Postville, as approved in last year's capital budget, will continue in 2010. These replacements are required to ensure that reliable service is provided to Hydro's isolated rural customers. Many of Hydro's diesel plants have deteriorated to a great extent and will require renovation or replacement. To prioritize this process, Hydro has initiated a review of the condition of the older plants to assist in planning the replacement or modification in a logical sequence. This review will be completed late in 2009 and will facilitate scheduling the work in the 20-year plan. Currently, the five-year plan includes the replacement of the Charlottetown diesel plant (2011 – 2013) in response to a significant increase in demand from the fish plant expansion, which was communicated to Hydro late in 2008.

Also, to comply with Hydro's planning criteria to meet load L'Anse au Loup generation must be increased to meet future load growth as proposed in the 2009 Capital Budget.

Information Systems

Obsolete technology and aging hardware are the strategic drivers which most significantly contribute to the five-year plan for information systems. Hydro's information systems provide the data required to effectively manage and control the activities of a complex business. Expenditures on these systems and personal computers will average over $2 million per year during the next five years, including a major expenditure in 2011 to upgrade Hydro's principal enterprise software applications.

Telecontrol

Obsolete technology and aging hardware are also the strategic reasons which most significantly contribute to the five-year plan for telecontrol assets. Hydro's communications network is vital to the operation and control of the power systems. Communications must be reliable and rapid to protect and control the generation, transmission and distribution equipment. It is expected that capital expenditures will average approximately $4 million per year for the next five years. The most significant of these projects will be the replacement of obsolete radio equipment (over $4 million during this period) and the replacement of fibre optic cable (nearly $3 million).

Transportation

Hydro's vehicles and mobile equipment must continue to be both safe and reliable. Hydro operates a diversified and dispersed fleet of mobile equipment throughout the Province that is required to operate and maintain our facilities in a challenging and sometimes harsh physical environment. Hydro selects, operates and maintains this equipment in a manner designed to achieve the least life cycle cost and replacements are scheduled in accordance with criteria submitted to the Board on previous occasions. Hydro anticipates that expenditures on mobile equipment will average more than $4 million over the next five-years.

Administration

Safety, cost efficiencies, reliability and security are the primary drivers of the five-year administration capital plan. Hydro expects to spend $3.4 million on items such as office equipment, security systems and building air conditioning equipment during the next five years.

Holyrood

The Holyrood Generating Station is among the largest generating plants on the Island Interconnected system, and, as a thermal plant, is by far the most complex. Stage I (Units 1 and 2) was commissioned in 1971 and has passed the normal 30-year design life for such a facility. Stage II (Unit 3) was commissioned in 1979 and has reached the end of its normal life. Similar aged plants have been retired or have been subjected to life assessment and extension studies and have received large injections of capital to extend their useful lives. Some have been redeveloped into other configurations, such as combined cycle power plants. The lack of certainty in recent years about the future of Holyrood, caused by the combination of having reached its maturity and the uncertainty of the Lower Churchill Project, has made it difficult for Hydro to formulate a definitive long term plan for this facility.

The “Generation Planning Issues 2009 Mid Year Update” report included in Volume II, Tab 26, explains the long term role for Holyrood. In an HVDC infeed scenario, all three units will be required to operate as synchronous condensers after the infeed is completed; in an isolated island scenario all three units will be required to operate as essential generating assets, as they do now. Depending on which scenario unfolds, some, or all of the Holyrood Generating plant will be required for decades into the future. Hydro has received approval from the Board to perform a condition assessment of the components of the Holyrood Generating Station required for synchronous condensing, and for those components required for generation prior to the completion of the HVDC infeed. The condition assessment is intended to provide Hydro with insight as to which components are likely to fail and when that will occur. This will provide the necessary information to determine the strategy to perform the required capital replacements orderly and efficiently, thereby avoiding or mitigating the impact of failures that may occur while the plant is in service. A failure would have a major impact on service, quality and reliability. This assessment will be performed in phases to ensure that the scope and progress of the work matches the progress of the Lower Churchill project so that only necessary expenditures are made. Hydro will periodically report to the Board on progress and will seek approval for the proposed scope of successive phases of the assessment as the work advances.

Five-Year Plan for Holyrood

The effect which the uncertainty of the Lower Churchill project has on the Holyrood facility was described in the previous section. To address this uncertainty Hydro has developed two separate generation expansion plans, described and discussed in the "Generation Planning Issues 2008 Mid Year Update" report located in Volume II, Tab 23. It is important to consider that whichever expansion scenario occurs, an isolated Island electrical system or interconnected to the Lower Churchill via HVDC link, Holyrood will be an integral and vital component of the Island Interconnected system for decades to come. In the isolated case, Holyrood will continue to be a generating station; in the interconnected case its three generating units will operate as synchronous condensers to provide system stability, inertia and voltage control. In developing the five-year project list for Holyrood, Hydro has selected only those projects associated with assets required to support synchronous condensing and those required to support generation to the expected in service of the HVDC infeed in 2015/16. Hydro also anticipates maintaining this facility as a generating facility for several years after the completion of the HVDC link, until the reliability of that source of energy has been thoroughly established.

Maintaining Holyrood for winter reliability is the primary focus of the five-year plan. The closure of the paper mill at Grand Falls will reduce demands on Holyrood somewhat prior to initial commissioning of the nickel processing facility at Long Harbor planned for 2011. Holyrood, however, remains a vital generation asset and must be maintained in reliable condition. Due to the environmental issues with the plant, legislative and regulatory requirements also contribute to the required expenditures. Each of the projects proposed to be implemented within the next five years is discussed below. These projects, required to ensure that the facility can continue to operate reliably until the completion of the Lower Churchill project, are associated with equipment required for synchronous condensing, or are related to safety or environmental concerns.

2010 Projects

Replace Programmable Logic Controllers: the existing equipment is obsolete and parts are difficult or nearly impossible to obtain. These individual controllers will be removed and control functions will be provided by expanding the existing distributed control system. This project will be completed in 2012. This project is required whether the plant operates in generation or synchronous condensing mode.

Refurbish Fuel Storage Facility: Inspection and repair of this facility is required to ensure reliable operation and to reduce the risk of a large volume oil spill. The condition of the storage tanks and tank farm were assessed by consultants who identified serious deficiencies and developed a program to ensure that the facility can operate into the future. This is a continuation of work started in 2008 and will continue until the facility is fully upgraded in 2012 and is required to ensure environmental compliance and reliable operation until completion of the HVDC infeed.

Install Unit 2 Cold Reheat Condensate Drains and High Pressure Heater Trip Level: Hydro's insurer, FM Global, identified a serious situation which could result in the ingress of water into the steam turbine, and cause considerable damage and an extensive outage. This project is required to ensure continued reliable operation until completion of the HVDC infeed.

Replace Pumphouse Motor Control Centers: These electrical panels are required to operate auxiliary equipment for pumping water crucial to the operation of the generating equipment. Their condition has deteriorated to the point where replacement is necessary. They will be required whether the plant operates as a generating or synchronous condensing facility

Replace Steam Seal regulator Unit 1: This device provides controlled steam flow to and from the turbine shaft seal, permitting the turbine shaft to operate. The existing steam seal regulator is obsolete and replacement parts are no longer available. The device will be replaced with a modern equivalent. This project is required to ensure continued reliable operation until completion of the HVDC infeed.

Improve On Site Drainage and Paving: This project is required to upgrade the plant site drainage and replace pavement which has deteriorated due to age. This project is required whether the plant operates in generation or synchronous condensing mode.

Replace Diesel Fire Pump: The existing pump was installed during construction of Stage I started in 1968 and can no longer be serviced. Replacement is the only practical option. This project is required whether the plant operates in generation or synchronous condensing mode.

Install Warm Air makeup Access: The existing methods of accessing some of the equipment creates a situation where personnel performing maintenance operations are working under confined space regulations. Providing a conventional access method will eliminate this requirement, reducing the number of personnel required when performing maintenance and providing a safer working environment.

Future Projects

2011 Projects

Replace Steam Seal regulator Unit 2: See explanation for Unit 1 in 2010.

Install Unit 3 Cold Reheat Condensate Drains and High Pressure Heater Trip Level: See explanation for Unit 2 in 2010

Implement Demand Side Management Initiatives: This project will be used to implement energy consumption reduction methodologies. This project is required whether the plant operates in generation or synchronous condensing mode.

Upgrade Facilities to Reduce Business Continuity Risk: A number of conditions have been identified which could cause a major outage at the facility. These conditions could be mitigated by relatively minor changes. This project will be used to affect these changes and is required whether the plant operates in generation or synchronous condensing mode.

Upgrade Stack Breeching: Breeching is large insulated ductwork which conducts exhaust gases from the boilers to the stacks. It carries hot corrosive gases, operating under very hostile conditions. The Breeching on the three units has been repaired many times and now requires replacement which will be performed over several years. This project is required to ensure continued reliable operation until completion of the HVDC infeed.

Hydrogen Systems Upgrade: An electrolyzer will be installed to permit the generation of hydrogen on site, removing the reliance on long supply lines for this essential gas. Additionally, obsolete control equipment will be replaced to ensure reliable operation. This project is required whether the plant operates in generation or synchronous condensing mode.

Install Support Vessel Access: The current access between the jetty (a wharf where tankers unload) and the support vessel consists of a deteriorated chain ladder that is not equipped with fall protection. Use of this chain ladder is hazardous, and creates a significant level of risk to those who use it. At both ends of the jetty safe access will be provided between the Jetty and the support vessel during the fuel oil tanker off-loading process. This project is required to ensure continued reliable operation until completion of the HVDC infeed.

Upgrade Electrical Equipment: This is a three year project to upgrade or replace existing motor control centers throughout the plant for the operation of motors, valves and other electrical equipment. They have become substandard and replacement parts are no longer available. This project is required whether the plant operates in generation or synchronous condensing mode.

2012 Projects

Upgrade Access Ladders: This project is required to replace external rusted and deteriorated access ladders on the powerhouse building. This project is required whether the plant operates in generation or synchronous condensing mode.

Upgrade Unit 3 Relay Control Panels: The existing panels are overloaded and the terminal blocks have deteriorated, representing a safety and reliability hazard. This project is required whether the plant operates in generation or synchronous condensing mode.

2013 Projects

Install Turbine Lube Oil Conditioners: This equipment is required to maintain the quality of the lubricating oil for the turbine generators. They will be used to condition the oil of the turbines and generators while the plant is in generation mode and will condition the oil of the generators while the plant is operated in synchronous condensing mode.

Construct New carpentry Shop: The existing shop is located in a very unsafe and inconvenient location, requiring personnel to move lumber and other materials as well as the finished products past the boiler fronts and around motor control centers, placing both personnel and equipment at risk. This project is required whether the plant operates in generation or synchronous condensing mode.

Replace Waste Water Basin Building: The building has deteriorated extensively due to corrosion which occurs in the humid interior environment and requires replacement. It will be required whether the plant operates in a generation or synchronous condensing mode..

Install Weatherhoods for Ventilating fans: Without weather hoods the twelve existing fans are overpowered by wind, preventing evacuation of fumes and dust from the plant. The accumulation of fumes and dust pose a health hazard to personnel. . This project is required whether the plant operates in generation or synchronous condensing mode.

2014 Projects

Upgrade Powerhouse Doors and Siding: The existing siding and doors are 40 years old and require replacement of various sections to maintain integrity of the building envelope. . This project is required whether the plant operates in generation or synchronous condensing mode.

Install Sprinkler System at Gas Turbine: At present the gas turbine is protected from fire by a gaseous suppression system, which is considered to be less effective and less reliable than a water sprinkler system. . This project is required whether the plant operates in generation or synchronous condensing mode.

Replace Gas Turbine Air Intake Structure: The existing air intake structure dates back to the 1960s, when this generating unit was located at the Hardwoods Terminal Station. It is badly corroded, requiring replacement in the near future. This gas turbine is used to black start the Holyrood Generating Station during a major power outage and is used to provide peaking power, which it will continue to do should the Holyrood plant be converted to a synchronous condensing facility. This project is required whether the plant operates in generation or synchronous condensing mode.

Refurbish Gas Turbine Building Enclosure: The existing building was constructed over 20 years ago and this work is required to correct deterioration to maintain the integrity of the building envelope. . This project is required whether the plant operates in generation or synchronous condensing mode.

Install Low NOx Burners: It is anticipated that Hydro may be required by regulatory authorities to reduce emissions of oxides of nitrogen. This project is required to ensure continued environmental compliance until completion of the HVDC infeed.

Upgrade Sootblowing Controls: The Holyrood Generating Station has no equipment to capture particulate emissions. Some emission reductions have been achieved in recent years by using lower sulphur content fuel, which also reduces the particulate content of the fuel. The installation of more sophisticated sootblowing controls would reduce peak particulate emissions. This project is required to ensure continued environmental compliance until completion of the HVDC infeed.

Upgrade Opacity System: This equipment was installed to monitor the particulate emissions from the plant and will require upgrading to operate accurately and reliably. This project is required to ensure continued environmental compliance until completion of the HVDC infeed.

**Holyrood Projects in a No Infeed Scenario*

The Province's Energy Plan indicated that should the Lower Churchill Project not be sanctioned, the emissions issues at the Holyrood Generating Station would be improved by the installation of scrubbers and precipitators. Hydro identified the technical parameters, construction schedule, capital and operating costs for this facility in a study performed during 2008. Should the Lower Churchill Project not be constructed, or be delayed, there is a significant amount of additional work required at Holyrood. To give an indication of the implications this would have on the 20-year Capital Plan a separate line item has been added to address Holyrood without an HVDC infeed. This deals solely with the Holyrood Generating Station and identifies those additional expenditures which will be required should the Lower Churchill Project not be sanctioned. These expenditures include new equipment, such as scrubbers, precipitators, low NOx burners, plant life extension and related projects to replace assets which have reached, or will reach, their end of life. At this time, these costs are estimated to orders of magnitude only. The table below is very preliminary, but provides an estimate of the expenditures required to maintain this facility in reliable and efficient operating condition.

Unit and Item Description	**($ 000)**
Unit 1 – Boiler	15,500
Unit 1 - Turbine	5,450
Unit 1 – Continuous Emission Monitoring System	235
Unit 1 - Steam Piping	1,090
Unit 1 - Condensate System	1,000
Unit 1 - Feedwater System	2,250
Unit 1 - Condensers	1,400
Unit 1 – Warm Air Makeup and Air Preheat	3,000
Unit 1 - Inside Building Fuel System	550
Unit 1 – Lube Oil System	500
Unit 2 - Boiler	17,000
Unit 2 - Turbine	5,000
Unit 2 - Continuous Emission Monitoring System	235
Unit 2 - Steam Piping	750

Unit and Item Description	**($ 000)**
Unit 2 - Condensate System	1,000
Unit 2 - Feedwater System	3,250
Unit 2 - Condensers	1,400
Unit 2 - Warm Air Makeup and Air Preheat	3,000
Unit 2 - Inside Building Fuel System	550
Unit 3 - Boiler	28,000
Unit 3 - Turbine	5,000
Unit 3 - Stack and Breeching	3,000
Unit 3 - Continuous Emission Monitoring System	235
Unit 3 - Steam Piping	1,050
Unit 3 - Condensate System	750
Unit 3 - Feedwater System	3,250
Unit 3 - Condensers	1,150
Unit 3 – Warm Air Makeup and Air Preheat	3,000
Unit 3 - Inside Building Fuel System	550
Common - Fuel Storage System Supply to Plant	650
Common - Ambient Air Monitoring Stations	750
Common - Fuel Unloading Dock and Bldg. Envelope	800
Common - Fuel Unloading Equipment	425
Stack Emissions Cleanup Equipment	570,000
Initial Plant Life Extension	100,000
Replace Burner with Low NOx Burners	17,500
Upgrade Soot Blowing Controls	3,500
Total	**802,770**

Should Hydro be required to operate the Holyrood facility as a generating plant significantly beyond the planned date for the HVDC infeed, considerable investigation and planning will be required to properly determine the extent and timing of work which will be required. The first step is detailed life assessment and extension study which will establish the scope and cost of the remedial work required, along with the optimal timing to perform the work, to ensure that least cost energy is produced from the plant. It is anticipated that this study will begin towards the end of the third quarter of 2009. As the items and estimates contained in the table were prepared without the benefit of a detailed assessment, it can be expected that the final scope and cost will differ from what is presented here.

APPENDIX A

Five-Year Capital Plan –

	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
GENERATION	1,282	18,679	18,109	18,196	9,047	20,205	85,517
TRANSMISSION AND RURAL OPERATIONS	1,796	24,753	34,606	37,382	38,907	29,517	166,961
GENERAL PROPERTIES	976	8,343	12,403	8,919	12,235	9,635	52,510
CONTINGENCY FUND	0	1,000	1,000	1,000	1,000	1,000	5,000
TOTAL CAPITAL BUDGET	4,055	52,775	66,117	65,497	61,189	60,356	309,988

	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
GENERATION							
Hydraulic Plant	73	11,455	4,579	7,474	2,588	9,150	35,318
Thermal Plant	1,210	5,352	11,721	5,886	2,739	6,128	33,035
Gas Turbines	0	1,638	1,623	4,624	3,649	4,893	16,426
Tools and Equipment	0	234	186	212	72	34	738
TOTAL GENERATION	1,282	18,679	18,109	18,196	9,047	20,205	85,517
TRANSMISSION AND RURAL OPERATIONS							
Terminal Stations	636	5,554	8,850	9,711	13,873	3,817	42,441
Transmission	968	5,115	4,770	4,653	6,718	9,587	31,811
Distribution	0	8,512	14,702	15,384	12,112	12,357	63,065
Generation	193	2,858	2,874	3,812	2,241	2,463	14,439
Properties	0	1,039	1,031	793	1,682	256	4,801
Metering	0	34	833	1,171	835	39	2,912
Tools and Equipment	0	1,642	1,545	1,858	1,448	999	7,492
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,796	24,753	34,606	37,382	38,907	29,517	166,961
GENERAL PROPERTIES							
Information Systems	0	2,008	5,910	2,251	1,559	1,557	13,286
Telecontrol	209	2,969	1,461	3,658	5,667	5,861	19,825
Transportation	0	2,156	4,489	2,493	4,519	1,679	15,336
Administrative	767	1,210	543	516	491	538	4,332
TOTAL GENERAL PROPERTIES	976	8,343	12,403	8,919	12,235	9,635	52,779
CONTINGENCY FUND	0	1,000	1,000	1,000	1,000	1,000	5,000
TOTAL CAPITAL BUDGET	4,055	52,775	66,117	65,497	61,189	60,356	310,257

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012 ($000)	2013	2014	Total
HYDRAULIC PLANT							
Replace and Purchase Stator Windings - Bay d'Espoir		4,687		4,888		5,189	14,764
Purchase Spare Stator Winding Units 2 - Bay d'Espoir	37	2,806					2,843
Upgrade Plant Access Road - Bay d'Espoir		1,550					1,550
Install Meteorological Stations - Various Sites		443	153	271			867
Replace 50 kW Diesel Generator - Bay d'Espoir	36	289					325
Upgrade Units 5 and 6 Cooling Water Systems - Bay d'Espoir		305					305
Upgrade Intake Gate Controls - Upper Salmon		284					284
Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg - Bay d'Espoir		236					236
Purchase Spare Spherical Valve Seal and Ring Assemblies - Bay d'Espoir		223					223
Replace A/C Units in Control Room and Communications Room - Upper Salmon		197					197
Replace Human Machine Interface (HMI) Computer - Paradise River		158					158
Upgrade Fuel Storage - Hinds Lake		149					149
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir		81					81
Install Air Conditioning at Burnt Spillway - Bay d'Espoir		48					48
Upgrade Access Roads - Various Sites			882	892		719	2,493
Replace Static Excitation System - Upper Salmon and Hinds Lake			1,163		1,223		2,386
Upgrade Surge Tanks - Bay d'Espoir			582			631	1,214
Install Dyn Air Gap Monitoring System on Units - Upper Salmon, Bay d'Espoir, Hinds Lake			292	216	227		735
Upgrade Intake Gate Controls - Bay d'Espoir			370				370
Install Trash Boom - Granite Canal			320				320
Upgrade Station Service Water Systems - Cat Arm and Upper Salmon			141			164	306
Install Partial Discharge Monitors - Various Sites			105	124			229
Replace Automatic Transfer Switches - Bay d'Espoir, Hinds Lake			170				170
Replace Fire Alarm System - Hinds Lake			109				109
Replace Compressor for Frazil Ice at Intake - Upper Salmon			103				103
Replace Two Service Water Pumps in Powerhouse - Cat Arm			98				98
Remove Safety Around Dams - Bay d'Espoir			48				48
Replace Trash boom at Control Structure - Hinds Lake			41				41

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012 ($000)	2013	2014	Total
HYDRAULIC PLANT (cont'd.)							
Upgrade Generator Bearings Units 2 and 4 - Bay d'Espoir				161		189	351
Automate Generator Deluge Systems Units 1 - 4 - Bay d'Espoir				257			257
Replace Microscada Computers - Granite Canal				199			199
Upgrade or Replace Bridge 1- Granite Canal				120			120
Replace Cooling Water Rotary Strainer - Upper Salmon				118			118
Install Gates RR Pond - Granite Canal				87			87
Replace Cooling Water Pumps 2 and 4 in Powerhouse 1 - Bay d'Espoir				72			72
Install Unit 1 Governor Oil Filtration System - Bay d'Espoir				68			68
Refurbish Turbines - Snook's Arm & Venam's Bight					163	638	801
Install Automatic Sprinkler System in Office Area - Bay d'Espoir					312		312
Install Automated Fuel Monitoring System at North Salmon Spillway - Upper Salmon					242		242
Upgrade Unit Relay Protection - Paradise River					158		158
Replace Units 1-6 Autogreasing Systems - Bay d'Espoir					150		150
Install New Fall Arrest Systems on Surge Tanks 1 - 3 - Bay d'Espoir					113		113
Construct New Site Support Facility at Camp Boggy - Bay d'Espoir						1,437	1,437
Replace Road Culverts - Granite Canal						104	104
Replace Low Pressure Air Compressor - Cat Arm						78	78
TOTAL HYDRAULIC PLANT	73	11,455	4,579	7,474	2,588	9,150	35,318

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
THERMAL PLANT							
Refurbish Fuel Storage Facility - Holyrood		2,500	2,500	2,732			7,732
Replace Programmable Logic Controllers - Holyrood		1,208	747	902			2,857
Condition Assessment and Life Extension Study - Holyrood	1,210	686					1,895
Replace Pump House Motor Control Centers - Holyrood		50	999				1,049
Replace Steam Seal Regulator Unit 1 - Holyrood		335	214				548
Install Cold Reheat Condensate Drains and High Pressure Heater Trip Level Units 1 and 3 - Holyrood		231	217				448
Replace Diesel Fire Pump - Holyrood		112	195				307
Install Warm Air Make-up Access - Holyrood		170					170
Improve On Site Paving and Drainage - Holyrood		59					59
Upgrade Stack Breaching - Holyrood			4,689			2,912	7,601
Upgrade Facilities to Reduce Business Continuity Risk - Holyrood			486	544	736		1,766
Hydrogen Systems Upgrade - Holyrood			1,021	446			1,467
Upgrade Electrical Equipment - Holyrood			234	220	306		760
Replace Steam Seal Regulator Unit 2 - Holyrood			182	411			593
Implement Demand Side Management Initiatives - Holyrood			114	147			260
Install Support Vessel Access - Holyrood			126				126
Upgrade Unit 3 Relay Panel Controls - Holyrood				372			372
Upgrade Outside Access Ladders - Holyrood				112			112
Replace Waste Water Basin Building - Holyrood					963		963
Install Turbine Lube Oil Conditioners - Holyrood					338		338
Construct New Carpentry Shop - Holyrood					220		220
Install Weatherhoods for Ventilating Fans - Holyrood					175		175
Upgrade Soot Blowing Controls - Holyrood						1,807	1,807
Upgrade Opacity System - Holyrood						1,168	1,168
Upgrade Powerhouse Door and Siding - Holyrood						133	133
Replace Units 1 to 3 Low Nox Burners - Holyrood						107	107
TOTAL THERMAL PLANT	1,210	5,352	11,721	5,886	2,739	6,128	33,035

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
GAS TURBINES							
Upgrade Gas Turbine Plant Life Extension - Hardwoods		1,305	1,324	3,367			5,995
Upgrade Glycol Systems - Stephenville		261	299				560
Upgrade Fuel Tank Farm Controls - Happy Valley		72					72
Upgrade Gas Turbine Plant Life Extension - Stephenville				1,257	1,577	3,730	6,563
Upgrade Gas Turbine Programmable Logic Controller - Happy Valley					1,882		1,882
Construct Gas Turbine Equipment Enclosure - Holyrood					190		190
Replace Gas Turbine Air Intake Structure - Holyrood						639	639
Install Sprinkler System at Gas Turbine - Holyrood						209	209
Refurbish Gas Turbine Building Enclosure - Holyrood						170	170
Replace Compressed Air Piping - Stephenville						146	146
TOTAL GAS TURBINE PLANTS	0	1,638	1,623	4,624	3,649	4,893	16,426
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000	0	154	186	124	72	34	570
Replace 21 Inch Metal Cutting Lathe		80					80
Install Handheld Pendant to Overhead Crane - Bay d'Espoir				88			88
TOTAL TOOLS AND EQUIPMENT	0	234	186	212	72	34	738
TOTAL GENERATION	1,282	18,679	18,109	18,196	9,047	20,205	85,517

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
TERMINAL STATIONS							
New 25 kV Terminal Station - Labrador City	283	2,700	3,500	3,507			9,990
Upgrade Power Transformers - Various Sites		816	862	870	4,578	884	8,009
Upgrade Circuit Breakers - Various Terminal Stations		342	346	351	360	370	1,769
Replace Insulators - Various Terminal Stations		399	410	420	430		1,659
Replace Instrument Transformers - Various Sites		197	199	202	207	214	1,019
Replace Disconnects - Various Sites		199	203	207			609
Perform Grounding Upgrades - Various Sites	252	291					543
Upgrade Trailer and Mobile Substation - Bishop's Falls		30	468				499
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood		79	417				496
Replace Surge Arrestors - Various Sites		73	74	75	77	80	380
Install Digital Fault Recorder - Various Sites		166	134				301
Replace Air Compressors - Various Sites		97		113			210
Upgrade Great Northern Peninsula Protection - Various Sites	101	91					192
Replace 230kV Breaker Controls - Massey Drive and Buchans		73					73

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
TERMINAL STATIONS (cont'd.)							
Replace Compressed Air Piping and Install Dewpoint Monitoring - Various Sites			576	522	487	524	2,108
Install Station Alarm Breakouts - Various Sites			549	453	466		1,468
Replace Compressed Air Systems - Various Sites			169	422		165	756
Replace 230 KV Circuit Breaker - Sunny Side			515				515
Replace SF6 69 KV Breaker - St. Anthony			341				341
Install Alternate Station Services - Stony Brook and Massey Drive			87	112			199
Install Additional 230kV Transformer - Oxen Pond				488	4,029		4,516
Install 20 MVAR Reactor - Bottom Brook				1,073	2,108		3,182
Install Breaker By-Pass Disconnect Switches - Various Sites				554	565	578	1,697
Perform Site Work to Accommodate MobileTransformer - Various Sites				221	288		510
Install B1C1 Annunciation and Alarms - Goose Bay				64			64
Upgrade Transformer Differential Circuit - Grandy Brook				57			57
Replace Compressed Air Piping - Hardwoods					278		278
Upgrade Control Building for Staff Working Spaces - South Brook and Deer Lake Station						534	534
Install Drainage to Stop Surface Flooding - Indian River						403	403
Install Transformer Fans - Conne River						67	67
TOTAL TERMINAL STATIONS	636	5,554	8,850	9,711	13,873	3,817	42,441

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
TRANSMISSION							
Perform Wood Pole Line Management Program - Various Sites		2,308	1,819	1,690	3,392	4,145	13,354
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		990	974	536			2,501
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	968	964					1,932
Replace Guy Wires TL-215 - Doyles to Grand Bay		301	307	316	327	338	1,589
Upgrade Line TL-244 - Plum Point to Bear Cove		141	1,055				1,197
Upgrade Anchors on C Structures TL-259 - Parson's Pond		353					353
Install Remote Ice Growth Detector Beams - Various Sites		58					58
Upgrade Line, Insulators and Poles - Various Sites			306	1,235	755	928	3,225
Upgrade Access Trails - Various Sites			309	318	329	340	1,295
Replace Insulators - TL-206				557	618	919	2,094
Reroute Remote Section of Line - TL-215 and TL-220					651	2,502	3,152
Upgrade Angle Structures - TL-259					646		646
Conduct Surveys - Various Sites						272	272
Replace Dampers - TL-247						144	144
TOTAL TRANSMISSION	968	5,115	4,770	4,653	6,718	9,587	31,811

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
DISTRIBUTION							
Upgrade Distribution Systems - All Service Areas		2,572	2,628	2,706	2,789	2,878	13,573
Provide Service Extensions - All Service Areas		2,428	2,479	2,554	2,631	2,715	12,807
Voltage Conversion - Labrador City		1,089	3,501	3,841	970		9,400
Replace Poles - Various Sites		1,083	805		250	264	2,402
Replace Recloser Control Panels - Various Sites		603	188	171	162	122	1,246
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois		82	511				593
Install New Voltage Regulators - Various Sites		170	170				340
Replace Submarine Cable from Pilley's Island to Long Island - South Brook			250	385			635
Perform System Upgrades - Williams Harbour			616				616
Upgrade Line - North West River			451				451
Upgrade Distribution System - Various Sites		485	3,104	5,727	5,095	5,878	20,288
Construct Storage Building - Springdale Depot and Change Islands					216	120	336
Replace Poles and Underground Feeder - McCallum						380	380
TOTAL DISTRIBUTION	0	8,512	14,702	15,384	12,112	12,357	63,065

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012 ($000)	2013	2014	Total
GENERATION							
Replace Diesel Units - Norman Bay, Postville and Paradise River	170	1,700					1,870
Increase Generation Capacity - L'Anse au Loup	23	821					844
Replace Diesel Unit 2001 and Engine 566 - Francois		168	450				619
Replace Diesel Unit 2018 - McCallum		19	421				440
Replace Main bus Splitter - Postville		149					149
Construct New Diesel Plant - Charlottetown			1,515	3,541	1,398		6,454
Install Sequence of Events Monitor in Diesel Plants - Various Sites			125	69			194
Upgrade Station Service - Grey River			150				150
Install Intermediate Tank - Nain			130				130
Install Fuel Storage Tank - Francois			84				84
Upgrade Generation Transformer - Cartwright				202	36		238
Increase Generation - Nain and Port Hope Simpson					51	1,739	1,790
Install Fuel Storage Tank - Nain					756		756
Install Nox Monitors - Various Sites						596	596
Upgrade Fuel Storage and Replace Generating unit - Little Bay Islands						127	127
TOTAL GENERATION	193	2,858	2,874	3,812	2,241	2,463	14,439

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012 ($000)	2013	2014	Total
PROPERTIES							
Install Fall Protection Equipment at Hydro Facilities - Various Sites		198	199	211	216		824
Install Pole Storage Ramps - Various Sites		90	380	342			812
Legal Survey of Primary Distribution Line Right of Way - Various Sites		65	74	148	148	152	588
Upgrade Accommodations - Norman Bay and Ebbegunbaeg		196			250		446
Install Waste Oil Storage Tanks - Various Sites		84	89	92			265
Install Transformer Storage Ramps - Various Sites		89	128				217
Upgrade Fire Protection System - Bishop's Falls		158					158
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls		88					88
Upgrade Properties - Port Hope Simpson		71					71
Upgrade Warehouse Lighting - Bishop's Falls			115				115
Upgrade Classroom and Boardroom in Main Office - Bishop's Falls			46				46
Replace Warehouse - Bay d'Espoir					1,068		1,068
Construct Steel Storage Building - Makkovik						103	103
TOTAL PROPERTIES	0	1,039	1,031	793	1,682	256	4,801

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
METERING							
Install Automatic Meter Reading - Various Sites			833	1,171	835		2,839
Purchase Meters and Equipment - Various Sites		34				39	73
TOTAL METERING	0	34	833	1,171	835	39	2,912
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000		237	97	100	68	71	573
Replace Off Road Track Vehicle - Various Sites		685	514	768	1,032	466	3,464
Replace Light Duty Mobile Equipment - Various Sites		554	559	857	348	260	2,577
Replace Heavy Duty Forklift - Unit 9799 - Bishop's Falls		166					166
Replace Bulldozer - Unit No. 7657 - Bishop's Falls			275				275
Replace Excavator - Various Sites				134		92	226
Replace Front End Loader - Unit No. 9813 - Holyrood						110	110
Purchase High Voltage Breaker Timing Sets			101				101
TOTAL TOOLS AND EQUIPMENT	0	1,642	1,545	1,858	1,448	999	7,492
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,796	24,753	34,606	37,382	38,907	29,517	166,961

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
INFORMATION SYSTEMS							
SOFTWARE APPLICATIONS							
New Infrastructure							
Perform Minor Application Enhancements - Hydro Place		121	122	130	133		505
Cost Recoveries		(36)	(37)	(26)	(27)		(125)
Work Protection Software Design		71	314				385
Cost Recoveries		(21)					(21)
Upgrade Intranet - Hydro Place		66	68	73	75		282
Cost Recoveries		(20)	(20)	(15)	(15)		(70)
Application Upgrades - Hydro Place			317				317
Cost Recoveries			(95)				(95)
Application Enhancements - Install MS SCOM - Hydro Place			231				231
Cost Recoveries			(63)				(63)

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
Upgrade of Technology							
Corporate Application Environment - Upgrade Microsoft Products		751	675	678			2,105
Cost Recoveries		(225)	(203)	(203)			(631)
Upgrade Business Intelligence Toolset Software - Hydro Place		84			179		262
Cost Recoveries		(25)			(54)		(79)
Upgrade Citrix Suite and Lotus Notes & JDE - Hydro Place			4,206				4,206
Cost Recoveries			(1,091)				(1,091)
Upgrade Internet - Hydro Place			89			97	186
Upgrade Lotus Notes - Hydro Place				283		459	742
Cost Recoveries				(57)		(125)	(182)
Upgrade Showcase Strategy Suite - Hydro Place				173			173
Cost Recoveries				(35)			(35)
Corporate Application Environment, Windows - iSeries - Hydro Place					119		119
Cost Recoveries					(32)		(32)
TOTAL SOFTWARE APPLICATIONS	0	765	4,513	1,001	377	431	7,087

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
COMPUTER OPERATIONS							
Infrastructure Replacement							
PC Replacement Program - Various Sites		407	443	426	478	478	2,230
Replace Peripheral Infrastructure - Various Sites		222	127	202	207	207	966
Upgrade Enterprise Storage Capacity - Hydro Place		241	576	89	91	92	1,089
Cost Recoveries		(72)	(173)	(24)	(25)	(25)	(319)
New Infrastructure							
Develop Learning Management System Safety Courses - Hydro Place		138	141	143	147	151	719
Cost Recoveries		(41)	(43)	(43)	(44)	(45)	(216)
Smart Card Implementation - Various Sites		133					133
Cost Recoveries		(40)					(40)
Upgrade Security SCADA Intrusion Prevention System - Hydro Place		62					62
Upgrade Security Vulnerability Management System - Hydro Place		81					81
Cost Recoveries		(24)					(24)
SAN Volume Control - Hydro Place			171				171
Cost Recoveries			(51)				(51)
Security Trip Wire - Hydro Place				102			102
Cost Recoveries				(31)			(31)
Install Password Vaulting - Hydro Place					94		94
Cost Recoveries					(28)		(28)
Upgrade of Technology							
Upgrade Server Technology Program - Various Sites		197	255	531	361	369	1,713
Cost Recoveries		(59)	(49)	(145)	(98)	(100)	(451)
TOTAL COMPUTER OPERATIONS	0	1,243	1,397	1,251	1,182	1,126	6,199
TOTAL INFORMATION SYSTEMS	0	2,008	5,910	2,251	1,559	1,557	13,286

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
TELECONTROL							
NETWORK SERVICES							
Infrastructure Replacement							
Install Fibre Optic Cable - Hinds Lake	209	483					692
Replace Radomes - Various Sites		212	145	170	164		691
Upgrade Remote Terminal Units - Various Sites		190	85			330	605
Purchase Tools and Equipment Less than $50,000		109	98	91	95	98	491
Install Fibre Optic Cable Deer Lake to Berry Hill - TL226			66	2,707			2,773
Refurbish Microwave Site - Deer Lake			184				184
Upgrade 1603 SONET Multiplexer - Various Sites			73				73
Replace Power Line Carrier TL-214 - Bottom Brook to Doyles				437			437
Replace MDR 6000 Microwave Radio (West) - Various Sites					2,644		2,644
Replace MDR 4000 Microwave Radio (West) - Various Sites					2,041		2,041
Replace Mobile Radio System Churchill Falls to Happy Valley - Happy Valley					550		550
Refurbish Microwave Sites - Various Sites						1,830	1,830
Replace MDR 4000 Microwave Radio (East) - Various Sites						1,200	1,200
Expand West Coast Microwave - Various Sites						453	453
Upgrade Towers - Various Sites						84	84

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
Network Infrastructure							
Replace Stationary Battery Banks and Chargers - Various Sites		717	281	41			1,039
Replace Network Communications Equipment - Various Sites		131	97	119	125	140	612
Install Mobile Communications - Port Hope Simpson, Charlottetown		208					208
Install Backup Communications Systems - Various Sites			200				200
Install Microwave Wind Generation Hybrid - Gull Pond Hill			79				79
Upgrade of Technology							
Replace Radio Link with Fiber - Bay d'Espoir		489					489
Upgrade Private Automated Branch Exchange (PABX) - Various Sites		339					339
Upgrade Operator Training Simulator - Hydro Place		92					92
Upgrade Site Facilities - Various Sites			47	45	48	49	189
Replace Telephone Keyset - Various Sites			105				105
Install Wireless Networking - Various Sites				48			48
Replace Power Line Carrier - Berry Hill and Peter's Barron						900	900
Replace Batteries - Various Sites						667	667
Upgrade IP Scada Network - Various Sites						110	110
TOTAL TELECONTROL	209	2,969	1,461	3,658	5,667	5,861	19,825

PROJECT DESCRIPTION	Expended to 2009	2010	2011	2012	2013	2014	Total
				($000)			
TRANSPORTATION							
Replace Vehicles and Aerial Devices - Various Sites		2,156	4,489	2,493	4,519	1,679	15,336
TOTAL TRANSPORTATION	0	2,156	4,489	2,493	4,519	1,679	15,336
ADMINISTRATION							
Remove Safety Hazards - Various Sites		252	250	256	262	269	1,559
Upgrade System Security - Various Sites	767	702					1,469
Purchase Tools and Equipment Less than $50,000		180	68	98	50	0	397
Replace Humidifiers in Air Handling Units - Hydro Place		75	78				153
Perform Upgrades as Determined in Building Condition Study - Hydro Place			146	162	178	269	755
TOTAL ADMINISTRATION	767	1,210	543	516	491	538	4,332
TOTAL GENERAL PROPERTIES	976	8,343	12,403	8,919	12,235	9,635	52,779

APPENDIX B

Twenty-Year Capital Plan

	Accuracy 10%	Accuracy 25%				Accuracy 50%				Accuracy 50% to order of magnitude										
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Generation																				
Hydro plants	11,455	4,579	7,474	2,838	9,150	7,000	5,860	7,198	4,935	6,785	3,293	2,586	735	2,425	3,080	1,985	1,520	1,660	970	2,100
Thermal Plant	4,864	11,920	6,097	2,955	6,128	4,725	4,700	4,200	2,750	5,100	5,250	3,700	6,750	5,300	2,325	2,850	3,000	4,700	3,650	3,900
Gas Turbines	1,638	1,744	4,624	3,649	4,893	2,215	1,400	250	950	2,450	3,450	3,100	3,325	3,410	3,450	3,250	3,530	2,220	1,600	1,200
Tools and Equipment	234	186	212	72	34	393	393	393	393	393	393	393	393	393	393	393	393	393	393	393
Transmission and Terminals																				
Terminal Stations	5,820	9,358	10,053	13,873	3,817	7,649	7,135	7,480	10,725	10,605	10,535	7,935	8,751	8,280	7,870	7,685	8,205	8,115	8,395	5,395
Transmission	5,180	4,844	4,801	6,866	9,739	9,412	8,202	10,407	9,428	8,123	8,591	11,574	12,476	11,370	18,594	16,250	15,201	16,072	17,556	23,434
Metering	34	833	1,171	835	39	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Tools and Equipment	1,642	1,545	1,858	1,448	999	1,150	1,283	1,150	1,081	1,053	1,552	1,444	1,246	1,074	1,362	3,186	1,280	1,255	1,106	1,517
Rural Systems																				
Distribution	8,512	14,702	15,384	12,112	12,357	14,162	13,337	13,267	14,276	14,307	11,437	11,007	9,559	10,138	7,977	9,955	10,066	9,362	8,730	5,630
Diesel Plants	3,209	2,963	3,903	2,241	2,566	6,375	6,242	5,340	5,265	4,338	2,605	3,160	2,190	2,180	1,075	1,130	3,535	3,940	1,195	1,100
General Properties																				
Information Systems	2,008	5,910	2,251	1,559	1,557	2,694	3,368	4,303	4,682	3,488	2,848	6,700	1,880	6,652	2,203	2,746	1,752	1,752	2,235	1,818
Telecontrol	2,969	1,461	3,658	5,667	5,861	5,038	8,139	1,140	2,119	2,000	3,550	6,037	5,762	1,984	3,247	1,805	2,592	1,251	2,931	2,373
Transportation	2,156	4,490	2,493	4,519	1,679	1,794	1,668	3,253	2,446	1,544	4,433	2,883	2,705	1,564	2,309	2,638	1,577	1,600	5,187	1,798
Administrative	1,368	704	516	1,558	538	518	468	318	398	478	618	518	518	418	678	718	468	618	618	318
Contingency Fund	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Total Existing Assets	**52,775**	**66,239**	**65,497**	**61,189**	**60,356**	**64,158**	**63,228**	**59,732**	**60,481**	**61,698**	**59,588**	**62,070**	**57,324**	**56,221**	**55,596**	**55,625**	**54,153**	**53,971**	**55,599**	**52,009**
Total for 20 Years	1,177,508																			
Average	58,875																			
Total Holyrood without Lower Churchill	705	60,000	205,000	235,000	130,000	54,440	36,800	31,650	19,650	20,150	2,900	1,425	1,000	0	1,500	50	0	0	2,500	0
Total for 20 Years	802,770																			
Average	40,139																			

	Expended to 2009	2010	Future Years	Total
		($000)		
GENERATION	1,282	18,679	8,046	28,007
TRANSMISSION AND RURAL OPERATIONS	1,796	24,753	23,575	50,124
GENERAL PROPERTIES	976	8,343	0	9,319
CONTINGENCY FUND		1,000	0	1,000
TOTAL CAPITAL BUDGET	4,055	52,775	31,621	88,450

	Expended to 2009	2010	Future Years	Total
		($000)		
GENERATION				
Hydraulic Plant	73	11,455	0	11,528
Thermal Plant	1,210	5,352	3,057	9,618
Gas Turbines	0	1,638	4,989	6,627
Tools and Equipment	0	234	0	234
TOTAL GENERATION	1,282	18,679	8,046	28,007
TRANSMISSION AND RURAL OPERATIONS				
Terminal Stations	636	5,554	7,892	14,081
Transmission	968	5,115	1,055	7,138
Distribution	0	8,512	13,757	22,268
Generation	193	2,858	871	3,922
Properties	0	1,039	0	1,039
Metering	0	34	0	34
Tools and Equipment	0	1,642	0	1,642
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,796	24,753	23,575	50,124
GENERAL PROPERTIES				
Information Systems	0	2,008	0	2,008
Telecontrol	209	2,969	0	3,179
Transportation	0	2,156	0	2,156
Administrative	767	1,210	0	1,977
TOTAL GENERAL PROPERTIES	976	8,343	0	9,319
CONTINGENCY FUND		1,000		1,000
TOTAL CAPITAL BUDGET	4,055	52,775	31,621	88,450

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
			($000)		
HYDRAULIC PLANT					
Replace and Purchase Stator Windings - Bay d'Espoir		4,687		4,687	B-4
Purchase Spare Stator Winding Units 2 - Bay d'Espoir	37	2,806		2,843	
Upgrade Plant Access Road - Bay d'Espoir		1,550		1,550	B-10
Install Meteorological Stations - Various Sites		443		443	C-2
Replace 50 kW Diesel Generator - Bay d'Espoir	36	289		325	
Upgrade Units 5 and 6 Cooling Water Systems - Bay d'Espoir		305		305	C-22
Upgrade Intake Gate Controls - Upper Salmon		284		284	C-31
Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg - Bay d'Espoir		236		236	C-43
Purchase Spare Spherical Valve Seal and Ring Assemblies - Bay d'Espoir		223		223	C-67
Replace A/C Units in Control Room and Communications Room Upper Salmon		197		197	D-3
Replace Human Machine Interface (HMI) Computer - Paradise River		158		158	D-10
Upgrade Fuel Storage - Hinds Lake		149		149	D-12
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir		81		81	D-15
Install Air Conditioning at Burnt Spillway - Bay d'Espoir		48		48	
TOTAL HYDRAULIC PLANT	73	11,455	0	11,528	
THERMAL PLANT					
Replace Programmable Logic Controllers - Holyrood		1,208	1,649	2,857	B-6
Refurbish Fuel Storage Facility - Holyrood		2,500		2,500	B-8
Condition Assessment and Life Extension Study - Holyrood	1,210	686		1,895	
Replace Pump House Motor Control Centers - Holyrood		50	999	1,049	B-12
Replace Steam Seal Regulator Unit 1 - Holyrood		335	214	548	B-16
Replace Diesel Fire Pump - Holyrood		112	195	307	C-9
Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level - Holyrood		231		231	C-50
Install Warm Air Make-up Access - Holyrood		170		170	D-6
Improve On Site Paving and Drainage - Holyrood		59		59	D-26
TOTAL THERMAL PLANT	1,210	5,352	3,057	9,618	
GAS TURBINES					
Upgrade Gas Turbine Plant Life Extension - Hardwoods		1,305	4,690	5,995	B-2
Upgrade Glycol Systems - Stephenville		261	299	560	B-14
Upgrade Fuel Tank Farm Controls - Happy Valley		72		72	D-20
TOTAL GAS TURBINE PLANTS	0	1,638	4,989	6,627	
TOOLS AND EQUIPMENT					
Purchase Tools and Equipment Less than $50,000	0	154	0	154	
Purchase 21 Inch Metal Cutting Lathe - Bay d'Espoir		80		80	D-18
TOTAL TOOLS AND EQUIPMENT	0	234	0	234	
TOTAL GENERATION	1,282	18,679	8,046	28,007	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
			($000)		
TERMINAL STATIONS					
New 25 kV Terminal Station - Labrador City	283	2,700	7,007	9,990	
Upgrade Power Transformers - Various Sites		816		816	B-38
Perform Grounding Upgrades - Various Sites	252	291		543	
Upgrade Trailer and Mobile Substation - Bishop's Falls		30	468	499	C-78
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood		79	417	496	C-84
Replace Insulators - Various Terminal Stations		399		399	C-103
Upgrade Circuit Breakers - Various Terminal Stations		342		342	C-119
Replace Disconnects - Various Sites		199		199	D-29
Replace Instrument Transformers - Various Sites		197		197	D-42
Upgrade Great Northern Peninsula Protection - Various Sites	101	91		192	
Install Digital Fault Recorder - Deer Lake		166		166	D-54
Replace Air Compressors - Western Avalon		97		97	D-65
Replace Surge Arrestors - Various Sites		73		73	D-80
Replace 230 kV Breaker Controls - Massey Drive and Buchans		73		73	D-82
TOTAL TERMINAL STATIONS	636	5,554	7,892	14,081	
TRANSMISSION					
Perform Wood Pole Line Management Program - Various Sites		2,308		2,308	B-28
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	968	964		1,932	
Upgrade Line TL-244 - Plum Point to Bear Cove		141	1,055	1,197	B-32
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		990		990	B-36
Upgrade Anchors on C Structures TL-259 - Parson's Pond		353		353	C-110
Replace Guy Wires TL-215 - Doyles to Grand Bay		301		301	C-128
Install Remote Ice Growth Detector Beams - Various Sites		58		58	D-93
TOTAL TRANSMISSION	968	5,115	1,055	7,138	
DISTRIBUTION					
Voltage Conversion - Labrador City		1,089	8,311	9,400	B-18
Upgrade Line 2 Distribution Feeder - Glenburnie		267	3,289	3,557	B-24
Upgrade Distribution Systems - All Service Areas		2,572		2,572	B-20
Provide Service Extensions - All Service Areas		2,428		2,428	B-26
Upgrade Distribution Lines - Various Sites		218	1,645	1,863	B-30
Replace Poles - Various Sites		1,083		1,083	B-34
Replace Recloser Control Panels - Various Sites		603		603	B-44
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois		82	511	593	B-46
Install New Voltage Regulators - Happy Valley		170		170	D-47
TOTAL DISTRIBUTION	0	8,512	13,757	22,268	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
			($000)		
GENERATION					
Replace Diesel Units - Norman Bay, Postville and Paradise River	170	1,700		1,870	
Increase Generation Capacity - L'Anse au Loup	23	821		844	
Replace Diesel Unit 2001 and Engine 566 - Francois		168	450	619	B-42
Replace Diesel Unit 2018 - McCallum		19	421	440	C-95
Replace Main Bus Splitter - Postville		149		149	D-59
TOTAL GENERATION	193	2,858	871	3,922	
PROPERTIES					
Install Fall Protection Equipment - Various Sites		198		198	D-32
Upgrade Accommodations - Norman Bay		196		196	D-44
Upgrade Fire Protection System - Bishop's Falls		158		158	D-57
Install Pole Storage Ramps - Various Sites		90		90	D-68
Install Transformer Storage Ramps - Various Sites		89		89	D-70
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls		88		88	D-74
Install Waste Oil Storage Tank - Port Hope Simpson		84		84	D-77
Upgrade Properties - Port Hope Simpson		71		71	D-86
Legal Survey of Primary Distribution Line Right of Way - Various Sites		65		65	D-89
TOTAL PROPERTIES	0	1,039	0	1,039	
METERING					
Purchase Meters and Equipment - Various Sites		34		34	
TOTAL METERING	0	34	0	34	
TOOLS AND EQUIPMENT					
Replace Off Road Track Vehicles - Whitbourne and Bishop's Falls		685		685	B-40
Replace Light Duty Mobile Equipment - Various Sites		554		554	B-48
Replace Heavy Duty Forklift - Unit 9799 - Bishop's Falls		166		166	D-52
Purchase Tools and Equipment Less than $50,000		237		237	
TOTAL TOOLS AND EQUIPMENT	0	1,642	0	1,642	
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,796	24,753	23,575	50,124	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years ($000)	Total	Page Ref
INFORMATION SYSTEMS					
SOFTWARE APPLICATIONS					
New Infrastructure					
Perform Minor Application Enhancements - Hydro Place		121		121	D-120
Cost Recoveries		(36)		(36)	
Work Protection Software Design - Hydro Place		71		71	D-129
Cost Recoveries		(21)		(21)	
Upgrade Intranet - Hydro Place		66		66	D-132
Cost Recoveries		(20)		(20)	
Upgrade of Technology					
Corporate Application Environment - Upgrade Microsoft Products		751		751	B-52
Cost Recoveries		(225)		(225)	
Upgrade Business Intelligence Toolset Software - Hydro Place		84		84	D-126
Cost Recoveries		(25)		(25)	
TOTAL SOFTWARE APPLICATIONS	0	765	0	765	
COMPUTER OPERATIONS					
Infrastructure Replacement					
PC Replacement Program - Various Sites		407		407	C-149
Replace Peripheral Infrastructure - Various Sites		222		222	C-166
Upgrade Enterprise Storage Capacity - Hydro Place		241		241	D-103
Cost Recoveries		(72)		(72)	
New Infrastructure					
Develop Learning Management System Safety Courses - Hydro Place		138		138	D-114
Cost Recoveries		(41)		(41)	
Smart Card Implementation - Various Sites		133		133	D-116
Cost Recoveries		(40)		(40)	
Upgrade Security SCADA Intrusion Prevention System - Hydro Place		62		62	D-124
Upgrade Security Vulnerability Management System - Hydro Place		81		81	D-127
Cost Recoveries		(24)		(24)	
Upgrade of Technology					
Upgrade Server Technology Program - Various Sites		197		197	D-107
Cost Recoveries		(59)		(59)	
TOTAL COMPUTER OPERATIONS	0	1,243	0	1,243	
TOTAL INFORMATION SYSTEMS	0	2,008	0	2,008	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
			($000)		
TELECONTROL					
NETWORK SERVICES					
Infrastructure Replacement					
Install Fibre Optic Cable - Hind's Lake	209	483		692	
Replace Radomes - Various Sites		212		212	C-172
Upgrade Remote Terminal Units - Various Sites		190		190	D-96
Purchase Tools and Equipment Less than $50,000		109		109	
Network Infrastructure					
Replace Stationary Battery Banks and Chargers - Various Sites		717		717	B-50
Install Mobile Communications - Port Hope Simpson, Charlottetown		208		208	C-187
Replace Network Communications Equipment - Various Sites		131		131	D-112
Upgrade of Technology					
Replace Radio Link with Fiber - Bay d'Espoir		489		489	C-141
Upgrade Private Automated Branch Exchange (PABX) - Various Sites		339		339	C-154
Upgrade Operator Training Simulator - Hydro Place		92		92	D-118
TOTAL TELECONTROL	209	2,969	0	3,179	
TRANSPORTATION					
Replace Vehicles and Aerial Devices - Various Sites		2,156		2,156	B-49
TOTAL TRANSPORTATION	0	2,156	0	2,156	
ADMINISTRATION					
Upgrade System Security - Various Sites	767	702		1,469	
Remove Safety Hazards - Various Sites		252		252	C-161
Purchase Tools and Equipment Less than $50,000		180		180	
Replace Humidifiers in Air Handling Units - Hydro Place		75		75	D-122
TOTAL ADMINISTRATION	767	1,210	0	1,977	
TOTAL GENERAL PROPERTIES	976	8,343	0	9,319	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
		($000)			
GENERATION					
Upgrade Gas Turbine Plant Life Extension - Hardwoods		1,305	4,690	5,995	B-2
Replace and Purchase Stator Windings - Bay d'Espoir		4,687		4,687	B-4
Replace Programmable Logic Controllers - Holyrood		1,208	1,649	2,857	B-6
Purchase Spare Stator Winding Units 2 - Bay d'Espoir	37	2,806		2,843	
Refurbish Fuel Storage Facility - Holyrood		2,500		2,500	B-8
Condition Assessment and Life Extension Study - Holyrood	1,210	686		1,895	
Upgrade Plant Access Road - Bay d'Espoir		1,550		1,550	B-10
Replace Pump House Motor Control Centers - Holyrood		50	999	1,049	B-12
Upgrade Glycol Systems - Stephenville		261	299	560	B-14
Replace Steam Seal Regulator Unit 1 - Holyrood		335	214	548	B-16
TOTAL GENERATION	1,246	15,388	7,850	24,484	
TRANSMISSION AND RURAL OPERATIONS					
New 25 kV Terminal Station - Labrador City	283	2,700	7,007	9,990	
Voltage Conversion - Labrador City		1,089	8,311	9,400	B-18
Upgrade Distribution Systems - All Service Areas		2,572		2,572	B-20
Upgrade Line 2 Distribution Feeder - Glenburnie		267	3,289	3,557	B-24
Provide Service Extensions - All Service Areas		2,428		2,428	B-26
Perform Wood Pole Line Management Program - Various Sites		2,308		2,308	B-28
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	968	964		1,932	
Replace Diesel Units - Norman Bay, Postville and Paradise River	170	1,700		1,870	
Upgrade Distribution Lines - Various Sites		218	1,645	1,863	B-30
Upgrade Line TL-244 - Plum Point to Bear Cove		141	1,055	1,197	B-32
Replace Poles - Various Sites		1,083		1,083	B-34
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		990		990	B-36
Increase Generation Capacity - L'Anse au Loup	23	821		844	
Upgrade Power Transformers - Various Sites		816		816	B-38
Replace Off Road Track Vehicles - Whitbourne and Bishop's Falls		685		685	B-40
Replace Diesel Unit 2001 and Engine 566 - Francois		168	450	619	B-42
Replace Recloser Control Panels - Various Sites		603		603	B-44
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois		82	511	593	B-46
Replace Light Duty Mobile Equipment - Various Sites		554		554	B-48
Perform Grounding Upgrades - Various Sites	252	291		543	
TOTAL TRANSMISSION AND RURAL OPERATIONS	1,695	20,479	22,269	44,443	
GENERAL PROPERTIES					
Replace Vehicles and Aerial Devices - Various Sites		2,156		2,156	B-49
Upgrade System Security - Various Sites	767	702		1,469	
Replace Stationary Battery Banks and Chargers - Various Sites		717		717	B-50
Install Fibre Optic Cable - Hind's Lake	209	483		692	
Corporate Application Environment - Upgrade Microsoft Products		526		526	B-52
TOTAL GENERAL PROPERTIES	976	4,583	0	5,560	
TOTAL PROJECTS OVER $500,000	3,918	40,450	30,119	74,487	

Project Title: Upgrade Gas Turbine Plant Life Extension
Location: Hardwoods
Category: Generation - Gas Turbines
Definition: Other
Classification: Normal

Project Description:

This project is to refurbish equipment and systems at the Hardwoods Gas Turbine Plant (Hardwoods). This is the final three years of a four-year refurbishment program to implement upgrades recommended by the engineering consulting company, Stantec, Inc. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**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**

Operating Experience:

Hardwoods operates approximately 60 percent of the time as a synchronous condenser to provide voltage support to the Island Interconnected System. It operates in generating mode less than one percent of the time, mainly at times of peak system load or for emergency purposes during unplanned outages.

Project Justification:

Major equipment at Hardwoods has reached the end of its useful life. As Hardwoods is required to provide voltage support and generation during peak load and emergency periods, the recommended refurbishments must be completed to enable Hydro to continue operating the plant reliably.

Future Plans:

There is a similar upgrade planned for the Stephenville Gas Turbine Plant. See the five-year plan (Capital Plan 2010 Tab, Appendix A).

Project Title: Upgrade Gas Turbine Plant Life Extension **(cont'd.)**

Attachment:

See report entitled "Plant Life Extension Upgrades – Hardwoods Gas Turbine" located in Volume II, Tab 1, for further project details.

Project Title: Replace and Purchase of Stator Windings
Location: Bay d'Espoir Hydroelectric Generating Station
Category: Generation - Hydraulic
Definition: Other
Classification: Normal

Project Description:

This project consists of the installation of a stator winding in generating Unit 2. This stator winding was originally purchased as a spare as approved in Board Order No. P.U. 36 (2008). 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 winding operates to its 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 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. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**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	0.0
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**

Operating Experience:

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, since they were commissioned in 1967-1968.

Project Justification:

This project is required to maintain system reliability. The Unit 2 stator winding will be replaced before a failure occurs and a spare winding will be purchased and retained on site in case another unit fails.

Project Title: Replace and Purchase of Stator Windings **(cont'd.)**

Project Justification: (cont'd.)

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.

Future Plans:

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 test and inspection results, 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 an additional winding for either Unit 1, 3 or 4. Proposals for purchase and installation of the other two windings will be made in future years. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replacement of Stator Windings at the Bay d'Espoir Hydroelectric Generating Station" located in Volume II, Tab 2, for further project details.

Project Title: Replace Programmable Logic Controllers
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description:

This project is to replace the programmable logic controllers (PLC) at the Holyrood Thermal Generating Station (Holyrood) with Foxboro Distributed Control Systems (DCS) for the Burner Management Systems on Units 1 and 2, the Warm Air Make-up, the Water Treatment Plant and the Waste Water Treatment Plant. The PLCs which control these critical processes are at the end of their useful lives. This project will integrate each new DCS into the existing plant DCS network. This will result in one common control system for the entire generating station providing cost savings related to training and spare parts inventory. This work is consistent with the Holyrood Gas Turbine PLC replacement project in 2009. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**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**

Operating Experience:

A failure of the PLC for the Warm Air Make-up System in 2006 caused the system to be out of service for six weeks. During that period, a risk of not obtaining replacement parts for the Modicon PLC systems was identified. Newfoundland and Labrador Hydro (Hydro) found replacement parts on the eBay website in order to get this system back in service. In addition, many of the Human Machine Interface (HMI) systems operate on obsolete computer systems that are no longer supported by the manufacturers.

Project Title: Replace Programmable Logic Controllers **(cont'd.)**

Project Justification:

This project is justified on the basis of maintaining the reliability of plant control systems through the replacement of obsolete equipment and software with a common controls system platform that has a redundant processing feature. A plant-wide installation of a common system delivers tangible cost benefits as well as intangible benefits to operations staff.

Future Plans:

The PLC replacement for the Water Treatment Plant is planned to be completed in 2011. The PLC replacement for the Warm Air Make-up System and the Waste Water Treatment Plant is planned to be completed in 2012. See the five-year plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replace Programmable Logic Controllers at the Holyrood Thermal Generating Station" located in Volume II, Tab 3, for further project details.

Project Title: Refurbish Fuel Storage Facility
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description:

This project involves the upgrade of existing components within the Fuel Oil Storage Facility at the Holyrood Generating Facility (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 No. 4. Table 1 below provides the budget estimate for this project.

Table 1: 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**

Operating Experience:

There are four above ground fuel oil storage tanks (capacity 200,000 barrels) 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.

Tank 4 was cleaned out 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 which provide the scope of work for this capital project.

Project Title: Refurbish Fuel Storage Facility **(cont'd.)**

Project 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.

Future Plans:

Upgrades are planned for the next two years as shown in the five-year plan. See the five-year plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Refurbishment of the Fuel Oil Storage Facility - Holyrood Thermal Generating Station" located in Volume II, Tab 4, for further project details.

Project Title: Upgrade Plant Access Road
Location: Bay d'Espoir
Category: Generation - Hydraulic
Definition: Other
Classification: Normal

Project Description:

This project involves roadside ditching, removal and replacement of 20 culverts, removal of old asphalt, sub grade repairs and placement of new Class "A" road topping and pavement along the 3.5 km main access road to the Bay d'Espoir Power House. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	165.0	0.0	0.0	165.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	1,100.0	0.0	0.0	1,100.0
Other Direct Costs	20.0	0.0	0.0	20.0
O/H, AFUDC & Escln.	130.7	0.0	0.0	130.7
Contingency	134.3	0.0	0.0	134.3
TOTAL	**1,550.0**	**0.0**	**0.0**	**1,550.0**

Operating Experience:

The road has been in service for over 40 years. There are numerous holes, depressions, bumps and frost heaves that make driving it extremely difficult. The entire equipment maintenance fleet for all of Hydro Generation resides at the Bay d'Espoir Facility and constantly travel over this road to access other Hydro Plants as well as other Bay d'Espoir assets in the area. While Hydro does not hold title to the road, Hydro built the road during construction in the 1960’s and subsequently paved the road in 1977.

Project Justification:

The main access road to the Bay d'Espoir Power House was constructed during the initial Stage 1 Hydroelectric Development in the mid 1960's. The asphalt surfacing is 30 years old and in deplorable condition. In its present state, it is somewhat hazardous to use, particularly in the winter time, and it is very hard on vehicles using the road, both fleet and personal. There have been numerous complaints from staff about its condition.

Project Title: Upgrade Plant Access Road **(cont'd.)**

Project Justification: (cont'd.)

This road is the main access road to the Province's largest Island Interconnected Hydroelectric Plant. In addition, this facility is the center for maintenance for all Hydro generating plants. This road needs to be re-built to a Provincial roadway standard. It is used every day by approximately 100 Hydro employees working at the Bay d'Espoir Plant as well as the general public, including up to 150 tourists who visit the plant annually.

Hydro Generation's Emergency Response Plan is structured around rapid response. This existing road is not in a suitable condition to move quickly with sick and injured people or to mobilize emergency response equipment and materials very quickly. In addition, if the local fire department has to respond to the site, the fully loaded pumper truck would be at great risk travelling the road in its current condition and would not be able to respond as quickly as it should. This exposes the plant to unnecessary risk.

Future Plans:

None.

Attachments:

A report entitled "Upgrade Plant Access Road – Bay d'Espoir" will be filed by the end of August 2009 *(To be placed in Volume II, Tab 5).*

Project Title: Replace Pump House Motor Control Centers
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description:

This project is required to replace the motor control center in pump house 1 and pump house 2, construct a new room in each pump house to accommodate the new motor control centers, replace power cables feeding the motor control centres from the main plant, and modify power supply cables and piping in the pump houses.

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

In pump house 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 pump house 2 there is sufficient space available such that this component of the work is not required.

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

Table 1: 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**

Operating Experience:

The existing motor control centers in pump house 1 and pump house 2 have been installed since 1969 and 1977, respectively, and are located in the main open equipment area of the pump house where they are exposed to a damp and corrosive environment. This environment has caused deterioration

Project Title: Replace Pump House Motor Control Centers **(cont'd.)**

Operating Experience: (cont'd.)

to the motor control centers such as rusting of contacts due to moisture buildup which results in an unreliable system and unplanned outages.

Project Justification:

The justification for this project is based on safety and reliability. The existing equipment does not comply with current safety codes and standards relating to exposure of live parts and the use of certain materials such as asbestos. Sections 22 and 26 of the Canadian Standards Association (CSA), Canadian Electrical Code contain extensive requirements for the design and manufacture of motor control centers and other electrical equipment that exceed the codes and standards of the 1960's and 1970's.

The Holyrood generating units cannot operate without a supply of water which is provided by pump house 1 and pump house 2. The motor control centers are integral to the pump house operation, and therefore integral to the Holyrood system and the reliability of generation supply to the Island Interconnected System. The existing equipment is built in a general purpose enclosure and therefore not suitable for applications where there are levels of corrosive elements or moisture as found in the pump house environment. The environment has therefore caused deterioration to the equipment such as moisture build up and rusting of electrical contacts which results in interruptions to the reliable supply of water to the plant and unplanned outages to the generation units.

Future Plans:

None.

Attachment:

The report entitled "Replace Pump House Motor Control Centers" located in Volume II, Tab 6 for further project details.

Project Title: Upgrade Glycol Systems
Location: Stephenville
Category: Generation - Gas Turbines
Definition: Other
Classification: Normal

Project Description:

The following equipment will be replaced at Stephenville Gas Turbine plant.

- Alternator glycol cooler, piping, valves, and pumps; and
- Main lube oil glycol pump.

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

Table 1: 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**

Operating Experience:

Over the past two summers, the alternator cooling system has been unable to adequately cool the alternator and emergency cooling was required to keep the alternator from overheating. 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 alternator glycol cooler were cleaned however the performance of the unit did not increase.

Project Title: Upgrade Glycol Systems **(cont'd.)**

Operating Experience: (cont'd.)

Replacement parts are unavailable for the main lube oil and alternator cooler glycol pumps. The three-way glycol mixing valve on the alternator cooling system has been operating in the full-open position since its internal components are no longer functioning. This no longer permits precise glycol temperature control.

Project Justification:

The alternator cooling system components are in critical condition and require replacement. The outdoor alternator glycol cooler has reached the end of its useful life. The glycol circulating pumps are obsolete and replacement parts cannot be sourced. The three-way glycol regulating valve has failed and requires replacement because its internal components are damaged and cannot be repaired. 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.

Since the main lube oil system is critical to the operation of the gas turbines and the alternator, neither power generation nor synchronous condensing may take place if the main lube oil system is not operational. Therefore, the obsolete main lube oil glycol pump must be replaced.

Future Plans:

None.

Attachment:

See report entitled "Upgrade Glycol Systems at Stephenville Gas Turbine Plant" located in Volume II, Tab 7, for further project details.

Project Title: Replace Steam Seal Regulator – Unit 1
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description:

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.

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

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	45.0	0.0	78.6
Contingency	0.0	42.7	0.0	42.7
TOTAL	**334.7**	**213.7**	**0.0**	**548.4**

Project Title: Replace Steam Seal Regulator – Unit 1 **(cont'd.)**

Operating Experience:

The existing Unit 1 steam seal regulator 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.

Project Justification:

The steam seal regulator servicing Unit 1 at Holyrood is 39 years old and Hydro has been unable to secure reliable support service from the original manufacturer, General Electric (GE). In recent years, this has necessitated replacement parts being made by local machine shops by copying the original components. The industry trend is to install the proposed control valve system.

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.

Future Plans:

A project to replace the steam seal regulator system on Unit 2 is planned for the years 2012 and 2013. Please see the five-year capital plan (Capital Plan 2010 Tab, Appendix A).

Attachment:

See report entitled "Replace Unit 1 Steam Seal Regulator" located in Volume II, Tab 8, for further project details.

Project Title: Voltage Conversion
Location: Labrador City
Category: Transmission and Rural Operations - Distribution Labrador
Definition: Other
Classification: Normal

Project Description:

This project will include all work required to complete the voltage conversion on the existing Labrador City distribution system from 4.16 kV to 25 kV. The scope of work will include upgrades to the system including the reconfiguration of the existing substations, the 46 kV sub-transmission lines and the distribution lines. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	250.0	1,400.0	1,400.0	3,050.0
Labour	270.0	300.0	360.0	930.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	400.0	1,200.0	2,100.0	3,700.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	76.9	311.2	564.2	952.3
Contingency	92.0	290.0	386.0	768.0
TOTAL	1,088.9	3,501.2	4,810.2	9,400.3

Operating Experience:

The Labrador City Distribution System was built, owned and operated by The Iron Ore Company of Canada (IOC) until acquired by Newfoundland and Labrador Hydro (Hydro) in 1992. At that time, a complete system upgrade was performed by Hydro to ensure that the system was capable of providing reliability to its customers. The system was upgraded to have the capacity to supply a local load of approximately 52 MW.

Project Justification:

The anticipated load growth in Labrador City is expected to surpass 52 MW by 2009. This increase in customer demand is the result of expansion at industrial sites such as the Iron Ore Company of Canada (IOC).

Project Title: Voltage Conversion **(cont'd.)**

Project Justification: (cont'd.)

Hydro has proactively completed a preliminary assessment of the current load growth in the area to determine if an additional system upgrade is required to meet the increasing demand. The assessment shows that the most economical and feasible method to address load growth in Labrador City is to perform a voltage conversion.

Future Plans:

None.

Attachments:

A report entitled "Voltage Conversion – Labrador City" will be filed by the end of August 2009 *(to be placed in Volume II, Tab 9)*.

Project Title: Upgrade Distribution Systems
Location: All Service Areas
Category: Transmission and Rural Operations - Distribution
Definition: Pooled
Classification: Normal

Project Description:

This project is an annual allotment based on historic expenditures to provide for the replacement of deteriorated poles, substandard structures, corroded and damaged conductors, rusty and overloaded transformers/street lights/reclosers and other associated equipment. This upgrading is identified through preventive maintenance inspections or when there is damage caused by storms and adverse weather conditions and salt contamination. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	2010	2011	Beyond	Total
Material Supply	1,576.0	0.0	0.0	1,576.0
Labour	608.0	0.0	0.0	608.0
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.	145.0	0.0	0.0	145.0
Contingency	243.0	0.0	0.0	243.0
TOTAL	**2,572.0**	**0.0**	**0.0**	**2,572.0**

Operating Experience:

An analysis of historical expenditures (2004 - 2008) on distribution upgrades by region is shown in Table 2. All historical dollars were converted to 2008 dollars using the Statistics Canada Utility Distribution Line Construction index and a five-year average was calculated.

Project Title: Upgrade Distribution Systems

Operating Experience: (cont'd.)

Table 2: Average Annual Expenditures

Region	Avg. Annual Expenditures (2004 - 2008) (2008 $000)
Central	1,011
Northern	1,050
Labrador	458
All Regions	2,519

The five-year expenditures for distribution upgrades by region are shown in Table 3.

Table 3: Five-year Expenditures

Expenditures ($000)											
	2004		2005		2006		2007		2008		2009
Region	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
Central	531	964	628	1,135	701	909	806	824	915	782	1,050
Northern	611	1,274	616	996	836	835	873	842	969	2,062	1,026
Labrador	329	432	357	364	375	404	356	558	409	859	450
Total	1,471	2,670	1,601	2,495	1,912	2,148	2,035	2,224	2,293	3,703	2,526

Other specifically approved projects for 2004 - 2009F are listed in Table 5.

Project Justification:

Based on the five-year average for distribution system upgrades for the period 2004 - 2008 the budget shown in Table 4 was developed, assuming distribution line cost escalation in 2010 of approximately two percent.

Table 4: Budget for Distribution System

Region	2010 Budget ($000)
Central	1,032
Northern	1,072
Labrador	468
Total	2,572

Project Title: Upgrade Distribution Systems **(cont'd.)**

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. See the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Table 5 shows the history of other specific distribution system upgrades that have been completed over the past 5 years.

Table 5: Five-Year 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
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

Project Title: Upgrade Distribution Systems **(cont'd.)**

Future Plans: (cont'd.)

Table 5: Five-Year Historical Information (cont'd.)

Year	Project Description	Budget ($000)	Actuals ($000)
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

Project Title: Upgrade Line 2 Distribution Feeder
Location: Glenburnie
Category: Transmission and Rural Operations - Distribution
Definition: Other
Classification: Normal

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 twenty 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 will be removed after the new line is commissioned. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	335.0	150.0	485.0
Labour	210.0	90.0	615.0	915.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	1,016.0	1,016.0
Other Direct Costs	32.0	69.0	120.0	221.0
O/H, AFUDC & Escln.	25.3	84.2	542.5	652.0
Contingency	0.0	0.0	267.7	267.7
TOTAL	**267.3**	**578.2**	**2,711.2**	**3,556.7**

Operating Experience:

The existing distribution line is a single 12.5 kV feeder originating from Glenburnie Terminal Station and extending to the community of Trout River, where it provides continuous service to approximately 300 customers. The line contains deteriorated components such as poles, cross arms and insulators that need replacement. 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.

Project 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 of the line components were installed at the time of original construction and

Project Title: Upgrade Line 2 Distribution Feeder **(cont'd.)**

Project Justification: (cont'd.)

have exceeded their service lives of 30 years. In addition, line components are deteriorated and may have remaining 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. 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. Existing line components are no longer at a standard used by Hydro for line applications; this increases the level of difficulty in material procurement for repair.

Future Plans:

Future distribution upgrades will be proposed in future capital budget applications. Please see the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Glenburnie Line 2 – Upgrade Distribution System" located in Volume II, Tab 10, for further project details.

Project Title: Provide Service Extensions
Location: All Service Areas
Category: Transmission and Rural Operations - Distribution
Definition: Pooled
Classification: Normal

Project Description:

This project is an annual allotment based on past expenditures to provide for service connections including street lights to new customers. Table 1 identifies the total budget for the Central, Northern and Labrador operating regions.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	1,172.0	0.0	0.0	1,172.0
Labour	890.0	0.0	0.0	890.0
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.	137.0	0.0	0.0	137.0
Contingency	229.0	0.0	0.0	229.0
TOTAL	**2,428.0**	**0.0**	**0.0**	**2,428.0**

Operating Experience:

An analysis of average historical expenditures (2004 - 2008) on new customer connections by region is shown in the Table 2. All historical dollars were converted to 2008 dollars using the Statistics Canada Utility Distribution Line Construction index and a five-year average was calculated.

Table 2: Average Annual Expenditures

Region	**Avg. Annual Expenditures (2004 - 2008) (2008 $000)**
Central	980
Northern	752
Labrador	645
Total	2,377

Project Title: Provide Service Extensions **(cont'd.)**

Operating Experience: (cont'd.)

The five-year actual expenditures for service extensions by region are shown in Table 3.

Table 3: Five Year Expenditures

Expenditures '($000)											
	2004		2005		2006		2007		2008		2009
Region	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Central	503	1,070	619	840	761	824	844	967	910	1,056	1,028
Northern	464	729	504	611	580	614	618	960	637	734	758
Labrador	591	484	605	556	643	535	622	873	612	1,340	653
Total	1,558	2,283	1,728	2,007	1,984	1,973	2,084	2,800	2,159	3,130 [1]	2,439

[1] The budgeted amount is an annual allotment based on the average of the annual expenditures for service extensions over the last five years. It is not based on a summary of specific projects. The majority of the increase in 2008 is due to growth located across the Labrador Interconnected System accounting for approximately $700,000. Other areas that had significant increases from the estimate were the Central area of the Island Interconnected System, the L'Anse au Loup System and the Pine Cove Interconnection at approximately $150,000, $120,000 and $130,000 respectively.

Project Justification:

Based on the five-year average of service extension expenditures for the period 2004 - 2008 the budget shown in Table 4 was developed, assuming distribution line cost escalation in 2010 of approximately two percent.

Table 4: Budget

Region	**2010 Budget ($000)**
Central	1,001
Northern	768
Labrador	659
Total	2,428

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. Please see the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Perform Wood Pole Line Management Program
Location: Various Sites
Category: Transmission and Rural Operations - Transmission
Definition: Pooled
Classification: Normal

Project Description:

The objective of this program is to maintain a comprehensive pole inspection and testing program using the conventional sound and bore methods supplemented by Non Destructive Evaluation (NDE), periodic full scale tests of poles removed from service, and remedial treatment application. Structural analysis to assess the line reliability, taking into account the system concept, is applied against all inspection information. Any replacement and/or refurbishment will be based on the assessment of quantitative risk with respect to in-service pole strength. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	482.3	0.0	0.0	482.3
Labour	1,257.9	0.0	0.0	1,257.9
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	115.8	0.0	0.0	115.8
O/H, AFUDC & Escln.	156.7	0.0	0.0	156.7
Contingency	195.6	0.0	0.0	195.6
TOTAL	**2,308.3**	**0.0**	**0.0**	**2,308.3**

Operating Experience:

Hydro operates approximately 2,400 kilometers of wood pole transmission lines, including approximately 26,000 poles. Hydro inspects 20 percent of a line each year using visual inspections and a “rule of thumb” approach to identify the “health” of a typical pole. Based on this program, Hydro has not had to replace many transmission size poles during the past 30 years. Previous intensive inspections targeting lines for specific issues on the Avalon Peninsula showed that decay and preservative retention were becoming an issue, showed extremely low preservative levels which are below minimum acceptable levels, and indicated that rot is becoming more prevalent in the 30-40 year old poles.

Project Title: Perform Wood Pole Line Management Program **(cont'd.)**

Project Justification:

Previous pole inspections indicate that almost half of the poles sampled did not meet the minimum preservative retentions and full scale pole tests of selected poles completed at Memorial University since 1999 indicate a 25 percent reduction of average pole strength over a 35 year period. When combined, these facts justify the strong need for a well managed wood pole inspection and treatment program that detects and corrects any "danger poles" in the system which will ensure safety as well as reliability.

Future Plans:

The program is based on two 10 year inspection cycles beginning in 2005. It provides an annual report to identify problem areas for the regional asset managers and to develop recommendations for appropriate pole replacements, as well as other components in the following years. Please see five-year capital plan (Capital Plan 2010 Tab, Appendix A).

Attachment:

See report entitled "2010 Wood Pole Line Management" located in Volume II, Tab 11, for further project details.

Project Title: Upgrade Distribution Lines
Location: Various Sites
Category: Transmission and Rural Operations - Distribution
Definition: Other
Classification: Normal

Project Description:

Newfoundland and Labrador Hydro (Hydro) provides service to residents in select rural communities within the province through the use of existing distribution lines. 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 budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	100.0	250.0	0.0	350.0
Labour	86.0	173.3	0.0	259.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	797.0	0.0	797.0
Other Direct Costs	13.4	82.7	0.0	96.1
O/H, AFUDC & Escln.	18.3	191.8	0.0	210.1
Contingency	0.0	150.2	0.0	150.2
TOTAL	**217.7**	**1,645.0**	**0.0**	**1,862.7**

Operating Experience:

The distribution lines were originally constructed over 40 years ago. Most of the line components were installed at the time of original construction and have exceeded the service life of 30 years. In addition, standardized inspection and testing procedures indicate line components are deteriorated and may have remaining life spans of only one to five years before widespread failure occurs.

Project Justification:

This project is justified on reliability. The conditions of the components could result in system failures and 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.

Future Plans:

Future distribution line upgrades will be approved in future capital budget applications. See five-year capital plan (Capital Plan 2010 Tab, Appendix A).

Project Title: Upgrade Distribution Lines **(cont'd.)**

Attachments:

See report entitled "Distribution Line Upgrades - 2010" located in Volume II, Tab 12, for further project details.

Project Title: Upgrade Transmission Line TL-244
Location: Plum Point to Bear Cove
Category: Transmission and Rural Operations - Transmission
Definition: Other
Classification: Normal

Project Description:

TL-244 has regularly sustained short, unexplained outages and currently experiences an outage frequency four times higher than the Hydro average. To determine the cause of this increased outage rate, an engineering study was completed by Hydro in 2008. This project proposes to 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
- The project also includes costs for alternate generation to the areas north of Plum Point.

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

Table 1: 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**

Operating Experience:

TL-244 currently experiences an outage frequency four times higher than the Hydro average and Hydro has determined that a number of corrections are required in order to correct this problem. The ground clearance is too low in one span and the cross arms on 41 structures need to be replaced.

Project Title: Upgrade Transmission Line TL-244 **(cont'd.)**

Project Justification:

The energized conductors that violate electrical clearances pose a general safety risk to both the general public and Hydro employees. This project is justified on the requirement to ensure safety and to improve the operational performance of the line.

Future Plans:

Future transmission line upgrades will be proposed in future capital budget applications. See the five-year Capital Plan (2010 Capital Plan Tab, Appendix A.)

Attachment:

See report entitled "TL-244 Line Upgrade" located in Volume II, Tab 13, for further project details.

Project Title: Replace Poles
Location: Various Sites
Category: Transmission and Rural Operations - Distribution
Definition: Pooled
Classification: Normal

Project Description:

Distribution lines located in the communities of Barachoix, English Harbour West, Fleur De Lys and Happy Valley have been identified as requiring pole replacements. 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. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	232.9	0.0	0.0	232.9
Labour	221.9	0.0	0.0	221.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	379.8	0.0	0.0	379.8
Other Direct Costs	61.6	0.0	0.0	61.6
O/H, AFUDC & Escln.	96.8	0.0	0.0	96.8
Contingency	89.6	0.0	0.0	89.6
TOTAL	**1,082.6**	**0.0**	**0.0**	**1,082.6**

Operating Experience:

The distribution lines were originally constructed over 40 years ago. The majority of line components were installed at the time of original construction and have far exceeded their economic lives 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 no longer used by Hydro due to safety and environmental concerns.

Project Title: Replace Poles **(cont'd.)**

Project Justification:

The distribution lines were originally constructed over 40 years ago. Most of the line components, still in operation, were installed at the time of original construction and have exceeded their estimated service lives. In addition, 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. The majority of the poles identified for replacement are blackjack poles, which no longer comply with Hydro standards due to safety and environmental concerns. 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.

Future Plans:

Future pole replacements will be proposed in future capital budget applications. See the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Attachments:

See report entitled "Pole Replacements - 2010" located in Volume II, Tab 14, for further project details.

Project Title: Construct Transmission Line Equipment Off-Loading Areas
Location: Various Sites
Category: Transmission and Rural Operations - Transmission
Definition: Other
Classification: Normal

Project Description:

This project is required to construct equipment off-loading areas near secondary provincial highways at points where Hydro accesses its transmission lines. 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. The budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

Hydro maintains 56 transmission lines on the island portion of the province which have a combined length of 3,473 kilometers. 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, which have narrow shoulders and steep embankments and where crews must contend with increasing levels of both traffic and speed. Safety is further compromised in adverse weather conditions with reduced visibility.

Project Title: Construct Transmission Line Equipment Off-Loading Areas **(cont'd.)**

Operating Experience: (cont'd.)

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.

Project 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.

Future Plans:

Construction of Off-Loading areas are planned in future years as shown in the five-year plan (2010 Capital Plan Tab, Appendix A).

Attachments:

See report entitled "Construct Transmission Line Equipment Off – Loading Areas" located in Volume II, Tab 15, for further project details.

Project Title: Upgrade Power Transformers
Location: Various Sites
Category: Transmission and Rural Operations - Terminal Stations
Definition: Pooled
Classification: Normal

Project Description:

This project consists of upgrading power transformers which will include either refurbishment or replacement based upon condition assessment techniques. See the attached report for details of the project description. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	406.0	0.0	0.0	406.0
Labour	229.0	0.0	0.0	229.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	33.0	0.0	0.0	33.0
O/H, AFUDC & Escln.	80.7	0.0	0.0	80.7
Contingency	66.8	0.0	0.0	66.8
TOTAL	**815.5**	**0.0**	**0.0**	**815.5**

Operating Experience:

With 55 percent of all 230 kV, 138 kV and 66 kV power transformers at an age of 30 years or greater, recent experience has shown the need to upgrade some of them due to problems with oil quality, tap changers, gasket systems, bushings, radiators and protective devices.

Project Justification:

The power transformers are one of the most important components on the transmission system. To maintain reliable operation of the transformer fleet it is critical to use condition assessments techniques to target weak units or problem areas within a unit for upgrading. The recommended upgrades will serve to extend the service lives of the transformers and decrease the probability of in service failures.

Project Title: Upgrade Power Transformers **(cont'd.)**

Future Plans:

Future upgrades will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Upgrade Power Transformers" located in Volume II, Tab 16, for further project details.

Project Title: Replace Off-Road Track Vehicles
Location: Whitbourne and Bishop's Falls
Category: General Properties - Transportation
Definition: Pooled
Classification: Normal

Project Description:

This project involves the replacement of vehicles V7839 (Whitbourne), a 1994 heavy-duty off-road track vehicle, and V7735 (Bishop’s Falls), a 1991 heavy-duty off-road track vehicle. The budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

The heavy-duty off-road track vehicles have an average life expectancy which ranges from 15 to 20 years, dependant on location and usage. Unit V7839 will be 17 years old at replacement and Unit V7735 will be 20 years old.

Project Justification:

This project provides for the normal replacement of heavy-duty off-road track vehicles due to age and condition.

Future Plans:

Future replacements will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Replace Off-Road Track Vehicles **(cont'd.)**

Attachment:

See report entitled "Replace Off-Road Track Vehicles - Whitbourne and Bishop's Falls", Volume II, Tab 17, for further project details.

Project Title: Replace Diesel Unit 2001 and Engine 566
Location: Francois
Category: Transmission and Rural Operations - Generation
Definition: Other
Classification: Normal

Project Description:

This project will replace Generating Unit 2001 and the diesel engine on Generating Unit 566 at the Francois Diesel Plant, and purchase critical spares for the engine 566 replacement. The budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

The engine block of unit 566 is pitted and requires replacement, but a replacement block is not available. In addition, parts for generating unit 566 must usually be shipped from Japan and require up to three months of lead time.

Generating unit (genset) 2001 is 28 years old and due for overhaul or replacement. Gensets requiring overhaul that are approaching 30 years of service are generally evaluated for replacement.

Project Justification:

Replacement of the engine of Unit 566 and purchase of critical spares is justified on the requirement to provide reliable electrical service. Lead times for Mitsubishi parts are unacceptable to maintain isolated prime power generation assets.

Replacement of Unit 2001 is justified based on age of equipment and efficiency improvements. This genset will be the oldest small (<500 kW) prime power generating unit in Hydro's inventory by the end

Project Title: Replace Diesel Unit 2001 and Engine 566 **(cont'd.)**

Project Justification: (cont'd.)
of 2009. Economic analysis favours replacement instead of overhaul as a result of fuel efficiency improvements with the new equipment.

Future Plans:

Future diesel unit replacements will be proposed in future capital budget applications.

Attachments:

See report entitled "Replace Unit 2001 and Engine 566 Francois" located in Volume II, Tab 18, for further project details.

Project Title: Replace Recloser Control Panels
Location: Various Sites
Category: Transmission and Rural Operations - Distribution
Definition: Pooled
Classification: Normal

Project Description:

The Recloser Control Panel Replacement Project is intended to be a five-year project to replace 36 aging reclosers. This project will commence in 2010 with the replacement of 16 recloser control panels. 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. The budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

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.

Project 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

Project Title: Replace Recloser Control Panels **(cont'd.)**

Project Justification: (cont'd.)

electronic components which can result in the recloser not operating properly and causing power outages to Hydro customers.

Future Plans:

Future Recloser Control Panels will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replace Recloser Control Panels" located in Volume II, Tab 19, for further project details.

Project Title: Upgrade Line 2 Voltage Conversion to 25 kV
Location: Gaultois
Category: Transmission and Rural Operations - Distribution
Definition: Other
Classification: Normal

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 to 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 budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

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 Hydro operations indicates that it has become deteriorated.

Project 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. Line components were installed at the time of original construction and have exceeded their estimated service life of 30

Project Title: Upgrade Line 2 Voltage Conversion to 25 kV **(cont'd.)**

Project Justification: (cont'd.)

years. In addition, standardized inspection and testing procedures, indicate 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. 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 its geographical location.

Future Plans:

Hydro will continue to inspect and maintain the asset as per the current standards. This inspection will be completed by regulated operations personnel and any corrective maintenance required is reported, scheduled and completed.

Attachments:

See report entitled "Voltage Conversion - Gaultois" located in Volume II, Tab 20, for further project details.

Project Title: Replace Light Duty Mobile Equipment
Location: Various Sites
Category: General Properties - Transportation
Definition: Other
Classification: Normal

Project Description:

This project consists of the replacement of 50 units of light-duty mobile equipment. The budget estimate for this project is shown in Table 1 below.

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**

Operating Experience:

Hydro staff regularly uses light-duty mobile equipment for maintenance, repair and operation of the transmission system. The equipment being used requires regular replacement.

Project Justification:

This project provides for the normal replacement of light-duty, mobile equipment which is at the end of its life cycle and is no longer dependable.

Future Plans:

Future replacements will be proposed in future capital budget applications. Light duty mobile equipment replacements are proposed for the next four years as shown in the five-year plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replace Light Duty Mobile Equipment – 2010" located in Volume II, Tab 21, for further project details.

Project Title: Replace Vehicles and Aerial Devices
Location: Various Sites
Category: General Properties - Transportation
Definition: Other
Classification: Normal

Project Description:

The scope of work is to replace 42 light-duty vehicles and 8 heavy-duty work vehicles. The budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

Hydro employees regularly utilize light-duty and heavy-duty equipment for maintenance, repair and operation of the electrical system.

Project Justification:

This project provides for the normal replacement of on-road fleet vehicles based on projected age and kilometers at disposal.

Future Plans:

Future replacements will be proposed in future capital budget applications. Vehicle replacements are planned for the next four years as shown in the five-year plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replace Vehicles and Aerial Devices – Hydro System 2010" located in Volume II, Tab 22, for further project details.

Project Title: Replace Stationary Battery Banks and Chargers
Location: Various Sites
Category: General Properties - Telecontrol
Definition: Other
Classification: Normal

Project Description:

This project is part of Hydro's ongoing program to replace stationary batteries and chargers at generating sites, terminal stations and telecommunications microwave sites. These batteries are the source of power for telecommunications and protection and control equipment during the loss of station service. The batteries are a direct current (DC) power source and thus require a charging system that converts alternating current (AC) to direct current (DC). The budget estimate for this project is shown in Table 1 below.

Table 1: 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**

Operating Experience:

Hydro generally inspects its battery banks semi-annually but more often as needed depending on age and condition. From inspection and testing, Hydro determines which banks need to be replaced. The rate of battery deterioration increases with age and reaches a point where they are unable to provide the required power level to operate equipment in the event of an outage.

Project Justification:

When the capacity of a battery falls to 80 percent of its rated capacity it has to be replaced as recommended by IEEE standards 450 and 1188. The batteries to be replaced are near the end of their useful lives and have deteriorated to the 80 percent capacity level. Batteries have to be replaced before total failure occurs to ensure continued reliable operation.

Project Title: Replace Stationary Battery Banks and Chargers **(cont'd.)**

Future Plans:

Future battery and charger replacements will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Stationary Battery and Charger Replacement Program" located in Volume II, Tab 23, for further project details.

Project Title: Corporate Application Environment - Upgrade Microsoft Products
Location: Various Sites
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

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 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	542.3	542.3	542.3	1,626.9
Labour	120.0	40.2	30.2	190.4
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.	22.9	34.3	48.3	105.5
Contingency	66.2	58.3	57.3	181.8
Sub-Total	751.4	675.1	678.1	2,104.6
Cost Recoveries	(225.4)	(202.5)	(203.4)	(634.3)
TOTAL	**526.0**	**472.6**	**474.7**	**1,473.3**

Operating Experience:

Hydro's Information Technology software is not current and needs to be updated in order to maintain a high level of system functionality.

Project Title: Corporate Application Environment - Upgrade Microsoft Products **(cont'd.)**

Justification:

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.

Future Plans:

None.

Attachment:

See report entitled "Corporate Application Environment Upgrade Microsoft Products" located in Volume II, Tab 24, for further project details.

The following projects are multi-year projects and have been reviewed by the Board at previous Capital Budget Applications. All of these projects, except the Condition Assessment and Life Extension Study for Holyrood were approved in Board Order No. P.U. 36 (2008) 2009 Capital Budget. The Condition Assessment project was approved in July 2009, Board Order No. P.U. 28 (2009). The projects are underway and have not had a material change in either scope, nature or forecast cost of the project from that contained in the original approval as defined on Page 8 of the Capital Budget Application Guidelines issued October 29, 2007.

Project Description	Expended to 2009	2010	Future Years	Total
		($000)		
Purchase Spare Stator Winding Units 2 – Bay d'Espoir	37	2,806		2,843
Replace 50 kW Diesel Generator – Bay d'Espoir	36	289		325
Condition Assessment and Life Extension Study – Holyrood	1,210	686		1,895
New 25 kV Terminal Station – Labrador City	283	2,700	7,007	9,990
Perform Grounding Upgrades – Various Sites	252	291		543
Upgrade Great Northern Peninsula Protection – Various Sites	101	91		192
Upgrade Transmission Line TL-212 – Sunnyside to Linton Lake	968	964		1,932
Replace Diesel Units – Norman Bay, Postville and Paradise River	170	1,700		1,870
Increase Generation Capacity – L'Anse au Loup	23	821		844
Install Fibre Optic Cable – Hind's Lake	209	483		692

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
			($000)		
GENERATION					
Install Meteorological Stations - Various Sites		443		443	C-2
Replace 50 kW Diesel Generator - Bay d'Espoir	36	289		325	
Replace Diesel Fire Pump - Holyrood		112	195	307	C-9
Upgrade Units 5 and 6 Cooling Water Systems - Bay d'Espoir		305		305	C-22
Upgrade Intake Gate Controls - Upper Salmon		284		284	C-31
Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg - Bay d'Espoir		236		236	C-43
Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level - Holyrood		231		231	C-50
Purchase Spare Spherical Valve Seal and Ring Assemblies - Bay d'Espoir		223		223	C-67
TOTAL GENERATION	36	2,123	195	2,355	
TRANSMISSION AND RURAL OPERATIONS					
Upgrade Trailer and Mobile Substation - Bishop's Falls		30	468	499	C-78
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood		79	417	496	C-84
Replace Diesel Unit 2018 - McCallum		19	421	440	C-95
Replace Insulators - Various Terminal Stations		399		399	C-103
Upgrade Anchors on C Structures TL-259 - Parson's Pond		353		353	C-110
Upgrade Circuit Breakers - Various Terminal Stations		342		342	C-119
Replace Guy Wires TL-215 - Doyles to Grand Bay		301		301	C-128
TOTAL TRANSMISSION AND RURAL OPERATIONS	0	1,524	1,306	2,830	
GENERAL PROPERTIES					
Replace Radio Link with Fiber - Bay d'Espoir		489		489	C-141
PC Replacement Program - Various Sites		407		407	C-149
Upgrade Private Automated Branch Exchange (PABX) - Various Sites		339		339	C-154
Remove Safety Hazards - Various Sites		252		252	C-161
Replace Peripheral Infrastructure - Various Sites		222		222	C-166
Replace Radomes - Various Sites		212		212	C-172
Install Mobile Communications - Port Hope Simpson, Charlottetown		208		208	C-187
TOTAL GENERAL PROPERTIES	0	2,128	0	2,128	
TOTAL PROJECTS OVER $200,000 AND UNDER $500,000	36	5,775	1,502	7,312	

Project Title: Install Meteorological Stations
Location: Various Sites
Category: Generation - Hydraulic
Definition: Pooled
Classification: Normal

Project Description:

Hydro uses precipitation data as a key input in its production planning and forecasting activities. Hydro currently collects meteorological data from five of its eight reservoirs. Installation of meteorological stations at all eight reservoirs will allow Hydro access to real time data such as temperature, precipitation, wind speed, wind direction and snowpack. This data can then be used by Hydro to optimize hydraulic power production and minimize thermal power production from the Holyrood Thermal Generating Station (Holyrood).

This is the third year of a five-year program to install meteorological stations at all of Hydro's reservoirs. This project is required to purchase and install meteorological stations at the Long Pond Reservoir, the Meelpaeg Reservoir, the Victoria Reservoir, and the Hinds Lake Reservoir in 2010. All stations will be equipped to provide precipitation data, air temperature, humidity, and snowpack data. The project involves identifying the measurement sites and the means of returning the data to the Energy Control Centre. Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	120.0	0.0	0.0	120.0
Labour	121.5	0.0	0.0	121.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	60.0	0.0	0.0	60.0
Other Direct Costs	68.7	0.0	0.0	68.7
O/H, AFUDC & Escln.	45.3	0.0	0.0	45.3
Contingency	27.8	0.0	0.0	27.8
TOTAL	**443.3**	**0.0**	**0.0**	**443.3**

Existing System:

Hydro operates eight reservoirs in three reservoir systems. These reservoir systems supply Bay d'Espoir, Hinds Lake and Cat Arm Hydroelectric Generating Stations.

The Hinds Lake and Cat Arm systems are single reservoir systems. The Bay d'Espoir system is a multi-reservoir system comprised of the following six reservoirs:

Project Title: Install Meteorological Stations **(cont'd.)**

Existing System: (cont'd.)

- Victoria Lake Reservoir (Victoria);
- Burnt Pond Reservoir (Burnt);
- Granite Lake Reservoir (Granite);
- Meelpaeg Lake Reservoir (Meelpaeg);
- Upper Salmon Reservoir (Upper Salmon); and
- Long Pond Reservoir (Long Pond).

The watersheds associated with these systems cover vast, variable terrain comprised of 7,200 square kilometers that have a variable and unpredictable climate. This leads to uncertainty in predicting inflows making management of these complex reservoir systems difficult.

As an example, the Cat Arm watershed encompasses 651 square kilometres of mountainous terrain on the Great Northern Peninsula. The climate in the area is influenced by weather systems from the Canadian mainland as well as the maritime systems from over the North Atlantic. The resulting climate tends to be unstable and characterized by rapid changes in weather conditions. There can be variation in weather patterns experienced in various portions of the watershed as a result of the proximity of part of the watershed to the ocean, while other portions are affected by their altitude and inland location.

As in the other two reservoir systems, inflows into the Cat Arm reservoir are heavily influenced by snowmelt, with inflows during the spring runoff (May and June) accounting for about half of all inflows for the reservoir for the year. Snowmelt inflows tend to take place in a two week period within the runoff season. Inflows can rise rapidly from a typical 20 cubic meters per second to 200 cubic meters per second within this period. The plant only consumes 40 cubic meters per second at full load. Accordingly, when the runoff starts, sufficient reservoir storage must be available to accommodate the rapid change in inflow. With poor precipitation and temperature information, preparing for and detecting the spring runoff is problematic. Furthermore, Hydro performs snow core sampling twice throughout the winter to obtain information on how the snow pack changes throughout the season. However, with no observations at the higher elevations within the watershed, Hydro has no direct indication as to how snow pack changes after each snow survey. In these eight reservoirs there are only six locations where Hydro currently receives meteorological data. Temperature, humidity, and precipitation meteorological data is collected at:

Project Title: Install Meteorological Stations **(cont'd.)**

Existing System: (cont'd.)

- the intake structure of the Long Pond Reservoir;
- the Ebbegunbaeg Control Structure of the Meelpaeg Reservoir;
- the intake structure of the Cat Arm Reservoir;
- the watershed area of the Cat Arm Reservoir (this site also collects snowpack data);
- the east end of the Granite Reservoir; and
- the intake structure of the Hinds Lake Reservoir (this site collects temperature and precipitation only).

Hydro uses a Water Management Decision Support System (WMDSS) to optimize hydraulic and thermal power production, water storage releases and flood handling. The WMDSS is comprised of three primary modules including long term generation forecasting (weekly, monthly and yearly schedules), short term generation forecasting (hourly to multi-hourly schedules) and inflow forecasts for the purposes of generation scheduling and flood management. The installation of meteorological stations at the eight reservoirs will provide Hydro access to real time data such as temperature, precipitation, snowpack, wind speed and direction. Real time meteorological data used in conjunction with the WMDSS will enhance decision making pertaining to optimizing hydraulic power production and, therefore minimize thermal power production at Holyrood.

This project is required to install meteorological stations to complement the WMDSS. Hydro received approval from the Board of Commissioners of Public Utilities (the Board) to install meteorological stations at four locations in 2008 and at three locations in 2009. Stations will be installed at Long Pond Reservoir, Meelpaeg Reservoir, and Victoria Reservoir on the Bay d'Espoir System and at Hinds Lake Control Reservoir on the Hinds Lake System in 2010.

As this is a new installation, there is no relevant information or data on the following:

- Age of equipment;
- Major work or upgrades;
- Maintenance history;
- Outage statistics;
- Availability of replacement parts;
- Safety performance;
- Environmental performance;

Project Title: Install Meteorological Stations **(cont'd.)**

Existing System: (cont'd.)

- Vendor recommendations; and
- Operating regime.

Anticipated Useful Life:

The equipment used in meteorological stations has different life expectancies. As the majority of these sites are remote, they will be powered by solar panels and batteries. It is anticipated that these batteries have a life expectancy of three to five years. Other components of the stations including radios, data loggers and sensors have a life expectancy of seven to ten years.

Justification:

This project is justified on Hydro's requirement to provide least cost power. Failure to properly prepare for the spring runoff can result in spillage. A one million cubic meter (1 MCM) spill at Cat Arm represents 900 MWh of production, which, if supplied by Holyrood, would result in a cost of approximately $86,000, based upon a 2009 forecast price of approximately $60 per barrel for fuel and 630 kWh per barrel conversion factor at Holyrood. In 2006, Hydro spilled 135 MCM at Cat Arm, due, in part, to poor information on precipitation and snow pack at Cat Arm.

By installing remote meteorological stations, Hydro will obtain critical information on snow pack around the reservoirs, which will help ensure that the reservoirs are operated in such a fashion to be well-positioned in advance of the spring runoff. These stations will also allow for improved decision-making and inflow forecasting for the various reservoirs throughout the year. Implementing this project supports Hydro's goals of being an environmental leader and maintaining operational excellence.

Net Present Value:

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

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.

Project Title: Install Meteorological Stations **(cont'd.)**

Justification: (cont'd.)

Cost Benefit Analysis:

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

Legislative or Regulatory Requirements:

There are no legislative or regulatory requirements for this project.

Historical Information:

In 2008, four meteorological stations were installed for data collection – one each at the Long Pond Reservoir and the Meelpaeg Reservoir, and two at the Cat Arm Reservoir, at a budgeted cost of $222,100 as approved in Board Order No. P.U. 30 (2007). This was the first year of a five-year program as shown in Table 2 below. Due to adverse weather conditions, works crews and helicopter bookings had to be rescheduled, and the project was carried over to 2009 to allow for equipment installation during non-winter months. The project is over budget and expenditures have been incurred to date in the amount of $272,000.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost Per Unit ($000)	Comments
2009F	252.5		3		Project Ongoing
2008	222.1	272	4	68	First Year of Meteorological Station Deployment

In 2009, the second year of the program, work has been approved by Board Order No. P.U. 36 (2008) to install three meteorological stations at the Burnt Dam Spillway, the Victoria Reservoir, and the Hinds Lake Control Structure at a budgeted cost of $252,500. The Victoria Reservoir will now be completed in 2010, as the design for Victoria includes snow sensor technology new to Hydro. The first snow sensor was installed at Cat Arm in June 2009. Before investing further into this snow sensor technology, operational data will be collected and analyzed prior to further snow sensor deployments.

Increases have been forecast in the 2010 estimate to reflect increased implementation costs based on the 2008 actual installation costs, and more up to date information on equipment costs.

Project Title: Install Meteorological Stations **(cont'd.)**

Justification: (cont'd.)

Forecast Customer Growth:

Customer load growth does not affect this project.

Energy Efficiency Benefits:

There are no energy efficiency benefits that can be attributed to the installation of meteorological stations. However, through better data availability, better scheduling decisions can be made which reduce spill potential and fossil fuel utilization.

Losses During Construction:

This project has no effect on the normal operation of the plants and will not cause any interruptions or system outages. Therefore, there will be no losses during construction.

Status Quo:

Hydro only receives meteorological data for five of its eight reservoirs. This makes predicting inflows into Hydro's reservoirs difficult and inaccurate. Poor precipitation and temperature information can make preparations for spring runoff problematic, potentially leading to unnecessary spills.

Alternatives:

There are no viable alternatives to this project. Neither Environment Canada nor the Provincial Government have stations in the locations chosen for new installations.

Conclusion:

Meteorological stations need to be installed to improve Hydro's inflow forecasting and dispatching of water resources to maximize hydraulic power production and minimize thermal power production.

Project Title: Install Meteorological Stations **(cont'd.)**

Conclusion: (cont'd.)

Project Schedule:

Table 3 presents the anticipated project schedule.

Table 3: Project Schedule

Activity	Milestone
Project Initiation	February 2010
Complete Design Transmittal	February 2010
Develop Equipment Specification	March 2010
Procure Equipment and Materials	June 2010
Installation and Commissioning - Long Pond Reservoir	August 2010
Installation and Commissioning - Meelpaeg Reservoir	August 2010
Installation and Commissioning - Victoria Reservoir	September 2010
Installation and Commissioning – Hinds Lake Reservoir	September 2010
Project Completion and Close Out	November 2010

Future Plans:

Future installations will be proposed in future capital budget applications. Table 4 shows a list of planned future installation and/or upgrades. Also see five-year capital plan (2010 Capital Plan Tab, Appendix A).

Table 4: Installation/Upgrades

Activity		Milestone
Upgrade at:	Victoria Spillway Granite Lake RR Pond Cat Arm Spillway[1]	2011
Installation at:	Victoria Control Structure Burnt Pond Reservoir Granite Lake Reservoir	2012

[1] Inadvertently omitted from 2009 Capital Budget Proposal

Project Title: Replace Diesel Fire Pump
Location: Holyrood
Category: Generation - Thermal
Type: Other
Classification: Normal

Project Description:

The Holyrood Thermal Generating Station's (Holyrood) diesel engine-driven fire pump and associated control panel will be replaced under this project. This equipment is located in the pump house 1. The flow testing manifold and associated valves will also be replaced. This equipment is essential to the successful operation of the plant's fire protection system. 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	0.0	0.0	0.0	0.0
Labour	24.2	36.2	0.0	60.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	75.0	105.0	0.0	180.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	12.7	30.2	0.0	42.9
Contingency	0.0	24.0	0.0	24.0
TOTAL	**111.9**	**195.4**	**0.0**	**307.3**

Existing System:

Fire Protection System

The fire protection system consists of both indoor and outdoor piping systems, fire pumps, and testing equipment. The outdoor system consists of a series of fire hydrants attached to an underground ring main that extends from the pump house 1 to the fuel oil tank farm. The indoor system consists of automatic sprinkler systems and fire hoses. Pumper connections are provided on the Power House and pump house exterior walls for use by mobile pump units. Water for the fire protection system is drawn from a 16 inch diameter fresh water supply line fed from Quarry Brook reservoir. Fire pumps, located in the pump house 1, are used to pump the water from Quarry Brook to the plant in the case of a fire or during a fire pump test. A testing manifold located outside of the pump house is used to periodically validate the performance of the fire pumps.

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Existing System: (cont'd.)

Fire Pumps

Normally, the fire pumps are not in service. During a fire situation, the system pressure drops when water flows from an open sprinkler head or fire hydrant. Once the pressure drop is detected, the small 20 US gallon per minute (USGPM) jockey pump starts automatically and attempts to boost the system pressure. If the jockey pump is incapable of increasing the system pressure to the set point, the large 1500 USGPM electric fire pump starts automatically. In the case of a failure of the electric fire pump, such as during loss of electrical power, the back-up fire pump starts. This back-up pump is a 1500 USGPM diesel engine-driven fire pump that does not require electricity to operate. Figure 1 contains a photo of the diesel fire pump.

Figure 1: Diesel Fire Pump

The performance of the diesel and electric fire pumps is periodically tested using the testing manifold located outside the pump house 1. During a fire pump test, fire hoses are connected to the manifold valves. The pumps are then turned on and the output flows and pressures are measured and recorded.

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Existing System: (cont'd.)

Since 1970, many new sprinkler systems have been added to the plant. In 2008 alone, 14 new sprinkler systems were added, including eight new deluge systems. As a result, the plant's fire protection system has a maximum water demand that is greater than the existing electric fire pump can supply. Therefore, both the electric fire pump and the diesel fire pump are now required to operate simultaneously during a fire in a location where maximum water demand is required. In this operational scenario, the diesel fire pump is no longer simply a back-up pump to the electric fire pump.

On March 27, 2009, a condition assessment was performed on the diesel engine fire pump. The condition assessment report is attached as Appendix A.

Age of Equipment or System

The diesel fire pump consists of a Cummins diesel engine and a Peerless Pump horizontal split case pump. Records from Cummins indicate that the diesel fire pump engine (serial number 679977) currently installed at Holyrood was built on July 28, 1969. The pump and engine were installed on a skid and supplied as a packaged unit during the construction of Holyrood. The Master Control Systems diesel fire pump control panel and the flow testing manifold were installed at the same time as the diesel fire pump. This equipment was placed in service in 1970.

Major Work/or Upgrades

There have been no major upgrades to the diesel fire pump, fire pump controller, or testing manifold since they were installed.

Anticipated Useful life

The diesel fire pump and associated equipment have an estimated service life of 25 years.

Maintenance History

The five-year maintenance history for the diesel fire pump is shown in Table 2.

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Existing System: (cont'd.)

Table 2: Five-Year Maintenance History

Year	**Preventive Maintenance ($000)**	**Corrective Maintenance ($000)**	**Total Maintenance ($000)**
2008	0.66	4.95	5.61
2007	0.35	3.26	3.61
2006	0.54	0.92	1.46
2005	0.43	1.79	2.22
2004	1.65	0.80	2.45

<u>Outage Statistics</u>

The operation of the diesel fire pump does not contribute to the plant's outage statistics since its function is not required for power generation.

<u>Industry Experience</u>

Industry experience has not been considered since this is simply a replacement of equipment that has reached the end of its useful service life.

<u>Maintenance or Support Arrangements</u>

No formal service agreement is in place for the diesel fire pump. Internal staff maintains equipment and diesel specialists are called in, when required.

<u>Vendor Recommendations</u>

The vendor has completed a condition assessment of the diesel engine. This assessment is attached as Appendix A.

<u>Availability of Replacement Parts</u>

The diesel fire pump at Holyrood consists of a Cummins model HR-6-BI 7 diesel engine and a Peerless model 6AF16 pump.

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Existing System: (cont'd.)

Manufacture of the Cummins HR-6-BI 7 diesel engine was discontinued in the early 1970's. Major components or parts are no longer being produced for this engine. Presently, the following parts are obsolete:

- Fuel injectors;
- Oil cooler;
- Water pump;
- Cylinder heads; and
- Castings (block and components).

Over the next five years, the following parts are anticipated to be obsolete:

- Fuel pump;
- Controls and panel;
- Gasket kit;
- Rocker covers;
- Base pan; and
- Rods, pistons and bearings.

<u>Safety Performance</u>

There are no identified safety issues related to the equipment being replaced under this project.

<u>Environmental Performance</u>

There are no identified environmental performance issues related to equipment being replaced under this project.

<u>Operating Regime</u>

The diesel fire pump being replaced under this project was originally designed to operate in continuous stand-by mode and act as a back-up to the electric fire pump. However, the electric fire pump alone can no longer supply the plant's maximum water demand required by recent sprinkler

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Existing System: (cont'd.)

system upgrades. The operating regime of the diesel fire pump has changed slightly from its original design. As per original design, the diesel fire pump will start when a prolonged decrease in fire system water pressure is experienced. This can occur upon failure of the electric pump during a power loss situation. In addition, as of 2008, the diesel fire pump will start and run together with the electric fire pump when the electric fire pump cannot keep up with the water flow demand requirements. The diesel fire pump control panel commands the diesel fire pump to start automatically. Starting this pump manually is also possible by engaging the start buttons in the Control Room. Once started, this pump requires a manual shutdown.

The diesel fire pump is tested weekly. The diesel fire pump control panel commands the diesel fire pump to start once a week and run for a 15 minute period. During this testing, both the start and stop of the engine is completely automatic.

Justification:

This project is justified due to the fact that the diesel fire pump (consisting of a Cummins diesel engine coupled to a Peerless Pump pump), diesel fire pump controller and testing manifold have been in service for 39 years and have reached the end of their service lives.

A condition assessment of the fire pump's diesel engine was performed in March 2009 by Cummins. It was revealed in the condition assessment report that excessive corrosion is present on the engine and that its general condition is below standard. In addition, major components and parts are currently obsolete and difficult to source. As a result, it is possible that this engine may not be repairable if a major component failed. Therefore, it is recommended that the diesel fire pump engine be replaced.

Since 1970, many new sprinkler systems have been added to the plant. This has increased the maximum water demand required by the plant's fire protection system. Therefore, both the electric fire pump and the diesel fire pump are now required to operate simultaneously during a fire in a location where maximum water demand is required. However, upon loss of power, only the diesel fire pump is operational. Since this pump is incapable of supplying the maximum water flow demanded by

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Justification: (cont'd.)

the plant's fire protection system, it is recommended that not only its engine be replaced under this project but its pump as well. Both the pump and the engine will be supplied together with a new control panel as a complete system. The new pump will be sized appropriately to meet current water demands. Testing of the new pump will require changes to the existing testing manifold. This manifold will be replaced with the appropriately sized unit.

<u>Net Present Value</u>

A net present value calculation has not been performed since there are no quantifiable benefits.

<u>Levelized Cost of Energy</u>

Levelized cost of energy is not a factor in this project.

<u>Cost Benefit Analysis</u>

A cost benefit analysis has not been performed since only one viable alternative exists.

<u>Legislative or Regulatory Requirements</u>

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

<u>Historical Information</u>

This is a two-year project and it is not expected to be repeated again.

<u>Forecast Customer Growth</u>

This project is not required to accommodate customer growth.

<u>Energy Efficiency Benefits</u>

There are no energy efficiency benefits resulting from this project.

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Justification: (cont'd.)

Losses During Construction

There will be no losses during construction as the work performed under this project does not need to take place during an outage.

Status Quo

If this project is not completed, reliability of the Holyrood fire protection system will decrease. This may affect the ability of the fire protection system to operate successfully in the case of a fire.

Alternatives

The only alternative is the complete replacement of the diesel fire pump, its control panel, and the testing manifold.

Conclusion:

The diesel fire pump is an integral part of the Holyrood fire protection system. Currently, however, many of the engine's major components are obsolete. If an obsolete part fails, it is possible that a replacement part may never be found and the engine will not be able to be repaired. Since this is the only fire pump at Holyrood that is able to supply water to the fire protection system during a power outage, this pump needs to be reliable. The only way to increase the reliability of this pump is to replace it. Due to the age of the diesel fire pump controller and testing manifold, it is recommended that this controller and manifold be replaced at the time the pump is replaced.

Project Title: Replace Diesel Fire Pump **(cont'd.)**

Conclusion: (cont'd.)

<u>Project Schedule</u>

The project schedule is shown in Table 3 below.

Table 3: Schedule

Activity	Milestone
Develop Specifications	May 2010
Purchase Equipment	July 2010
Install and Commission Equipment	June 2011
Close Project	Sept 2011

Future Plans:

None.

APPENDIX A

Diesel Fire Pump Condition Assessment

Eastern
Canada

Mount Pearl Branch
122 Clyde Avenue
Mount Pearl, NL, AIN 4S3

April 2, 2009

Newfoundland & Labrador Hydro
500 Columbus Drive
P.O. Box 12400
St. John's NL.
A1B-4K7

Attn: Andrea MacDonald
Cc: Gerard Cochrane

Re: Fire Pump - Diesel Engine Condition Assessment
Thermal Generating Station - Holyrood

On March 27, 2009 Cummins Technician traveled to HTGS Holyrood for inspection and analysis of the diesel engine attached to the fire pump.

Engine Model number # HR-6-BI 7

Engine Serial number # 679977

This engine was built July 28, 1969 by Cummins Engine Plant in Columbus, USA. This model of engine was produced from approximately mid 1940's to early 1970's. This model of engine is presently discontinued. There are no major components or parts being produced by Cummins Engine Company for this discontinued engine model.

There are some obsolete parts and inventory scattered through out North America at local distributors such as ourselves. Obtaining obsolete parts required in the event of a breakdown would be unlikely unless some distributor had old dusty parts still on their stockroom shelves. The possibility of locating the particular parts required in the event of a breakdown would be virtuously impossible.

Issue 1) Engine is forty years old – This model has been discontinued and major components / parts are not available. The general condition of the engine is below standards. There is excessive corrosion on the entire unit. Possible hazard noticed - fuel and oil lines are extremely rusted / corroded.

Issue 2) Obsolete Parts (presently)

- Fuel lines
- Oil lines
- Fuel Injectors
- Oil Cooler
- Water pump
- Cylinder Heads
- Castings (including block and components)

Issue 3) Parts anticipated to be obsolete over the next five years:

- Fuel pump
- Controls and Panel
- Gasket Kits
- Rocker covers
- Base pan
- Rods / Pistons / Bearings

Issue 4) Engine is a mechanical controlled engine. Upgrading to electronic controls is not an option. The cost of engine conversion would be more than the price of a new engine with electronic controls. The existing engine has a 24 Volt positive ground system. This would not be compatible with today's electronics.

Issue 5) Budget price to remove any obsolete parts that may be discontinued over the next five years.

$ 12,434.00 (parts) + $ 14,280.00 labor = $27,714.00

Note/ The above price of $27,714.00 plus tax does not cover parts that are obsolete presently. Repairs and upgrading can be preformed, but parts that are obsolete now could fail after upgrading. It is conceivable that $27,714.00 could be invested into the engine and then have an obsolete part failure which would essentially scrap the engine.

Summary

It is the author's opinion that the Fire Pump Engine should be replaced with a new electronic control Cummins Engine.

Parts that are presently obsolete or unavailable, combined with additional obsolete parts to be announced over the next few years would make this engine virtuously impossible to repair. if there was a major parts failure. If any obsolete parts could be located and sourced the downtime / waiting time would be excessive.

Modern electronic engines and controls increase efficiency, increase reliability, lower emissions and offer the ability to communicate with remote panels off site for monitoring purposes. Advances in engine technology over the past ten years have been astonishing. Comparing the engine in use today with a new engine would be similar to comparing the wooden wheel to a modern radial tire.

Please see attached spec sheet on the existing engine and a quotation for the replacement of the Fire pump engine with a modern, electronic controlled Cummins engine. Please feel free to contact me with any comments, questions or concerns.

Thank You

Keith Coombs
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Project Title: Upgrade Units 5 and 6 Cooling Water Systems
Location: Bay d'Espoir
Category: Generation - Hydraulic
Type: Other
Classification: Normal

Project Description:

This project is required to replace the supply and discharge piping and associated components of the generator surface air coolers on Units 5 and 6 at the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir). The existing four inch diameter carbon steel pipe will be replaced with four inch diameter stainless steel pipe, which is both corrosion and foul resistant. The existing six inch diameter piping will be replaced with standard carbon steel pipe. Additionally, the cooling water strainer and flow control valves on each unit will be replaced. 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	155.6	0.0	0.0	155.6
Labour	84.5	0.0	0.0	84.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.6	0.0	0.0	6.6
O/H, AFUDC & Escln.	33.2	0.0	0.0	33.2
Contingency	24.7	0.0	0.0	24.7
TOTAL	**304.6**	**0.0**	**0.0**	**304.6**

Existing System:

Bay d'Espoir is Newfoundland and Labrador Hydro's (Hydro's) largest hydroelectric station serving the Island Interconnected System, with seven generating units producing a total capacity of 604 MW. Each unit is equipped with a cooling water system used to maintain the temperature of key generator and turbine components. In addition, the cooling water system provides lubrication water for the turbine shaft seal during operation. The cooling water system of each unit is comprised of a pump, flow control devices, piping and a large strainer. The existing systems are fabricated entirely of carbon steel components which are highly susceptible to corrosion. Refer to Figure 1 for an example of a fouled cooling water pipe removed from service in Bay d'Espoir during the spring of 2008.

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Existing System: (cont'd.)

Figure 1. Fouled Cooling Water Pipe, Bay d'Espoir

Unit 1 or Unit 2 Spring 2008

Age of Equipment or System

The cooling water systems on Units 5 and 6 are original and have been in operation since the units were placed in service in 1970.

Major Work/or Upgrades

There have been no major upgrades performed on the cooling water systems for Units 5 and 6 since installation.

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Existing System: (cont'd.)

Anticipated Useful life

The cooling water system with existing carbon steel components has an estimated service life of 25 years.

Maintenance History

The five-year maintenance history for the cooling water systems for Units 5 and 6 is shown in Table 2. Although no major problems have occurred, preventive maintenance is difficult due to the deteriorated condition of the piping that, if disturbed, further leaking occurs.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.6	0.0	0.6
2007	0.6	0.7	1.3
2006	0.6	0.0	0.6
2005	0.6	1.9	2.5
2004	0.6	0.0	0.6

Outage Statistics

Table 3 lists the 2004 to 2008 average Capability Factor, Derated Adjusted Forced Outage Rate (DAFOR) and Failure Rate for the Bay d'Espoir Units 5 and 6 compared to all Hydro's hydraulic units and the latest CEA averages (2002 to 2006). The measures for cooling water system failures only are also provided.

In the past five years there have been two maintenance outages and no forced outages attributed to the cooling water systems.

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Existing System: (cont'd.)

Table 3: Outage Statistics

Five Year Average 2004-2008

	All Causes			Cooling Water Related Causes Only		
Unit	**Capability Factor (%)**	**DAFOR (%)**	**Failure Rate**	**Capability Factor (%)**	**DAFOR (%)**	**Failure Rate**
Bay d' Espoir 5	93.76	0.16	0.00	99.99	0.00	0.00
Bay d' Espoir 6	95.45	0.01	0.00	100.00	0.00	0.00
Bay d' Espoir Units 5 & 6	94.60	0.08	0.00	99.99	0.00	0.00
All Hydraulic Units (2004-2008)	93.36	0.52	2.08	99.45	0.01	0.25
CEA (2002-2006)	91.02	2.03	2.30	99.82	0.05	N/A*

*CEA does not provide failure rate by component failure

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.

DAFOR is defined as Derated Adjusted Forced Outage Rate. It is the ratio of equivalent forced outage time to equivalent forced outage time plus the total equivalent operating time.

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.

<u>Industry Experience</u>

Hydro investigated alternative piping during the construction of the Granite Canal Generating Station and found that stainless steel was the most appropriate piping to use. As well, Hydro Quebec installed stainless steel piping on Unit 3 in Menihek during a unit refurbishment in 2007.

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Existing System: (cont'd.)

Maintenance or Support Arrangements

Maintenance of the cooling water systems at Bay d'Espoir is conducted by Hydro staff at the plant. Inspections are completed annually and repairs are performed as required.

Vendor Recommendations

There are no vendor recommendations.

Availability of Replacement Parts

Existing piping and fittings are readily available. However, because of age, it has become difficult to find replacement parts for many of the isolation and flow control valves. Also, the existing strainers are no longer available or supported by the equipment manufacturer, Weir Canada Inc.

Safety Performance

There are no safety performance issues related to this project.

Environmental Performance

There are no environmental performance issues related to this project.

Operating Regime

The piping and flow control valves are in constant operation except when the unit is down for maintenance. Each strainer operates cyclically and is only in use when the cooling water pump for that unit is in operation. During normal operation of the entire Power House, consisting of six units, three cooling water pumps and therefore three strainers are in operation. The cooling load of the units dictates if more or less pumps should be placed in operation.

Justification:

This project is justified on the requirement to replace deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. A failure or a serious leak in a piece of surface air cooler water piping with a unit in service could cause extensive damage as the water piping is

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Justification: (cont'd.)

contained within the generator housing right next to the electrical stator/rotor assembly. A study titled *The Bay d'Espoir Generating Station Units 1 through 6 Service Water Systems Study*, was performed in 2002. This study was filed in response to a Request for Information as Attachment 1 to PUB NLH 6.0 as part of Hydro's 2008 Capital Budget Application. The study concluded that all four-inch diameter piping and smaller should be replaced with corrosion resistant piping for corrosion and fouling protection. By changing the piping material from mild steel to stainless steel, the corrosion and fouling problems will be reduced, thereby improving unit reliability and reducing future maintenance costs associated with the cleaning of fouled pipes.

Net Present Value

A net present value calculation has not been performed as there are no viable alternatives.

Levelized Cost of Energy

As this project does not relate to a generation source, levelized cost of energy is not applicable.

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

The cooling water system upgrade history is shown in Table 4.

Table 4: Cooling Water System Upgrade History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)	Comments
2009F	287.1		2		BDE Units 3 and 4
2008	263.6	197.7	2	98.9	BDE Units 1 and 2

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Justification: (cont'd.)

The upgrade of the piping of the cooling water systems of Units 1 and 2 to corrosion resistant piping was approved with a budget of $263,600 in Board Order No, P.U. 30 (2007) and the work was completed during the annual outage in 2008. The upgrade to the cooling water systems for Units 3 and 4 was approved with a budget of $287,100 in Board Order No. P.U. 36 (2008) and the work is planned for completion in 2009.

Forecast Customer Growth

Forecast customer load has no affect on this project.

Energy Efficiency Benefits

This project will result in minor but unquantifiable improvement in energy efficiency through modest reductions in energy consumption by the cooling water pumps.

Losses During Construction

No losses during construction will be incurred. This work will be completed during regular planned unit outages in the off-peak season (summer).

Status Quo

The status quo is unacceptable. Cleaning was last attempted in Bay d'Espoir over 15 years ago. This practice was abandoned due to the leaks that occurred after cleaning. The pipe wall has corroded to a point where pin holes have developed and cannot be sealed. This is an unsatisfactory condition that could potentially damage the generators. A major leak could result in the loss of cooling water for an entire generator which could, if not detected in time, lead to damaged bearings or an overheated stator. Repair of either of these would involve a major unplanned outage. Minor leaks in the area of the stator would result in the unit being shutdown and removed from service until the stator could be properly dried and tested to ensure no damage has occurred.

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Justification: (cont'd.)

Alternatives

Because of the condition of the piping system, replacement is required. The cooling water study, performed in 2002, considered two additional alternatives to correct the problem of corroded and fouled piping.

The first alternative was to replace the existing carbon steel pipe with new carbon steel pipe. This is not a viable alternative as a new carbon steel piping system will experience, within approximately five years, the same corrosion and fouling problems that currently exist. Three sections of piping on Units 1 and 2 have been replaced with carbon steel piping in the last seven years. These sections of piping were inspected in the spring of 2008 and are corroded to the point where replacement is once again required.

The second alternative was to replace the existing pipe with corrosion resistant plastic pipe. A corrosion resistant plastic piping system was installed at the Upper Salmon Generating Station in 2003. The system was found to be unacceptable as several major cracks developed in the piping that lead to leaks and was subsequently replaced with a stainless steel piping system in 2004. Based on this experience, a corrosion resistant plastic system is not a viable alternative.

Conclusion:

The replacement of the cooling water piping on Units 5 and 6 at Bay d'Espoir is required because of its deteriorated condition. The existing piping is 40 years old, well beyond its estimated service life of 25 years, and has become fouled and corroded to a point that leaks occur if cleaning is conducted. A cooling water study performed in 2002 determined that all existing carbon steel piping four inches and less in diameter should be replaced with corrosion and fouling resistant piping.

Project Schedule

This project will be completed during the scheduled outages for each unit. Project milestones are included in Table 5.

Project Title: Upgrade Units 5 and 6 Cooling Water Systems **(cont'd.)**

Conclusion: (cont'd.)

Table 5: Project Milestones

Activity	Milestone
Initiation	January 2010
Design Complete	February 2010
Equipment Ordered/Delivered	May 2010
Installation Commences	June 2010
Installation Complete	July 2010
Project Closeout	September 2010

Future Plans:

None.

Project Title: Upgrade Intake Gate Controls
Location: Upper Salmon
Category: Generation - Hydraulic
Type: Other
Classification: Normal

Project Description:

This project is required to upgrade the electrical controls at the Upper Salmon intake gate. The new system will use a programmable logic controller (PLC) with a gate positioning sensor to precisely control the position of the intake gate throughout its entire operating range. The system will offer accurate gate position feedback. The system will also monitor the fill up rate of the penstock using a water pressure sensor to be installed at the base of the penstock. This sensor is a back-up device employed to address safety concerns arising from filling the penstock after partial or complete dewatering. Another PLC and a Human Machine Interface (HMI) will be installed inside the Upper Salmon Control Room to provide operators with relevant information regarding reservoir and intake structure conditions. Other auxiliary electrical equipment used in the gate controls will also be replaced. Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	96.4	0.0	0.0	96.4
Labour	121.2	0.0	0.0	121.2
Consultant	5.0	0.0	0.0	5.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.1	0.0	0.0	10.1
O/H, AFUDC & Escln.	28.2	0.0	0.0	28.2
Contingency	23.3	0.0	0.0	23.3
TOTAL	**284.2**	**0.0**	**0.0**	**284.2**

Existing System:

The Upper Salmon Generating Station (Upper Salmon) is one of nine hydroelectric generating sites owned and operated by Hydro that are connected to the Island Interconnected System. Upper Salmon is located in the Bay d'Espoir watershed area, approximately 52 kilometers from the Bay d'Espoir

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

generating site. Upper Salmon has one generating unit rated at a capacity of 84 MW. Figure 1 shows the Upper Salmon Generating Station. The intake structure can be seen in the upper left part of the picture.

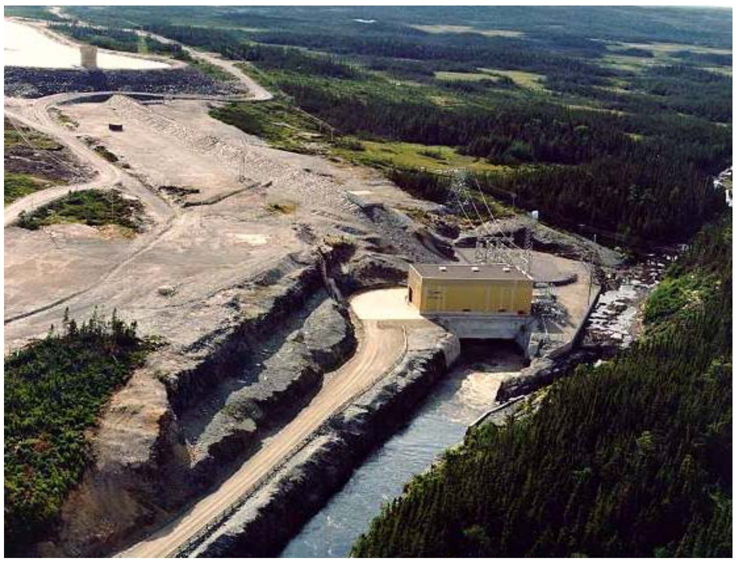


Figure 1: Upper Salmon Generating Station

The existing main components of the Upper Salmon intake gate consist of a control panel, an electric hoist motor, two separate gear reduction assemblies, a wire wound drum, several cam limit switches[1] and a dial position indicator. The system employs an electromagnetic brake and a mechanical brake that is used during the emergency lowering of the intake gate. See Figure 2 for a diagram of the Intake Gate Hoisting System. Since there is no shut off valve on the Upper Salmon generating unit to isolate the turbine from the water in the penstock, the intake gate is used to isolate the turbine and provide backup protection in the event of a generator over speed condition (which occurs when there is a sudden loss of electrical load on the generating unit), a turbine pit flood or loss of oil level or pressure in the unit governor system.

[1] a mechanical device that breaks electrical contact as the hoist drum rotates

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

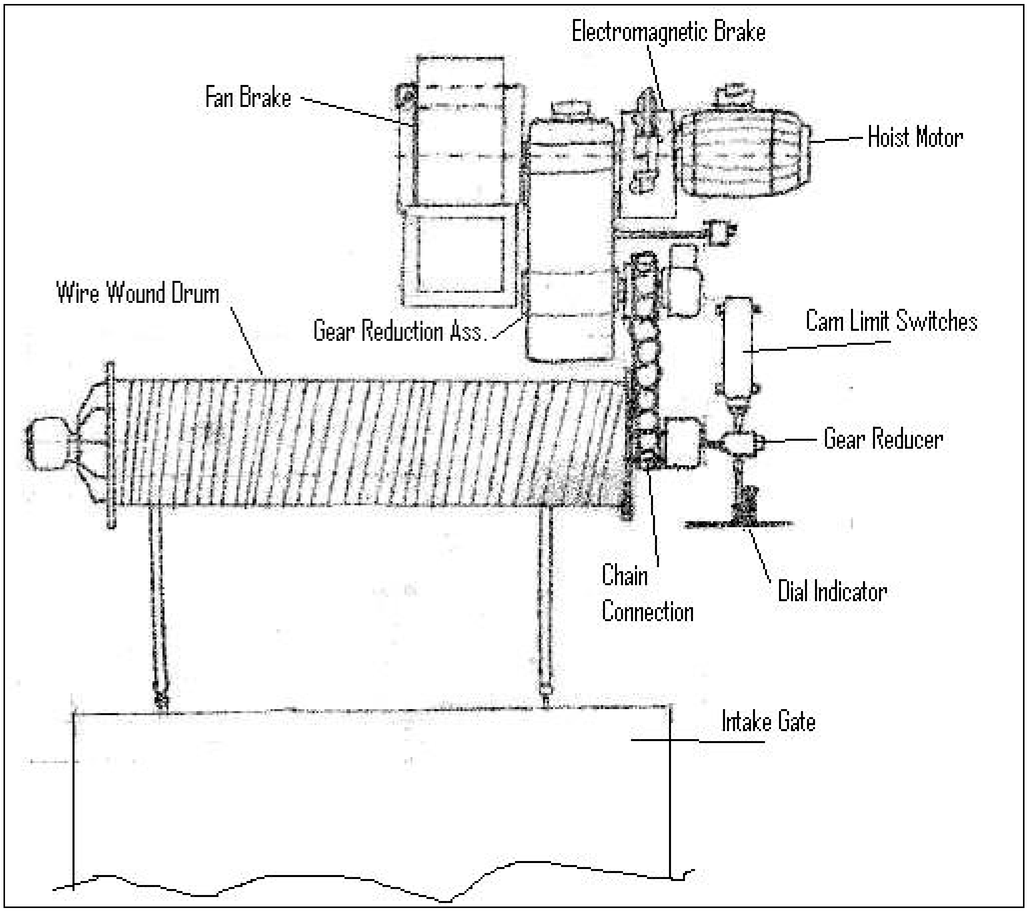


Figure 2: Intake Gate Hoisting System

The existing gate controls used by the operator to reposition the intake gate work inaccurately in that they do not offer the required precision that is needed during a penstock water-up procedure. That is, after the penstock has been partially or fully dewatered, the intake gate must be brought to precisely 6.4 cm above the bottom sill plate of the gate (prime position) to allow the penstock to fill slowly. This precise positioning of the intake gate during a penstock water up procedure prevents pressure surges on the penstock wall and the formation of a large air bubble that could rise up through the penstock and destroy the vent house and/or injure personnel.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

Currently, this prime position is determined using a hoisting system that has shown wear over time. The slackness or play in the gear assembly interface with other system components has introduced positional error that has increased over time and is currently estimated to be plus or minus 18 cm. The system is also equipped with a timer that serves as backup protection in the event of a cam limit switch failure. However, since the intake gate travel time to the prime position usually varies under different operating conditions and gate starting positions, the backup timer is not reliable. These deficiencies result in difficulties when trying to accurately stop the gate at the 6.4 cm prime position. As a result, equipment and personnel safety are at risk every time the intake gate is opened after a complete or partial dewatering of the penstock.

As a result of a failure of one of these limit switches in October 2005 the system can no longer indicate remotely the intake gate position. This prevents both local operators and operators at Hydro's Energy Control Center (ECC) in St. John's from knowing the current position of the intake gate. Since Upper Salmon is an unmanned remote plant, this can lead to penstock damage and a loss of production if the intake gate were to inadvertently close while the generator was online.

<u>Age of Equipment or System</u>

The existing intake gate controls were installed in 1982 when the Upper Salmon Plant was originally built and commissioned.

<u>Major Work/or Upgrades</u>

There have been no major upgrades to this system since it was originally installed.

<u>Anticipated Useful life</u>

The controls that are currently on this system have an anticipated useful life of 25 years.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

Maintenance History

The five-year maintenance history for the Upper Salmon intake gate controls is shown in Table 2. Labor costs of travel to and from the plant are not included in this table as maintenance was often performed during annual shutdowns when personnel were already at the plant.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	0.0	0.0
2007	0.0	0.0	0.0
2006	0.3	1.6	1.9
2005	1.1	0.0	1.1
2004	0.8	0.0	0.8

Outage Statistics

No generation outages have been attributed to the intake gate system at Upper Salmon.

Industry Experience

The Hydroelectric Generating Station at Churchill Falls has 11 generating units. Each unit has its own penstock with an intake gate. A similar design using a PLC and gate position sensor is installed in Churchill Falls and has proven to be successful. This system was also installed in Bay d'Espoir in 2008 and has operated without incident. Last year, a capital project was approved by the Board in Order No. P.U. 36 (2008) to install a similar system at Hinds Lake in 2009.

Through the Centre for Energy Advancement through Technological Innovation's Hydraulic Plant Life Interest Group, Hydro participated in a survey that was submitted to other participants including

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

Canadian utilities such as Fortis BC, New Brunswick Power, and Hydro Quebec as well as international companies. The results of this June 2007 survey indicate that most utilities are using similar PLC based control systems to monitor and control their intake gates. The survey also indicates that utilities using designs similar to the existing system at Upper Salmon do not allow remote operation due to the potential for damage during penstock filling.

<u>Maintenance or Support Arrangements</u>

All maintenance work is completed using Hydro's internal forces.

<u>Vendor Recommendations</u>

No vendor recommendations were evaluated for this proposal.

<u>Availability of Replacement Parts</u>

The existing Upper Salmon intake gate controls consist of relays, timers, contactors and mechanical limit and proximity switches which are available.

<u>Safety Performance</u>

Protection control devices that were originally installed on the Upper Salmon intake gate controls no longer function properly. As a result, over the years, operators and maintenance crews were forced to block the protection that stops the gate at the prime position in order to allow the gate to operate as required. Currently, the Upper Salmon intake gate is operated manually, a process where the operator has to hold down a pushbutton until the gate reaches its required position. As a result, it is only the operator's actions that prevent the intake gate from traveling past its prime position during a penstock water-up. Since bringing the intake gate to the prime position depends solely on the operator's actions and there is no backup system to prevent the penstock from filling too quickly, the existing system is currently unreliable.

In the event that the intake gate is allowed to travel past its prime position, the penstock will fill too

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

quickly resulting in the possible formation of a large air bubble that will rise up through the penstock and could destroy the vent house and/or injure personnel. This air bubble forms as a result of the penstock filling faster than the air can escape. As water rushes into the penstock, the air is trapped and is pushed down under the rising water level inside the penstock. The result is an air bubble that continues to grow until it becomes so large that it overcomes the force of the incoming water and rises up through the penstock and into the vent house.

As a result of this problem, personnel and equipment are at risk every time the intake gate is opened after a complete or partial dewatering of the penstock. Hydro has experienced two major incidents that resulted in the complete destruction of an intake vent house and presented the possibility for personnel injury or death. Figure 3 shows several pictures taken by Bay d'Espoir employees after a failure in July 2000 on Intake 2 at the Bay d'Espoir generating site. A similar incident occurred in 1984 on Intake 4 at Bay d'Espoir. The pictures illustrate the destructiveness of the event and the potential safety risk.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

Intake Gates 1 and 2

Intake Gate 2

Intake Gate 2

Intake Gate 2

Figure 3. Intake Gate 2 Destroyed in July 2000

<u>Environmental Performance</u>

There are no environmental concerns with the existing system.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Existing System: (cont'd.)

Operating Regime

The Upper Salmon intake gate is operated on average twice a year to provide isolation for the generating unit during maintenance procedures.

Justification:

This project is required to enhance safety at the intake controls at Upper Salmon. In the past, Hydro has experienced two major incidents that resulted in the complete destruction of two intake gate vent houses. The incidents occurred at the Bay d'Espoir Intake Gate 4 in early 1984 and at Intake Gate 2 in July 2000 when the penstock was being refilled after a complete dewatering. During both of these incidents, Hydro personnel were working in the area and thus narrowly escaped without serious injury. In addition to these incidents, in July 2005, the Bay d'Espoir Intake Gate 4 was once again opened beyond the prime position causing the penstock to be filled too quickly. As a result, operators were forced to give the gate an emergency drop command to stop water from entering the penstock too quickly and therefore averted damage.

Since there is no spherical valve[2] on the generating unit at the Upper Salmon Hydroelectric Generating Station to isolate the turbine from the penstock water, the intake gate must be lowered at least once a year to provide isolation for maintenance purposes. While opening the intake gate to refill the penstock, the gate must be first brought to the prime position to allow the penstock to fill slowly.

To stop the gate at the prime position, the intake gate is currently equipped with a rotary cam limit switch that is coupled to the hoist drum through a mechanical gearing assembly. The play or slackness in this gearing assembly introduces errors as large as plus or minus 18 cm to the final gate position, resulting in poor overall gate control. A timer was also installed as a backup priming device but does not provide acceptable reliability since the intake gate travel time usually varies under different

[2] A large mechanical device that is installed at the base of a penstock that serves to isolate the turbine from the water in the penstock. Also called a turbine shut off valve.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Justification: (cont'd.)

operating conditions. Protection devices of the original control circuit no longer function correctly and have been blocked to allow the gate to operate when required. As a result, personnel and equipment are at risk every time the intake gate is opened after a complete or partial dewatering of the penstock.

The new intake gate control system will improve reliability, reduce maintenance requirements, reduce safety concerns with priming and will allow the gate to be controlled accurately throughout its entire operating range.

<u>Net Present Value</u>

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

<u>Levelized Cost of Energy</u>

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.

<u>Cost Benefit Analysis</u>

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

<u>Legislative or Regulatory Requirements</u>

There are no legislative or regulatory requirements for this project.

<u>Historical Information</u>

This project is the third of a four year program to upgrade six out of the eleven intake structures within Hydro's hydro generation system to a more accurate gate positioning system. In 2008, Bay d'Espoir Intake Gate 4 was upgraded. That project included only the installation of a PLC inside the intake vent house and did not include a Power House PLC or communication equipment since that had been installed in 2002 under another capital project. In 2009, upgrades are being made to the Hind's Lake Intake Gate system. Table 3 provides cost information.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Justification: (cont'd.)

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	263.1		1		Hind's Lake Intake
2008[1]	115.5	133.7	1	133.7	Bay d'Espoir Intake 4

[1] 2008 was the first year of the Upgrade Intake Gate Control Program.

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to the upgrade of intake gate controls.

Losses During Construction

There will be no losses during construction as this upgrade will take place during the planned annual unit outage on the generating unit.

Status Quo

The status quo is not acceptable. There is a significant safety hazard with continuing to operate with the existing system.

Alternatives

There are no viable alternatives to this project.

Project Title: Upgrade Intake Gate Controls **(cont'd.)**

Conclusion:

This upgrade is necessary due to the safety concerns that surround this project and the unreliability of the equipment to operate properly.

Project Schedule

Table 4 presents the anticipated project schedule.

Table 4: Project Schedule

Activity	Milestone
Project Initiation	February 2010
Equipment Procurement	May 2010
Engineering Design	June 2010
Installation	August 2010
Commissioning	September 2010
As Built Documentation	November 2010
Project Closeout	December 2010

Future Plans:

Future upgrades will be proposed in future capital budget applications. Hydro plans to Upgrade Intake Gates 1, 2 and 3 at Bay d'Espoir in 2011. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg
Location: Bay d'Espoir
Category: Generation - Hydraulic
Type: Other
Classification: Justifiable

Project Description:

This project is required to install an automated fuel monitoring system at the Ebbegunbaeg control structure. This system will be a Programmable Logic Controller (PLC) based fuel delivery system for the two diesel storage tanks located at the site. This system will provide all necessary controls for the transfer of fuel between the bulk storage tank and the day tank and will allow for remote monitoring from Hydro's Energy Control Center (ECC). The costs include helicopter time and network services work. Table 1 contains the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	52.2	0.0	0.0	52.2
Labour	103.6	0.0	0.0	103.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	31.4	0.0	0.0	31.4
O/H, AFUDC & Escln.	29.6	0.0	0.0	29.6
Contingency	18.7	0.0	0.0	18.7
TOTAL	**235.6**	**0.0**	**0.0**	**235.6**

This project is to be implemented in an unmanned control structure, where fuel reconciliation is required by environmental regulations (see the Environmental Performance section of this report).

Existing System:

There are six reservoirs in the Bay d'Espoir reservoir system. The largest reservoir is the Meelpaeg Lake Reservoir with a drainage area of approximately 970 km^2. The flow of water from Meelpaeg Lake is controlled by the Ebbegunbaeg Control Structure located on the northeastern end of the reservoir. The water flows in a northeasterly direction through a rock cut channel to the Great Burnt Lake Reservoir. The main source of power to the control structure is supplied through a 25 kV distribution line, approximately 20 kilometers long, from the North Salmon Dam which receives power from the Upper Salmon Generating Station. Back-up power for the control structure is provided by a 100 kW diesel unit. Fuel for the diesel unit is provided from a 9,000 litre bulk storage tank and a 900 litre day storage tank.

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg **(cont'd.)**

Existing System: (cont'd.)

Figure 1: Ebbegunbaeg Control Center

The Ebbegunbaeg control structure is operated remotely from Hydro's ECC. Figure 1 is a picture of the site of the Ebbegunbaeg Control Structure. To the left of the control structure (center of the photo), is the diesel plant and the bulk storage tank. The day tank is located inside the diesel plant. Operations personnel visit the site every two weeks for routine inspection and to perform maintenance work, if required. During the visits, the tanks are dipped, which is a process whereby an operator lowers a graduated measuring stick into a tank to measure the depth of the fuel for the purposes of fuel reconciliation. Fuel reconciliation is the process of accounting for the addition and removal of fuel in a system. It is done by comparing the measured level in the tank to the expected level based on fuel consumption. Due to temperature changes in the fuel, and human error, the reconciliation of the fuel levels is often difficult. As the site is only inspected every two weeks, there is a potential for fuel spills to go unnoticed for that period of time.

Since this is a new installation, the following are not applicable to this project:

- Major Work/or Upgrades;
- Anticipated Useful Life;
- Maintenance History;

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg **(cont'd.)**

Existing System: (cont'd.)

- Outage Statistics;
- Vendor Recommendations;
- Availability of Replacement Parts; and
- Safety Performance.

Age of Equipment or System

The fuel tanks are six years old.

Industry Experience

There is no known relevant industry experience.

Maintenance or Support Arrangements

Maintenance on the fuel tanks is performed by Hydro personnel.

Environmental Performance

Fuel reconciliation is a reporting requirement of Part 18 of the Storage and Handling of Gasoline and Associated Products Regulations (GAP) under the Environment Protection Act which states:

> The operator of an above-ground tank system shall:
>
> *18 (2) (a)*
>
> *ensure that the tank or tanks are gauged or dipped, including a water dip, at least weekly or at such less frequent interval as the minister may approve in writing to accommodate remote installations.*
>
> *18 (2) (b)*
>
> *reconcile gauge or dip readings with receipt and withdrawal records at least weekly.*

This is a non-compliance issue, as Hydro is presently completing these dips on a bi-weekly basis. One potential environmental impact from the status quo is that a spill or leak could continue for up to two weeks before anyone is alerted. The implementation of the proposed system would alert the ECC immediately of a possible spill condition, allowing them to formulate a timely response.

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg **(cont'd.)**

Existing System: (cont'd.)

Operating Regime

This automated fuel monitoring system will be in operation continuously, allowing the ECC to monitor fuel consumption and detect leaks.

Justification:

Fuel reconciliation must be performed at least weekly, as required by GAP regulations. Presently, dip readings are only taken bi-weekly at the fuel storage tanks. It is presently completed bi-weekly to align with the crew change out at the Burnt Dam; weekly trips would introduce significant costs and are included in the cost benefit study, which follows. The installation of an automated fuel monitoring and PLC based delivery system will ensure continuous monitoring of the levels of the fuel in the tanks and alert ECC personnel of problems with either the fuel transfer system or the fuel tanks. In the event of a spill, Hydro can respond immediately. This reduces the likelihood of diesel fuel loss. Hydro will therefore likely be able to receive a variance[3] from the Provincial government so that regular manual fuel reconciliation or tank dipping is not required. A similar automated fuel monitoring system was installed at the Cat Arm Generating Station in 2007 and is performing well. It has received a government variance so that manual tank dips and reconciliation are no longer required.

Net Present Value

The net present value of the automated monitoring system is $223,014. The net present value of weekly visits to manually dip the tanks is $1,067,583. Please see the Cost Benefit Analysis section for details.

Cost Benefit Analysis

A cost benefit analysis was performed on two alternatives for this project.

[3] A variance is an exception to a given practice, which is obtained in writing from the government. A variance in this circumstance will have the same outcome as Cat Arm, where no dips and reconciliation are required.

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg **(cont'd.)**

Justification: (cont'd.)

Alternative 1: Manually dip the tanks on a weekly basis.

Currently, tanks are manually dipped on a bi-weekly basis. During the routine helicopter trip to make a crew change at the Burnt Dam structure, a stop is made at the Ebbegunbaeg Control Structure to allow operations personnel to perform routine inspection and maintenance at which time the tanks are also dipped. To perform dips on the tanks on the alternate weeks when crew changes at Burnt Dam do not occur, an additional helicopter trip to the Ebbegunbaeg Control structure would be required at an estimated cost of $3,500 per trip. For 26 more trips per year, the additional annual cost would be approximately $91,000.

Alternative 2: Install an automated fuel monitoring system.

An automated fuel monitoring system could be installed at an estimated cost of $235,500. This alternative assumes a PLC replacement in the year 2025 and sensor replacements throughout the life of the system.

Utilizing a 25 year study period for these 2 alternatives, the cumulative net present value for each alternative is as follows:

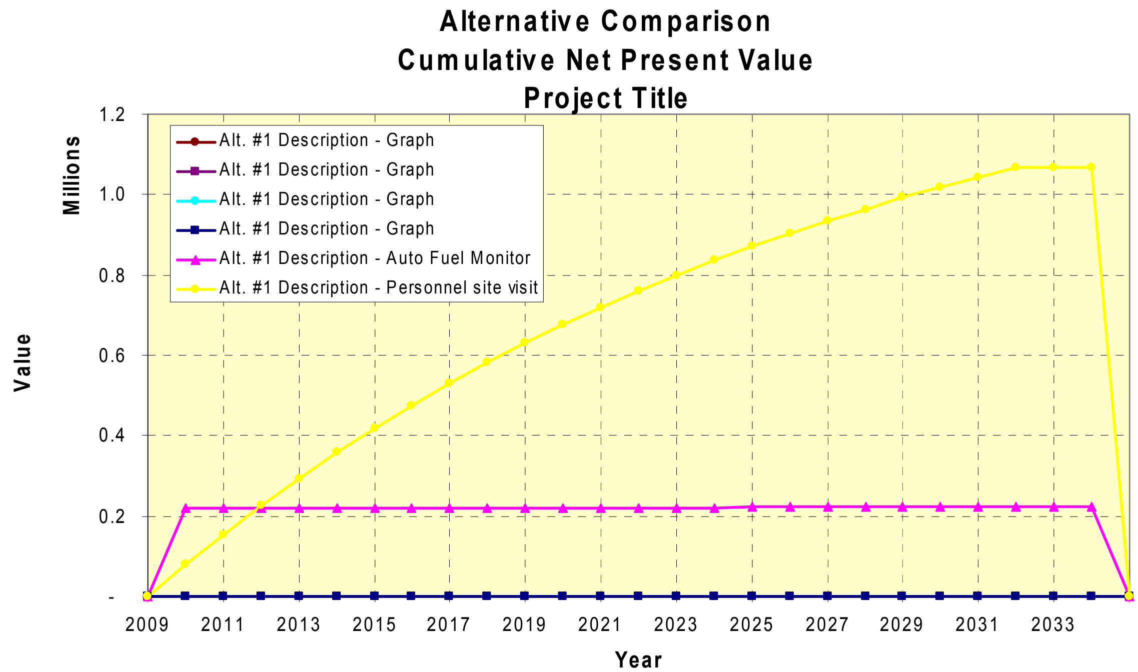
Alternative 1: $1,067,583

Alternative 2: $ 223,014

A savings of $844,569 would result if Alternative 2, the automatic fuel monitoring system, is chosen. Based on this analysis, Alternative 2 is the preferred alternative.

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg **(cont'd.)**

Justification: (cont'd.)



Legislative or Regulatory Requirements

See Environmental Performance section for the appropriate GAP regulation   A written variance from the Provincial Government may be obtainable to avoid the required weekly dips.

Historical Information

There is no comparable historical information associated with this proposal.

Status Quo

The status quo is not acceptable due to noncompliance with GAP Regulations.

Alternatives

Two alternatives were considered for this project:

1) Weekly dips via helicopter trip to the control structure; and
2) Installation of the automated fuel monitoring system.

Please refer to the Cost Benefit Analysis section of this report for further detail on these alternatives.

Project Title: Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg **(cont'd.)**

Conclusion:

To conform to GAP regulations, action must be taken to better monitor the fuel in the bulk and day tanks at the Ebbegunbaeg Control Structure. A cost benefit analysis indicates a potential financial savings of $844,600 over 25 years by installing an automated fuel monitoring and PLC enhanced system.

Project Schedule

The project schedule is outlined in Table 2.

Table 2: Project Schedule

Activity	Milestone
Project Initiation, Design and Equipment Ordering	July 2010
Operations Installations	July 2010
Commissioning	July 2010
In Service	August 2010
Project Completion and Close Out	December 2010

Future Plans:

Future diesel plant monitoring systems will be proposed in future capital budget applications.

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level
Location: Holyrood
Category: Generation - Thermal
Type: Other
Classification: Normal

Project Description:

This project is required to install a condensate collection system (known as drain pots) on the Unit 1 Cold Reheat (CRH) steam lines, at the Holyrood Thermal Generating Station (Holyrood). At present, the Unit 1 CRH steam lines do not have drain pots to collect condensate that may be present. In addition, there is no provision to test the high condensate level trip functionality of the Unit 1 high pressure feed water heaters. Both of these conditions can allow the induction of condensate into the high pressure turbine and cause damage to the turbine blades. The CRH drain line will be modified to provide a drain pot at the low point of each CRH line. These will be physically located as close as possible to the turbine, and fitted to provide a signal to permit operator action to stop water inflow. Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	9.0	0.0	0.0	9.0
Labour	70.9	0.0	0.0	70.9
Consultant	40.0	0.0	0.0	40.0
Contract Work	66.6	0.0	0.0	66.6
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	24.0	0.0	0.0	24.0
Contingency	18.9	0.0	0.0	18.9
TOTAL	**231.4**	**0.0**	**0.0**	**231.4**

Existing System:

Holyrood is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW. Generating Units 1 and 2, capable of producing 150 MW each, were brought in service in 1971. These units were up-rated to 170 MW in 1988 and 1989. In 1979, generating Unit 3, capable of producing 150 MW, was brought in service. Holyrood represents approximately one third of Newfoundland and Labrador Hydro's (Hydro) total Island Interconnected System generating capacity.

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Existing System: (cont'd.)

The three main components of each generating unit are the boiler, turbine and generator. The main components of the boiler are the water wall tubes, boiler drum, superheater, re-heater, and economizer. A component of the piping system on each generating unit is called the CRH steam line which conveys steam from the high pressure turbine and back to the boiler re-heater section. The CRH line also supplies steam to the boiler's high pressure heater for the purpose of increasing the temperature of the boiler feed water prior to entering the boiler.

There is no condensate collection system (drain pot) on Unit 1. Condensate is defined as the formation of water in steam lines during a reduction in steam temperature. The new condensate collection system will be installed at the lowest point of elevation on the CRH steam line between the boiler and turbine (see Figure 1). It is necessary to prevent water induction into the steam turbine to prevent damage to the turbine caused by condensate ingression. A sketch of the CRH drain pot can be found in Appendix A.

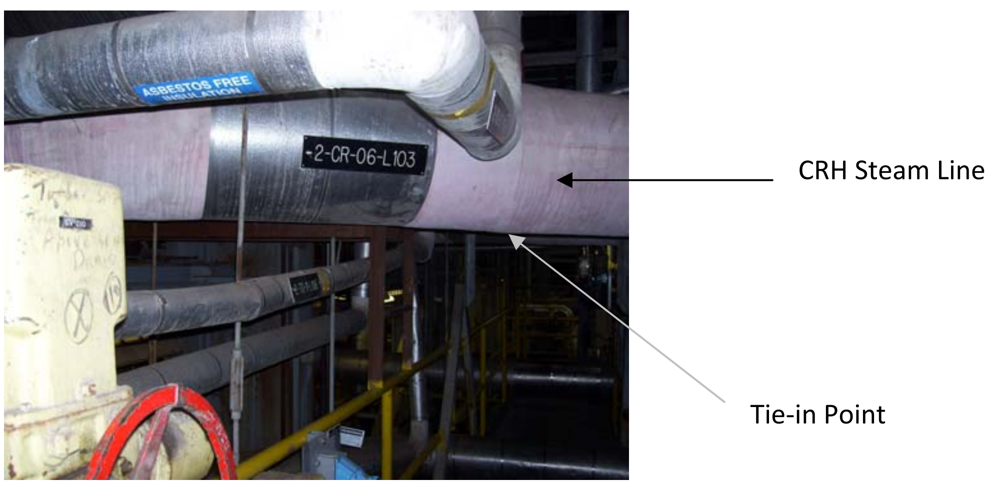


Figure 1 – Tie-in Point for CRH Drain Pot

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Existing System: (cont'd.)

A modification of the high pressure heater condensate piping will provide a means to test the high condensate level trip functionality of the high pressure feed water heater. CRH steam is used to increase the temperature of the boiler feed water in the high pressure heater before it enters the boiler. During the process of heating the feed water, the CRH steam temperature drops and forms condensate. The high pressure heater is equipped with a level probe to detect high condensate levels in the heater. A malfunction of the level probe would allow water induction into the turbine through the CRH steam line. To simulate a high level of condensate, a vent valve and drain pipe will be installed above the probe on top of the level column (see Figure 2 below). Opening the new vent valve and closing the existing valve on the steam side of the probe will cause the condensate level in the column to rise and activate the probe. An existing switch located in the electrical box adjacent to the heater will be used to disable the generating unit trip mechanism when the new vent valve is opened for testing purposes. Proper operation of the level probe will be confirmed by an indicator light in the electrical box. FM Global, the insurance carrier for Hydro, has recommended that Hydro install CRH drain pots and make provision to test for high condensate levels in the HP heater of Unit 1. See recommendation numbers 06-01-003 Part A and 06-01-003 Part B in the FM Global Risk Report 2006 located in Appendix B.

Figure 2 – HP Heater Level Probe

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System

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

Major Work/or Upgrades

Unit 1 was originally rated at a capacity of 150 MW. In 1988, it was upgraded to a capacity of 170 MW. However, the upgrade on Unit 1 in 1988 did not have any affect on the CRH system.

Anticipated Useful life

The anticipated useful life of Unit 1 has been forecasted to extend to the year 2020.

Maintenance History

Maintenance records indicate that there has been no turbine damage that can be attributed to the induction of condensate into the turbine through the cold reheat steam lines at Holyrood.

There have been instances whereby condensate has been introduced into the high pressure turbine of Unit 1 through the reheat steam piping during start-ups and has required manual opening of the existing cold reheat drain valves to remove the condensate. The frequency and times when this has occurred has not been documented. Hydro has not incurred any damages from those instances.

Outage Statistics

There have been no outages on Unit 1 caused by water ingression into the turbine through the CRH steam lines.

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Existing System: (cont'd.)

Industry Experience

FM Global, Hydro's insurance company, indicates that there have been occurrences in the power utility industry of turbine water induction damage caused by water in the CRH steam line. Water is usually introduced into the turbine from the high pressure feed water heater which extracts steam from the CRH line. Please refer to Appendix B, FM Global Recommendation, Part B: The Hazard.

Maintenance or Support Arrangements

Hydro currently has a service contract with Alstom Power, a boiler service contractor, to perform boiler maintenance during the annual scheduled outage.

Vendor Recommendations

There are no vendor recommendations to install CRH drain pots or test the functionality of the high pressure water heater high level trip. Completion of this project is based on a recommendation from FM Global to minimize the risk of equipment damage.

Availability of Replacement Parts

As there is no condensate control system currently in place, availability of replacement parts is not applicable in this case. However, replacement components for the new CRH drain pots, such as spare conductivity probes and a motorized drain valve for the pot, are readily available.

Safety Performance

There are no safety performance concerns or safety violations associated with this project.

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Existing System: (cont'd.)

Environmental Performance

There are no environmental performance concerns or environmental violations associated with this project.

Operating Regime

Holyrood operates in a seasonal regime. The full plant capacity is needed to meet the winter peak loads on the Island Interconnected System. The CRH steam pipe and high pressure water heater high level trip functionality are integral components of Unit 1.

Justification:

This project is required to install CRH drain pots and modify the high pressure feed water heater condensate piping to provide a means to test the functionality of the boiler high pressure feed water heater high condensate level trip system on Unit 1. FM Global, Hydro's insurance company, indicates that there have been occurrences in the power utility industry of turbine water induction damage caused by water in the CRH steam line. The water is usually introduced into the turbine from the high pressure feed water heater, which extracts steam from the CRH line. As a result, both a provision to detect and drain water from the CRH steam line and to test the high pressure feed water heater high condensate level trip system is essential for reliable operation of the turbine. The installation of the CRH drain pots will prevent damage to the turbine caused by possible water ingression. CRH drain pots and a means to test high condensate levels in feed water heaters are recommended by the American Society of Mechanical Engineers (ASME) as per ASME standard TDP-1-1998 to prevent water induction into the turbine. See Section 3.5 in ASME TDP-1-1998 located in Appendix C. FM Global, the insurance carrier for Hydro, has recommended that Hydro install CRH drain pots and make provision to test for high condensate levels in its high pressure feed water heaters. See recommendation numbers 06-01-003 Part A and 06-01-003 Part B in the FM Global Risk Report 2006 located in Appendix B.

Net Present Value

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

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Justification: (cont'd.)

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.

Cost Benefit Analysis

A cost benefit analysis has not been performed since only one viable alternative exists.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

In 2008, a capital project was approved by Board Order P.U. 36 (2008) to install a condensate collection system on Unit 1 in 2009. However, due to outage schedule restrictions, that project was changed to have the devices installed on Unit 2 instead. The Board of Commissioners of Public Utilities approved the 2009 project change in Order No. P.U. 19, 2009. This project revisits the installation of the devices on Unit 1. The budget estimate for the 2009 project is $191,600.

The cost to install the condensate collection system on Unit 1 in 2010 has increased by approximately $40,000 when compared to the budget proposal submitted to the Board of Commissioners of Public Utilities in 2008 to have the installation completed in 2009. The increase is primarily due to the use of consultants to complete detailed engineering design and to develop technical specifications required for contract preparation. In addition, the cost to have the installation completed by a contractor in 2010 has been escalated by 10 percent.

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Justification: (cont'd.)

Forecast Customer Growth

Forecast customer growth does not affect this project.

Energy Efficiency Benefits

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

Losses During Construction

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

Status Quo

According to FM Global, there have been numerous reported cases in industry of steam turbine damages and failures as a result of water induction through CRH piping. Successful completion of this project will improve the reliability of electrical service provided by Unit 1 and will minimize customer energy cost that would potentially escalate in the event of a catastrophic failure of the turbine.

Alternatives

There are no viable alternatives to this project.

Conclusion:

This project provides for the installation of a protection monitoring system as recommended by FM Global and is necessary to improve the reliability of electrical service provided by Unit 1 and to ensure that electrical energy is provided to the customer at the lowest possible cost. Turbine damage and failures caused by water induction have occurred in other generating

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level **(cont'd.)**

Conclusion: (cont'd.)

plants that did not have this protection. CRH drain pots and a means to test high condensate levels in feed water heaters are recommended by the American Society of Mechanical Engineers as per ASME standard TDP-1-1998 to prevent water induction into the turbine.

Project Schedule

Table 2 provides the anticipated project schedule.

Table 2: Project Schedule

Activity	Milestone
Project Kick-off Meeting	January 2010
Complete Design Transmittal	February 2010
Detailed Engineering Design	April 2010
Develop Installation Specification	April 2010
Issue Tender and Award Job	May 2010
Procurement of Materials	May 2010
Contract Execution	August 2010
Commissioning	September 2010
Project Final Documentation and Closeout	December 2010

Future Plans:

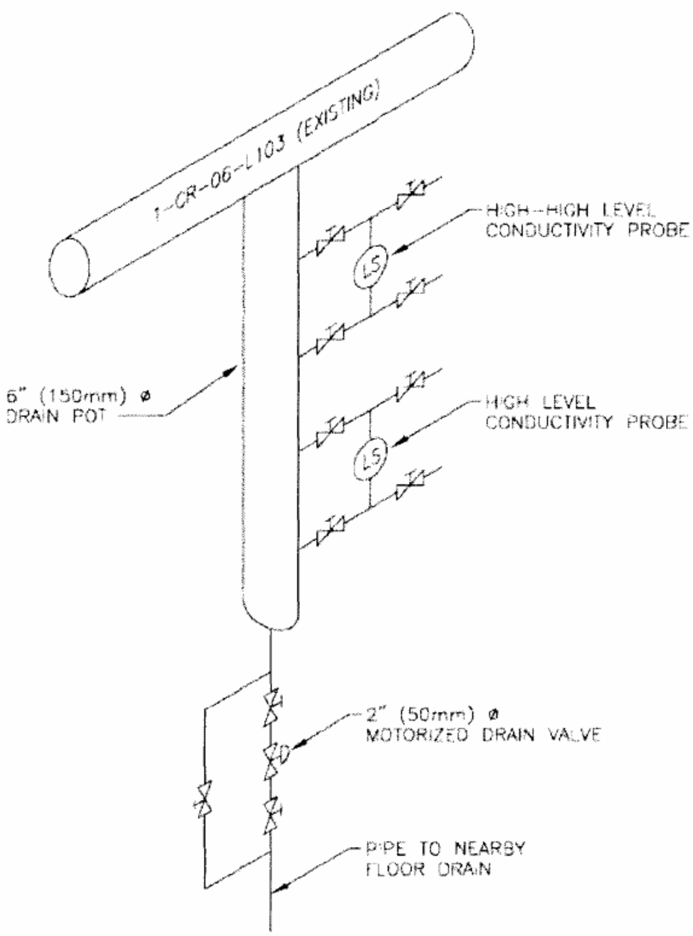
None.

APPENDIX A

Holyrood – Unit 1 Cold Reheat Drain Pot

HOLYROOD - UNIT NO. 1 COLD REHEAT DRAIN POT

N.T.S.



NOTES:

1) CONDUCTIVITY PROBE MANIFOLD PIPING AND VALVES TO BE 2" (50mm) ø.
2) DRAIN POT TO BE 6" (150mm) ø PIPING.
3) ALL CONTROLS WIRING TO BE DONE BY PLANT. (LABOR & MATERIALS)
4) CONDUCTIVITY PROBES TO BE HYDRATECK 2462, PN: 246785A.
5) PROBE INSERTS TO BE HYDROTECK PN: 24673540A.
6) DRAIN POTS AND CONDUCTIVITY PROBE PIPING TO BE INSULATED.

APPENDIX B

FM Global Recommendations

FM Global Risk Report | Newfoundland & Labrador Hydro-Electric Corporation

03-05-001 continued

Status	The budget for completion of this recommendation will be submitted in 2007. Improvements in ground fault protection would then be implemented on all three units in 2008.

06-01-003 Improve protection against steam turbine water induction.

Steam Turbine Water Induction

Part A. Test high and high-high level switches on feedwater heaters.

The high and high-high level switches on the boiler HP feedwater heaters should be tested at least quarterly using the simulation method. These should be provided with a means to test the high water level alarm and interlocks without endangering the operation of the unit.

The switches which have inconsistent test results should be repaired or replaced.

The Hazard	The admission of water into the hot turbine, valves and piping can cause premature failure of critical components, and feedwater heaters in particular represent the most frequent source of potential water induction. If a high-high water alarm is not quickly sensed in a feedwater heater and the protection interlocks do not operate as designed, water can pass through the block valve and reach the extraction non return valve (NRV). This valve could be distorted due to thermal shock, allowing water to enter and damage rotating components of the turbine. In the worst case, thermal shock and distortion result in rubbing or blade failure and downstream damage. Testing the feedwater heaters' safety devices will help ensure that all components operate as designed to prevent such an event.
Technical Detail	Presently, these safety devices are only tested during outages. Simulation of a high water level condition is feasible by means of a two-way valve (try cock) or the isolation and vent valves on the steam side of the switch. The steam chamber can be isolated from the heater and, at the same time, be vented to the atmosphere, reducing the pressure above the condensate in the gauge, and permitting the condensate level to rise and actuate the level switch at alarm level. Prior and upon completion of the test, make sure to test/inspect the heaters to confirm the normal water level is in range. Upon completion of the test, restore the equipment to its original condition of operation.
Status	The test is considered warranted by management, however, carrying out the testing will require physical modifications which cannot be completed until the next outage. This will be looked into.

Index: 000009.36-02 / Account: 1-74568 / Order ID: 676515-40 5

FM Global Risk Report — Newfoundland & Labrador Hydro-Electric Corporation

06-01-003 continued Cold R.H. Line

Part B. **Install a drain pot with a high level switch on the cold reheat line.** Level SW

The cold reheat drain line should be modified to provide a drain pot at the low point of each cold reheat line. These should be physically located as close as possible to the turbine, and should be fitted to provide a signal to permit operator action to stop water inflow.

The Hazard	Numerous occurrences of turbine water induction damage have been attributed to the presence of water in the cold reheat line. This water is usually introduced into the system from the reheat attemperators spray station, the feedwater heaters extracting steam from the cold reheat line, or condensation forming in the line and being introduced during startup. The recommended modifications will help prevent damage to the turbine from the above-mentioned sources.
Technical Detail	The drain pot should be fabricated from six-in. or larger diameter piping and be no longer than is required to install level sensing equipment. If there is a low point in the cold reheat line other than that near the turbine which is upstream of the attemperator or the extraction supply to the feedwater heaters, then an additional drain pot should be installed at this point for increased protection. Each pot should be provided with a drain line of nominal two-in. minimum size and a full-size and full-ported automatic power-operated drain valve, arranged to fail open if possible. To prevent condensation, all lines should be fully insulated. Each drain pot should be provided with a minimum of two level sensing devices. The first (high level) should actuate the drain valve to fully open and send an alarm notifying that the valve has opened. The second (high-high) should initiate an alarm in the control room. For more details, please refer to ASME TDP-1-1998, Section 3.4 Cold Reheat Piping.
Status	Management understands the hazard and indicated that this will be completed. Completion has been scheduled for 2008.

03-05-002 **Consider the installation and use of automatic sychronization of electric generators.** Auto Sync

The Hazard	Improper synchronization of a generator during manual operation can result in damage to any type of generating units. The damage incurred can be slipped couplings, increased shaft vibration, a change in bearing alignment, loosened stator windings, loosened stator laminations and fatigue damage to shafts and other mechanical parts.
Technical Detail	In order to avoid damaging the generator during synchronizing, the generator's manufacturer generally provides synchronizing limits in terms of breaker closing angle and voltage matching, and frequency difference limits. During manual synchronizing, these limits may not be followed, resulting in damage to the unit. The complete automatic synchronizing equipment usually consists of a synchronizing relay, speed-matching relay and voltage matching relay.

Index: 000009.36-02 / Account: 1-74568 / Order ID: 676515-40 6

APPENDIX C

ASME Standard TDP-1-1998, Section 3.5

be designed basically in accordance with criteria set forth earlier in this Section for drain lines. This similarity should include the installation of power-operated valves, control room indications of valve position, and control room operation of the valves. The drain lines, connections, and valve ports should, however, be a minimum of $\frac{3}{4}$ in. I.D.

3.4 Cold Reheat Piping

3.4.1 Numerous occurrences of turbine water induction damage have been attributed to the presence of water in the cold reheat line. This water is usually introduced into the system from either the reheat attemperator spray station or the feedwater heaters which extract steam from the cold reheat line. The design of a drainage system with sufficient capacity to remove all water that can be introduced into the cold reheat pipe from these sources is considered impractical because of the high rate of flow into the piping. For this reason the recommended system is designed to provide a signal to permit operator action to stop water inflow.

3.4.2 Provide a drain pot at the low point of each cold reheat line, preferably as close to the turbine as possible. This pot should be fabricated from 6 in. or larger diameter pipe and be no longer than is required to install level sensing equipment. If there is a low point in the cold reheat line other than that near the turbine (either in the cold or hot condition) which is upstream of the attemperator or the extraction supply to the feed-water heaters, an additional drain pot should be installed at this point for increased protection.

3.4.3 Each pot should be provided with a drain line of nominal 2 in. minimum size and a full size and full ported automatic power-operated drain valve. The valve should be arranged to fail open if such a choice is available.

3.4.4 To help ensure that the pot remains dry during normal unit operation, the pot and connecting piping should be fully insulated.

3.4.5 Each drain pot should be provided with a minimum of two level sensing devices (see Fig. 4). The first level (high level) shall actuate to fully open the drain valve and shall initiate an alarm in the main control room indicating that the valve has opened. The second level (high-hi level) shall initiate a high-hi level alarm in the control room.

3.4.6 The drain valve control should provide the following features:

(a) open automatically on high water level in the drain pot (see para. 3.4.5);

(b) ability to be opened or closed by remote manual controls in the main control room with a high level control capable of overriding the manual closed position;

(c) position indication in the control room.

3.4.7 When a cooling steam pipe is provided from the cold reheat pipe to the intermediate pressure turbine, this pipe should not be connected at or near the low point of the cold reheat pipe. If routing of the cooling steam pipe creates a low point, a continuous drain should be provided from the cooling steam pipe.

3.4.8 In addition to the drain pot and level switches to detect water in the system, thermocouples can be installed on the pipe or in wells. Two thermocouples, one on the cold reheat pipe close to the turbine connection and one on the bottom of the horizontal run below the turbine, can be used to detect water by differential temperature. This system, however, should not be considered as a substitute for the drain pot and level switches.

3.5 Reheat Attemperator

3.5.1 Spray water injection in the cold reheat line is used as a means to control steam temperature at the outlet of the reheater. These sprays are not effective or required for reducing final reheat steam temperature when used at low loads or during turbine rolling. Most incidents of turbine water damage caused by attemperators have occurred during these periods as a result of over-spraying. The water thus formed accumulates and, in most cases because of low steam velocity and the arrangement of the piping, flows back to the turbine. Another possibility, that occurs less frequently, results when water accumulates from condensation in pendant elements of the reheater during a low load operation. The water can then be injected into the turbine if flow is increased rapidly.

3.5.2 A power-operated block valve should be installed in series with the attemperator spray control valve. This valve provides tight shutoff to prevent water leaking past the spray control valve and provides a backup in the event that the spray control valve fails to close when required (see Fig. 5). The spray control and block valves constitute a double line of defense against the inadvertent introduction of spray water into the cold reheat lines. Since spray control valves are susceptible to leakage, additional protection can be obtained by use of a second block valve.

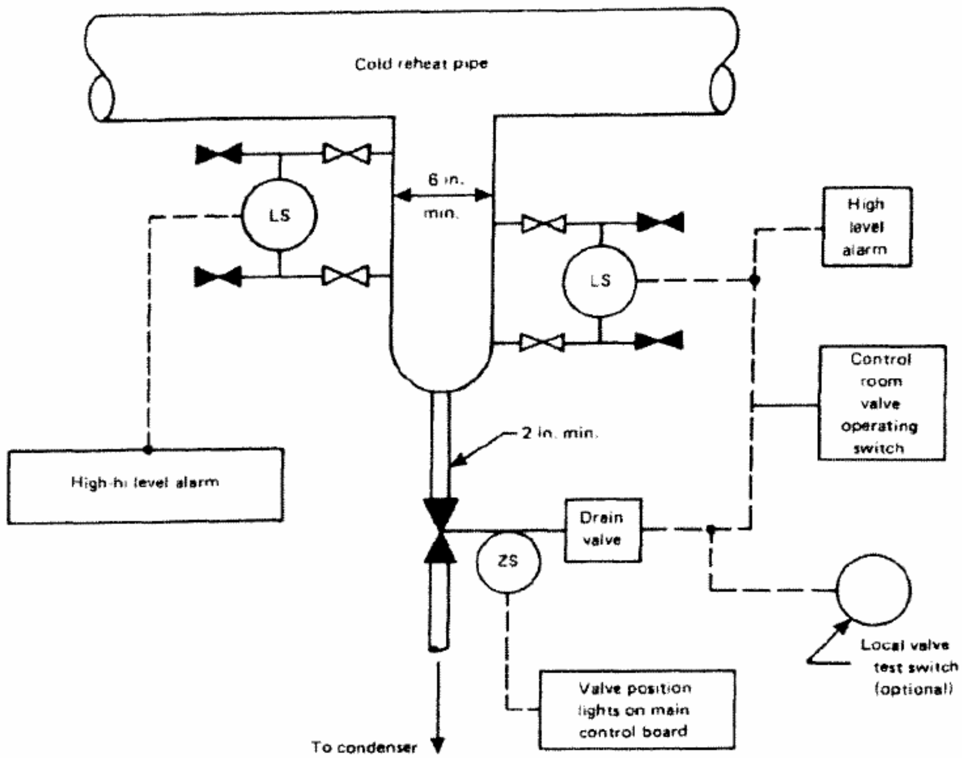


FIG. 4 TYPICAL COLD REHEAT DRAIN SYSTEM

3.5.3 The control system should automatically close and override all manual and automatic settings of the reheat spray control and block valves when the master fuel trip actuates or the turbine trips.

3.5.4 The block valve should be automatically closed below a predetermined minimum load and any time the demand signal to the control valves does not call for spray. Reheat spray should not be released for automatic control at loads where it can be determined that it is relatively ineffective in reducing final reheat steam temperature. The loads used should be in accordance with the boiler manufacturer's recommendations. Manual control must not prevent the automatic protection features specified in para. 3.5.3 from operating in the event the master fuel trip actuates or the turbine trips.

3.5.5 The control system for opening the spray control valve should be designed to prevent the sudden injection of large quantities of water.

3.5.6 A manually-operated drain valve should be installed between the power-operated block valve and the spray control valve. This connection can be equipped as a *tell-tale* for periodically testing for block valve leakage.

3.5.7 A manual bypass valve around the spray control valves is not recommended. If this recommendation is not followed, administrative control should be used to reduce the inherent possibilities of water induction.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies
Location: Bay d'Espoir
Category: Generation - Hydraulic
Type: Other
Classification: Normal

Project Description:

This project is required to purchase two spare sets of spherical valve seal components for both the upstream and downstream seals of the spherical valves for generating Units 1 through 6 at the Bay d'Espoir Generating Station. Two spare sets are required because of the difference in the design of the valves for Units 1 through 4 compared to the design of the valves for Units 5 and 6, as described in the Existing System section below. The spare set for Units 1 through 4 includes the purchase of the moveable seal and stationary seat components. The spare set for Units 5 and 6 includes the purchase of the following components:

- Downstream Piston Ring (moveable seal)
- Downstream Seal (stationary seat)
- Upstream Piston Ring (moveable seal)
- Upstream Seal (stationary seat)

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	152.0	0.0	0.0	152.0
Labour	23.9	0.0	0.0	23.9
Consultant	6.2	0.0	0.0	6.2
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.	22.4	0.0	0.0	22.4
Contingency	18.2	0.0	0.0	18.2
TOTAL	**222.7**	**0.0**	**0.0**	**222.7**

Existing System:

Bay d'Espoir is Hydro's largest hydroelectric generating station on the Island Interconnected System. Power House 1 has six generating units, each having a rated capacity of 75 Megawatts and Power House 2 has one generating unit with a rated capacity of 154 Megawatts. Each generating unit in Power House 1 is equipped with an 87 inch diameter spherical valve that is able to stop the flow of water to the unit.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

Spherical valves for Units 1 through 4 were designed and manufactured by Dominion Engineering and valves for Units 5 and 6 were designed and manufactured by English Electric. Although the designs are different, the valves operate in a similar manner. Each seal makes use of a movable seal and a stationary seat. When the valve is closed the moveable seal travels in the direction of the valve plug and makes contact with the stationary seat that is mounted on the valve plug to form a seal. Figure 1 shows a typical downstream seal assembly currently in use on spherical valves for Units 5 and 6.

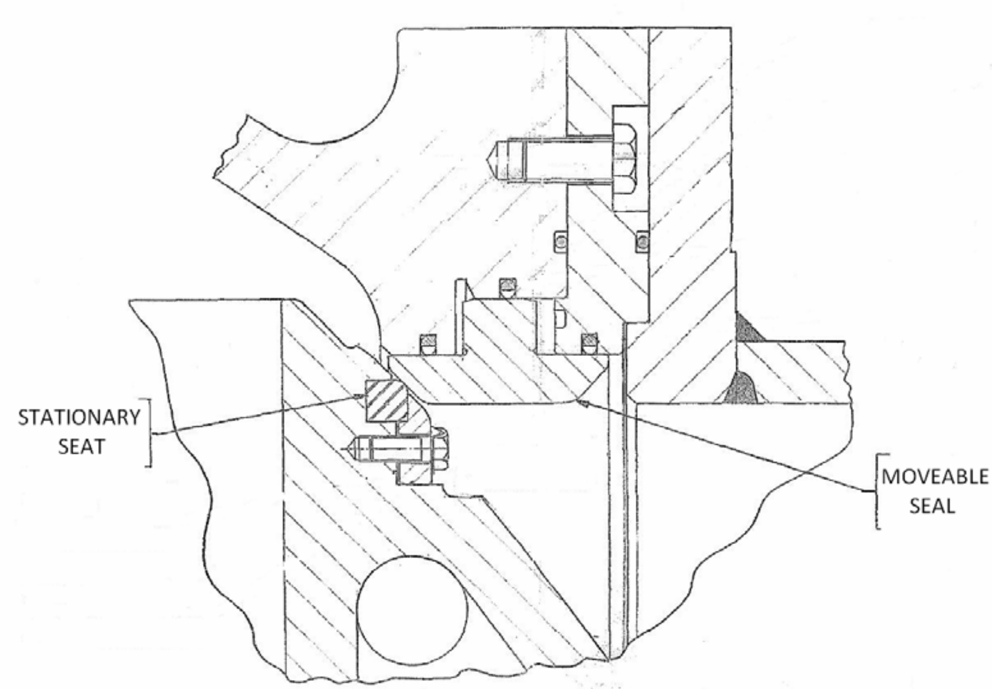


Figure 1: Typical Downstream Moveable Seal Spherical Valve Five and Six, Bay d'Espoir

The downstream seal is automatically applied when the spherical valve is closed. Usually this happens when the generating unit is being taken off-line, typically when it is no longer needed to meet load. However, the spherical valve can also close and the downstream seal apply in the case of an emergency, such as when a turbine goes into an overspeed condition upon the abrupt loss of electrical load on the generator. The valve acts to quickly stop the flow of water to the unit. Figure 2 shows the downstream moveable seal spherical valve one.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

The upstream seal is manually applied by plant personnel as part of the process to isolate a generating unit to perform necessary work. Before the work begins, a leakage test is performed to measure the total leakage across the seal. If the leakage rate is higher than the acceptable limit, work will not proceed. The acceptable limit has simply been an observation of the pressurized water flow from a test line and a judgment by operations personnel. However, Hydro plans to quantify this amount to remove uncertainty in determining what is acceptable. If the leakage rate remains high, work can only be completed by shutting down the adjacent generating unit sharing the same penstock, and closing the intake gate to completely drain the penstock. The upstream seal is a worker protection device while the downstream seal is a unit protection device.

Originally each valve was purchased with a complete set of spare seals which have been used but not replaced. As the various components are custom made and not off the shelf items, it is essential to have spare seals ready when needed, to limit the amount of time a spherical valve is operating without acceptable worker protection or unit protection capability. It is estimated that from the date of order it would take two months for delivery of a spare seal assembly.

Figure 2: Downstream Moveable Seal Spherical Valve One, Bay d'Espoir

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System

The exact age and period of service of many of the seal components currently in use at Bay d'Espoir could not be determined. Some components are original and in service since commissioning while others were replaced during the late 1980's and early 1990's but detailed records of the work do not exist. What is known for certain is that the spare assemblies supplied for spherical valves one through four have been used and only one seal remains from the spare assembly supplied for valves five and six.

The spherical valve on Unit 6 is scheduled to undergo major maintenance during the summer of 2009 during which time the condition of the upstream seal will be assessed and replaced if necessary. If this occurs, all spare rings provided by the manufacturers will have been used.

Major Work/or Upgrades

The control systems that operate the spherical valves have had major upgrades. Table 2 provides a listing of the upgrades that have occurred since installation:

Table 2: Major Work and Upgrades

Year	Major Work/Upgrade	Cost of Upgrade ($000)
2006	Controls Upgrade on Unit 6	176.9
2005	Controls Upgrade on Unit 5	212.3
2004	Controls Upgrade on Unit 3	211.4
2003	Controls Upgrade on Unit 1	236.5
2002	Controls Upgrade on Unit 2	172.2
2001	Controls Upgrade on Unit 4	194.9

Anticipated Useful life

The seal ring components have an estimated service life of 25 years from the date of installation.

Maintenance History

The five-year maintenance history for each of the spherical valves is shown in Tables 3 through 8.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

Table 3: Spherical Valve One Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.6	0.0	0.6
2007	0.0	0.4	0.4
2006	0.7	0.7	1.4
2005	0.0	1.7	1.7
2004	0.5	0.0	0.5

Table 4: Spherical Valve Two Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.7	0.0	0.7
2007	0.7	0.0	0.7
2006	0.7	1.0	1.7
2005	0.7	0.0	0.7
2004	0.5	0.2	0.7

Table 5: Spherical Valve Three Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.7	0.0	0.7
2007	0.7	0.6	1.3
2006	0.7	1.1	1.8
2005	0.6	0.0	0.6
2004	0.5	4.1	4.6

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

Table 6: Spherical Valve Four Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.7	0.0	0.7
2007	0.7	0.6	1.3
2006	0.7	1.1	1.8
2005	0.6	0.0	0.6
2004	0.5	0.0	0.5

Table 7: Spherical Valve Five Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.7	31.0	31.7
2007	0.7	0.0	0.7
2006	0.7	0.0	0.7
2005	0.0	0.0	0.0
2004	0.0	0.0	0.0

Table 8: Spherical Valve Six Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.7	0.0	0.7
2007	0.7	4.6	5.3
2006	0.0	0.0	0.0
2005	0.0	0.0	0.0
2004	0.0	0.0	0.0

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

The above costs are the corrective and preventive maintenance for the spherical valves. There is no specific preventive maintenance for the seal components only. When the seal components fail, they are replaced through corrective maintenance.

Outage Statistics

Table 9 lists the 2004 to 2008 average Capability Factor, Derated Adjusted Forced Outage Rate (DAFOR) and Failure Rate for the Bay d'Espoir Plant compared to all Hydro's hydraulic units and the latest CEA averages (2002 to 2006). These measures are also provided for spherical valve failures only. It should be noted that the six units in Bay d'Espoir and the two units in Cat Arm are the only ones in Hydro's system that have spherical valves.

In the past five years there have been 13 maintenance outages and four forced outages related to the Spherical Valves.

Table 9: Outage Statistics

Five Year Average 2004-2008

	All Causes			Spherical Valve Related Causes Only		
Unit	**Capability Factor (%)**	**DAFOR (%)**	**Failure Rate**	**Capability Factor (%)**	**DAFOR (%)**	**Failure Rate**
Bay d' Espoir Plant	94.00	0.21	1.95	99.76	0.01	0.18
All Hydraulic Units (2004-2008)	93.36	0.52	2.08	99.69	0.02	0.25
CEA (2002-2006)	91.02	2.03	2.30	99.95	0.01	N/A*

*CEA does not provide failure rate by component failure

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.

DAFOR is defined as Derated Adjusted Forced Outage Rate. It is the ratio of equivalent forced outage time to equivalent forced outage time plus the total equivalent operating time.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

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.

<u>Industry Experience</u>

There is no available industry experience regarding procurement of spare spherical valve seal components.

<u>Maintenance or Support Arrangements</u>

Maintenance of the spherical valves at Bay d'Espoir is conducted by Hydro personnel. Inspections are conducted on an annual basis.

<u>Vendor Recommendations</u>

Both English Electric and Dominion Engineering, the original manufacturers who supplied spare components, have gone out of business.

<u>Availability of Replacement Parts</u>

Since both original equipment manufacturers have gone out of business, replacement parts are unavailable. However, the required components have detailed engineering drawings which will allow Hydro to have the components fabricated by a qualified company.

<u>Safety Performance</u>

Hydro's Work Protection Code is used to ensure all equipment is properly isolated from sources of energy for safe work to proceed. This code identifies the necessary isolation points for work on the rotating parts of the generating units. One of these isolation points is the upstream seal of the spherical valves. If the seal is not functioning properly or has a high leakage, work is not permitted to proceed. Availability of spare upstream seal components is therefore crucial to worker protection.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Existing System: (cont'd.)

Environmental Performance

There are no environmental performance issues related to this project.

Operating Regime

Each seal on the spherical valve is operated intermittently. The downstream seal is automatically applied each time the spherical valve is closed. As the upstream seal is solely used for worker protection, it is manually applied when personnel are to work on the rotating parts associated with the unit. The downstream seal is operated more frequently than the upstream seal.

Justification:

This project is justified on the requirement to replace critical spares in order for Hydro to provide safe, least-cost, reliable electrical service.

Net Present Value

The cost of refurbishment, as indicated in the Alternatives section is so close to the replacement cost that a net present value calculation is unwarranted due to the increase in service life of a new seal.

Levelized Cost of Energy

As this project does not involve new generation sources, the levelized cost of energy is not applicable.

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

As this is not a recurring project, there is no applicable historical information.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Justification: (cont'd.)

Forecast Customer Growth

Forecast customer load has no affect on this project.

Energy Efficiency Benefits

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

Losses During Construction

There is no construction or installation associated with this project since it is a procurement of spare components.

Status Quo

The status quo is unacceptable. If failure of either of the seal rings occurs it would take several months to procure and install replacement parts. If the downstream seal malfunctions it would compromise the spherical valve's unit protection capability. If the upstream seal fails it would prevent any work from being completed on rotating parts while the second unit on the same penstock is operating. This would mean two units would have to be shut down for the duration of the work on a single unit and the penstock would have to be de-watered.

Alternatives

An available alternative to having new components fabricated is to refurbish the old components removed from service. This alternative was investigated in 2008 by Hydro's Engineering Services Division. A cost of $63,955 was quoted by a local machine shop to refurbish one set of rings. Engineering Services estimated a cost of $75,000 to fabricate one set of new seal rings. It is because the cost of refurbishment is so close to the cost of replacement and that refurbished rings are anticipated to be of a lesser quality with a shorter useful life than new rings that the procurement of new components is the recommended approach.

Project Title: Purchase Spare Spherical Valve Seal and Ring Assemblies **(cont'd.)**

Conclusion:

Improperly functioning spherical valve seals are not acceptable as both the generating unit protection and worker protection function of the spherical valve is compromised. It is essential to have critical spares on hand to limit the amount of time that a spherical valve would be in operation without acceptable worker or unit protection capability.

Purchasing new spare rings is the recommended approach as the life expectancy of refurbished seal assemblies is less than that of new assemblies and the cost of refurbishment is approximately 85 percent the cost of replacement.

Project Schedule

Project milestones are listed in Table 10.

Table 10: Project Milestones

Activity	Milestone
Initiation	March 2010
Design Review	April 2010
Fabrication Starts	May 2010
Fabrication Completed	June 2010
Components Received at BDE Warehouse	July 2010
Project Closeout	October 2010

Future Plans:

None.

Project Title: Upgrade Trailer and Mobile Substation
Location: Bishop's Falls
Category: Transmission and Rural Operations - Terminal Stations
Type: Other
Classification: Normal

Project Description:

This project consists of the upgrade of the trailer and the replacement of the low voltage oil circuit breaker on the mobile substation. The trailer upgrade involves strengthening the trailer structure and installation of an air ride suspension system to replace the existing spring suspension system.

The mobile substation has to be dismantled for this upgrade and therefore will be transported to the manufacturer's plant in Winnipeg. All the equipment on the trailer will be removed. The trailer upgrade work will be done and the equipment will be remounted, re-tested and commissioned before being returned to Newfoundland.

The upgrades will be done during the winter off-season so as not to interfere with normal utility operations. 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	15.0	300.0	0.0	315.0
Labour	7.5	11.5	0.0	19.0
Consultant	5.0	0.0	0.0	5.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	66.0	0.0	66.0
O/H, AFUDC & Escln.	2.9	50.3	0.0	53.2
Contingency	0.0	40.5	0.0	40.5
TOTAL	**30.4**	**468.3**	**0.0**	**498.7**

Existing System:

The mobile substation is a trailer mounted transformer/switchgear assembly. The unit is used at multiple sites on the Island Interconnected System to provide service to customers when power transformers are taken out of service for maintenance or emergency repairs. The unit is thirty seven years old and repeated travelling on the province's rough highways and roads has caused the trailer and the oil circuit breaker mounted on the trailer to exhibit signs of stress fatigue and wear to such a degree that the trailer and the oil circuit breaker are near the end of their useful lives.

Project Title: Upgrade Trailer and Mobile Substation **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System

The mobile substation is 37 years old.

Major Work/or Upgrades

There have been no major upgrades to the substation since its purchase.

Anticipated Useful life

The normal service life of this equipment is 30 years. The upgrades as proposed here will extend the life of this equipment by approximately 15 years.

Maintenance History

The five-year maintenance history for the trailer mobile substation is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.6	11.1	11.7
2007	0.6	11.5	12.1
2006	0.2	0.7	0.9
2005	6.5	11.0	17.5
2004	9.7	3.4	13.1

Outage Statistics

There are no applicable outage statistics related to the mobile substation.

Industry Experience

There are a variety of design types and sizes of mobile substations in service among other utilities today, with many different applications and periods of time they are in service. The amounts of transportation and the condition of the service roads of other utilities are also unknown, and as a result it is not possible to make a direct comparison of the experiences of these other utilities' mobile substations with that of Newfoundland and Labrador Hydro (Hydro).

Project Title: Upgrade Trailer and Mobile Substation **(cont'd.)**

Existing System: (cont'd.)

<u>Maintenance or Support Arrangements</u>

All maintenance for this asset is done by Hydro maintenance personnel.

<u>Vendor Recommendations</u>

The mobile substation was originally manufactured by Maloney Electric, in Ontario. Maloney Electric discontinued their mobile substation business and sold all rights and designs to Pauwells Canada Inc of Winnipeg. A Pauwells representative visited Bishop's Falls to perform a general assessment of this mobile substation and subsequently provided a verbal report and quotation on their recommendations, which is considered in this proposal.

<u>Availability of Replacement Parts</u>

Replacement parts and sub-components are generally available for the mobile substation except for the oil circuit breaker. This breaker is 37 years old, and parts and servicing are no longer available.

<u>Safety Performance</u>

Safety concerns with the mobile substation are those related to the misalignment of the adjustable linkages of the 138 kV disconnect mounted on the trailer. During transportation, these linkages vibrate and move out of alignment. Thus when attempts are made to operate the disconnect the misalignments prevent the disconnect from operating properly and causes components to break and fall to the ground. This creates safety hazards for the personal trying to operate the disconnect.

<u>Environmental Performance</u>

There are no identified environmental performance issues with this equipment.

<u>Operating Regime</u>

This equipment is used as a standby for temporary emergency services in the event of a failure of another transformer on the system, however it is also used for back up when a transformer has to be taken out of service for routine maintenance.

Project Title: Upgrade Trailer and Mobile Substation **(cont'd.)**

Justification:

This project is justified on the basis that the mobile substation is an integral part of the Hydro asset group and must be in reliable service condition in order for Hydro to provide safe, least cost, reliable electrical service. These upgrades will enable the unit to be transported over the rough provincial highways without damage or deterioration to the unit such that its serviceability and reliability is compromised.

Net Present Value

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

Levelized Cost of Energy

The capital expenditures for this project will not affect the levelized cost of energy.

Cost Benefit Analysis

There was no cost benefit analysis completed, however consideration was given to the purchase of a new mobile transformer. The budget cost for a new mobile substation was in the order of $2.5 million which is significantly higher than the approximately $500,000 being requested in this proposal.

Legislative or Regulatory Requirements

There are no applicable legislative or regulatory requirements.

Historical Information

There have been no similar projects.

Forecast Customer Growth

The forecast customer load on the system has no effect on this project.

Energy Efficiency Benefits

There are no direct energy efficiency benefits resulting from this project.

Project Title: Upgrade Trailer and Mobile Substation **(cont'd.)**

Justification: (cont'd.)

Losses During Construction

There will be no losses during construction associated with this project. This work will be scheduled and performed outside of the transformer maintenance period and temporary arrangements will be made with Newfoundland Power to borrow their mobile substation if necessary.

Status Quo

Status quo is not an option. Failure to undertake this upgrade will eventually lead to the mobile substation being unavailable for service.

Alternatives

There are only two alternative solutions to the problems described in this proposal. These are to upgrade the damaged unit or replace it with a new unit. The upgrade was chosen because it is the least cost and has the shorter delivery time.

Conclusion:

This mobile substation is used to supply emergency power when the permanent station equipment is out of service or when maintenance or repairs are being done. The mobile sub-station is an essential piece of equipment used to maintain the permanent transmission system. The unavailability of this equipment will result in extended system outages should a permanent transformer fail in service.

Project Schedule

The schedule for this work is to ship the mobile substation to the Winnipeg facility after the regular maintenance season in late 2010 and have it returned to service in the spring of 2011. Table 3 shows the planned project schedule.

Project Title: Upgrade Trailer and Mobile Substation **(cont'd.)**

Conclusion: (cont'd.)

Table 3: Project Milestones

Activity	Milestone
Project Initiation	January 2010
Engineering Design	March 2010
Contract Approval	August 2010
Installation	November 2010
Commissioning	February 2011
Completion and close out	March 2011

Future Plans:

None.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring
Location: Holyrood
Category: Transmission and Rural Operations - Terminal Stations
Type: Other
Classification: Normal

Project Description:

This project consists of the replacement of the existing compressed air piping, the installation of a redundant air dryer, and the installation of a dew point temperature monitoring system at the Holyrood Terminal Station (HRDTS). The budget estimate for this project is shown below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	60.0	84.5	0.0	144.5
Labour	8.5	100.3	0.0	108.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	122.6	0.0	122.6
Other Direct Costs	0.0	5.5	0.0	5.5
O/H, AFUDC & Escln.	10.5	66.1	0.0	76.6
Contingency	0.0	38.1	0.0	38.1
TOTAL	**79.0**	**417.0**	**0.0**	**496.0**

Existing System:

Holyrood Thermal Generating Station (Holyrood) is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW. Generating Units 1 and 2, capable of producing 150 MW each, were placed in service in 1971. These units were up-rated to 170 MW in 1988 and 1989. In 1979, generating Unit 3, capable of producing 150 MW, was placed in service. Holyrood represents approximately one third of Newfoundland and Labrador Hydro’s (Hydro) total Island Interconnected System generating capacity. The power generated at Holyrood is transmitted to the Island Interconnected System via the HRDTS.

Air blast circuit breakers play an integral role in the operation of the Island Interconnected System. The circuit breakers provide fault protection to transmission lines and transformers. They also provide isolation for the safe execution of work on the same equipment. On the Island Interconnected System there are currently 66 air blast circuit breakers, nine of which are installed at the HRDTS. This type of circuit breaker requires compressed air to open and close the circuit breaker as well as to extinguish the arc generated by the circuit breaker operation.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

To ensure the reliable and optimal operation of these circuit breakers, high quality compressed air is required. At HRDTS, this is provided by a high pressure compressed air system. Ambient air is produced at 5.5 megapascals (MPa) by compressors. Upon leaving a compressor, air is filtered and dried by an air dryer, and stored in receiver tanks. When needed, compressed air leaves a receiver tank and passes through copper piping and one of nine pressure reducing valves to arrive at its point of use – one of the nine circuit breakers. The pressure reducing valves reduce the air pressure to 2.5 MPa, which is the pressure required by the circuit breakers.

High quality compressed air is free of debris and very dry. The dryness of compressed air is expressed as the dew point temperature - the temperature at which water vapour starts to condense into liquid water, for a volume of air at constant pressure. The air at the HRDTS is required to have a dew point temperature of -50 degrees celsius or lower at 2.5 MPa, to ensure optimal operation of the circuit breakers. This maximum dew point temperature is an established standard for all Hydro's air blast circuit breakers and is consistent with other utilities' standards and manufacturers' recommendations. If the moisture content of the air is higher than this, the internal components of the circuit breakers can corrode. (See Figure 1.) This can result in the catastrophic failure of the circuit breaker, potentially resulting in injury to any personnel in the area and damage to other equipment. Hydro has experienced two circuit breaker failures in recent years which have been attributed to moisture contamination. They occurred at the Stoney Brook and Hardwoods Terminal Stations. (See Figures 2 and 3.) Fortunately those incidents did not result in any personal injury. Temporary repairs have been made at those sites to fix leaks in the compressed air systems.

Leaks which occur in the compressed air piping result in the loss of air, requiring the air compressors and air dryers to operate more frequently, increasing operating and maintenance costs and prematurely wearing this equipment.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

Figure 1: Corroded Air Blast Circuit Breaker

Figure 2: Breaker Failure Due to Moisture Ingress at the Hardwoods Terminal Station.

Figure 3: Failure of Phase B of Breaker B1L36 at the Hardwoods Terminal Station.

The existing compressed air system includes a dryer which is capable of drying air to the required maximum dew point temperature of -50 degrees celsius. However, moisture is entering the system downstream of the dryer. The consequence of these leaks is that the dew point temperature at the point of use (the circuit breakers) is too high. This is evident from dew point temperature measurements which have been taken at HRDTS on a quarterly basis since November 2006, shown in Table 2. The dew point temperature at the operating pressure of 2.5 MPa has ranged from -17 degrees celsius to -7 degrees celsius, which is significantly higher than the required maximum of -50 degrees celsius. As the dew point temperature of the compressed air is higher than the ambient temperature in winter, condensation can occur, producing water drops which are detrimental to the circuit breakers.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

Table 2: Dew Point Temperatures

Measurement Date (mm/dd/yyyy)	**Dew Point Temperature (Degrees Celsius)**	
	Measured at Atmospheric Pressure	**Adjusted for 2.5 MPa Operating Pressure***
11/28/2006	-40	-7
01/17/2007	-45	-14
04/24/2007	-48	-17
09/15/2007	-42	-10
11/29/2007	-48	-17
02/04/2008	-48	-17
05/21/2008	-48	-17
09/16/2008	-46	-15

** Dew point temperature increases with increasing pressure. When measured at a given pressure, dew point temperature can be calculated for any other pressure. In this case, the dew point temperature was measured at atmospheric pressure (0 psig) and then calculated for the compressed air system's operating pressure of 2.5 MPa.*

There are several problems associated with the existing compressed air piping system that have resulted in leaks and the ingress of moisture into the compressed air. Significant sections of the 5.5 MPa piping, installed in cable trenches, are inaccessible due to the installation of electrical cables on top of the piping. Some of these cables were installed at construction of the HRDTS, and others have been added for various purposes since that time. As part of the original installation, steel rebar was installed in the trenches to support the cabling but this support structure has corroded and failed. The weight of the cables bearing down on the piping has caused the copper piping to bend and fail, resulting in leaks. Also, the soldered copper pipe fittings have deteriorated and have developed leaks at the joints. Piping failures have been repaired by replacing the failed copper piping with Synflex Hose, which is a flexible pneumatic hose. This hose was used because it is flexible and much easier to install than rigid pipe. However, Hydro's experience with this hose over many years, has proven that its fittings are susceptible to corrosion, resulting in more compressed air leaks (see Figure 4). Furthermore the Synflex Hose material absorbs moisture, is permeable and that moisture is transferred to the compressed air.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

Figure 4: Corroded Synflex Hose Fittings.

With these mechanisms for ingress of moisture into the compressed air system, it has become impossible to maintain the required dew point temperature of -50 degrees celsius at 2.5 MPa, at the HRDTS. All of these failure mechanisms will be reduced by replacing the copper piping and synflex hose with stainless steel piping with welded connections. Stainless steel piping is stronger, more durable and more corrosion resistant than copper piping and welded joints are stronger than soldered copper joints.

The HRDTS is unmanned and remotely operated from the Energy Control Center (ECC) in St. John's. Hydro personnel visit the HRDTS on a quarterly basis to measure dew point temperature. This frequency is not adequate for the timely detection of compressed air system failure. There is a need to provide continuous monitoring of the dew point temperature, so that failures can be detected immediately and repairs can be made before damage is done to the air blast circuit breakers. This will be achieved with the installation of a dew point temperature monitoring system. Should a leak occur or the air dryer fail, the dew point temperature will begin to rise. When this temperature rises above -35 degrees celsius, an alarm will be activated in the ECC, notifying the control room operators of a potential problem. This will allow corrective maintenance to be performed before poor air quality can lead to a circuit breaker failure. A dew point temperature monitoring system was installed at the Bay d'Espoir Terminal Station in 2008 and is currently in operation.

The existing compressed air system has a single air dryer. Whenever unscheduled corrective

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

maintenance has been performed on this dryer, the compressed air system had to be taken out of service. Depending upon the duration of the necessary repairs, this could result in a terminal station outage that could disrupt the normal flow of electricity from Holyrood to the Island Interconnected System. This will be mitigated by the addition of a second air dryer. If a problem occurs with either air dryer, it could be isolated, repaired and placed back in service without affecting the flow of electricity through the HRDTS.

Age of Equipment or System

The existing compressed air system was constructed in two phases. The first phase was completed in conjunction with the installation of Units 1 and 2 at Holyrood in 1971. The second phase was completed in conjunction with construction of Unit 3 at Holyrood in the late seventies. The only significant components that are not original are the air compressors, which were replaced in 2007.

Major Work/or Upgrades

The only major work or upgrade that has occurred since installation is the replacement of the compressors in 2007.

Anticipated Useful life

Compressed air systems have an estimated service life of 30 years.

Maintenance History

In the past five years the compressed air system at the HRDTS has experienced 34 incidents that have disrupted the compressed air system and required maintenance. Of these 34 incidents, nine were controls issues, including the failure of control relays, pressure switches, contactors, timers, and other various controls equipment. There were eleven incidents related to valve problems. This included failed pressure relief valves, and leaking manual and solenoid operated valves. The remaining fourteen incidents involved leaks in piping and soldered connections requiring the installation of Synflex Hose, as well as failed Synflex Hose fittings requiring replacement.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

Maintenance History (cont'd.)

The five-year maintenance expenditures for the HRDTS compressed air system are summarized in Table 3.

Table 3: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	7.1	5.8	12.9
2007	3.3	14.6	17.9
2006	2.5	16.9	19.4
2005	8.1	8.1	16.2
2004	2.6	2.5	5.1

Outage Statistics

From available outage statistics for the HRDTS, there have been no forced outages of the air blast circuit breakers attributed to problems or failures with the compressed air system.

Industry Experience

Hydro participates in a discussion medium managed by Doble Engineering, a company that helps clients in the electric power industry improve operations and optimize system performance. Utilizing this forum, Hydro posted a questionnaire to like utilities regarding moisture problems for air blast circuit breakers. Through a response from another Canadian utility, it was concluded that moisture can penetrate Synflex Hose rendering it unlikely to maintain a dew point temperature of -50 degrees celsius at 2.5 MPa and that Synflex Hose fittings tend to rust and fail. This utility experienced one failure which resulted in a near miss incident - the Synflex Hose failed and snaked down the cable tray, lifting cable tray covers as it went. The solution for that utility was to replace all piping with stainless steel piping with welded connections at multiple terminal stations. This reduced the hazard and resulted in immediate correction of moisture problems, improving the dew point temperature from -20 degrees celsius to -80 degrees celsius.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

Maintenance or Support Arrangements

This compressed air system is maintained by Hydro personnel.

Vendor Recommendations

ABB, the manufacturer of the air blast circuit breakers at the HRDTS, recommends that compressed air be supplied at a dew point temperature not exceeding -50 degrees celsius. During a site visit, a representative of ABB recommended that the Synflex Hoses not be used for the compressed air system due to their propensity to absorb moisture and transfer it to the compressed air.

Availability of Replacement Parts

Replacement parts are readily available for all components of the compressed air system.

Safety Performance

There are significant safety hazards associated with the existing high pressure compressed air system that will be reduced through implementation of this project. The majority of the compressed air system operates at 5.5 MPa and is reduced to the operating pressure of 2.5 MPa at the circuit breakers. Should the compressed air piping fail, the high pressure air may cause the flexible Synflex Hose sections of the piping to violently snake and pop off cable trench covers, possibly causing injury to anyone in the area at the time of failure. This type of failure has actually occurred at another utility's terminal station, as described in the *Industry Experience* section of this report. The likelihood of failure is high given the deteriorated condition of both the copper piping and Synflex hose. The hazard will be reduced when piping is replaced with durable, rigid stainless steel piping with welded connections.

In addition, there is significant risk of catastrophic failure of a circuit breaker if the dew point temperature is not maintained at or below the maximum required. This failure could result in metal shrapnel being violently thrown from the circuit breaker, possibly causing injury or death to personnel in the area at the time of failure. Hydro has experienced two such failures at other terminal stations, as described in the *Existing System* section of this report. Adequate control and monitoring of the dew point temperature will reduce this risk to an acceptable level.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Existing System: (cont'd.)

<u>Environmental Performance</u>

There are no environmental concerns with the compressed air system.

<u>Operating Regime</u>

This compressed air system operates continuously.

Justification:

This project is justified on the requirement to replace and upgrade failing and deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service.

<u>Net Present Value</u>

Net present value is not applicable.

<u>Levelized Cost of Energy</u>

Levelized cost of energy is not applicable.

<u>Cost Benefit Analysis</u>

Cost benefit analysis is not applicable.

<u>Legislative or Regulatory Requirements</u>

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

<u>Historical Information</u>

There have been no similar upgrades to compressed air systems at Hydro's other terminal stations. Therefore, no historical data is available.

<u>Forecast Customer Growth</u>

This project is not impacted by forecast customer growth.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Justification: (cont'd.)

Energy Efficiency Benefits

Energy efficiency benefits will be realized by reducing the operating hours on the compressors. Leaks in the compressed air system result in a pressure drop in the system. This causes the compressors to operate in order to re-pressurize the system. Implementation of this project will significantly reduce compressed air leaks. The quantity of past leaks has not been measured; therefore, the benefits can not be quantified.

Losses During Construction

There will be no losses during construction.

Status Quo

If status quo is maintained the integrity and reliability of the compressed air system and thus the circuit breakers and ultimately the Island Interconnected System will continue to be compromised and the safety risk will remain unacceptably high.

Alternatives

There are no acceptable alternatives.

Conclusion:

Replacement of the copper piping and Synflex Hose with stainless steel piping will reduce the probability of piping failure, to ensure that consistently dry air is provided to the air blast circuit breakers, ensuring their integrity. Installation of a continuous dew point temperature monitoring system will ensure that all piping and dryer failures will be detected before damage can be done to the circuit breakers. And the installation of a second air dryer will allow air dryer corrective maintenance to proceed without impact on the operation of HRDTS and the Island Interconnected System. These improvements will improve the reliability of the HRDTS and, from a safety perspective, will reduce both the probability and consequence of failure.

Project Title: Replace Compressed Air Piping and Install Dew Point Monitoring **(cont'd.)**

Conclusion: (cont'd.)

Project Schedule

Project milestones and a schedule are shown in Table 4.

Table 4: Project Milestones

Activity	Milestone
Initiation	February 2010
Design Complete	August 2010
Equipment Ordered/Delivered	November 2010
Installation Commences	July 2011
Installation Complete	September 2011
Project Closeout	October 2011

Future Plans:

None.

Project Title: Replace Diesel Unit 2018
Location: McCallum
Category: Transmission and Rural Operations - Rural Generation
Type: Other
Classification: Normal

Project Description:

This proposal is required to replace the 136 kW Diesel Generating Unit 2018 with a new generating unit with a rated capacity in the range of 50 kW to 70 kW. The exact size of the unit will be determined in the tender process since different manufacturers have similar size units within the desired range. The project scope includes the replacement of the generating unit and associated switchgear. The budget estimate for this project is shown in table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	210.6	0.0	210.6
Labour	16.0	89.1	0.0	105.1
Consultant	0.0	6.0	0.0	6.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.0	23.2	0.0	24.2
O/H, AFUDC & Escln.	2.3	57.5	0.0	59.8
Contingency	0.0	34.6	0.0	34.6
TOTAL	**19.3**	**421.0**	**0.0**	**440.3**

Existing System:

McCallum is a small community located on the south coast of the Island, one of four isolated diesel generating systems owned and operated by Newfoundland and Labrador Hydro (Hydro) in the south coast region. It has three generating units. Units 2063 and 2064 were installed in 2001, and have a rated capacity of 210 kW and 136 kW respectively. Unit 2018 was installed in 1986 and is rated at 136 kW, resulting in installed capacity of 482 kW and firm capacity of 272 kW. Figure 1 shows the engine hall in the McCallum Diesel Plant. Unit 2018 is the third unit to the left, near the open door. The plant provides electricity to 52 residential customers, 12 general service customers and two street light customers in the community.

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Existing System: (cont'd.)

Figure 1 - McCallum Engine Hall

Age of Equipment or System

Unit 2018 has been in service since 1986 and is now 23 years old. It currently has approximately 97,500 hours of operation.

Major Work/or Upgrades

Unit 2018 has been overhauled five times since its installation. Hydro's current practice is to replace diesel engines after four overhauls, each completed after approximately 20,000 hours of operation. When Unit 2018 was installed, an older asset management practice was to perform five overhauls, each after approximately 15,000 hours of operation. The engine was last rebuilt in 2005 after 89,644 hours of operation and there are approximately 8,000 hours since the overhaul.

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Existing System: (cont'd.)

Anticipated Useful life

Diesel generating units have an economic life of 20 years and an expected average service life of 25 years.

Maintenance History

Maintenance of generating units includes preventive maintenance, corrective maintenance and periodic overhauls. Corrective maintenance is performed to repair equipment after a failure has occurred, such as a fuel pump failure. Preventive maintenance consists of oil and filter changes and operational checks of the wear of components on an annual basis. The purpose of an overhaul is to replace worn parts, which is meant to restore performance to near new conditions.

Table 2 provides the five-year maintenance history for Unit 2018.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.7	5.6	6.3
2007	0.5	10.2	10.7
2006	0.7	14.2	14.9
2005	25.4[4]	7.2	32.6
2004	0.9	15.2	16.1

Outage Statistics

Hydro does not currently maintain a diesel generating unit reliability database. Only outages which have a customer impact are recorded. The customer impact is recorded in the general category of loss of supply and includes outages in addition to those caused by the units to be replaced.

[4] Includes cost of 2005 overhaul.

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Existing System: (cont'd.)

The Canadian Electrical Association defines Loss of Supply as:

> *Customer interruptions due to problems in the bulk electricity supply system such as under frequency 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.*

Table 3 lists the 2004 to 2008 average System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) for Loss of Supply caused outages for the McCallum Diesel Plant compared to the total Hydro central region isolated and complete systems.

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 3: Five-year Average Interruption Indices (2004 – 2008)

SYSTEM	All Causes		Loss of Supply	
	SAIFI	**SAIDI**	**SAIFI**	**SAIDI**
McCallum	2.27	2.62	0.60	0.22
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

The generating unit is not being replaced based on outage statistics but rather based on the age and hours of operation of the unit.

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Existing System: (cont'd.)

Industry Experience

Industry experience varies on the replacement of diesel engines. Most utilities rebuild the engines based on the number of operating hours and replace them at the end of their economic lives.

Maintenance or Support Arrangements

Maintenance for the McCallum Diesel Plant is completed by internal forces from Bishop's Falls.

Vendor Recommendations

There are no relevant vendor recommendations for this replacement.

Availability of Replacement Parts

Spare parts are readily available for these diesel units.

Safety Performance

There is no safety performance issues related to these diesel units replacements.

Environmental Performance

Engine emission improvements may be expected when replacing older units with more modern generating units. It is important to note this engine replacement will install a smaller engine in the McCallum Diesel Plant to minimize soot releases from operating larger engines at light loads. Due to the current size of the engine mix at the McCallum Diesel Plant, Hydro has experienced soot releases in recent years at McCallum that will be reduced with the installation of a smaller engine. The most recent complaint from a customer noticing soot coming from the exhaust stack occurred in May 2009. In response, Hydro removed the stack and cleaned it. The soot problem was caused by the engine operating at low loads.

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Existing System: (cont'd.)

Operating Regime

The McCallum 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 in each plant 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. The operation of the generating units in each plant is cycled to distribute operating hours among all three units throughout the year.

Justification:

This project is justified based on Hydro's current asset management strategy to replace engines when they approach 100,000 operating hours. Unit 2018 at the McCallum Diesel Plant is forecast to surpass 100,000 operating hours before engineering and procurement work is completed in 2010 and the new unit is commissioned in 2011.

With the unit scheduled for replacement, it also allows Hydro to minimize emissions and sooting events through ensuring a correct size unit is installed at the McCallum Diesel Plant. With a smaller size unit, modifications will be required to the switchgear as outlined previously.

Net Present Value

A net present value calculation has not been performed as there are no viable alternatives.

Levelized Cost of Energy

As this project does not relate to a new generation source, the levelized cost of energy is not applicable.

Cost Benefit Analysis

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

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Justification: (cont'd.)

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

Table 4 provides historical information on similar projects completed over the last five years.

Table 4: Historical Information TRO Rural Generation

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)
2009F	1,869.6		4	
2006	1,512.5	1,515.1	4	378.8
2005	304.0	236.6	1	236.6
2004	258.1	247.1	1	247.1

Forecast Customer Growth

The load in McCallum is predicted to slightly decline over the next five years. Table 5 shows the expected loading for the plant.

Table 5: McCallum Peak Load Forecast

	2009	2010	2011	2012	2013	2014
Gross Peak (kW)	172	170	168	166	164	162

Energy Efficiency Benefits

Fuel efficiency improvements may be expected when replacing older units such as Unit 2018 with more modern, appropriately-sized equipment, but any such improvement cannot be accurately quantified.

Losses During Construction

No losses during construction are anticipated, since the generating unit will be replaced during a planned outage while the remaining units continue to generate power.

Project Title: Replace Diesel Unit 2018 **(cont'd.)**

Justification: (cont'd.)

Status Quo

Continuing to operate Unit 2018 may lead to reduced reliability of the McCallum Diesel Plant because of the age of the generating unit. This unit has been in operation since 1986, has been overhauled five times, and will have in excess of 100,000 hours of operation by the end of 2011.

Alternatives

There are no viable alternatives to replacing this diesel unit.

Conclusion:

Unit 2018 was installed in 1986 and is projected to have in excess of 100,000 hours of operation by the end of 2011. According to Hydro's current asset management philosophy, this unit has reached the end of its useful life and should be replaced. The replacement of the engine will also result in a slight increase in fuel economy and reduction of exhaust emissions.

Project Schedule

Table 6 shows the planned project schedule.

Table 6: Project Schedule

Activity	Milestone
Project Initiation	February 2010
Project Design	June 2010
Equipment Tender	July 2010
Equipment Tender Award	September 2010
Installation	August 2011
Project Closeout	December 2011

Future Plans:

Future diesel unit replacements will be proposed in future capital budget applications.

Project Title: Replace Insulators
Location: Various Terminal Stations
Category: Transmission and Rural Operations – Terminal Stations
Type: Pooled
Classification: Normal

Project Description:

This project consists of the purchase and installation of 230, 138, 69, and 25 kV station post and suspension insulators at various terminal stations on the Island Interconnected System. This project is part of a multi- year program for replacement of insulators which started in 2003. The insulators will be purchased in bulk and delivered to Hydro's central maintenance facility at Bishop Falls. Then as outages are scheduled, the insulators will be shipped from this central location for installation in the particular stations. The 2010 budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	186.5	0.0	0.0	186.5
Labour	124.0	0.0	0.0	124.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escln.	37.6	0.0	0.0	37.6
Contingency	32.9	0.0	0.0	32.9
TOTAL	**399.0**	**0.0**	**0.0**	**399.0**

Existing System:

Insulators are an integral part of the transmission system. They support and insulate the energized portions of the system from the structures and grounded areas. Terminal Stations contain post-type insulators, cap and pin-top insulators, mulitcone design insulators, and suspension type insulators. As the cement in these insulators age, it grows and cracks. As the cement growth progresses, it exerts increased pressure on the porcelain part of the insulator such that the porcelain cracks and causes the insulator to fail.

Age of Equipment or System

The insulators in use on the Island Interconnected System range in age from one to forty one years. The insulators targeted for replacement under this project were manufactured before the mid 1970's.

Project Title: Replace Insulators **(cont'd.)**

Existing System: (cont'd.)

Major Work/or Upgrades

There has been no major work or upgrades on terminal station insulators since they were installed. Replacements have only been made as failures occurred or as part of this insulator replacement program.

Anticipated Useful life

The anticipated service life of the new insulators is 40 years; however, this may vary depending on the service environment.

Maintenance History

Normal maintenance for insulators is to replace them upon failure.

Outage Statistics

Hydro tracks all system outages using industry standard indexes System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI). SAIDI and SAIFI 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 2 lists the 2004 to 2008 system average transmission (T) T-SAIFI and T-SAIDI data and the latest CEA five-year averages (2003 to 2007).

Project Title: Replace Insulators **(cont'd.)**

Existing System: (cont'd.)

Table 2: SAIFI/SAIDI Average

Five-year Averages		
	T-SAIFI	**T-SAIDI**
Hydro System (2004-2008)	1.16	62.61
CEA (2003-2007)	0.85	130.71

Industry Experience

The industry experience of cement growth and cracking with the older Canadian Ohio Brass (COB) insulators manufactured prior to the mid 1970's is the same as Hydro's.

Maintenance or Support Arrangements

Normal operation and maintenance work is performed by Hydro personnel.

Vendor Recommendations

Hydro maintains regular contact with other major utilities and equipment manufacturers on matters related to the operation and maintenance of its equipment. Current insulator manufacturers have identified and researched the cement growth problems and have developed more sophisticated cement compounds to eliminate the cement growth problem. The manufacturers recommend that the older insulators be replaced.

Availability of Replacement Parts

Replacement insulators are generally readily available within six to eight weeks of an order. However, long delivery times may occur depending on the market conditions.

Safety Performance

In general terms, the safety performance of the insulators is good. However, in situations where the insulators are under structural stress, the cement growth condition will lead to a failure of the insulator. This failure creates a safety hazard for operations personnel when broken insulator parts fall to the ground.

Project Title: Replace Insulators **(cont'd.)**

Existing System: (cont'd.)

Environmental Performance

There are no specific environmental issues relating to insulators other than the proper disposal of the retired insulators.

Operating Regime

The insulators are in continuous use.

Justification:

This project is justified on the requirement for Hydro to provide safe and reliable power and a safe working environment for its staff. Insulators provide electrical insulation between energized equipment and ground. When insulators fail, a short circuit to ground is created and loose and falling parts can result. Both create system outages and safety hazards to personnel. "In service" failures have occurred while maintenance personnel were working on the equipment. To prevent such failures from occurring Hydro proposes and plans to replace deteriorated post, suspension and multi-cone type insulators.

The manufacturers have identified and researched the cement growth problems and have developed more sophisticated cement compounds to eliminate the problem in the future. For existing installations, the manufacturers recommend that the older insulators be replaced.

Net Present Value:

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

Levelized Cost of Energy:

The capital expenditures for this project will not affect the levelized cost of energy for the system.

Project Title: Replace Insulators **(cont'd.)**

Justification: (cont'd.)

Cost Benefit Analysis:

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

Legislative or Regulatory Requirements:

There are no applicable legislative or regulatory requirements

Historical Information

Table 3 contains the historical information for insulator replacements for the period 2003 to 2009. Hydro expects to have its insulator replacement plan completed by 2013.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	390.9				
2008	294.3	324.0	1,963	0.2	
2007	323.0	297.5	2,140	0.1	
2006	306.8	256.2	1,140	0.2	
2005	228.0	163.3	2,304	0.1	
2003	236.3	253.5	2,649	0.1	

The unit cost for insulators varies with voltage class. For example, a 230 kV station post insulator will cost approximately $900, a 138 kV will cost approximately $400, a 69 kV will cost approximately $300 and a suspension insulator will cost approximately $25. As a result, in any given year, the quantity of units replaced vary and as a result, the annual average cost can be considerably different.

Forecast Customer Growth

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

Project Title: Replace Insulators **(cont'd.)**

Justification: (cont'd.)

Energy Efficiency Benefits

There are no issues related to energy efficiencies associated with this project.

Losses During Construction

The replacement of the insulators will be coordinated with the normal outage plans for the system. These outage plans are designed around the system load requirements. Therefore, there are no production or revenue losses resulting from this project.

Status Quo

The status quo is not an option. The insulators must be replaced to maintain system reliability and a safe working environment.

Alternatives

There are no alternative solutions to the problems described with the insulators other than direct replacements.

Conclusion:

When insulators fail they create a short circuit to ground and result in loose and falling parts. This creates safety hazards to personnel and results in system outages. To prevent such failures from occurring, Hydro proposes to replace all post, suspension and multi-cone type insulators manufactured by Canadian Ohio Brass.

Project Schedule

Table 4 presents the anticipated project schedule.

Project Title: Replace Insulators **(cont'd.)**

Justification: (cont'd.)

Table 4: Project Schedule

Activity	**Milestone**
Project Start	January 2010
Initial Planning and Equipment Ordering Tendering	February 2010
Equipment Delivery	July 2010
Equipment Installations and Commissioning	November 2010
Project In Service	November 2010
Project Completion and Close Out	December 2010

Future Plans:

Future replacements will be proposed in future capital budget applications. Insulator replacements are planned for the next three years as shown in the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Upgrade Anchors on C Structures TL-259
Location: Parson's Pond
Category: Transmission and Rural Operations - Transmission
Type: Other
Classification: Normal

Project Description:

This project is required to upgrade anchors on TL-259 at Parson's Pond.

The proposed work site is located at the bridge crossing in Parson's Pond. As a result of rising tides, sea water continues to move inland causing a mixture with the fresh water source at the mouth of the existing river system. The rising water floods areas adjacent to the original river banks. The structures identified in this report are located in these adjacent flood plains and are therefore exposed to the salt water contaminants. The presence of sea water poses two major threats to the structural integrity of the existing structures. The salt water is corrosive and capable of accelerating the process and extent to which anchor rods experience corrosion. In addition, the presence of water causes the soil to become saturated thereby reducing the structural capacity of the anchors significantly with respect to anchor pullout. See Figure 1 and Figure 2 showing typical corrosion to anchor rods.

Figure 1: Corroded anchor rod (Typical)

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Project Description: (cont'd.)

Figure 2: Corroded anchor rod (Typical)

The scope of this project will include the design, supply and installation of new anchors on structures 304 and 305 of TL-259. The project will include the construction and placement of timber cribs, granular rock fill and new anchor rods. Sacrificial anodes will also be installed at the anchor locations to reduce the amount of corrosion experienced due to the salt water exposure. The work tasks will include design, supply of materials, construction, environmental monitoring, construction management, project management and inspection.

The proposed work will include the completion of an environmental assessment, which will identify any risks to the surrounding environment that this project may present.

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Project Description: (cont'd.)

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	60.0	0.0	0.0	60.0
Labour	40.0	0.0	0.0	40.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	180.0	0.0	0.0	180.0
Other Direct Costs	12.0	0.0	0.0	12.0
O/H, AFUDC & Escln.	31.7	0.0	0.0	31.7
Contingency	29.2	0.0	0.0	29.2
TOTAL	**352.9**	**0.0**	**0.0**	**352.9**

Existing System:

TL-259 is a 138 kV Wood Pole Transmission Line from Berry Hill to Peter's Barren - a distance of 86.63 km. It operates on a continuous basis and supplies power to community distribution systems along the Northern Peninsula. The existing electrical system for this area consists of a redundant system with both TL-259 and TL-227 being capable of supplying power to the same area. Despite the presence of a back up transmission line, TL-259 is the primary source of power supply to the upper section of the Northern Peninsula. In the event of an extended outage experienced by TL-259, it is anticipated that TL-227 in coordination with diesel generator availability at the Hawkes Bay Terminal Station would be required to supply power to the local areas. Under these particular circumstances, the system would be so stressed that any additional requirements would be crippling to the electrical system, possibly requiring voltage regulation and causing limited customer outages throughout the system in order to maintain system reliability.

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System

TL-259 was originally constructed in 1990.

Major Work/or Upgrades

There have been no major upgrades to TL-259 since its original construction.

Anticipated Useful life

The anticipated life of a transmission line constructed with wooden structures is 40 years.

Maintenance History

There has been no major maintenance performed on TL-259 to date. All minor maintenance associated with TL-259 include work directly linked to tasks such as line inspection, trouble calls and routine minor maintenance.

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.

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Existing System: (cont'd.)

Terminal equipment outage statistics are provided in Tables 2 and 3. The first table lists the transmission line performance for the latest five years (2003 to 2007) on transmission line TL-259 compared to the latest available five-year average (2001-2005) for all of the Hydro System and CEA. Table 3 details the effect of trips on TL-259 on the delivery points it supplies.

Table 2: Transmission Line Performance

Listing of Transmission Line Terminal Equipment Performance

	Frequency (per terminal year)	Unavailability (%)
TL259 (2003-2007)	2.40	0.0202
Hydro 138 kV (2001-2005)	0.57	0.1054
CEA 138 kV (2001-2005)	0.14	0.0381

Frequency (per a) is number lines outages per line terminal.

Unavailability is amount of time the line is not available for terminal related causes.

Table 3: TL-259 Delivery Points

Five Year Averages (2004-2008) Forced Outages Only

Transmission Line	Delivery Point	T-SAIFI	T-SAIDI
TL259	Bear Cove	2.20	92.40
	Daniels Harbour	2.20	38.00
	Hawkes Bay	4.80	41.80
	Main Brook	5.00	169.80
	Parsons Pond	2.20	15.40
	Plum Point	1.60	32.80
	Roddickton	5.00	251.20
	St. Anthony	4.60	47.34
	Total	**3.45**	**86.09**
	Northern Region	3.03	102.23
	Hydro System	1.16	62.93
	CEA (2003-2007)	0.85	130.71

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Existing System: (cont'd.)

Industry Experience

There is no relevant industry experience.

Maintenance or Support Arrangements

All minor maintenance and trouble shooting on TL-259 is performed by Hydro employees.

Vendor Recommendations

There are no specific vendor recommendations for this project.

Availability of Replacement Parts

Replacement parts are readily available for this project.

Safety Performance

The presence of salt water poses two major threats to the structural integrity of the existing structures. The salt water is corrosive and capable of accelerating the process and extent to which anchor rods experience corrosion. In addition, the presence of water causes the soil to become saturated thereby reducing the structural capacity of the anchors significantly with respect to anchor pullout.

The structures identified in this report for anchor replacement are critical structures to the integrity and reliability of TL-259. A premature failure of existing anchor rods as a result of localized corrosion would increase the probability of structural failure significantly. Structure failure could possibly result in a failure of the existing line.

Environmental Performance

The proposed work site is located at the bridge crossing in Parson's Pond. As a result of rising tides, sea water continues to move inland causing a mixture with the fresh water source at the mouth of the existing river system. The rising water floods areas adjacent to the original river banks. The structures identified in this report are located in these adjacent flood plains and are therefore exposed to the salt water contaminants.

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Existing System: (cont'd.)

All construction activity in or near water is subject to compliance with regulations outlined by the Department of Environment and the Department of Fisheries and Oceans. Under the Water Resources Act, SNL 2002 cW-4.01, Section(s) 39, 48 and Section 35(1) of the Fisheries Act, permits are required for construction that is located within 15 meters of the high water mark of a water body.

Work shall be performed in such a way as to ensure that deleterious substances including, but not limited to, materials such as sediment, fuel, and oil do not enter water bodies.

Appropriate erosion control measures will be used to mitigate any affect on the surrounding aquatic environment. All work will be conducted at low tide to minimize the affect on the surrounding environment.

<u>Operating Regime</u>

TL-259 operates on a continuous basis as the primary supply of power to the Northern Peninsula. The line status is monitored and controlled continuously at Hydro's Energy Control Center.

Justification:

This project is justified on the basis of reliability. The structures identified in this report are located in tidal flood plains and are therefore exposed to the salt water. The presence of sea water poses two major threats to the structural integrity of the existing structures.

- The accelerated corrosion of steel anchor rods due to the interaction with salt water may cause premature failure of the structures. The capacity of a galvanized steel anchor rod is dependant upon the type and size of material used to manufacture the product. Larger cross sections of the same material will provide a larger tension capacity that is required to restrain the tension exerted on the structure by the transmission line. The ability of salt water to cause corrosion of a galvanized material may result in the reduction of the cross section and ultimately reduce the capacity of the anchor rod. If the cross section is reduced to such a size that it cannot contain the applied load, the anchor rod may fail prematurely. Regular inspections have identified the presence of surface corrosion on the existing steel anchor rods.

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Justification: (cont'd.)

- The ability of soil to become saturated with water will result in a reduction in the bearing, overturning and pull out resistance of the soil.

Since TL-259 is a critical component to the supply of power to the Northern Peninsula, a failure of the critical structures may result in the cascading failure of the line. Failure of this nature would result in significant outage time to rebuild the line.

Net Present Value

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

Levelized Cost of Energy

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

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

Regulatory requirements associated with this project, in relation to construction within 15 meters of the high water mark of a body of water, can be found under the Water Resources Act, SNL 2002 cW-4.01, Section(s) 39, 48 and The Fisheries Act, Section 35(1).

Historical Information

Since this is not a recurring project, historical information is not available.

Forecast Customer Growth

Forecast customer load growth has no effect on this project.

Project Title: Upgrade Anchors on C Structures TL-259 **(cont'd.)**

Justification: (cont'd.)

Energy Efficiency Benefits

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

Losses During Construction

There are no anticipated energy losses during construction.

Status Quo

The status quo is not an acceptable solution in this particular case. The decision to take no action may result in the premature failure of an anchor component(s) and ultimately the failure of the structure(s) and transmission line.

Alternatives

There are no viable alternatives to this approach.

Conclusion:

Replacement of the existing anchors is critical and should be performed to prevent the event of a premature transmission line failure.

Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	Milestone
Planning, Assessment and Tender Contract	May 2010
Pre-Construction Meeting	June 2010
Contractor Mobilization	July 2010
Install Foundations	July 2010
Cleanup Site and Demobilize	August 2010

Future Plans:

None.

Project Title: Upgrade Circuit Breakers
Location: Various Terminal Stations
Category: Transmission and Rural Operations - Terminal Stations
Type: Pooled
Classification: Normal

Project Description:

This project is required as part of an upgrading program to refurbish all Brown Boveri DCVF, DCF and DLF models of air blast circuit breakers, at a rate of four each year. The breakers will be completely dismantled, cleaned, refitted with new parts, gaskets and seals as required and reassembled. The porcelain housings will be inspected and tested for cracks or weaknesses. Depending on the results of these tests, the porcelain housings may also be replaced as part of the upgrades. The breaker will then be tested to confirm that it is ready for return to service.

The order of the upgrades is done according to the priority and criticality of the breaker on the system. The highest priority breakers are those serving the generation units and the main power transformers. The upgrade rate of four units each year is based on system requirements, available outages to remove and re-install the breakers, and the available personnel to complete the work. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	160.0	0.0	0.0	160.0
Labour	103.0	0.0	0.0	103.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	15.5	0.0	0.0	15.5
O/H, AFUDC & Escln.	35.8	0.0	0.0	35.8
Contingency	27.9	0.0	0.0	27.9
TOTAL	**342.2**	**0.0**	**0.0**	**342.2**

Existing System:

There are 66 air blast breakers on the Hydro system, critical to maintaining reliable system operations. The first generation of air blast circuit breakers on Hydro's systems has seen approximately 40 years of service. Problems have been experienced with air leaks, sticking valves, and other issues, resulting not only in maintenance costs but also breaker unavailability.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System

The air blast circuit breakers were installed in the 1960's and 1970's.

Major Work/or Upgrades

There have been no major upgrades to these breakers since they were originally installed. There have been some minor modifications done on some units according to the manufacturer's recommendations. Other than this, the units have seen the standard maintenance inspections and servicing over the years.

Anticipated Useful life

The normal service life of power circuit breakers is 30 years. Beyond 30 years, it is normally expected that such equipment would either have to be upgraded or replaced. This upgrade will extend the service life by approximately 15 years.

Maintenance History

Hydro has experienced problems with air leaks or valves sticking, resulting in increased maintenance costs and breaker unavailability. Some maintenance modifications, as recommended by the manufacturer, were completed to correct these problems. In particular there have been problems with the generator breakers at Bay d'Espoir which have resulted in the generating unit being unavailable. The problems being experienced by Hydro are common in the utility industry and owners of these types of air blast breakers have addressed the problem through similar upgrading programs. Detailed maintenance costs by breaker are not readily available.

At the Sunnyside Terminal Station, broken insulator supports caused breaker interrupter heads to drop off and fall to the ground. This caused damage to adjacent equipment and resulted in system outages.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

At the Massey Drive Terminal Station, there were timing and phase disagreement problems that could have caused an extended outage to the Corner Brook Pulp and Paper Mill. At Bay d'Espoir, there were timing and air quality problems with breakers serving the generation units. These problems had the potential of causing generation and system wide outages. Other nuisance trips and outages of shorter nature have also occurred at various points on the system.

Maintenance inspections performed in the earlier in-service years of these breakers provided little evidence of the anticipated wear of parts and gasket fatigue. In later years, however, inspections of gaskets and seals, plus evidence of wear and tear of other mechanical components confirmed that a 'one time' upgrade program is the best approach to extending the service lives of the breakers. This conclusion was derived through consultations with other utilities and with the original equipment manufacturer.

The five-year maintenance history for the Brown Boveri DCVF, DCF and DLF models of air blast circuit breakers is shown in Table 2:

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	16.4	116.0	132.4
2007	7.7	121.0	128.7
2006	7.8	189.0	196.8
2005	10.7	157.0	167.7
2004	12.0	218.0	230.0

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Outage Statistics

Table 3 lists the 15 and five-year averages for the performance of the 66 Air Blast Circuit Breakers on the Hydro system. This table is the same as last year's submission as all relevant statistics for the 2008 operating year have not been compiled to date. A comparison is made between Hydro's last five years performance to the latest Canadian Electrical Association (CEA) five-year average (2001-2005). There have been 25 forced outages due to problems with these breakers over the last 15 years.

Table 3: Breaker Performance

	Number of Forced Outages	**Frequency (per a) [1]**	**Unavailability (percent) [2]**
230 kV			
1993-2007	20.00	0.02	0.016
2003-2007	3.00	0.01	0.023
CEA (2001-2005)	254.00	0.07	0.216
138 kV			
1993-2007	5.00	0.03	0.037
2003-2007	3.00	0.05	0.004
CEA (2001-2005)	158.00	0.08	0.444

[1] Frequency (per a) is the number of failures per year.

[2] Unavailability is the percent of time per year the unit is unavailable.

Industry Experience

Hydro's experience is that the breakers are capable of providing reliable service to the system, however, there have been operational issues centered around leaking seals and gaskets, malfunctioning valves, failing capacitors and resistors, porcelain failures and minor controls issues.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Hydro has consulted with other Canadian Utilities and the manufacturer of these breakers. Again, Hydro's experience is the same as other utilities using these breakers. Other utilities are managing the issue by either replacing the breakers or doing upgrades similar to Hydro. A replacement would be necessary if there was some system expansion or modification that required a breaker with ratings greater than the one in service. Otherwise, other utilities are upgrading the air blast circuit breakers.

<u>Maintenance or Support Arrangements</u>

Normal operation and maintenance work is performed by Hydro staff.

<u>Vendor Recommendations</u>

Hydro obtains support and advice on its major terminals equipment through regular consultations with the equipment manufacturers. The breaker manufacturer confirms that these breakers are at the end of their expected service lives. They recommend that unless system requirements or rating increases require a breaker with ratings greater than the one in service, the appropriate action to extend the service lives is to upgrade the breakers as proposed in this project.

Some breakers are located in highly critical locations on the Hydro system relative to generation and transmission requirements. These breakers have the greatest potential for affecting overall system reliability and must provide unquestionable performance. Any upgrade program would be directed at the most critical breakers first. These upgrades are required to maintain system performance and reliability.

Hydro's system requirements are well below the design ratings of these breakers in terms of fault interrupting capacity and expected number of operations. All breakers are suitably rated for their particular duty requirements, and there are no anticipated upgrades required for these locations in the foreseeable future.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Net Present Value

There are two solutions to the problems described with the air blast breakers. These are to upgrade the breakers, as proposed, or to replace them. The operation and maintenance costs of either alternative are generally the same. Upgrading the breakers is more cost effective than a replacement program. The average upgrade cost is approximately $73,000 as indicated in Table 4, whereas the average replacement cost of a 230 kV breaker is $350,000. Replacements would include costs for modifications to civil, mechanical, electrical, and controls subsystems associated with each breaker. With the upgrades, these costs are eliminated.

Levelized Cost of Energy

The capital expenditures for this project will not affect the levelized cost of energy for the system.

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

No legislative or regulatory requirements affect this project. The existing breakers comply with all applicable codes and standards of the industry.

Historical Information

The upgrade program was started in 2007 and is forecast to continue until 2013. For the years 2007 and 2008, Table 4 shows the summary costs for each year.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Table 4: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	$339.7		4		
2008	$315.2	$289.7	4	$72.4	Completed Breakers B1L18 OPD, B1L31 STB, L05L31 STB, B1L36 OPD
2007	$257.8	$146.4	2	$73.2	Completed B1L28 MDR, B5B6 BDE

It should be noted that the cost per unit to upgrade a breaker will vary depending on a number of factors related to location, weather, outages, systems requirements, etc. The unit cost is the quotient of the total actual expenditures divided by the number of breakers upgraded.

<u>Forecast Customer Growth</u>
The forecast customer load on the system has no affect on this project.

<u>Energy Efficiency Benefits</u>
There are no issues related to energy efficiencies associated with this project.

<u>Losses During Construction</u>
The removal and re-installation of each breaker 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.

<u>Status Quo</u>
The status quo is not an option as the breakers must be upgraded to maintain system reliability.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

<u>Alternatives</u>

There are two solutions to the problems described with the air blast beakers. These are to upgrade the breakers, 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.

Replacement would require purchase of newer technology - SF6 gas breakers - which have a different arrangement and size as compared to the air blast units. Replacement with gas breakers would mean major modifications to the breaker foundations, controls systems, station protection systems and general station arrangements. This is why the cost for the replacement alternative is significantly higher than the upgrade alternative.

Conclusion:

The justification for this project is based on the deteriorated condition of the breakers. Upgrading is required for the breakers to operate properly and reliably, and to extend the reliable service lives of the breakers.

<u>Project Schedule</u>

Table 5 presents the anticipated project schedule.

Table 5: Project Schedule

Activity	Milestone
Project Start	January 2010
Initial Planning and Equipment Ordering Tendering	February 2010
Equipment Delivery	July 2010
Equipment installations and Commissioning	November 2010
Project In Service	November 2010
Project Completion and Close Out	December 2010

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Future Plans:

Future upgrades will be proposed in future capital budget applications. Circuit Breaker upgrades are planned for the next four years as shown in the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Replace Guy Wires TL-215
Location: Doyles to Grand Bay
Category: Transmission and Rural Operations - Transmission
Type: Other
Classification: Normal

Project Description:

Transmission line structures are anchored to the ground with steel guy wires to provide support and prevent them from falling over. The unusually windy conditions in this area cause rapid and frequent cyclic loading of the guy wires. This cyclic loading fatigues the guy wire pre-formed grips where they pass through the eye of the guy wire anchor.

This project is required to replace this current guy wire arrangement, with an assembly that eliminates the fatigue problems. The proposed design, illustrated in Figure 1, includes a long U-Bolt that supports a two inch pipe. The pipe increases the bend radius of the pre-form around the anchor which will greatly reduce the tendency for the guy wire pre-form to fatigue. This assembly has been successfully used on other lines in the area, such as TL-214 between the Bottom Brook and Doyles Terminal Stations.

Figure 1: Proposed Anchor Assembly on TL-215

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Project Description: (cont'd.)

This project will be completed by Hydro personnel in conjunction with contractual arrangements with external work crews so that the construction phase can be as short as possible to minimize the requirement of alternate diesel generation. This project requires diesel generation for 14 days.

In 2013 of Hydro's Five-year capital Plan, it is proposed to relocate the remote section of TL-2 15 between Structure 223 and 312 out of the hills to a more accessible area. Therefore no work has been proposed for this section under this proposal.

In addition to replacing the pre-forms, the guy wires themselves will also be replaced on 50 structures. These guy wires were identified as having corrosion problems during the last Wood Pole Line Management (WPLM) Inspection. They have been monitored since the inspection and now require replacement. A list of structures with corroded guy wires is given in Appendix A. 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	123.0	0.0	0.0	123.0
Labour	35.8	0.0	0.0	35.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	107.0	0.0	0.0	107.0
Other Direct Costs	4.6	0.0	0.0	4.6
O/H, AFUDC & Escln.	3.3	0.0	0.0	3.3
Contingency	27.0	0.0	0.0	27.0
TOTAL	**300.7**	**0.0**	**0.0**	**300.7**

Existing System:

TL-215 is one of 16, 69 kV transmission lines within the Newfoundland and Labrador Hydro (Hydro) Island Interconnected System. It was built in 1969, and is situated between the Doyles and Grand Bay Terminal Stations located in the Southwest part of Newfoundland near Port aux Basques (see Figure 2). The line generally traverses rough terrain, including the Wreckhouse area which is subject to extremely high winds and icing.

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Existing System: (cont'd.)

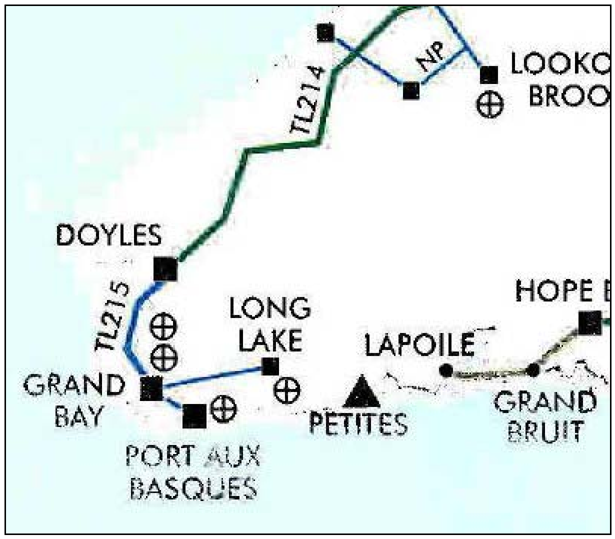


Figure 2: Route Photo of TL-215

TL-215 is a part of the radial system that provides electrical power to the Port aux Basques area. A radial system is a sole provider of transmission power to a load as compared to a looped system in which the power requirements can be provided through more than one transmission route. A failure of TL-215 will result in a short unplanned outage to the region of approximately 30 minutes. When TL-215 is out of service (planned or unplanned), alternate power is provided by diesel generation owned and operated by Newfoundland Power. To avoid unplanned outages, the upkeep and maintenance of TL-215 is a priority.

TL-215 has a total length of 27 kilometers and consists of 371 wood pole structures with an average span length of approximately 90 metres. Figure 3 shows a typical section of TL-215 through some rough terrain.

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Existing System: (cont'd.)

Figure 3: Typical Section of TL-215

TL-215 is strung with two types of conductor. The conductor between the Doyles Terminal Station and Structure 224, a distance of 16.5 kilometers, is a non-standard design, specially made for TL-215, of 6/13 steel reinforced aluminum conductor (ACSR), which has an overall diameter of 20.30 millimeters. The remainder of the line is strung with 4/0 American Wire Gauge (AWG) ACSR Penguin Conductor that has a total outside diameter of 14.31 millimeters.

Hydro designs and maintains its transmission lines to meet the requirements of the 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-215 was originally designed to operate under the following conditions:

- Extreme Ice Load: 38.1 millimeters (1.5 inch) of ice accumulation on the conductor;
- Extreme Wind Load: 193 kilometers per hour (120 miles per hour);
- Extreme Wind Load: 241 kilometers per hour (150 miles per hour) in the Wreckhouse area;
- Combined Ice and Wind Load: 25.4 millimeters (1.0 inches) of ice accumulation combined with 117.4 kilometers per hour (73 miles per hour) of wind; and
- 6.4 meters (21 feet) of ground clearance.

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Existing System: (cont'd.)

In total, the line is comprised of 371 wood structures that range from the basic single pole tangent structure to multiple pole angle and dead-end structures. The majority of structures are supported with guys and anchors. Table 2 gives a summary of the structure types and quantities on TL-215.

Table 2: TL- 215 Summary of Structure Types

Structure Type	Quantity	Percent Total	Pole Strength Class
B	23	6.2%	2
C	10	2.7%	2
D	336	90.6%	2
E	2	0.5%	2

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.

<u>Age of Equipment or System</u>

TL-215, constructed in 1969, is approximately 40 years old.

<u>Major Work/or Upgrades</u>

There have been no major upgrades since the original construction.

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Existing System: (cont'd.)

Anticipated Useful life

The anticipated useful life of a wood pole structure is 40 years. However, Hydro has implemented a Wood Pole Line Management (WPLM) program, with the mandate to thoroughly inspect, treat and refurbish the transmission structures prior to any serious failure on the line. This type of proper inspection and maintenance can increase the expected life of a transmission line to over 50 years.

Maintenance History

TL-215 is inspected through Hydro's Wood Pole Line Management (WPLM) Program, in which the wood structures undergo a complete inspection every ten years.

In addition to the scheduled WPLM inspection, TL-215 undergoes an annual ground patrol with the intent of replacing worn guy wires and pre-forms before they fail. This extra ground patrol was initiated at the start of the WPLM Program (2005) because of the high number of broken pre-forms that were found.

The five-year maintenance history for TL-215 is shown in the Table 3:

Table 3: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	41.6	192.7	234.3
2007	2.8	11.2	14.0
2006	12.3	9.6	21.9
2005	100.8	19.8	120.6
2004	15.1	45.3	60.4

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Existing System: (cont'd.)

Outage Statistics

Terminal equipment outages statistics are provided in the following two tables. Table 4 lists the transmission line performance for the latest five year's (2003 to 2007) on transmission line TL-215 compared to the latest available five-year average (2001-2005) for all of the Hydro System and CEA.

Table 5 details the effect of trips on TL-215 on the delivery points it supplies.

Table 4

Listing of Transmission Line Terminal Equipment Performance

	Frequency (per terminal year)	Unavailability (%)
TL215 (2003-2007)	0.80	0.0209
Hydro 138 kV (2001-2005)	0.57	0.1054
CEA 138 kV (2001-2005)	0.14	0.0381

Frequency (per a) is number lines outages per line terminal.

Unavailability is amount of time the line is not available for terminal related causes.

Table 5

Five Year Averages (2004-2008) Forced Outages Only

Transmission Line	Delivery Point Affected	T-SAIFI	T-SAIDI
TL215	Port aux Basques	**0.60**	**96.14**
	Central Region	1.14	118.95
	Hydro System	1.90	163.20
	CEA (2003-2007)	0.86	127.92

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Existing System: (cont'd.)

<u>Safety Performance</u>

The replacement of worn components is required to provide reliable service and is not considered to be a safety issue.

Justification:

Over the last five years, the pre-forms on 50 structures have been replaced because they were found to be prematurely worn or have failed. A failure of this guy attachment may lead to a collapse of the entire structure during high wind conditions, resulting in an outage to the Port aux Basque area.

This replacement of the guy wire attachment assemblies is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service.

<u>Net Present Value</u>

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

<u>Levelized Cost of Energy</u>

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

<u>Cost Benefit Analysis</u>

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

<u>Legislative or Regulatory Requirements</u>

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

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Justification: (cont'd.)

Historical Information

The new anchor attachments, as shown in Figure 4 on page 4, will be the same assembly as currently used on TL-214, which is located north of TL-215 (see Figure 1, page 1). TL-214 is also a 69 kV transmission line of similar construction as TL-215 and generally experiences the same weather conditions as TL-215. There have been no issues of premature wear or failure with the new pre-forms on this line.

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

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

Losses During Construction

There are no anticipated energy losses during construction, as the customer load supplied by TL-215 can be supplied through diesel generation.

Status Quo

The status quo is not an acceptable alternative. The deterioration of guy wires and associated hardware may lead to structure failures and unplanned outages to the customers in the Port aux Basque area.

Alternatives

The problem on TL-215 is associated with a specific assembly on the guy wire and anchor attachment point. Several commercially available connections were considered, but were immediately discounted because of significantly higher costs associated with their procurement. The proposed solution was chosen because it was the least cost as well as being successfully used in the area.

Project Title: Replace Guy Wires TL-215 **(cont'd.)**

Conclusion:

The replacement of guy wire attachment assemblies is essential for Hydro to provide safe, least-cost, reliable electrical service. The scope of the project includes changing the guy wire attachments on 264 structures to the more reliable assembly that is currently used on TL-214 as well as changing the guy wires on 50 structures.

The project also includes costs for approximately 14 days of diesel generation to allow the work to be completed. The cost estimate of $27,500 per day for diesel generation is based on actual costs paid during the 2008 refurbishment work of TL-251 and TL-252.

Project Schedule

The project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	Milestone
Project Initiation	Jan 2010
Complete Design Transmittal	Feb 2010
Detailed Engineering Design	April 2010
Issue Tender and Award Job	June 2010
Material Delivery	July 2010
Develop Construction Package	July 2010
Contract Execution	Aug 2010
Commissioning	Sept 2010
Close Out and Documentation	Dec 2010

APPENDIX A

List of Structures with Corroded Guys

TL-215 List of Corroded Guy Wires

Insp Date	T.L. No.	Str. No.	Condition	No. of Guys
6/1/2003	TL-215	251	Corroded	2
6/1/2003	TL-215	252	Corroded	2
6/1/2003	TL-215	253	Corroded	3
6/1/2003	TL-215	254	Corroded	2
6/1/2003	TL-215	277	Corroded	2
6/1/2003	TL-215	278	Corroded	3
6/1/2003	TL-215	282	Corroded	3
6/1/2003	TL-215	285	Corroded	3
6/1/2003	TL-215	293	Corroded	3
6/1/2003	TL-215	296	Corroded	2
6/1/2003	TL-215	299	Corroded	7
6/1/2003	TL-215	300	Corroded	2
6/1/2003	TL-215	303	Corroded	3
6/1/2003	TL-215	309	Corroded	3
6/1/2003	TL-215	315	Corroded	7
6/1/2003	TL-215	317	Corroded	3
6/1/2003	TL-215	321	Corroded	3
6/1/2003	TL-215	323	Corroded	3
6/1/2003	TL-215	327	Corroded	3
6/1/2003	TL-215	328	Corroded	2
6/1/2003	TL-215	331	Corroded	8
6/1/2003	TL-215	332	Corroded	2
6/1/2003	TL-215	333	Corroded	3
6/1/2003	TL-215	334	Corroded	2
6/1/2003	TL-215	335	Corroded	3
6/1/2003	TL-215	336	Corroded	2
6/1/2003	TL-215	337	Corroded	3
6/1/2003	TL-215	338	Corroded	3
6/1/2003	TL-215	339	Corroded	0
6/1/2003	TL-215	341	Corroded	3
6/1/2003	TL-215	343	Corroded	3
6/1/2003	TL-215	344	Corroded	0
6/1/2003	TL-215	345	Corroded	3
6/1/2003	TL-215	347	Corroded	2
6/1/2003	TL-215	348	Corroded	3
6/1/2003	TL-215	350	Corroded	3
6/1/2003	TL-215	352	Corroded	3
6/1/2003	TL-215	356	Corroded	3
6/1/2003	TL-215	358	Corroded	2
6/1/2003	TL-215	360	Corroded	3
6/1/2003	TL-215	361	Corroded	2
6/1/2003	TL-215	362	Corroded	2
6/1/2003	TL-215	364	Corroded	2
6/1/2003	TL-215	365	Corroded	3

Insp Date	T.L. No.	Str. No.	Condition	No. of Guys
6/1/2003	TL-215	366	Corroded	2
6/1/2003	TL-215	367	Corroded	3
6/1/2003	TL-215	368	Corroded	2
6/1/2003	TL-215	369	Corroded	11
7/8/2008	TL-215	84	Corroded	3
7/8/2008	TL-215	85	Corroded	2

Project Title: Replace Radio Link with Fiber
Location: Bay d'Espoir
Category: General Properties - Telecontrol
Type: Other
Classification: Normal

Project Description:

This project will replace the existing microwave radio link between the Bay d'Espoir Generating Station (BDE) and the Bay d'Espoir Hill Hilltop Repeater Site (BDH) with a newer generation of microwave radio. Please refer to Figure 1 which illustrates the microwave route. The vendor has discontinued the model of microwave radio equipment currently installed, replacement parts are unavailable, and replacement of the existing radio equipment is required. The scope of this work would involve the replacement of the existing MDR-4000 radio equipment with the MDR-8000 microwave radio, which is the currently available model and is utilized elsewhere in the Newfoundland and Labrador Hydro (Hydro) microwave radio system.

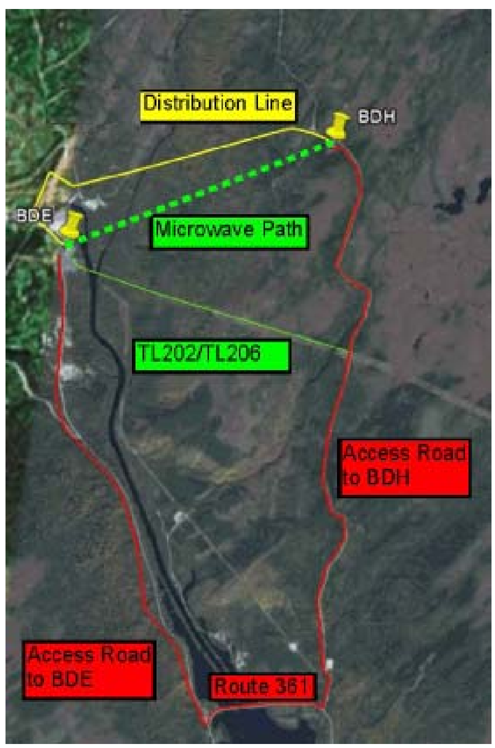


Figure 2 - Bay d'Espoir Microwave Route

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Project Description: (cont'd.)

The project will involve both internal and external resources. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	30.0	0.0	0.0	30.0
Labour	114.4	0.0	0.0	114.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	217.0	0.0	0.0	217.0
Other Direct Costs	15.5	0.0	0.0	15.5
O/H, AFUDC & Escln.	55.3	0.0	0.0	55.3
Contingency	56.5	0.0	0.0	56.5
TOTAL	**488.7**	**0.0**	**0.0**	**488.7**

Existing System:

The Hydro microwave radio system provides the Corporation with a private high-bandwidth voice and data wide area network between Deer Lake in the west, Bay d'Espoir in the south and St. John's in the east. The Bay d'Espoir Plant (BDE) - Bay d'Espoir Hill (BDH) microwave radio link is the last high-bandwidth link of the microwave system between BDE and the Energy Control Centre in St. John's.

Age of Equipment or System

The BDE-BDH radio link was originally installed in 1985 and was replaced with the current equipment in 1998.

Major Work/or Upgrades

There has been no major work and/or upgrades on the BDE-BDH radio link since the replacement of the equipment in 1998.

Anticipated Useful life

Microwave radio equipment is depreciated over 15 years.

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Existing System: (cont'd.)

Maintenance History

The five-year maintenance history for this system is minimal, at less that $1,000 per year. With regards to other MDR-4000 microwave radio links, consisting of a total of eight links connecting ten sites, the five-year maintenance history is provided in Table 2. Data for the 2004 through 2006 period is not readily available. Total maintenance costs for 2009 as of April 30 is $10,940, $4,830 of which is preventative maintenance and $6,110 of which is corrective maintenance.

Table 2 – Five-Year Maintenance History for MDR-4000

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	4.2	6.2	10.4
2007	0.9	0.2	1.1

Outage Statistics

There have not been any outages related to the BDE-BDH radio link.

Industry Experience

Many utilities throughout North America utilize optical fibre instead of installing microwave equipment for communications over short distances. Utilization of fibre optic cable was considered for this project, however, it was proven to be a higher cost alternative than installing new microwave radio equipment. See the Cost Benefit Analysis and the Alternatives Sections below.

Maintenance or Support Arrangements

This equipment is maintained primarily by Hydro personnel. A support contract with the vendor allows access to technical support personnel when required to troubleshoot and assist in solving more complex problems.

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Project Description: (cont'd.)

Vendor Recommendations

The vendor has discontinued the product line of the model of microwave radio equipment that is installed on the BDE-BDH link, and has recommended the replacement of the radio equipment with the current model.

Availability of Replacement Parts

New replacement parts for the existing microwave radio equipment are unavailable. Some replacement parts may be obtained via third parties. These parts would typically be used or refurbished components, thereby decreasing their reliability.

Safety Performance

There are no known safety performance concerns or safety code violations associated with this product. However, failure of the microwave radio system would impact both the administrative and operational voice systems, and the VHF mobile radio system. Both of these modes of communication are relied on by field personnel to communicate switching orders or emergencies which have associated safety issues.

Environmental Performance

Environmental non-compliance is not an issue for this project or equipment.

Operating Regime

This system is required continuously. As it carries teleprotection signals, reliability is of the utmost concern.

Justification:

This project is justified on the requirement to replace infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. The current equipment is discontinued and the vendor is

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Justification: (cont'd.)

recommending replacement with the newer model. Replacing the existing equipment with new microwave equipment is the least cost alternative, and will allow Hydro to utilize the removed radio to provide spare parts to extend the life of the remainder of its Alcatel MDR-4000 microwave radio equipment.

Net Present Value

The cumulative net present value of replacing the existing microwave radio equipment with new microwave radio equipment is $603,362. See the Cost Benefit Section below for details.

Levelized Cost of Energy

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

Cost Benefit Analysis

A cost benefit analysis was performed with three alternatives. Alternative 1, replacement of the microwave radio with new microwave radio equipment, is the lowest cost alternative. Alternatives 2 and 3, both involving replacement with redundant optical fibre, are the higher cost alternatives. The Table 3 provides the results of the cost benefit analysis.

Table 3 - Alternative Comparison to 2039

Alternative	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Microwave Radio	$ 603,362	$0
Redundant Fibre (along access road)	$1,569,742	$ 966,380
Redundant Fibre (along TL-202/206)	$1,101,594	$ 498,232

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements.

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Justification: (cont'd.)

Historical Information

In 2009, the microwave radio link between the Hinds Lake Generating Station and the Blue Grass Hill Repeater Site is to be replaced with optical fibre. The budget for this project is $692,100 and is to be completed over a two-year period. As this project is currently ongoing, the actual expenditure is unavailable.

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no projected energy efficiency benefits related to the replacement of the microwave radio equipment.

Losses During Construction

There are no losses during construction that can be attributed to this project.

Status Quo

The status quo is not an acceptable alternative. The MDR-4000 radio is manufacturer discontinued and must be replaced in the near future. By completing this project now, Hydro can utilize the removed radio to provide spare parts for the 36 remaining MDR-4000 radios, thereby delaying their replacement.

Alternatives

Three alternatives were considered including the replacement of the MDR-4000 with a newer generation of microwave, and two options to replace with optical fibre. As demonstrated in Table 3, the former is the preferred alternative as it has a lower net present value.

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Justification: (cont'd.)

Alternative 1 – New Microwave Radio Equipment:

Under this scenario, the microwave radio equipment is replaced in 2010 with a newer generation of microwave radio. This new microwave radio will be selected to match other equipment in the radio system to decrease the amount of spares required and to take advantage of the knowledge and experience of personnel on the operation and maintenance of this equipment.

Alternative 2 – Optical Fibre (along access road):

This alternative consists of the installation of fibre optic cable along a route approximately four kilometres in length, from Bay d'Espoir Plant to Bay d'Espoir Hill, and the installation of wood poles and fibre optic cable along an alternate route, which is approximately 13 kilometers in length. The four kilometer route would involve either the structural upgrade or replacement of the existing 25 kV distribution line between the sites. This would be determined during the project design phase if the alternative was selected. The 13 kilometer route was chosen to follow the existing access roads to both sites.

Alternative 3 – Optical Fibre (along TL-202/TL-206):

This alternative consists of the installation of fibre optic cable along a route approximately four kilometres in length, from Bay d'Espoir Plant to Bay d'Espoir Hill, and the installation of wood poles and fibre optic cable along an alternate route, which is approximately five kilometers in length. The four kilometer route would involve either the structural upgrade or replacement of the existing 25-kV distribution line between the sites. This would be determined during the project design phase if the alternative was selected. The five kilometer route was chosen to follow a portion of the existing access road to BDH and follow the TL-202/TL-206 right-of-way.

Conclusion:

This project is required in order to replace aging microwave radio equipment that is no longer supported by the manufacturer. By replacing the microwave radio with a newer model of microwave radio, the lowest cost solution will be implemented.

Project Title: Replace Radio Link with Fiber **(cont'd.)**

Conclusion: (cont'd.)

Project Schedule

The proposed project schedule is shown in Table 4.

Table 4 - Project Milestones

Activity	**Milestone**
Project Initiation Complete	January 2010
Design and Procurement Complete	June 2010
Installation and Commissioning Complete	November 2010
Project Closed	December 2010

Future Plans:

None.

Project Title: PC Replacement Program
Location: Various Sites
Category: General Properties - Information Systems
Type: Pooled
Classification: Normal

Project Description:

The PC Replacement program (formerly referred to as the End Use Evergreening program) is required to enhance the efficiency of Newfoundland and Labrador Hydro (Hydro) employees by replacing the personal computers (PCs) used for their day to day requirements.

This project will enable Hydro to replace 215 personal computers that were deployed in 2004 and 2005. 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	230.1	0.0	0.0	230.1
Labour	30.6	0.0	0.0	30.6
Consultant	96.7	0.0	0.0	96.7
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.	13.3	0.0	0.0	13.3
Contingency	35.7	0.0	0.0	35.7
TOTAL	**406.6**	**0.0**	**0.0**	**406.6**

Existing System:

Hydro has over 800 end-user personal computers in service. It is important to refresh this equipment on a regular cycle to keep the technology current to maintain a reliable, efficient and productive workforce. Refreshing is the replacement of end user equipment, such as desktops, laptops and thin clients, on a life cycle depending on the type of device.

Minimum specifications for replacement of personal computers are reviewed on an annual basis to ensure that the PCs in service continue to remain effective. Industry best practices, technology and application trends are taken into consideration when specifications for computer devices are decided for the current year. The annual review continues the replacement life cycle for laptops of every four years and desktops every five years.

Project Title: PC Replacement Program **(cont'd.)**

Existing System: (cont'd.)

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice the following items under the existing system section are not relevant to the proposal:

- Major Work/Upgrades;
- Maintenance History;
- Outage Statistics;
- Safety Performance;
- Environmental Performance; and
- Operating Regime.

Age of Equipment or System

The existing PCs that are to be replaced under this project will have been in service between five and six years depending on the hardware platform used. No Laptops are being replaced with this budget.

Anticipated Useful life

According to Gartner[5], the useful life for a laptop is three years while a desktop is four to five years. The North American industry standard life cycle for end-user devices is three years for laptops and five years for desktops. Hydro has adopted a four to six year life cycle and utilizes extended warranties to ensure reliable operation.

Industry Experience

Hydro has a similar life cycle plan for computer equipment as other companies in the utility industry, including Newfoundland Power.

[5] Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

Project Title: PC Replacement Program **(cont'd.)**

Existing System: (cont'd.)

Maintenance or Support Arrangements

Hydro has purchased maintenance agreements with Lenovo Corporation, the manufacturer, that cover laptops for four years and desktops for five years.

Vendor Recommendations

The vendor predicts a 30 percent failure rate on desktops in the sixth year and a 40 percent failure rate on laptops in the fifth year.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements. Once the maintenance agreement has expired there is no guarantee that replacement parts can be obtained.

Justification:

Hydro must keep computers current in order to adequately support and protect the Information Technology applications and information required to operate its business. The replacement and addition of PC components to achieve this goal requires investment over the life cycle of the computers.

The refresh program makes it possible for computers to be replaced in a planned and consistent manner. This allows for even distribution of budgets and ensures that the computers are available and reliable to support the user's applications. Continued review of the computer life cycle allows Hydro to adjust plans based on performance, technology changes and new business requirements.

In addition, the computers to be replaced under this project are approaching the end of their useful lives and failures can be expected. The maintenance agreements for these computers will have expired and replacement parts can no longer be guaranteed.

Project Title: PC Replacement Program **(cont'd.)**

Justification: (cont'd.)

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses During Construction.

Net Present Value

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

Cost Benefit Analysis

This project is subject to a lease or purchase cost benefit analysis to determine the lowest cost alternative. The cost benefit analysis is done in the year of replacement to ensure consideration of incentives or other benefits that may be offered by the providers.

Historical Information

Historical information on computer replacement over the last five years is presented in Table 2.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	491.4		230		
2008	451.4	456.7	215	2.1	
2007	395.0	393.7	102	3.9	Laptops only replaced
2006	0.0	0.0	0	0.0	
2005	710.5	663.1	280	2.4	

Project Title: PC Replacement Program **(cont'd.)**

Justification: (cont'd.)

Status Quo

If the end user infrastructure is not kept current the following scenarios could potentially occur:

- New applications may not run on the old hardware platform;
- Decreased speed may result in lost production;
- Failure rates will exceed 50 percent;
- Maintenance agreements will not be offered by vendor; and
- Operating systems may be unsupported.

Alternatives

The only alternative is to consider leasing the equipment. However, this has been done in the past and has proven to be more expensive and difficult to manage.

Conclusion:

The PC Replacement Program as proposed in this project is the preferred solution for the following reasons:

- It enables the end user equipment to remain current.
- It improves workforce efficiency by providing reliable hardware.
- It allows for a predictable annual budget.

Project Schedule

The project is scheduled to start in March 2010 and be completed before December 31, 2010.

Future Plans:

Future replacements will be proposed in future capital budget applications. Computer replacements are planned for the next four years as shown in the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Upgrade Private Automatic Branch Exchange (PABX)
Location: Various Sites
Category: General Properties - Telecontrol
Definition: Other
Classification: Normal

Project Description:

The private automatic branch exchange (PABX) at the Bishop's Falls Main Office (Bishop's Falls), the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) and the Holyrood Thermal Generating Station (Holyrood) will be upgraded to the latest software and hardware versions in order to maintain support from the manufacturer. In addition, the voicemail users at Bishop's Falls will be migrated from the Bishop's Falls PABX to the centralized voice mail system at Hydro Place in St. John's.

The latest software version for the Nortel Meridian 1 PABX is Succession 6.0, which is scheduled for release in July 2010. This release will provide the necessary technical support to enable Newfoundland and Labrador Hydro (Hydro) to maintain the level of service required by an electrical utility. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	138.2	0.0	0.0	138.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	128.3	0.0	0.0	128.3
Other Direct Costs	6.8	0.0	0.0	6.8
O/H, AFUDC & Escln.	38.1	0.0	0.0	38.1
Contingency	27.3	0.0	0.0	27.3
TOTAL	**338.7**	**0.0**	**0.0**	**338.7**

Existing System:

The Corporation's PABX infrastructure provides Hydro employees with administrative voice communications either within the specific locale, to other corporate locations on a private network, or to the Public Switched Telephone Network (PSTN). In addition, it provides vital operational voice communications between the Energy Control Centre in St. John's and field personnel.

Project Title: Upgrade Private Automatic Branch Exchange (PABX) **(cont'd.)**

Existing System: (cont'd.)

Currently, Bay d'Espoir and Holyrood utilize the Hydro Place PABX for voicemail services. This is possible due to the high bandwidth link between the locations. In 2003, the high bandwidth link was extended to Bishop's Falls. By switching Bishop's Falls voicemail users to the Hydro Place PABX, there would be less hardware and therefore lower maintenance expenses.

Table 2 shows the three locations and the existing PABX models and software releases to be upgraded.

Table 2: Current PABX Models and Software Release

Location	PABX Model	Current Release
Bishops Falls	Meridian 1 Option 11C	Succession 4.5 (X21 4.5)
Bay d'Espoir	Meridian 1 Option 61C	Succession 4.0 (X21 4.0)
Holyrood	Meridian 1 Option 11C	Ver. 25.15 (X11 25.15)

Age of Equipment or System

Table 3 lists each PABX and the year of its installation.

Table 3: Age of Equipment/System

Location	Year of Installation
Bishops Falls	1996
Bay d'Espoir	1998
Holyrood	1996

Major Work/or Upgrades

Table 4 below lists the upgrades that have occurred on each PABX since its installation:

Project Title: Upgrade Private Automatic Branch Exchange (PABX) **(cont'd.)**

Existing System: (cont'd.)

Table 4: Major Work and Upgrades

Location	Year	Major Work and Upgrades	Comments
Bishops Falls	2006	Upgraded software and hardware	Utilized existing high capacity link with St. John's PABX to provide tie trunks, etc.
	2000	Added Meridian Mail (voice mail)	
Bay d'Espoir	2006	Added Meridian Mail (voice mail) via high capacity link to St. John's PABX	Voice mail configuration activities
	2005	Upgraded software and hardware	Utilized existing high capacity link with St. John's PABX to provide centralized voice mail, tie trunks, etc.
	1999	Upgraded software and hardware	Moved services provided by Siemens and Mitel PABXs in order to provide operational voice capability on a single platform (St. John's 61C)
Holyrood	2002	Upgraded software and hardware	Utilized existing high capacity link with St. John's PABX to provide centralized voice mail, tie trunks, etc.

Anticipated Useful Life

A PABX system is depreciated over a 10-year period.

Maintenance History

The five-year maintenance history for the Bishop's Falls and Bay d'Espoir PABXs is shown in Table 5. The costs do not include day-to-day operational activities, such as moving, adding or changing telephone sets, repairing telephones or lines, and reconfiguring software. Preventative maintenance is typically carried out during the normal inspection maintenance routine and costs are included in corrective maintenance. Maintenance has not been required on the Holyrood PABX.

Project Title: Upgrade Private Automatic Branch Exchange (PABX) **(cont'd.)**

Existing System: (cont'd.)

Table 5: Five-Year Maintenance History

Location	Year	Corrective Maintenance ($000)
Bishop's Falls	2004-08	0.74
Bay d'Espoir	2004-08	2.72

Outage Statistics

There have been no outages of the PABX at any location.

Industry Experience

Most utilities in North America utilize private voice services in order to reduce the operating cost associated with telephone line and trunk rental.

Maintenance or Support Arrangements

Hydro has developed in-house expertise to perform corrective and preventative maintenance on PABX systems.

Vendor Recommendations

The vendor has recommended that the software for all PABX equipment be upgraded to the latest release, Succession 6.0, scheduled for July 2010. The current software Release 25 installed on the Holyrood PABX receives limited technical support from the vendor. The vendor is progressing to a newer version to be released in July 2010 thereby removing its support for expansion of the current release as well as the correction of any bugs/errors in the software and its documentation. After 2010, there will be no vendor support for the existing version.

Project Title: Upgrade Private Automatic Branch Exchange (PABX) **(cont'd.)**

Existing System: (cont'd.)

The current software releases of Succession 4.5 and Succession 4.0 are installed on the Bishop's Falls and Bay d'Espoir PABXs, respectively, and receive only limited technical support from the vendor. Based on the software release status and limited vendor support, the remaining useful life of the equipment is less than one year each. The upgrades will extend the service life for an additional five years (this is the typical Release life). Since the installation of the PABX equipment, release updates have been completed due to the need for other applications. For example, in 1999 the software releases for the Bay d'Espoir and Hydro Place PABXs were updated to permit the use of the Meridian PABX for operational voice.

Availability of Replacement Parts

Spare parts for components of the PABX equipment are readily available.

Safety Performance

The administrative and operational voice services provided by the PABX equipment are vital to the safety of personnel. During both normal day-to-day activities and in emergency situations, the PABX equipment provides a link between field personnel and the Energy Control Centre.

Environmental Performance

There are no environmental performance issues related to this equipment.

Operating Regime

This equipment operates continuously. During the day employees access the telephone system, and during the night the PABX runs diagnostic testing and generates reports. It is also used during regular business hours for communications between the Energy Control Centre and field personnel during planned and forced outages.

Project Title: Upgrade Private Automatic Branch Exchange (PABX) **(cont'd.)**

Justification:

This project is justified on the need to maintain a reliable telephone service that ensures vendor technical support is readily available. Failure to upgrade creates a risk of outages to the PABX that will impede the ability for employees to access telephone services in the performance of their duties.

<u>Net Present Value</u>

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

<u>Levelized Cost of Energy</u>

As this project does not involve new generation sources, the levelized cost of energy is not applicable.

<u>Cost Benefit Analysis</u>

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

<u>Legislative or Regulatory Requirements</u>

There are no legislative or regulatory requirements for this project.

<u>Historical Information</u>

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

<u>Forecast Customer Growth</u>

Customer load growth is not affected by this project.

<u>Energy Efficiency Benefits</u>

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

<u>Losses During Construction</u>

As no generation outage is required to complete this project, there are no losses during construction.

<u>Status Quo</u>

To maintain the status quo would result in the loss of technical support from the manufacturer.

Project Title: Upgrade Private Automatic Branch Exchange (PABX) **(cont'd.)**

Justification: (cont'd.)

Alternatives

There are no viable alternatives for this Project.

Conclusion:

To extend the operational life of the PABX equipment at Bishops Falls Main Office, the Bay d'Espoir Hydroelectric Generating Station and the Holyrood Thermal Generating Station, it is necessary to upgrade the equipment to the most current software release for the PABX models. The next release, scheduled for July 2010, will provide Hydro with continued technical support.

Project Schedule

The project is scheduled to commence in January 2010, with an expected completion date of December 31, 2010. The implementation activities would commence in August 2010 to coincide with the release of Meridian 1 PABX Succession 6.0 software. The anticipated project schedule is shown in Table 6.

Table 6: Project Milestones

Activity	Milestone
Project Initiation Complete	January 2010
Design and Procurement Complete	July 2010
Installation and Commissioning Complete	November 2010
Project Closed	December 2010

Future Plans:

None.

Project Title: Remove Safety Hazards
Location: Various Sites
Category: General Properties - Administrative
Type: Other
Classification: Normal

Project Description:

This project is required to ensure adequate capital funding is available to quickly address capital-related safety hazards as they are identified. In an effort to avoid injury and/or fatality Newfoundland and Labrador Hydro (Hydro) has initiated a Safe Work Observation Program (SWOP). This program trains employees in the importance of identifying and reporting conditions that can potentially lead to an incident or an accident. 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	112.0	0.0	0.0	112.0
Labour	56.0	0.0	0.0	56.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	56.0	0.0	0.0	56.0
O/H, AFUDC & Escln.	28.4	0.0	0.0	28.4
Contingency	0.0	0.0	0.0	0.0
TOTAL	**252.4**	**0.0**	**0.0**	**252.4**

Existing System:

A capital project for removing safety hazards was executed in 2008. The following projects were performed under that capital project:

- Modified overhead crane and hoist at Mary's Harbor Diesel Plant - $15,200
- Installed stairway to Draft Tube Gallery at the Upper Salmon Power House. - $7,100
- Installed stairwell to fire pump at Granite Canal Power House. $10,700
- Rerouted the walkway on the 11th floor of the Holyrood Power House. $88,500
- Installed CO/NOx Monitors at the Nain and Mary's Harbor Diesel Plants $2,300
- Installed Fire Fighter Training System at Port Saunders. $7,100

Project Title: Remove Safety Hazards **(cont'd.)**

Existing System: (cont'd.)

The work was intended to continue on an annual basis however the capital proposal for 2009 was not submitted due to an oversight. It is intended to continue the work on an annual basis. For 2009, any capital expenditures related to safety will have to be addressed through the Allowance for Unforeseen Capital.

As this project involves removing safety hazards as they are identified at various sites through the SWOP system there is no relevant data related to:

- Age of Equipment or System;
- Major Work/or Upgrades;
- Anticipated Useful life;
- Maintenance History;
- Outage Statistics;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts; and
- Operating Regime.

<u>Safety Performance</u>

Hydro must comply with the Newfoundland and Labrador Occupational Health and Safety Regulations. Hydro's Safety and Health Program aims to create a safe work environment so that nobody gets hurt.

<u>Environmental Performance</u>

There are no environmental issues associated with removing safety hazards.

Justification:

This project is required to provide a safe work environment for Hydro employees , contractors, visitors

Project Title: Remove Safety Hazards **(cont'd.)**

Justification: (cont'd.)

and the public in compliance with Hydro's policies and the Occupational Health and Safety Regulations. The SWOP program involves workers actively looking for safety hazards and spotting problems that may otherwise go unnoticed, and, thus, lead to serious health and/or safety issues for Hydro customers, employees or contractors, and to the general public. The availability of capital funding enables Hydro to respond immediately to address unsafe conditions rather than waiting for the normal capital budget process. This provision allows Hydro to eliminate safety and health risks from the workplace quickly. This project provides Hydro the means to address unsafe situations where capital work is identified as the solution.

Some deficiencies have existed in Hydro facilities for years and were acceptable under safety standards that existed when the facilities were constructed. By today's more stringent standards and greater awareness of hazards, these deficiencies need to be immediately corrected to provide a safe work environment.

<u>Net Present Value</u>

The net present value is not applicable for this project as it is a general proposal to remove safety hazards from the workplace. For each unsafe situation identified if more than one alternative exists to correct the problem, a net present value calculation will be done to determine the least cost solution.

<u>Levelized Cost of Energy</u>

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.

<u>Cost Benefit Analysis</u>

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

Project Title: Remove Safety Hazards **(cont'd.)**

Justification: (cont'd.)

Legislative or Regulatory Requirements

Hydro must comply with the Newfoundland and Labrador Occupational Health and Safety Regulations. Each situation identified as a safety hazard will be corrected to comply with current legislative and regulatory requirements.

Historical Information

Hydro removed safety hazards under a capital project in 2008. This was the first year for this program with a budget of $252,300 of which $130,400 was spent.

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to removing safety hazards.

Losses During Construction

This project will have no effect on normal plant operations and will not cause any interruptions or system outages. Therefore, there will be no losses during construction.

Status Quo

The status quo is not acceptable since there are safety hazards to be identified and corrected.

Alternatives

This project is a general proposal to correct various identified safety hazards in the workplace. Each situation will be evaluated to determine whether one or more alternatives exist to correct the unsafe situation.

Project Title: Remove Safety Hazards **(cont'd.)**

Conclusion:

Hydro must remove safety hazards as identified at all of its facilities.

Project Schedule

As this budget relates to unanticipated safety issues, no schedule is available.

Future Plans:

Future Safety Hazards Removal projects will be proposed in future capital budget applications.

Project Title: Replace Peripheral Infrastructure
Location: Various Sites
Category: General Properties - Information Systems
Type: Pooled
Classification: Normal

Project Description:

The Peripheral Infrastructure Replacement Project is an ongoing project to replace the printers, copiers, fax machines and video conference equipment used in the day to day operation of the business. For the year 2010, this project will consist of the replacement of five Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning, as well as 29 Laser Printers. Of the MFDs to be replaced, four are located in Hydro Place, St. John's and one in Bay d'Espoir. The location of the laser printers to be replaced are as follows: fourteen in Hydro Place; eight in Bishop's Falls, two in Holyrood, two in Port Saunders, two in Bay d'Espoir and one in Wabush. The project also includes funds for two new video conferencing units, one in Hydro Place and one in Stephenville. An Increase in this budget from previous years is due to the larger MFD that is being replaced in the mailroom, which has a cost of $60,000. 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	173.8	0.0	0.0	173.8
Labour	21.8	0.0	0.0	21.8
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.	6.8	0.0	0.0	6.8
Contingency	19.6	0.0	0.0	19.6
TOTAL	**222.0**	**0.0**	**0.0**	**222.0**

Existing System:

The units scheduled for replacement have been in service for five years or more and normal maintenance contracts have expired. As the devices age, they require increasing maintenance and service time resulting in loss of reliability and productivity. If these units are kept in service until failure occurs, then the availability of scanning, coping, faxing or high volume printing services is limited. Depending on the location of the unit it may take four to five weeks to replace.

Project Title: Replace Peripheral Infrastructure **(cont'd.)**

Existing System: (cont'd.)

There is no relevant information for:

- Safety Performance;
- Environmental Performance; or
- Operating Regime.

Major Work/Upgrades

There have been no major upgrades since installation.

Age of Equipment or System

The units scheduled for replacement have been in service for over five years and normal maintenance contracts have expired. As the devices age, they require increasing maintenance and service time resulting in loss of reliability and productivity. If these units are kept in service until failure occurs then the office is limiting the availability of scanning, coping, faxing or high volume printing services. Depending on the location of the unit it may take four to five weeks to replace it.

The decision when to replace a printer or MFD is based on many criteria, including:

- Vendor's product roadmap (new features like secure print and scanning will not support older equipment);
- Users' printing requirements (color need, print volumes & speed);
- Number of users supported by the equipment;
- Availability of alternate printing;
- Available support for the equipment; and
- Age of equipment.

Anticipated Useful life

According to Gartner[6], the useful life for a color printer is three years while a black/white printer is between three and five years.

[6] Gartner Inc. provides of research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

Project Title: Replace Peripheral Infrastructure **(cont'd.)**

Existing System: (cont'd.)

Maintenance History

Please refer to the Outage Statistics section.

Outage Statistics

An average of twenty seven service calls has been made on each of the main printers being replaced.

Industry Experience

Industry best practices indicate that the typical service life for a peripheral device is four to five years. Hydro has a similar life cycle plan for peripheral devices as other companies in the utility industry including Newfoundland Power.

Maintenance or Support Arrangements

Hydro has purchased a maintenance agreement with a supplier (Xerox) that covers the larger Multi-Function Devices for five years. Smaller laser printers have only a manufacturer's warranty of one to three years duration.

Vendor Recommendations

The vendor (Xerox) recommends a maximum lifespan of five years.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements and warranties. Once these agreements and warranties have expired replacement parts may or may not be available.

Justification:

This is the continuation of the Peripheral Infrastructure Replacement Project to replace peripheral devices as they reach the end of their useful lives. The units scheduled for replacement in 2010 have all been in service for five years or more and maintenance contracts and warranties have expired. The manufacturer will only guarantee the operation of these MFDs for a period of five years.

Project Title: Replace Peripheral Infrastructure **(cont'd.)**

Justification: (cont'd.)

Hydro must keep its peripheral infrastructure current in order to adequately support the needs of its business. This project makes it possible for such equipment to be replaced in a planned and consistent manner. This allows for even distribution of budgets and ensures that these peripherals are available and reliable to support the user's needs. Continued review of the products lifecycle allows Hydro to adjust plans based on performance, technology changes and new business requirements.

Net Present Value

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

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

As this budget proposal is for the routine replacement of computer peripherals based on industry accepted standards the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses During Construction.

Historical Information

Table 2 contains a five-year history of the Peripheral Infrastructure Replacement Project.

Project Title: Replace Peripheral Infrastructure **(cont'd.)**

Justification: (cont'd.)

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit [1] ($000)	Comments
2009F	161		36		
2008	159	159	32	5.0	
2007	139	139	10	13.9	
2006	199	196	8	24.5	
2005	117	121	56	2.2	

(1) The variability in unit costs are due to specifications of the printers being replaced such as pages per minute, memory, fax and scanning capability.

<u>Status Quo</u>

If the peripheral infrastructure is not kept current the following scenarios could potentially occur:

Increase in failure rates; and

Lack of maintenance agreements offered by vendor

<u>Alternatives</u>

The only alternative is to consider leasing the equipment. The lease versus buy decision will be evaluated during the tendering process.

Conclusion:

The ongoing plan involves a coordinated effort to keep Hydro's peripheral infrastructure in good working order and use current technologies while delivering a cost effective solution to the end-user.

<u>Project Schedule</u>

The project is scheduled to start in March 2010 and be completed before December 31, 2010.

Project Title: Replace Peripheral Infrastructure **(cont'd.)**

Future Plans:

Future replacements will be proposed in future capital budget applications. Equipment replacements are planned for the next four years as shown in the five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Replace Radomes
Location: Various Sites
Category: General Properties - Telecontrol
Definition: Pooled
Classification: Normal

Project Description:

To reduce the probability of system outages resulting from radome failure, Hydro has initiated a radome replacement program for the microwave antennas of the corporate network. This is an ongoing program to replace microwave antenna radomes, the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system. The radome replacement program proposed by Hydro is based on operational experience and manufacturer's recommendation. Due to financial and operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimal.

Radomes are replaced at different sites throughout the network each year, depending on age and condition. The radome replacement schedule for 2010-2013 is provided in Appendix A. Eleven radomes are scheduled to be replaced in 2010. Historically, this project has been performed through the joint effort of an external contractor who performs the actual work and internal forces that perform project management and provide technical support. This joint effort will be continued in 2010. 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	27.6	0.0	0.0	27.6
Labour	41.6	0.0	0.0	41.6
Consultant	17.0	0.0	0.0	17.0
Contract Work	75.0	0.0	0.0	75.0
Other Direct Costs	8.4	0.0	0.0	8.4
O/H, AFUDC & Escln.	25.1	0.0	0.0	25.1
Contingency	17.0	0.0	0.0	17.0
TOTAL	**211.7**	**0.0**	**0.0**	**211.7**

Project Title: Replace Radomes **(cont'd.)**

Existing System:

Hydro has a network of microwave radio, by which corporate communications and system data are transmitted. The microwave radio system provides the backbone for all corporate voice and data communications. Traffic carried over the microwave system includes:

- Teleprotection signals for the provincial transmission system;
- Data pertaining to the provincial Supervisory Control and Data Acquisition (SCADA) system;
- Data pertaining to the corporate administrative system; and
- Operational and administrative voice systems.

Microwave radio signals are transmitted from one location to the next using parabolic antennas attached to towers. These antennas are mounted up to heights of 120 meters and range in diameter from 2 meters to 5 meters. At such extreme heights, the antennas are subjected to high wind and ice loading when storms occur, and must be protected. To provide this protection, the delicate components of the antennas responsible for sending and receiving microwave radio signals are covered using a shell known as a radome. These covers are made of advanced plastics known as Hypalon and Teglar that prevent the accumulation of ice and snow which could bend or break these elements. The white cover illustrated in Figure 1 is an example of a radome on an uninstalled antenna.

Figure 1: Microwave Antenna with Radome

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

Damage to radomes can occur in several ways. Exposure to wind, sun, rain, and ice causes the radomes to deteriorate over time. When the radome weakens, tears form in the fabric, as shown in Figure 2. Left unchecked, the tears quickly grow in size (Figure 3) and the material can be torn free by wind. Such tears may result in severe damage to the delicate antenna components.

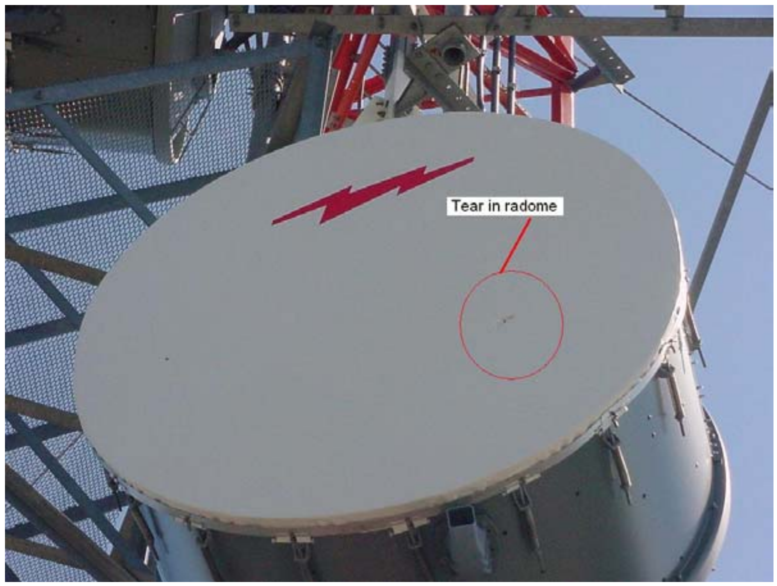


Figure 2: Tear in Radome

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

Figure 3: Heavily Damaged Radome

Other modes of failure are less common. Ice falling from the tower can damage radome components, such as the hardware that hold the radome in place, as shown in Figure 4. Vandalism by the use of shotguns, rocks, or other projectile has also occurred at sites that are accessible by road. Each of these occurrences has the potential to damage the radome and make it prone to complete failure.

Figure 4: Missing Radome Mounts

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

There are 80 radomes throughout Hydro's system. They are installed on towers from St. John's to Deer Lake, and south to Bay d'Espoir. Figure 5 shows Hydro's Telecommunication Network.

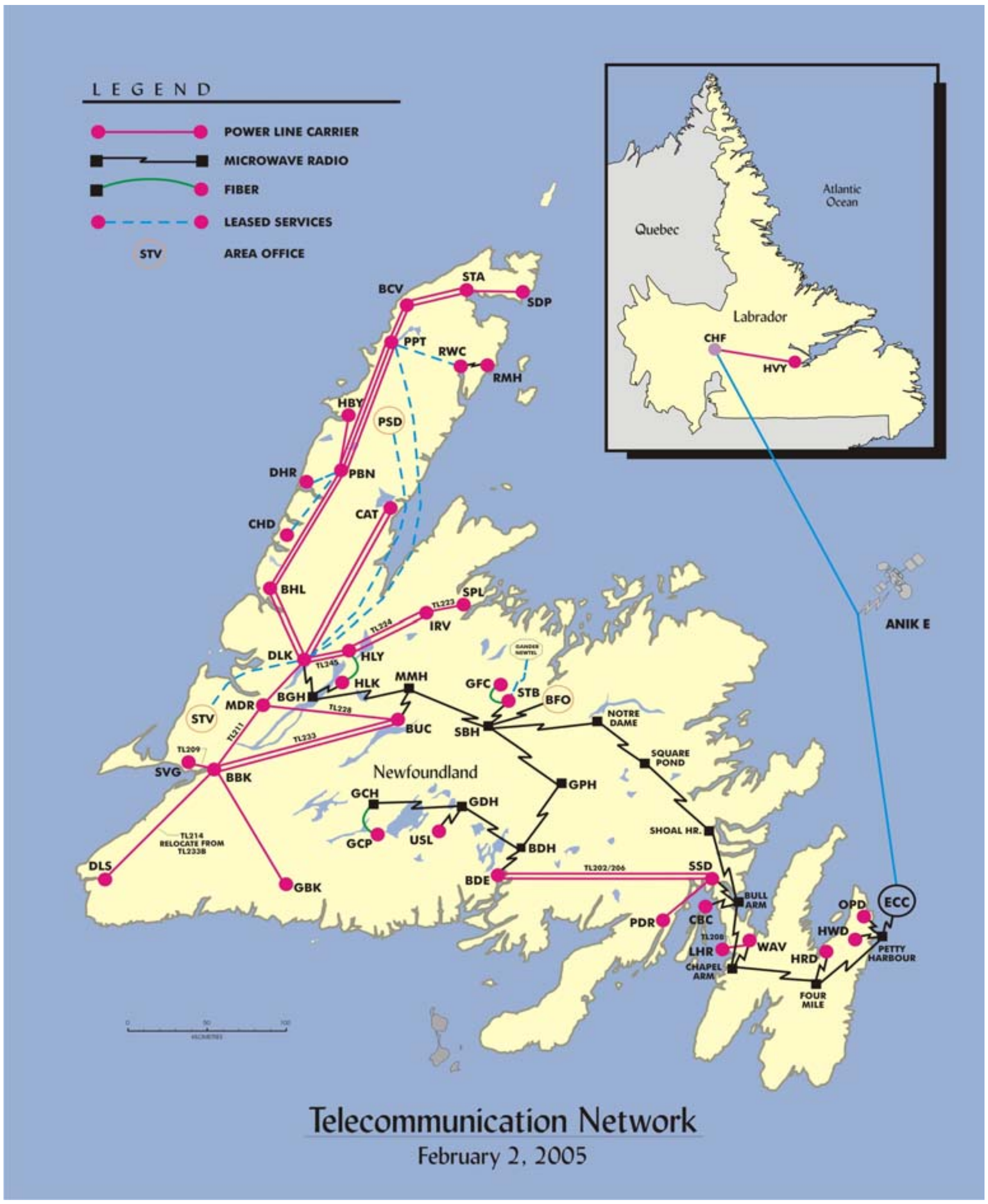


Figure 5: Location of Towers

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment

Refer to the Installed/Last Replaced column of Appendix A for the ages of the radomes being replaced.

Major Work and/or Upgrades

There are no upgrades available for a radome. They must be replaced based upon the estimated useful lives of the individual radomes or upon observed damage during inspection.

Anticipated Useful Life

Hydro's microwave antennas are supplied primarily by two manufacturers, Andrew Solutions and CableWave. Each manufacturer uses a different radome. Radomes used on antennas manufactured by CableWave have a useful life of seven years, and the radomes used on Andrew antennas have a useful life of eight years.

For calculating depreciation expense, radomes are assumed to have an economic life of ten years.

Maintenance History

Radome maintenance consists of inspection when the tower is inspected. Because radomes cannot be repaired, damaged radomes are replaced when identified.

Outage Statistics

In the winter of 1996, a wind storm caused a significant and sustained outage to a part of Hydro's communications network as a result of the failure of two separate radomes at the Sandy Brook Hill and Mary March Hill Microwave Sites. Despite routine inspections, the radomes were torn and the material of the shells became entangled in the antenna feed horns. As a result, critical components at both sites were irreparably damaged and the antennas required replacement. Once the storm cleared and the cause of the outage was identified, antennas could not be replaced until three weeks later, due to lead times

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

associated with material procurement and weather related delays. In total, the microwave radio system was out of service for approximately six weeks. During that time, temporary leased services were procured and installed, resulting in unanticipated labour and materials costs.

<u>Industry Experience</u>

Industry experience information is not available.

<u>Maintenance or Support Arrangements</u>

There are no maintenance or support arrangements associated specifically with radomes. Radome inspection is included as part of an overall periodic tower inspection which occurs annually.

<u>Vendor Recommendations</u>

As a result of the costs and outage time associated with the 1996 storm, personnel from Hydro consulted with manufacturers to develop a proactive radome replacement plan. Based on discussions with representatives from radome manufacturers Andrew Solutions and CableWave, the following conclusions were met:

- CableWave radomes (made of Hypalon material) should be replaced on a seven-year cycle;
- Andrew Solutions radomes (made of Teglar material) should be replaced on an eight-year cycle.

Andrew Solutions radomes, with a slightly longer life, cannot be substituted for CableWave radomes on CableWave antennas on account of the structural differences associated with each type of antenna.

<u>Availability of Replacement Parts</u>

A radome consists of one piece of material with mounting hardware to connect it to an antenna. Mounting hardware is available should a piece be found missing or damaged. If a radome must be replaced, the mounting hardware is typically not re-used on account of wear and tear.

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

Safety Performance

There is no known safety performance issues associated with the radomes.

Environmental Performance

There are no environmental performance concerns or environmental code violations associated with the operation of microwave radomes.

Operating Regime

A microwave antenna, and by extension its radome, is in continuous use and has a 100 percent duty cycle.

Justification:

One of the challenges associated with the development of the radome replacement schedule is that many of Hydro's microwave sites were installed in the same year. For example, during the installation of the East Cost Microwave System in 2001, approximately 20 antennas were installed. To avoid the financial and logistical challenges that would be created by replacing each of these radomes in the same year, Hydro decided that the replacement program for these sites would be distributed over seven years, from 2007 - 2013.

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

The decision to distribute the replacement of radomes presents another obstacle: some radomes will be left in service for periods longer than recommended. In response to this issue, Hydro has initiated an inspection program that allows for the identification of radomes which are torn or otherwise damaged, as illustrated in Figure 2. These radomes must be replaced as soon as the damage is identified to ensure that the integrity of the microwave system is maintained.

The cost of a microwave failure today would be far more significant than the incident of 1996 due to the fact that teleprotection signals, which protect transmission lines in the event of a system disturbance, are now transmitted using the microwave network. Today, protection signals for 17 of Hydro's 24 critical 230 kV transmission lines are carried on the microwave network. Because of this, a microwave failure would cause the Energy Control Centre to lose control of the system stations and likely cause and/or extend customer outages.

<u>Net Present Value</u>

A net present value calculation has not been done as there is only one viable alternative.

<u>Levelized Cost of Energy</u>

As the radomes are not related to generating units, the levelized cost of energy is not applicable.

<u>Cost Benefit Analysis</u>

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

<u>Legislative or Regulatory Requirements</u>

There are no legislative or regulatory requirements associated with radome replacement.

Project Title: Replace Radomes **(cont'd.)**

Existing System: (cont'd.)

Historical Information

Table 2 shows the historical information for the Radome Replacement Program which commenced in 2007.

Table 2: Capital Budget and Expenditures for the Last Five Years

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	129.7		9		
2008	123.8	111.0	9	12.3	
2007[7]	26.9	9.2	1	9.2	Labour only. No replacement.

Forecast Customer Growth

Radomes are not impacted by forecast customer growth.

[7] First year of replacement program.

Project Title: Replace Radomes **(cont'd.)**

Justification: (cont'd.)

Energy Efficiency Benefits

There are no projected energy efficiency benefits related to the replacement of radomes.

Losses During Construction

There is no system outage required for this project.

Status Quo

The status quo is unacceptable. Allowing radomes to stay in service until failure will cause protracted outages on Hydro's communications system and will increase the likelihood of power system outages.

Alternatives

No viable alternatives exist to radome replacement.

Conclusion:

Hydro's Radome Replacement Program is necessary in order to avoid outages caused by radome damage.

The radome replacement program proposed by Hydro is based on operational experience and manufacturer's recommendations. Historically, this project has been executed by external contractors and supported by internal resources and this joint effort will continue in 2010.

Due to financial and operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimal.

Project Title: Replace Radomes **(cont'd.)**

Justification: (cont'd.)

Project Schedule

The proposed project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Milestone
Project Initiation	February 2010
Installation & Commissioning Complete	October 2010
Project Closed	November 2010

Future Plans:

Future replacements will be proposed in future capital budget applications. Radom replacements are planned for the next three years as shown in the five-year capital plan (2010 Capital Plan Tab, Appendix A).

APPENDIX A

2010-2013 Radome Replacement Schedule

2010 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
CAH	FMH-main	2001	3.0m(10')	Andrew	HP10-71D
CAH-div	FMH-div	2001	2.4m(8')	Andrew	HP8-71D
CAH	WAP	2001	2.4m(8')	Andrew	HP8-71D
CAH-main	BAH-main	2001	3.0m(10')	Andrew	HP10-71D
CAH-div	BAH-div	2001	2.4m(8')	Andrew	HP8-71D
WAP	CAH	2001	2.4m(8')	Andrew	HP8-71D
WAP	WAV	2001	2.4m(8')	Andrew	HP8-71D
FMH	HRP	2001	2.4m(8')	Andrew	HP8-71D
PHH-main	FMH-main	2001	3.0m(10')	Andrew	HP10-71D
PHH-div	FMH-div	2001	1.8m(6')	Andrew	HP6-71E

2011 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
STB	SBH	2001	1.8m(6')	CW	DA6-71hp
MMH	BUC	2001	1.8m(6')	CW	DA6-71hp
BAH-main	SHH-main	2004	2.4m(8')	Andrew	HP8-71GE
BAH-div	SHH-div	2004	2.4m(8')	Andrew	HP8-71GE
CBC	BAH	2001	1.8m(6')	Andrew	HP6-71E
SSD	BAH	2001	1.8m(6')	Andrew	HP6-71E
WAV	WAP	2001	1.8m(6')	Andrew	HP6-71E
FMH-main	PHH-main	2001	3.0m(10')	Andrew	HP10-71D
FMH-div	PHH-div	2001	1.8m(6')	Andrew	HP6-71E
FMH-main	CAH-main	2001	3.0m(10')	Andrew	HP10-71D
FMH-div	CAH-div	2001	2.4m(8')	Andrew	HP8-71D

2012 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
GDH-main	GCH-main	2004	3.0m(10')	Andrew	HP10-71D
GDH-div	GCH-div	2004	2.4m(8')	Andrew	HP8-71D
GCH-main	GDH-main	2004	3.0m(10')	Andrew	HP10-71D
GCH-div	GDH-div	2004	2.4m(8')	Andrew	HP8-71D
DLK	DLP	2001	4.5m(15')	Gabriel	SR15-71B
BFI	SBH	2004	2.4m(8')	Andrew	HP8-71GE
NDH-main	SPH-main	2004	3.6m(12')	Andrew	HP12-71E
NDH-div	SPH-div	2004	3.6m(12')	Andrew	HP12-71E
HRP	FMH	2001	2.4m(8')	Andrew	HP8-71D
PHH	HWD	2001	1.8m(6')	Andrew	HP6-71E
PHH	OPD	2001	1.8m(6')	Andrew	HP6-71E
OPD	PHH	2001	1.8m(6')	Andrew	HP6-71E

2013 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
GDH	USL	2004	3.0m(10')	CW	DA10-71hp
GDH	BDH	2004	3.0m(10')	CW	DA10-71hp
MMH	BGH	2004	2.4m(8')	CW	DA8-71hp
MMH	SBH	2004	3.6m(12')	CW	DA12-71hp
BGH	DLP	2004	3.6m(12')	CW	DA12-71hp
BGH	MMH	2004	2.4m(8')	CW	DA8-71hp
SPH-main	NDH-main	2004	3.6m(12')	Andrew	HP12-71E
SPH-div	NDH-div	2004	3.6m(12')	Andrew	HP12-71E
SPH-main	SHH-main	2004	3.6m(12')	Andrew	HP12-71E
SPH-div	SHH-div	2004	3.6m(12')	Andrew	HP12-71E
ECC	PHH	2001	1.8m(6')	Andrew	HP6-71E
HWD	PHH	2001	2.4m(8')	Andrew	HP8-71E

Project Title: Install Mobile Communications

Location: Port Hope-Simpson, Charlottetown
Category: General Properties - Telecontrol
Type: Other
Classification: Normal

Project Description:

The objective of this project is to provide communications to the Diesel System Representatives (DSR) in the communities of Port Hope-Simpson and Charlottetown in Labrador by installing a communications link with the Energy Control Centre in St. John's, and with the regional offices in St. Anthony and Port Saunders. The DSRs in these two communities work as required, i.e. in response to forced outages and for regular maintenance activities. In many cases, when a forced outage occurs, the DSR cannot be reached due to the limited telecommunications facilities in the areas. Cellular telephone is not offered in the area by the cellular service providers due primarily to the lack of a business case, and satellite telephone service has limited coverage in the northern parts of Canada.

This proposal addresses the VHF radio alternatives only, including the expansion of the Newfoundland and Labrador Hydro (Hydro) VHF mobile radio system and the implementation of standalone VHF radio systems in each community. As further described in the Alternatives Section, cellular and satellite telephone are not feasible due to the implementation cost and limited coverage, respectively.

With regards to the expansion of Hydro's VHF mobile radio system, this option has the potential to provide the greatest benefit. Preliminary discussions with the Department of Transportation and Works (DOTW), who also service this area, have resulted in the exploration of cost sharing the expansion. DOTW have expressed interest in at least two additional VHF radio repeater sites to service the Cartwright area and highway onto Happy Valley-Goose Bay. As the use of the highway by Hydro personnel increases, this extended coverage would increase the safety of traveling personnel. In summary, this option presents an opportunity to extend coverage with four new sites at the cost of two new sites. The figures in Appendix A show the VHF radio coverage predictions for the two sites in this proposal as well as the coverage that would be available should DOTW and Hydro agree to cost share the project. This option was not selected due to the cost differential.

Project Title: Install Mobile Communications **(cont'd.)**

Project Description: (cont'd.)

With regards to the implementation of standalone VHF radio systems in each community, this option is the lowest cost alternative. It provides local coverage to each community and a Public Switched Telephone Network (PSTN) interface to enable telephone calls to the Energy Control Center and other regional offices.

The project will involve both internal and external resources, with the majority of work completed by contractors. In addition, Industry Canada approval is required for the use of the radio frequencies. 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	20.0	0.0	0.0	20.0
Labour	48.6	0.0	0.0	48.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	89.0	0.0	0.0	89.0
Other Direct Costs	11.7	0.0	0.0	11.7
O/H, AFUDC & Escln.	21.7	0.0	0.0	21.7
Contingency	16.9	0.0	0.0	16.9
TOTAL	**207.9**	**0.0**	**0.0**	**207.9**

Existing System:

Telecommunications infrastructure currently in place at Port Hope-Simpson or Charlottetown is inadequate for the provision of reliable communications with DSRs. As this project involves the installation of new equipment, there is no relevant information in regards to the following:

- Age of Equipment or System;
- Major Work/or Upgrades;
- Anticipated Useful Life;
- Maintenance History;
- Outage Statistics;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;

Project Title: Install Mobile Communications **(cont'd.)**

Existing System: (cont'd.)

- Availability of Replacement Parts;
- Environmental Performance; and
- Operating Regime.

Safety Performance

With respect to safety, DSRs working on the restoration of power require a back-up communications link to the outside world in case of an accident or incident. In addition, an accident or incident may occur when the DSR is en route to the plant. The proposed mobile communications will provide the DSR with a means to contact emergency personnel if such an accident or incident occurs.

Justification:

This project is justified on the requirement to provide reliable and easily accessible telecommunications for the safety of employees and to enhance Hydro's ability to react to forced outages. The ability for the Energy Control Centre and general public to contact the DSR during a forced outage is paramount in having service restored. Currently, the telecommunications options are limited in the area. The chosen alternative to install a local VHF radio system, although not offering the greatest benefit to employees with respect to ease of access, is the least cost alternative to effectively provide reliable communication to DSRs in the communities of Port Hope-Simpson and Charlottetown.

Net Present Value

As shown in Table 2 below, the cumulative present worth differences is $915,086, less if the local VHF radio option is selected. Please refer to the Cost Benefit Analysis Section below for details.

Levelized Cost of Energy

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

Project Title: Install Mobile Communications **(cont'd.)**

Existing System: (cont'd.)

Cost Benefit Analysis

A cost benefit analysis for this project was performed with two alternatives. Alternative 1, expansion of Hydro's VHF radio system, is the higher cost alternative but offers greater benefits. Alternative 2, installation of a local VHF radio system (consisting of base stations, mobile and portable radios, and telephone interconnect) is the lower cost alternative. The difference is $915,087 in 2009 dollars over an assumed 20-year life of either system. Table 2 below illustrates the results.

Table 2- Alternative Comparison to 2029

Alternative	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
VHF Radio System Expansion	1,127,066	915,086
Local VHF Radio System	211,980	0

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements.

Historical Information

The history of expenditures for similar projects over the past five years is provided in Table 3.

Table 3 – Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2007	8,388.34	7,194.86	1	7,194.86	Replaced existing VHF mobile radio system on Island portion of Province, southern Labrador and Happy Valley-Goose Bay

Forecast Customer Growth

Customer load growth does not affect this project.

Project Title: Install Mobile Communications **(cont'd.)**

Justification: (cont'd.)

Energy Efficiency Benefits

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

Losses During Construction

There will be no losses during construction.

Status Quo

The status quo is unacceptable due to the need to maintain contact with personnel in the Port Hope-Simpson and Charlottetown areas for both safety and operational requirements. Without this mode of communications, forced outages to the diesel plants serving the communities may be impacted due to the inability to contact the DSRs.

Alternatives

This report considered two possible alternatives, both using VHF radio technology. Two other possible alternatives for this Project include the following:

- Cellular telephone; and
- Satellite telephone.

With regards to the cellular telephone alternative, a quotation from Bell Aliant for a cellular telephone repeater site would cost in the range of $800,000 to $1,000,000 per site, or approximately $1.6 - 2.0 million in capital cost for the supply and install only. In addition, the operating cost for cellular service to serve one to two individuals in each community is not feasible.

With regards to the satellite telephone alternative, experience with the use of satellite telephones in Labrador, due primarily to the distance from the satellite(s) (thereby reducing coverage and access to the system) has proven these services as unreliable. The chosen solution of utilizing VHF mobile radio has been shown to be the most cost effective solution to meet the objectives of the project.

Project Title: Install Mobile Communications **(cont'd.)**

Conclusion:

This project is required in order to provide reliable and easy-to-use communications to Hydro personnel located in southeast Labrador. The communications are needed to ensure that the DSRs in the communities of Port Hope-Simpson and Charlottetown can be reached in a timely manner by the Energy Control Centre in St. John's during forced outages. Currently, the DSR has to be stationed either at the generation station or at home for this to be possible, as there are no cellular services available and satellite services are unreliable. This report proposes to proceed with the option of implementing a standalone VHF radio system to cover these communities. Each system will also provide an interface to the PSTN to enable the DSR to make and receive telephone calls using the VHF radio.

Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	**Milestone**
Project Initiation Complete	February 2010
Design and Procurement Complete	May 2010
Installation and Commissioning Complete	September 2010
Project Closed	November 2010

Future Plans:

None.

APPENDIX A

Coverage Predictions

Southeast Labrador VHF Coverage Predictions

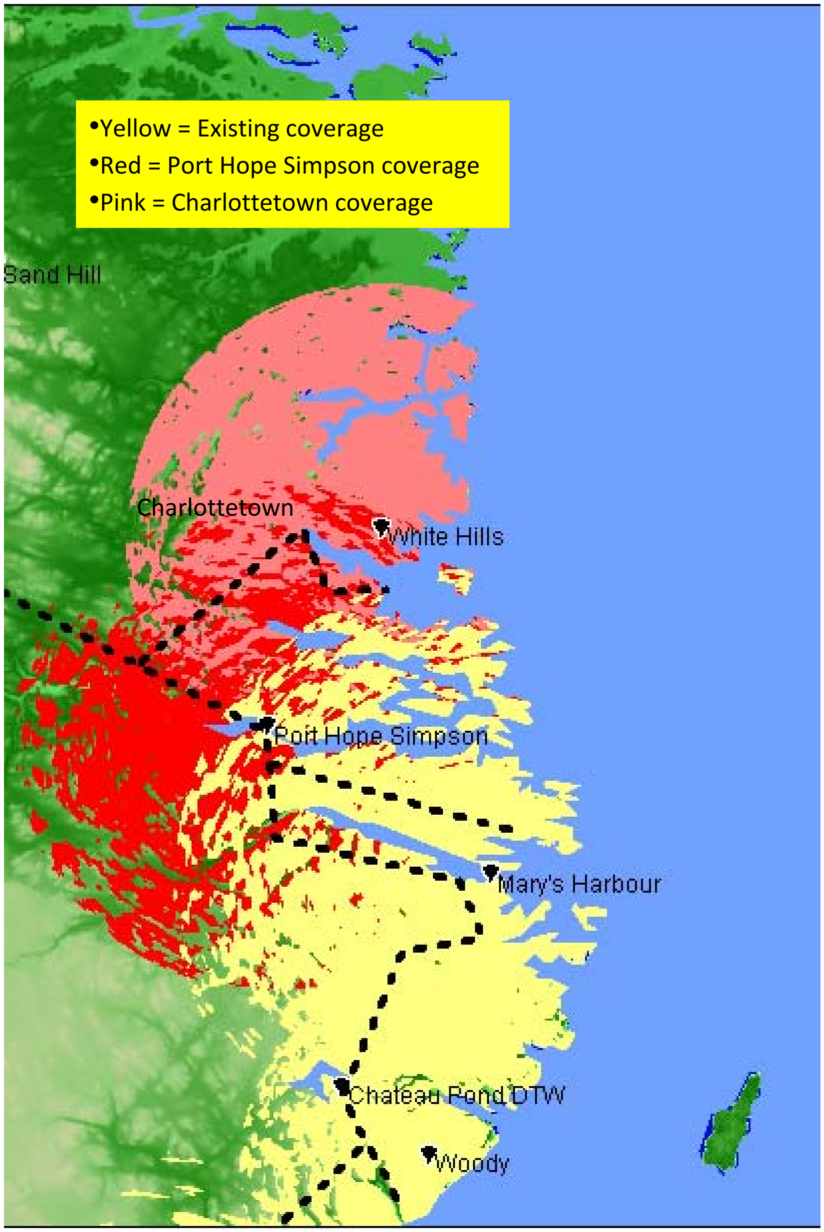


Figure A1 – VHF Coverage Prediction for Port Hope Simpson and Charlottetown

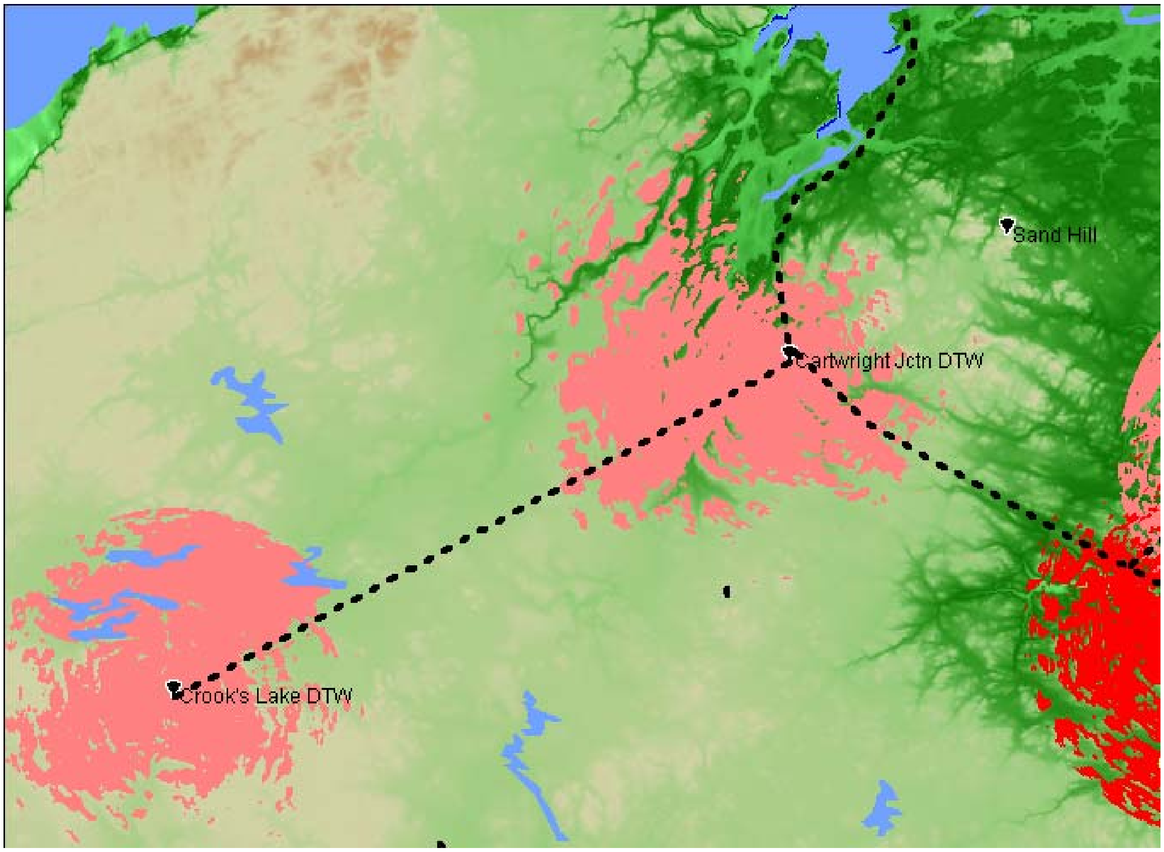


Figure A2 –VHF Coverage Prediction for Trans Labrador Highway in southeast Labrador

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
		($000)			
GENERATION					
Replace A/C Units in Control Room and Communications Room - Upper Salmon		197		197	D-3
Install Warm Air Make-up Access - Holyrood		170		170	D-6
Replace Human Machine Interface (HMI) Computer - Paradise River		158		158	D-10
Upgrade Fuel Storage - Hinds Lake		149		149	D-12
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir		81		81	D-15
Purchase 21 Inch Metal Cutting Lathe - Bay d'Espoir		80		80	D-18
Upgrade Fuel Tank Farm Controls - Happy Valley		72		72	D-20
Improve On Site Paving and Drainage - Holyrood		59		59	D-26
TOTAL GENERATION	0	967	0	967	
TRANSMISSION AND RURAL OPERATIONS					
Replace Disconnects - Various Sites		199		199	D-29
Install Fall Protection Equipment - Various Sites		198		198	D-32
Replace Instrument Transformers - Various Sites		197		197	D-42
Upgrade Accommodations - Norman Bay		196		196	D-44
Upgrade Great Northern Peninsula Protection - Various Sites	101	91		192	
Install New Voltage Regulators - Happy Valley		170		170	D-47
Replace Heavy Duty Forklift - Unit 9799 - Bishop's Falls		166		166	D-52
Install Digital Fault Recorder - Deer Lake		166		166	D-54
Upgrade Fire Protection System - Bishop's Falls		158		158	D-57
Replace Main Bus Splitter - Postville		149		149	D-59
Replace Air Compressors - Western Avalon		97		97	D-65
Install Pole Storage Ramps - Various Sites		90		90	D-68
Install Transformer Storage Ramps - Various Sites		89		89	D-70
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls		88		88	D-74
Install Waste Oil Storage Tank - Port Hope Simpson		84		84	D-77
Replace Surge Arrestors - Various Sites		73		73	D-80
Replace 230 kV Breaker Controls - Massey Drive and Buchans		73		73	D-82
Upgrade Properties - Port Hope Simpson		71		71	D-86
Legal Survey of Primary Distribution Line Right of Way - Various Sites		65		65	D-89
Install Remote Ice Growth Detector Beams - Various Sites		58		58	D-93
TOTAL TRANSMISSION AND RURAL OPERATIONS	101	2,479	0	2,580	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Page Ref
		($000)			
GENERAL PROPERTIES					
Upgrade Remote Terminal Units - Various Sites		190		190	D-96
Upgrade Enterprise Storage Capacity - Hydro Place		169		169	D-103
Upgrade Server Technology Program - Various Sites		138		138	D-107
Replace Network Communications Equipment - Various Sites		131		131	D-112
Develop Learning Management System Safety Courses - Hydro Place		96		96	D-114
Smart Card Implementation - Various Sites		93		93	D-116
Upgrade Operator Training Simulator - Hydro Place		92		92	D-118
Perform Minor Application Enhancements - Hydro Place		85		85	D-120
Replace Humidifiers in Air Handling Units - Hydro Place		75		75	D-122
Upgrade Security SCADA Intrusion Prevention System - Hydro Place		62		62	D-124
Upgrade Business Intelligence Toolset Software - Hydro Place		59		59	D-126
Upgrade Security Vulnerability Management System - Hydro Place		57		57	D-127
Work Protection Software Design - Hydro Place		50		50	D-129
Upgrade Intranet - Hydro Place		46		46	D-132
TOTAL GENERAL PROPERTIES	0	1,342	0	1,342	
TOTAL PROJECTS OVER $50,000 AND UNDER $200,000	101	4,788	0	4,888	

Project Title: Replace A/C Units in Control Room and Communications Room
Location: Upper Salmon
Category: Generation - Hydraulic
Definition: Other
Classification: Normal

Project Description:

This project is required to replace two air conditioning units located at the Upper Salmon Generating Station powerhouse with similar new air conditioning units. One unit provides cooling and heating for the plant communications room and the second unit provides cooling and heating for the plant control room. The project is estimated to cost $197,200 as show in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	1.5	0.0	0.0	1.5
Labour	55.7	0.0	0.0	55.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	96.3	0.0	0.0	96.3
Other Direct Costs	8.7	0.0	0.0	8.7
O/H, AFUDC & Escln.	18.8	0.0	0.0	18.8
Contingency	16.2	0.0	0.0	16.2
TOTAL	**197.2**	**0.0**	**0.0**	**197.2**

Operating Experience:

The two existing air conditioning units have been in service since the plant was commissioned in 1983. They have reached the end of their useful lives of 25 years. Hydro contacted a local vendor, Heating Products (1978) Limited and was informed that the air conditioning units are obsolete. The combined five-year maintenance history for the units is shown in Table 2. The maintenance costs include the purchase and replacement costs of main components shown in Table 3.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.00	0.00	0.00
2007	0.00	3.91	3.91
2006	1.50	4.85	6.35
2005	1.96	0.45	2.41
2004	1.50	0.78	2.28

Project Title: Replace A/C Units in Control Room and Communications Room **(cont'd.)**

Operating Experience: (cont'd.)

Table 3: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2007	Replace heating element	Air conditioner in the Communications Room
2006	Replace compressor	Air conditioner in the Communications Room
2006	Replace compressor	Air conditioner in the Control Room
2004	Replace blower motor	Air conditioner in the Control Room

Preventive maintenance consisting of operational checks on the air conditioning units is usually done prior to the summer season. The purpose is to identify potential problems before the summer cooling season begins in order to reduce the number of unexpected breakdowns of the air conditioning units. However, breakdowns have been experienced as indicated in Table 4. These incidents are directly related to the replacement of the main components as listed in Table 3.

Table 4: Breakdowns of Air Conditioning Units

Year	Incident
2007	Low temperature alarm indicating loss of heating element
2006	Inoperable compressor unable to circulate refrigerant
2006	Internal electrical grounding and loss of refrigerant pressure
2004	Irreparable blower unable to supply heating to room

Justification:

Communication and plant control equipment produce heat during operation. It is critical that excessive heat be removed to prevent overheating and potential failure of critical plant controls or communications equipment, which could lead to a plant outage or loss of remote monitoring and control from the Energy Control Centre. It is the job of the air conditioning units to remove this extra heat and maintain a safe operating temperature to help ensure equipment overheating does not occur. Over the past five years, main components of the air conditioning units as shown in Table 3 have failed. The failures have resulted from the units reaching the end of their useful lives. Besides

Project Title: Replace A/C Units in Control Room and Communications Room **(cont'd.)**

Justification: (cont'd.)

the main components, auxiliary components such as the evaporator, internal tubing, internal electrical system and unit housing are at risk of failure. Since the air conditioning units are obsolete, they cannot be considered reliable. This project is justified on the need to provide reliable air conditioning equipment to reduce the risk of communication and control equipment failure that could result in a plant outage. Given the age of the existing equipment the status quo is unacceptable due to the increased risk of failure. There are no viable alternatives to this project.

Future Plans:

None.

Project Title: Install Warm Air Make-up Access
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description:

This project is required to provide exterior access to six warm air make-up enclosures attached to the north and south sides of the Holyrood Thermal Generating Station (Holyrood) Power House, as shown in Figures 1 and 2. Access will be provided by constructing a galvanized steel stairway on the outside of the power house. The stairway will be mounted on a concrete foundation and have a platform at the top. Access to the enclosures will be gained by installing a steel door into the existing exterior wall. A total of six staircases will be constructed, one for each enclosure.

The project is estimated to cost $170,400 as is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	16.1	0.0	0.0	16.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	124.5	0.0	0.0	124.5
Other Direct Costs	1.0	0.0	0.0	1.0
O/H, AFUDC & Escln.	14.6	0.0	0.0	14.6
Contingency	14.2	0.0	0.0	14.2
TOTAL	**170.4**	**0.0**	**0.0**	**170.4**

Operating Experience:

The warm air make-up system was installed in 1992 to provide the Holyrood power house with fresh warm air to improve power house air quality and to reduce vacuum pressures within the plant created by the combustion air required by each generating unit. Prior to 1992, the issue was dealt with by opening the ground level overhead doors, which created an uncontrollable, and cold climate within the power house.

Each of the three generating units has two two-storey warm air make-up enclosures. Three of the enclosures are located on the north side of the power house, and three are located on the south side

Project Title: Install Warm Air Make-up Access **(cont'd.)**

Operating Experience: (cont'd.)

of the power house. The warm air make-up system is used to balance air pressures within the power house during the operation of the generating units. The enclosures are two-storey because they consist of an intake and an outlet, separated by elevation.

Project Justification:

This project is justified on the requirement to provide safe access to a confined space. The second floor rooms are considered confined spaces because current access is through a small opening in the concrete floor, accessed from a vertical ladder at the first floor of the enclosure. If a worker suffers an injury or illness while on the second level of the warm air make-up enclosure, that person cannot get out because of the restricted means of access and egress. As a result, a specialized rescue team must be hired to set up at the work location and be ready to remove a worker from the enclosure. These rescue operations are complex and expensive. The Remote Access Technology rescue team is on site for an average of 13 days per year, at a cost of $1,500 per day. Thus the total annual cost is approximately $19,500. This project pays for itself in 12 years.

Occupational Health and Safety, OHS Regulations, 2007 (Draft) Clause 509.(3).(b)
"(3) confined space means an enclosed or partially enclosed space that has restricted means of access and egress."

The confined space issue is not due to the availability of fresh air, the confined space issue is due to limited means of egress through a small opening in the floor that leads to a vertical ladder. The staircase will provide immediate egress from the second floor onto a landing and efficient, unrestricted access to the ground level. The implementation of external access will eliminate the confined space designation.

Future Plans:

None.

Project Title: Install Warm Air Make-up Access **(cont'd.)**

Figure 1 - Warm Air Make-Up Enclosures, South Side of Power House.

Project Title: Install Warm Air Make-up Access **(cont'd.)**

Figure 2 - Warm Air Make-Up Enclosures, North Side of Power House.

Project Title: Replace Human Machine Interface (HMI) Computer
Location: Paradise River
Category: Generation - Hydraulic
Definition: Other
Classification: Normal

Project Description:

The purpose of this project is to replace the Human Machine Interface (HMI) software and the computer hardware and peripherals at the Paradise River Generating Station. The new computer hardware will be suitable for an industrial environment. The HMI program software, currently offered by GE Fanuc Intelligent Platforms (GE Fanuc)[1], will be upgraded to the iFIX 5.0 version. The license shall include GlobalCare Support[2] with an on-line knowledge center, software service packs, product fixes and phone support. The HMI software upgrade will provide enhanced displays of plant operations, new software licenses, added engineering features to make future modifications, if required, and HMI software training for Hydro personnel. The estimated cost for this project is outlined in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	55.6	0.0	0.0	55.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	52.2	0.0	0.0	52.2
Other Direct Costs	16.1	0.0	0.0	16.1
O/H, AFUDC & Escln.	19.3	0.0	0.0	19.3
Contingency	12.6	0.0	0.0	12.6
TOTAL	**157.8**	**0.0**	**0.0**	**157.8**

Operating Experience:

The HMI computer is used by the plant operator to display machine operating status along with any alarm conditions. If communications from the Energy Control Center is interrupted or there is a need to control the plant at site, the operator can control the plant through the HMI. The HMI computer and the GE Fanuc Programmable Logic Controller (PLC) provide automated control of the plant when the operator is controlling it at site. If the HMI is not available for local control, the operator will have to use the manual controls. Manual control is used as an emergency backup to control the plant when no HMI or PLC is available.

[1] GE Fanuc is a joint venture between General Electric (NYSE:GE) and FANUC Ltd. Of Japan. The company, which is part of GE Enterprise Solutions, is a global provider of hardware and software used in automation and embedded computing.
[2] Technical support and maintenance service developed by GE Fanuc to support their hardware, software and machine tool products.

Project Title: Replace Human Machine Interface (HMI) Computer **(cont'd.)**

Operating Experience: (cont'd.)

In September 2007 the HMI computer at the Paradise River Generating Station malfunctioned. Hydro personnel retrieved data from the computer hard drive before any changes to the computer were attempted. At the time, the printer and monitor screen were replaced. Efforts were made to apply updates to the computer operating system; however, the computer hard drive failed after two reboots and had to be replaced due to bad sectors. A Central Processing Unit (CPU) fan was added to the computer to prevent overheating and the last available updates to the computer operating system were made.

Project Justification:

The original Intellution HMI software has not been updated since its 1998 installation. GE Fanuc purchased Intellution in 2002. The version of HMI software and single license exists only at the Paradise River Generating Station. The original HMI software is no longer supported by GE Fanuc. Also, Hydro has no support agreement from GE Fanuc through the GlobalCare program.

The new iFIX 5.0 HMI software can be used with Microsoft XP or Vista operating systems. The Microsoft Windows NT 4.0 Server for the Paradise River HMI computer is obsolete. The computer, with its Windows operating system, was originally installed in 1998. Microsoft provided the last full service package in November 1999 and stopped providing security updates in December 2004. The computer operating system is quite old and not compatible with the new HMI software. Future computer hardware failures are also likely due to age.

Future Plans:

None.

Project Title: Upgrade Fuel Storage
Location: Hinds Lake
Category: Generation - Hydraulic
Definition: Other
Classification: Mandatory

Project Description:

This project is required to install a new 7,000 litre double wall horizontal bulk storage fuel tank and a new 900 litre double wall day storage fuel tank at the Hinds Lake Generating site. The installation consists of a new concrete pad foundation, a bulk storage tank, a day tank, all associated piping and required site work. A special day tank or modifications to the diesel building may have to be made to enable a proper day tank to be installed. Sufficient control and monitoring must be installed for automatic pump operation, and fuel tank monitoring. The piping system between the diesel room and the main bulk tank must be a properly closed loop system to ensure no fuel spillage should a malfunction occur in the fuel pumping system.

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	46.0	0.0	0.0	46.0
Labour	45.7	0.0	0.0	45.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	11.3	0.0	0.0	11.3
Other Direct Costs	17.3	0.0	0.0	17.3
O/H, AFUDC & Escln.	16.8	0.0	0.0	16.8
Contingency	12.0	0.0	0.0	12.0
TOTAL	**149.1**	**0.0**	**0.0**	**149.1**

Operating Experience:

As part of Hydro's Environmental Management System, a committee annually reviews the fuel storage tank systems in their regions in order to determine which tanks may require cleaning, inspection, or replacement. The tanks in Hinds Lake were noted to be past their useful life and were not in compliance with GAP regulations. The existing bulk storage tank was installed in 1979. It is a single wall tank installed inside a concrete dyke constructed to contain fuel in the event of a leak. Hydro's

Project Title: Upgrade Fuel Storage **(cont'd.)**

Operating Experience: (cont'd.)

current standard for fuel storage tanks is a double wall, vacuum sealed tank design. The existing tank does not conform to the current standard for fuel storage, and is past its useful life of 20 years. The dyke continuously fills up with ice and snow during the winter months reducing the secondary containment beyond acceptable limits stipulated by the Storage and Handling of Gasoline and Associated Products (GAP) Regulations, 2003. In addition, when the ice and snow melts in the spring, the water drains through the floor drain in the dyke and into the oil/water interceptor in the powerhouse, reducing its capacity for leak containment. The intended use and design of the oil/water interceptor is to handle any water/oil mixture that results from spills or leaks from within the powerhouse. The runoff from the dyke reduces its capacity to perform as intended. Through the Fuel Storage Enhancement Program, bulk storage tanks in Cat Arm, Upper Salmon (three sites), Burnt Dam, and Ebbegunbaeg have been replaced with new double wall tanks. The historical costs for Fuel Storage Enhancement Program are shown in Table 2. A similar project for the replacement of the fuel storage tank in Cartwright, Labrador was approved by the Board in Order P.U. 36 (2008) with a budget cost of $139,100.

Table 2: Historical Costs

Location	Year	Capital Budget ($000)	Actual Expenditures ($000)
Cat Arm	2006	149.5	134.0
Upper Salmon	2005	327.0	329.0
Burnt Dam - Ebbegunbaeg	2003	97.4	96.0

Note: Burnt Dam/Ebbegunbaeg had one new bulk tank installed, and a second bulk tank relocated. Upper Salmon had a new bulk tank and new day tank installed at three separate sites. Cat Arm had one new bulk tank installed.

Project Justification:

This project is justified on the need to conform to the GAP regulations and mitigate the risk of

Project Title: Upgrade Fuel Storage **(cont'd.)**

Project Justification: (cont'd.)

environmental damage. The Storage and Handling of Gasoline and Associated Products (GAP) Regulations, 2003 state in Section 27.(8)(a) "where a dyked area contains only one storage tank, the dyked area shall retain not less than 110% of the capacity of the tank". The existing system is not in compliance with these regulations during the winter months. In addition, as the bulk storage tanks in the system exceed their useful lives, maintenance and repair work will start to increase. The environmental risks increase as the tank deteriorates, and the existing design is not up to Hydro's standard and does not meet GAP regulations. This is the last of the fuel tank systems to be replaced.

Future Plans:

None.

Project Title: Install Gain Heaters Gate 2 Burnt Dam Spillway
Location: Bay d'Espoir
Category: Generation - Hydraulic
Definition: Other
Classification: Normal

Project Description:

This project consists of the installation of four gain heaters on Gate 2 in the Burnt Dam Spillway. The heaters will be installed in the existing gain heater ducts on the upstream and downstream sides of the gate. Gate 2 is not presently equipped with heaters. 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	30.0	0.0	0.0	30.0
Labour	30.0	0.0	0.0	30.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.5	0.0	0.0	4.5
O/H, AFUDC & Escln.	10.3	0.0	0.0	10.3
Contingency	6.0	0.0	0.0	6.0
TOTAL	**80.8**	**0.0**	**0.0**	**80.8**

Operating Experience:

The Burnt Dam Spillway is located on Burnt Pond between the Victoria Control Structure and Granite Lake. The spillway is a two gate structure used to control and manage water levels in the Bay d' Espoir Reservoir System by spilling water into White Bear River when the reservoir water levels get too high for the design level of the reservoir's dams and dykes.

The structure was constructed in the 1960's as part of the Bay d' Espoir Reservoir Development. The structure has two control gates, similar in design, which have gain heating ducts on the upstream and downstream sides of the gate. Presently, the gates at Burnt Dam have gain heating on Gate 1 and no heating on Gate 2. The heating system on Gate 1 has required little maintenance, with the average heater element requiring replacement every 10 to 15 years.

Project Title: Install Gain Heaters Gate 2 Burnt Dam Spillway **(cont'd.)**

Operating Experience: (cont'd.)

The Burnt Dam spillway gates are not normally operated in winter. If a quick period of mild weather occurs, however, and especially if it coincides with precipitation as happened as recently as 2006, winter operation is required. Burnt Pond is a very flashy reservoir, in that the water level rises very quickly following water inflow caused by precipitation or melting of the snowpack. If the heated gate (Gate 1) cannot be raised for any reason and Gate 2 cannot be raised because it is frozen in ice, the water level will quickly rise to a critical level due to the flashy nature of the reservoir The fusible plug will activate, spilling water to prevent dams from overtopping. Additionally, if the flows are large enough to constitute a relatively large flood, the single heated gate will not be able to pass the flow, also resulting in the activation of the fusible plug. This fusible plug, which is actually a section of the dam designed to fail when water levels reach a prescribed level, will, until it is repaired, isolate Victoria reservoir and prevent that water from being conducted through the Bay d'Espoir system. Until the fusible plug is replaced, the capacity of the hydroelectric plants at Granite Canal, Upper Salmon and Bay d'Espoir will be limited. As the Victoria basin represents approximately 30 percent of the storage and approximately 20 percent of the drainage area in the Bay d'Espoir system, the energy producing potential of the system will be severely impacted. Water will also have to be spilled from the Burnt and Victoria basins until the fusible plug is restored.

Reconstruction of the fusible plug and consequential damage is expected to be in the order of $3 to $5 million. A substantial portion of the cost will be associated with mobilization to such a remote site during the anticipated winter conditions after a major flood event and the processing of materials to execute the repair during the winter season.

Project Justification:

Spillway control gate operation is required to be available for operation at all times and in all weather conditions in order to manage water levels in the reservoir system. Gain heaters are electrical heating elements specifically designed to fit into special gain heating ducts in the control gates and provide heating to the interior of the gate. This heating prevents ice build-up and allows for the free operation of the gate during freezing conditions.

Project Title: Install Gain Heaters Gate 2 Burnt Dam Spillway **(cont'd.)**

Project Justification: (cont'd.)

The Burnt Dam Spillway is in a remote location and because of the critical nature of the structure within the Bay d'Espoir reservoir, reliable operation of both structure gates is essential during all weather conditions to manage the worst case water level scenario in the reservoir. Installation of gain heaters in Gate 2 is therefore required to meet this operating criterion.

Future Plans:

None.

Project Title: Replace 21-inch Stanly Metal Cutting Lathe
Location: Bay d'Espoir
Category: Generation - Tools and Equipment - Hydraulic
Definition: Other
Classification: Normal

Project Description:

This project is required to replace the 21-inch Stanley Metal Cutting Lathe with a new 21-inch Colchester Lathe at the Bay d'Espoir Generating Station. 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	78.8	0.0	0.0	78.8
Labour	0.0	0.0	0.0	0.0
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.	1.2	0.0	0.0	1.2
Contingency	0.0	0.0	0.0	0.0
TOTAL	**80.0**	**0.0**	**0.0**	**80.0**

Operating Experience:

The existing lathe is over 30 years old and has become obsolete. It is experiencing mechanical problems that affect its precision and accuracy. The gearing, drive mechanism and carriage have worn and spare parts are difficult to obtain. The vendor, Rideout Tool and Machine Incorporated, said they are unable to source parts for this machine. The lathe is essential to Hydro's operation as it is used almost on a daily basis to fabricate parts for routine maintenance. It is also used during generating unit overhaul and other major projects such as machining wicket gates for units 1 - 6 at the plant.

Project Justification:

This project is justified on the need to ensure that accurate parts can be machined for the reliable operation of the generating units at Bay d'Espoir. The lathe is used regularly to machine wicket gates, bushings, rollers and fabricate precision parts for equipment associated with the turbine and generator units and spillway control structures. The present lathe is starting to loose it's accuracy due to worn components. Without this critical piece of machinery, Hydro is subjected to inaccurate

Project Title: Replace 21-inch Stanly Metal Cutting Lathe **(cont'd.)**

Project Justification: (cont'd.)

machining and downtime. To have machining performed externally, downtime could last between two days to a month depending on the size of the piece of equipment required.

Future Plans:

None.

Project Title: Upgrade Fuel Tank Farm Controls
Location: Happy Valley
Category: Generation - Gas Turbines
Definition: Other
Classification: Normal

Project Description:

This project is required to upgrade the fuel tank farm controls and integrate the system with the gas turbine control system. 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	14.0	0.0	0.0	14.0
Labour	42.0	0.0	0.0	42.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	5.0	0.0	0.0	5.0
O/H, AFUDC & Escln.	8.3	0.0	0.0	8.3
Contingency	3.1	0.0	0.0	3.1
TOTAL	**72.4**	**0.0**	**0.0**	**72.4**

Operating Experience:

The fuel supply control system is no longer functioning properly. This project is required to resolve the following issues:

1. The fuel level monitor for tank 1 failed resulting in the need for an additional person besides the operator to attend to fuel delivery.
2. Both the fuel tank monitoring equipment and the programmable logic controller (PLC) are obsolete.
3. The automation logic and associated equipment need to be changed to add operating mode indication to enhance the operation of the fuel tank control system. Presently, the operating mode status is not available to the PLC for discernment between a manually operated valve and an inoperative valve.
4. Present fuel supply operation presents an environmental risk of fuel spillage in that all three valves are opened when the gas turbine is required. Each tank has a dyke which can hold the volume of one tank. Should a leak occur while all valves are open, the other tanks would empty into the leaking tank thus overflowing the dyke. A fully operational fuel control system would operate valves as required.

Project Title: Upgrade Fuel Tank Farm Controls **(cont'd.)**

Operating Experience: (cont'd.)

5. The fuel tank farm system information is not presently linked to the gas turbine control system operator interface. The operator, therefore, does not have a display of fuel tank farm conditions while operating the gas turbine.

Because the fuel level monitoring for tank 1 has failed, the amount of fuel in the tank cannot be indicated at the fuel delivery station which is approximately 160 metres from the tank. During tank filling, the operator and another worker are required to be present; one at the tank and the other at the delivery station. This project will relieve the local operator of attending to the fuel supply and allow for his full concentration on the operation of the plant.

There are three fuel tanks for the Happy Valley Gas Turbine each of which can hold fuel to supply the gas turbine for eight hours based on the gas turbine operating at full load. Each tank has a motorized valve that can be operated locally or remotely. A device on the valve called an actuator serves as its electrical control and the means for remote operation. Figure 1 shows the tank farm and location of the valves and actuators.

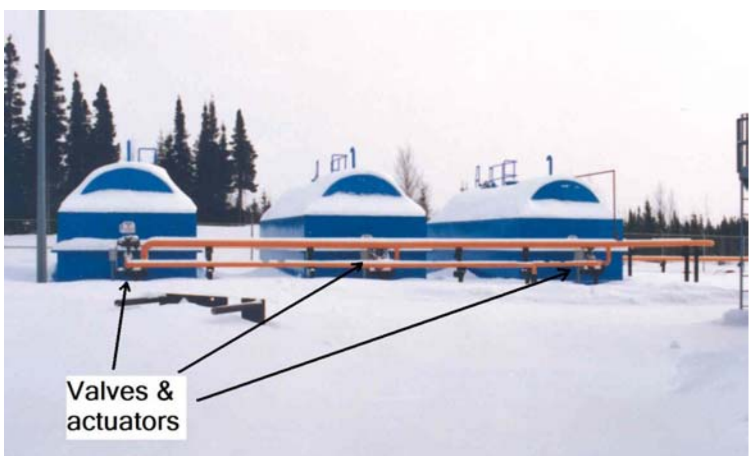


Figure 1: Happy Valley Tank Farm

During the installation of the gas turbine in 1992, the tank farm was equipped with a fuel control system to automatically select fuel supply from either tank based on fuel levels. Figure 2a shows the enclosure that houses the tank level indication meters and Figure 2b shows the controller inside. This enclosure is situated in the gas turbine control system building but outside of the control room.

Project Title: Upgrade Fuel Tank Farm Controls **(cont'd.)**

Operating Experience: (cont'd.)

Figure 2a: Enclosure

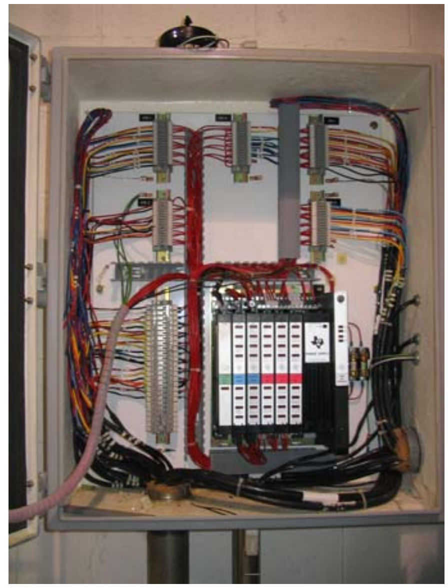


Figure 2b: Controller

The enclosure, shown in Figure 3, located at the fuel delivery station provides the fuel delivery operator an indication of the fuel level and a switch to select which tank to fill. This device interfaces with the tank level indication meters (Figure 2a) and the controller (Figure 2b).

Figure 3: Enclosure

Project Title: Upgrade Fuel Tank Farm Controls **(cont'd.)**

Operating Experience: (cont'd.)

At the time of installation, the actuators could only provide an indication of a fully open or fully closed valve. The valves operate either manually or automatically. Automatic, or remote control, can be turned off through a switch on an actuator.

The control system was programmed to operate such that if one of the valves was placed in manual mode, in the event of trouble with that particular valve, the control system, upon attempting to open or close it and not receiving acknowledgement of the required action, would identify that valve as inoperative. This was necessary as there was no way of knowing if the valve was operated manually or had jammed thereby failing to fully open or close. If all three valves were used manually while the control system was attempting to change tanks, the control system would eventually identify all three tanks as unavailable and trip the gas turbine. Upon returning the valve to automated service, its status was reset to normal automatic operation by the action of the operator pressing a pushbutton on the PLC cabinet. If the procedure to reset the valve condition was overlooked, the tank would remain unavailable to deliver fuel to the gas turbine although capable to do so. This project will eliminate the need for resetting control logic conditions. There is a need for operating mode status (automatic, manual) from each actuator to be brought into the controller. An auxiliary relay is to be mounted in each actuator junction box for this purpose. Figure 4 shows a picture of a fuel tank valve, actuator and associated junction box.

Figure 4: Fuel tank valve, actuation and associated junction box

Project Title: Upgrade Fuel Tank Farm Controls **(cont'd.)**

Operating Experience: (cont'd.)

The level indication meter for tank 1 failed as can be seen by its absence in Figure 2a. It is an obsolete unit that is no longer available. To replace it with another of similar functionality requires both a new transmitter on the tank as well as a new meter. The absence of level monitoring also prevents remote indication of tank levels to Hydro's Energy Control Center. Without local and remote fuel level indication, the local operator has to physically check the tank levels and consistently monitor consumption. This is not an optimal operating situation in that the operator has to leave the control area to check the tanks and manually switch the valves to maintain consistent fuel delivery to the gas turbine and be present to monitor refilling. The control system has been removed from service until it can be made fully operational.

The fuel tank farm Programmable Logic Controller (PLC) is obsolete and has not been supported by the manufacturer since 2003.

At present, when the gas turbine is required for generation, all three valves are opened so that the operator does not have to alternate the supply between tanks. This requires particular operator attention as each tank has its own dyke for leak containment but it can only hold the volume of one tank. When all three valves are open, and if a leak in one tank occurs, the other two tanks will supply sufficient volume of fuel to overload the dyke of the faulty tank. This presents an environmental concern.

A control system graphic representing the fuel tank farm will be added to the gas turbine operator interface to provide the local operator with a visual indication of the tank farm levels and operating conditions. Figure 5 is a preliminary representation of this graphic.

Project Title: Upgrade Fuel Tank Farm Controls **(cont'd.)**

Operating Experience: (cont'd.)

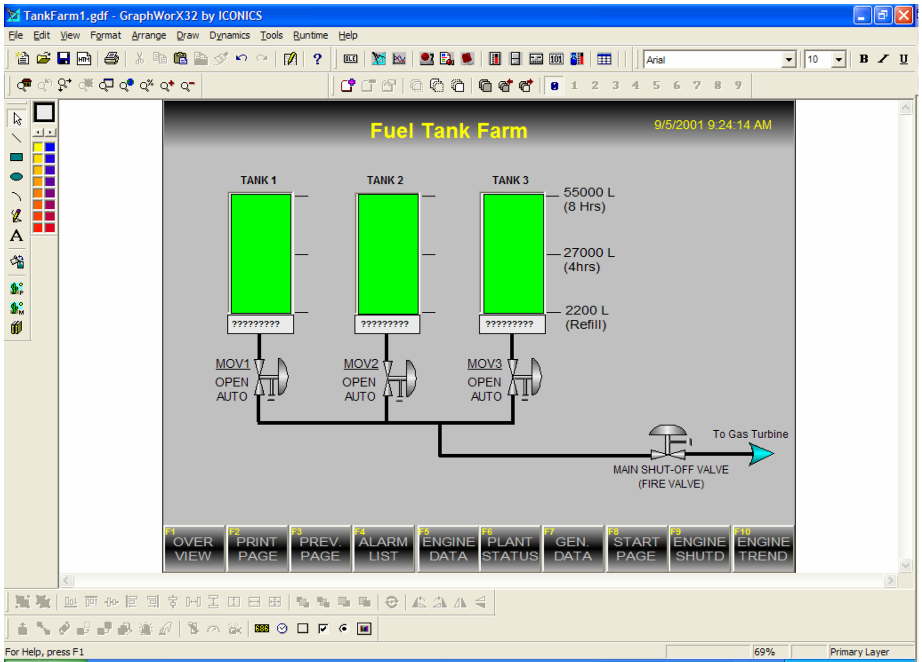


Figure 5: Control System Graphic

Project Justification:

This project will improve the functionality of the fuel tank farm controls, replace the PLC, increase confidence of availability for both local and remote operation of the gas turbine, address any environmental concern relating to fuel supply procedures, provide the local operator with tank farm information at the gas turbine console and relieve the local operator of manually attending to the fuel delivery system while operating the gas turbine. This project will return the fuel tank control system to its originally intended purpose with additional functionality and reporting features.

Future Plans:

None.

Project Title: Improve On Site Paving and Drainage
Location: Holyrood
Category: Generation - Thermal
Definition: Other
Classification: Normal

Project Description:

This project is required to install three catch basins and associated pipe, to install asphalt paving, and to make improvements to the finished grade around the high traffic areas of the Holyrood Generating Station Powerhouse. Two catch basins will be installed on the east side and one on the north side of the powerhouse. Due to the proximity of a dense array of buried utilities on both the north and east sides, there is a requirement for shallow burial of approximately 170m of high strength 200mm diameter PVC storm water drain pipe. The high strength PVC pipe shall be placed within approximately 600mm of the ground surface. 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	0.0	0.0	0.0	0.0
Labour	7.8	0.0	0.0	7.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	39.8	0.0	0.0	39.8
Other Direct Costs	1.0	0.0	0.0	1.0
O/H, AFUDC & Escln.	5.8	0.0	0.0	5.8
Contingency	4.9	0.0	0.0	4.9
TOTAL	**59.3**	**0.0**	**0.0**	**59.3**

Operating Experience:

During and after rainfall events, approximately 250 mm of water rests along the east side of the powerhouse, and covers an area of approximately 100 m x 50 m within the high traffic zone of the Holyrood Generating Station Powerhouse. Please refer to Figure 1.

Similarly, during each rainfall event, standing water can be found on the north side of the powerhouse, particularly, in the vicinity of Stack 1 and the waste water treatment plant.
This problem creates safety hazards and deterioration of infrastructure. Standing water within the traveled areas of the powerhouse create a number of problems regarding safety, increased

Project Title: Improve On Site Paving and Drainage **(cont'd.)**

Operating Experience: (cont'd.)

maintenance, and reduced access to and around the powerhouse and contractor's office trailer zone. Standing water also creates safety issues with pedestrian and vehicular traffic when it freezes, covering the entire road and entrances to the powerhouse.

The freeze thaw action has deteriorated the asphalt roadway on the north and east sides of the powerhouse. Existing steel buildings within the flood zone have deteriorated due to the standing water. This is evident by the oxidized condition of the bottom 600mm of the exterior metal siding on the south side of the Waste Water Treatment Plant.

Figure 1: East Side of Powerhouse, December 2008.

250mm of Standing Water Covering Entire Road.

Project Title: Improve On Site Paving and Drainage **(cont'd.)**

Project Justification:

This project is justified on the need to provide a safe working environment on the grounds at the Holyrood Thermal Generation Station, and to limit the deterioration of existing infrastructure.

Future Plans:

None.

Project Title: Replace Disconnects
Location: Various Sites
Category: Transmission and Rural Operations - Terminal Stations
Definition: Other
Classification: Normal

Project Description:

This project is an ongoing program to replace 66, 69 138 and 230 kV disconnect switches in Hydro's terminal stations on the Island Interconnected System. The disconnects targeted for replacement in 2010 are two 69 kV units at Conne River, two 69 kV units at Barachoix and one 69 kV unit at Bay d'Espoir. In 2010 a further review of the prioritized list for the replacement or upgrades will be made based on the condition of the disconnects combined with their location on the interconnected system.

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	74.0	0.0	0.0	74.0
Labour	56.2	0.0	0.0	56.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	30.0	0.0	0.0	30.0
O/H, AFUDC & Escln.	22.6	0.0	0.0	22.6
Contingency	16.0	0.0	0.0	16.0
TOTAL	**199.0**	**0.0**	**0.0**	**199.0**

Operating Experience:

The disconnect switches in use on the Island Interconnected System range in age from one to forty years and have an anticipated service life of thirty years, depending on the service environment. The tables below show a summary, of the maintenance work and cost history identified from 2000 to 2008. In summary the maintenance history of these disconnects involves repair or replacement of insulators, control systems, drive motors, gearboxes, auxiliary contact cams, brakes, heaters, motor contactors, control arms, jaws, springs, blades, couplings, and hinges. The hot spot data in Table 2 refers to events where operations staff had to respond to overheating conditions resulting from the failure of mechanical and current carrying parts.

Project Title: Replace Disconnects **(cont'd.)**

Operating Experience: (cont'd.)

Table 2: Work History

Work History Summary (2000 to 2008)				
kV Class	**Replace Insulators**	**Repair Controls**	**Hardware And Mechanical Issues**	**Hot Spots and Emergencies**
230	15	90	102	4
138	9	16	22	6
69	13	3	41	16
Total	37	119	165	26

Table 3 shows the history of maintenance costs for these disconnects for the period 2004 to 2008.

Table 3: Maintenance History

Year	**Preventive Maintenance ($000)**	**Corrective Maintenance ($000)**	**Total Maintenance ($000)**
2008	13.6	22.4	36.0
2007	8.8	23.1	31.9
2006	26.0	32.9	58.9
2005	5.1	26.1	31.2
2004	16.5	51.7	68.2

There have been no major replacements of terminal station disconnect switches since they were installed. Repairs have been made on a piecemeal basis as failures occurred.

Project Justification:

The disconnect switches are used to isolate equipment on the interconnected system either for maintenance activities or system operations and controls. Reliable and secure operation of the switches is essential to a safe work environment and for reliable and secure system operation. Faulty and/or malfunctioning disconnect switches do not operate properly when required and as such prevent reliable and secure system operation. Faulty and/or malfunctioning disconnects also create

Project Title: Replace Disconnects **(cont'd.)**

Project Justification: (cont'd.)

safety hazards for personnel when malfunctioning parts break and fall onto the workers below. Therefore all disconnect switches on the system must be in full reliable operating condition at all times. The condition of the

disconnects which are targeted for replacement in this program is such that continued piecemeal repair and replacement of components is not recommended. The only effective solution for eliminating the safety hazards and ensuring reliable operation is complete replacement of the disconnects in an orderly prioritized replacement program.

Future Plans:

This is a multi-year program for the replacement of disconnects. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Install Fall Protection Equipment
Location: Various Sites
Category: Transmission and Rural Operations - Properties
Definition: Pooled
Classification: Mandatory

Project Description:

This project is required to design, supply and install fall protection systems at several Hydro facilities. It includes installing roof fall protection systems on the control buildings at the Western Avalon and Sunnyside Terminal Stations and on the St. Lewis and Williams Harbor Diesel Plants, anchor plates for transformers where needed, hand rail and cat walks on two diesel fuel tanks at the Holyrood Generating site and railings and roof anchors on three hydraulic structures. The project estimate is $198,400, as shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	2010	2011	Beyond	Total
Material Supply	28.0	0.0	0.0	28.0
Labour	44.0	0.0	0.0	44.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	60.0	0.0	0.0	60.0
Other Direct Costs	9.0	0.0	0.0	9.0
O/H, AFUDC & Escln.	21.3	0.0	0.0	21.3
Contingency	16.1	0.0	0.0	16.1
TOTAL	**198.4**	**0.0**	**0.0**	**198.4**

Operating Experience:

Hydro initiated a five year program in 2005 to install fall protection systems on transformers, fuel tanks and roofs at its facilities. The last proposal in that program was part of Hydro's 2009 Capital Budget Application to the Board of Commissioners of Public Utilities, pages C-130 to C-136. At the start of the five year plan in 2005, Hydro did not have a comprehensive listing of all sites that needed fall protection systems. Only high priority sites were identified at the beginning. During the execution of the program, other sites were identified (see Appendix A) as needing fall protection systems and Hydro realized that all required fall protection systems could not be installed in the original five year program. Many of the new sites are remote structures.

Project Title: Install Fall Protection Equipment **(cont'd.)**

Operating Experience: (cont'd.)

Below is a discussion of the three basic types of fall protection systems installed by Hydro. The photographs illustrate how each system is used.

Roof Fall Protection System

Figure 1: Roof Fall Protection System

Generally, a fall protection system is not a complex system. Figure 1 above shows a worker tethered to a permanently installed system comprised of a cable secured to the roof by a series of fall arrest anchors. The tether is called a lifeline and the anchors are travel restraints. As the worker moves around on the roof, he is able to attach the lifeline between the anchors as needed. If a fall occurs, the anchors will arrest the fall, thereby, saving the worker's life.

Project Title: Install Fall Protection Equipment **(cont'd.)**

Operating Experience: (cont'd.)

Ladder Fall Protection System

In this system, a safety cable is installed vertically on the side of the ladder as shown in Figures 2 and 3 to the right. The workers secure themselves to the ladder fall protection system by attaching themselves to a D ring, as shown in the picture that is attached to a cable grab which in turn rides on the cable. The cable grab allows the worker to move with ease up the ladder but in the event of a sudden downward movement, as in a fall, the cable grab is designed to abruptly grab the cable, securing the worker and preventing a fall. This action is similar to the behavior of a seat belt in a car.

Figures 2 and 3: Ladder Fall Protection System

Project Title: Install Fall Protection Equipment **(cont'd.)**

Operating Experience: (cont'd.)

<u>Transformer Fall Protection System</u>

Figure 4 illustrates a transformer fall protection system used by the three workers standing on top of a transformer. This system is a portable system. The fall protection system is mounted on a fixed anchor plate welded to the top of the transformer. When work is completed, the fall protection system can be taken to another site. The three basic types of fall protection systems shown above are for illustrative purposes. Systems may vary when they are installed because of, for example, extra cable arrangements or the need for railings. The systems will be inspected annually. The anticipated useful life of a fall protection system is 20 years.

Figure 4: Transformer Fall Protection System

Fall protection systems are required to perform work safely at elevations above 3.05 meters. Hydro must conform to Section 60 of the Occupational Health and Safety Regulations. The section, "Safety Belts and Lifelines" states in part "the employer shall ensure that fall protection systems are used by all workers employed over pits, shafts or moving machinery and by all workers working at elevations greater than 3.05 meters above ground or floor level". The complete Section 60 regulations are presented in Table 3. Without proper fall protection systems in place, a worker can refuse to perform his/her assigned duties.

Project Title: Install Fall Protection Equipment **(cont'd.)**

Project Justification:

This project is justified on the requirement to provide a safe work environment and to comply with Section 60 of the Occupational Health and Safety Regulations. The fall protection system program started in 2005 did not provide for installations at all of Hydro's sites where fall protection systems were needed. New sites were identified throughout the program. Table 2 presents annual capital budget and actual expenditures for years 2005 to 2009.

Table 2: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2009F	321.7		Tanks, transformers & roofs
2008	404.5	193.9[1]	Tanks, transformers & roofs
2007	250.9	245.2	Tanks, transformers & roofs
2006	268.1	241.9	Tanks, transformers & roofs
2005	206.2	208.7	Tanks, transformers & roofs

[1]Operations personnel were scheduled to install roof lines on three powerhouse buildings but could not meet the obligation due to other commitments. It was too late to tender when this was discovered. Also some design changes to the fall protection system for the penthouse roof at the Holyrood Thermal Generating Station also provided significant savings.

This work must continue until all facilities are properly equipped with fall protection systems in compliance with Section 60 "Safety belts and lifelines" of the Occupational Health and Safety Regulations.

Future Plans:

Future fall protection installations will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Install Fall Protection Equipment **(cont'd.)**

Future Plans: (cont'd.)

Table 3. Safety belts and lifelines from Occupational Health and Safety

60.	(1) Where it is impracticable to provide adequate work platforms or staging, the employer shall ensure that fall protection systems are used by all workers employed over pits, shafts or moving machinery and by all workers working at elevations greater than 3.05 metres above grade or floor level in accordance with current standards of the C.S.A. Code with respect to fall protection and fall protection systems. (2) Rep. by 23/99 s2 (2) (3) When a worker is employed under circumstances where he or she might become entrapped by material, or be overcome by another cause, he or she shall wear a safety-belt or safety-harness attached to a lifeline or other device attended by another worker who shall be stationed, equipped and capable of immediately effecting a rescue. (4) Safety-belts, safety straps, lifelines and all interconnecting parts shall be of sufficient strength to support before breaking a weight of 1134 kilograms. (5) All metal fittings used on or with safety-belts shall conform to the metallurgical strength requirement standards as specified by the Canadian Standards Association. (6) Permanent anchors to which safety straps or rope terminals may be attached shall conform to the requirements of subsections (4) and (5). (7) Rope used for lifelines or safety straps shall comply with the requirements of current C.S.A. Code standards with respect to fall protection. (8) When axes or other tools are used which are likely to sever, abrade or burn the lifeline or safety strap, a wire rope or wire cored fibre rope shall be used. (9) Where workers are engaged in work in proximity to energized electrical circuits where conductive safety straps cannot be used, 2 non-conductive safety straps shall be worn to provide the additional protection required. (10) The safety strap shall be so attached to the safety-belt that it cannot pass through the belt fittings should either end become loose from its anchorage. (11) Thimbles shall be installed to protect ropes from chafing at points of connection to eyes, rings and snaps. (12) Safety-belts, safety straps and lifelines shall be arranged to limit the free fall of a worker to 1.22 metres. (13) No more than one worker shall be attached to a lifeline. (14) Belts, straps, harnesses, lifelines and other similar devices shall be kept free from substances and conditions which could contribute to deterioration and this equipment shall be carefully inspected before use. (15) If an impairment of function is detected the defective part shall be removed from service.

APPENDIX A

Fall Protection Project List

Fall Protection
Project List

Area	Description
BAY D'ESPOIR	
Burnt Dam	Install ladder system at spillway
	Design for roof catwalk , to provide access to structure ladder
Ebbegunbaeg	Control Structure - Ladder Leading to Staff Guage
Intake 1	Install ladder system
Intake 2	Install ladder system
Intake 3	Install ladder system
Intake 4	Install ladder system
Powerhouse 1	Supply and Install Roof Lines
	Overhead Crane NE - Ladder
	Overhead Crane SE - Ladder
	Down Stream of Unit 5 (1) -Ladder
	Down Stream of Unit 5 (2) -Ladder
	Down Stream of Unit 6 - Ladder
	Cable Tunnel Shelter - Ladder
	Install ladder system powerhouse roof
	Options for self rescue from overhead crane
	Load ratings for gratings and recommendations for improvements
	Fall arrest or restraint systems when working atop the overhead cranes
	Design for safe access to Powerhouse 1 overhead cranes.
	Access ladder is split with section of ladder attached to mobile crane
	Recommendations for a proper ladder to access cab are of overhead crane
	Requirements for proper height and standard for cab rail for overhead crane
Powerhouse 2	Supply and Install Roof Lines
	Install Ladder System Powerhouse Roof
	Overhead Crane NE - Ladder
	Overhead Crane SE - Ladder
	To Sump Pit - Ladder
	To Sump - Ladder
	Transformer Interceptor -Ladder
Salmon Spillway	Design for platform access to hoist control panel
	Design for suitable access to aircraft warning lights
Site	
Warehouse 1	Roof System
Warehouse 2	Roof System
Garage	Roof System
Carpenter Shop	Roof System
Lineshop/Fire	Roof System
Snowmobile Storage	Roof System
Salt Storage	Roof System
Security	Roof System
Switchyard	Roof System
Guest Trailer	Roof System

Fall Protection
Project List

Area	Description
Surge Tanks	One Leg of Tank Structure and Tank
Victoria Control	Ladder leading to Staffguage Barrier Required
	Ladder leading to Staffguage
	Ladder Leading to Upper Deck
CAT ARM	Install Roof Lines at Cat Arm
	Install Ladder System Powerhouse Roof
HINDS LAKE	Install Roof Lines at Hinds Lake
	East End Ladder - Rigid Barrier Required
	West End Ladder - Rigid Barrier Required
	Draftube Area Ladder - Rigid Barrier Required
	Sump Pit Ladder - Anchor Points Accessible
	Intake - Roof System
	Control Structure
	Warehouse - Roof System
PARADISE RIVER	Install Roof Lines at Paradise River
	Design for platform for power house overhead crane.
UPPER SALMON	Supply and Install Roof Lines Powerhouse
	Walkway and short stair access to the spider area
	Ship stair detail
	Install ladder system powerhouse roof
	Drafttube crane access
	Intake - Roof System
	North Salmon Spillway
	West Salmon Spillway
	Warehouse Roof System
HOLYROOD	Rail on ladder on stack
	Wastewater treatment building
	Pumphouse 1
	Powerhouse Roof Railing Work
CENTRAL	Install plates on transformers at various terminal stations
	Cat Arm Generating Station - install insulator access platform
	Platform at Corner Brook Frequency Converter
	Stephenville Gas Turbine - Install ladder cable systems on tanks
	Investigate fall protection system for stack inspection at Hardwoods, Stephenville Gas Turbines
	Ladder Addition at Oxen Pond Terminal Station
	Terminal Station Roofs
	Little Bay Islands
	Stephenville Office Ladder
NORTHERN	Install plates on transformers at various terminal stations
	Charlottetown Diesel Plant - install ladder system and roof cable
	St. Anthony New Maintenance Shop
	St. Anthony Office Building
	St. Anthony Existing Maintenance Building
	St. Anthony Airport Terminal Station Control Bldg
	St. Lewis Diesel Plant
	Williams Harbor Diesel Plant
	Norman's Bay Diesel Plant
	Mary's Harbour Tanks - 2- 36' ladders

Fall Protection
Project List

Area	Description
NORTHERN	**(cont'd.)**
	Bear Cove Control Bldg
	Plum Point Control Bldg
	Roddickton Building
	Hawkes Bay - Control Buildings - 3
	Peters Barren Control Building
	Daniels Harbor Control Building
	Cow Head Lineshop Building
	Berry Hill Control Building
	L'Anse Au Loup Diesel Plant -install fixed ladder
	Do up drawings for ladders installed at Charlottetown
LABRADOR	Happy Valley Gas Turbine - install fall arrest system powerhouse
	Nain Diesel Plant - install fall arrest system
	Makkovik Diesel Plant - install fall arrest system
	Hopedale Diesel Plant - cable from new ladder to FA system
	Black Tickle 3/8" cable with 5/16 cable
	Supply and Install ladder cable system - 1 tank in Rigolet
	Supply and Install ladder cable systems - 3 tanks in Makkovik
	Do up drawings for ladders installed at Hopedale, Cartwright

Project Title: Replace Instrument Transformers
Location: Various Sites
Category: Transmission and Rural Operations – Terminal Stations
Definition: Other
Classification: Normal

Project Description:

This project involves the purchase and installation of replacement instrument transformers (potential transformers, capacitive voltage transformers and current transformers) at various terminal stations as maintenance assessments dictate or failure occurs. 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	142.0	0.0	0.0	142.0
Labour	34.0	0.0	0.0	34.0
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.	3.4	0.0	0.0	3.4
Contingency	17.6	0.0	0.0	17.6
TOTAL	**197.0**	**0.0**	**0.0**	**197.0**

Operating Experience:

Instrument transformers have a typical service life of 30 to 40 years, depending on the service conditions. Units are inspected and tested regularly, and replaced based on these maintenance assessments or in-service failures. The maintenance assessments for instrument transformers include visual inspections and voltage/current checks of the secondary circuits. This proposal also provides for an allowance of $80,000 for testing and replacement of instrument transformers that are determined to be noncompliant with PCB regulation, which requires that all equipment with PCB levels above 2 parts per million (ppm) to be taken out of service by 2025.

Project Title: Replace Instrument Transformers

Operating Experience: (cont'd.)

Table 1 shows the history of expenditures for this project for the past five years.

Table 2. Budget History

Year	Budget ($000)	Actual ($000)	Units	Average Unit Cost ($000)
2009F	106.6		10	
2008	73.7	75.3	7	10.8
2007	79.7	80.1	5	16.0
2006	78.0	81.4	8	10.2
2005	75.0	54.0	7	7.7
2004	77.0	65.2	12	5.4

Project Justification:

Instrument transformers provide critical inputs to protection, control and metering equipment required for the reliable operation and protection of the electrical system. Instrument transformers which fail in-service can result in faults on the electrical system and outages to customers.

Replacement of instrument transformers is the only option available. When these units fail, they are not repairable and require replacement. The normal utility practice in North America is to hold a reserve inventory and replace units as they fail. The project estimate is based on an equal number of units in each voltage class failing, or requiring replacement. It has also been identified that older vintage instrument transformers may contain PCBs, and Hydro has a program in place to reduce PCBs in its assets, requiring PCB filled instrument transformers to be replaced. Based upon preliminary work completed for Hydro's Environmental Management Program for PCB reduction, there will be a requirement to change more than twice the number of units changed historically in a given year to meet the 2025 PCB free date. Based upon this, the investment for instrument transformers will have to be increased from previous years.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Upgrade Accommodations
Location: Norman Bay
Category: Transmission and Rural Operations - Properties Northern
Definition: Other
Classification: Normal

Project Description:

This project involves the construction of a new accommodation building for the Norman Bay Diesel Plant. The building will measure 20'x32' and consist of three bedrooms, one bathroom, and an open kitchen and living area. Work will include site preparation and leveling work, construction of a new accommodation trailer and all associated plumbing, heating and electrical work. 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	10.0	0.0	0.0	10.0
Labour	25.0	0.0	0.0	25.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	115.0	0.0	0.0	115.0
Other Direct Costs	9.1	0.0	0.0	9.1
O/H, AFUDC & Escln.	20.9	0.0	0.0	20.9
Contingency	15.9	0.0	0.0	15.9
TOTAL	**195.9**	**0.0**	**0.0**	**195.9**

Operating Experience:

The existing accommodation trailer was constructed in 1986. It was originally intended to be used as the temporary construction camp. It measures 10' by 30' and consists of two bedrooms, one bathroom, and a kitchen area. There is no common/living room and the bathroom and bedrooms are very small. The kitchen table includes the only seating in the trailer and can only accommodate three people. Due to the lack of space, baggage must be kept on the floor creating tripping hazards; the only television in the building is on top of the refrigerator; and the microwave oven is currently set up in one of the bedrooms. The building foundation was designed for a temporary structure and consequently when the ground heaves during the winter months, the walls and ceilings shift and separate, causing the doors and windows to jam. Mold and mildew was discovered inside the walls while minor repair work was performed in the fall of 2008. A formal investigation into the mold was

Project Title: Upgrade Accommodations **(cont'd.)**

Operating Experience: (cont'd.)

not carried out, as any major repair work was not deemed feasible given the overall condition of the trailer. An average trip to site would normally consist of two people, with duration of two to three nights. There has been an average of 15 trips to site per year over the past three years. The trailer only has sufficient space to accommodate a maintenance crew consisting of two people, therefore, when any major work is to be performed, which requires additional crew members, alternate accommodations must be found. Engine replacement work scheduled for 2010 will require additional accommodation space. The nearest accommodations are in Charlottetown which is a two hour trip on the ferry. The trailer also serves as a lunch room and office for the crews on site. Figure 1 provides a picture of the existing accommodation trailer in Norman Bay. The new accommodations will be constructed in May 2010 before engine replacement commences.

Figure 1: Existing Accommodation Trailer

Project Justification:

The trailer is 23 years old and was originally intended to be a temporary construction camp, it has outlasted its useful life. The trailer is not up to general standards that would be expected of an accommodation building in an industrial setting, and due to the foundation issues and the possibility of a mold issue, the trailer should be demolished. There is major work scheduled for the diesel plant in 2010 which will require a work crew on site for extended periods. All three generating units and all

Project Title: Upgrade Accommodations **(cont'd.)**

Project Justification: (cont'd.)

associated switchgear are being replaced. The existing trailer is not large enough to accommodate the crew in terms of sleeping quarters or in terms of general livable space. Given the fact alternate accommodations are not available locally, a suitable building should be constructed. Transportation to and from Norman Bay is dependant on weather, and on the time of year. The ferry only runs from June to November and does not travel on a daily schedule.

Future Plans:

None.

Project Title: Install New Voltage Regulators
Location: Happy Valley
Category: Transmission and Rural Operations - Distribution Labrador
Definition: Other
Classification: Normal

Project Description:

This project is required to purchase and install a set of three single-phase 7.2/14.4 kV, 200 amp voltage regulators on the Happy Valley Distribution System. The new regulator bank will be installed on a new three-pole structure, located approximately 20 kilometers from the Happy Valley Terminal Station (Happy Valley) on distribution Line 7. 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	80.5	0.0	0.0	80.5
Labour	29.4	0.0	0.0	29.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	20.0	0.0	0.0	20.0
Other Direct Costs	8.0	0.0	0.0	8.0
O/H, AFUDC & Escln.	18.3	0.0	0.0	18.3
Contingency	13.8	0.0	0.0	13.8
TOTAL	**170.0**	**0.0**	**0.0**	**170.0**

Operating Experience:

Line 7 is a 25 kV distribution line that serves the communities of Sheshatshiu and Northwest River at approximately 37 kilometers from Happy Valley. Load growth on Line 7 has been significant in the past few years. Over the five year period 2004 through 2008, an average of 18 residential customers has been added annually for an approximate four percent growth in energy sales per year. Line 7 currently supplies power to 844 customers.

The load on Line 7 is automatically regulated by the power transformers at Happy Valley and two voltage regulator banks on the line. The power transformers have on load tap changers which boost the voltage by 2.5 percent. A single line diagram is attached as Appendix A, and shows the positions of the two existing voltage regulator banks and the proposed new bank on Line 7 in relation to Happy Valley and the communities of Sheshatshiu and Northwest River. Voltage regulator bank, HV7-VR1

Project Title: Install New Voltage Regulators **(cont'd.)**

Operating Experience: (cont'd.)

was installed in 1994, 33.0 kilometers from Happy Valley, and HV7-VR2 was installed in 2006, 9.6 kilometers from Happy Valley. Voltage profile modeling indicates that the proposed new voltage regulator bank be installed at the midway point between the existing ones at approximately 20 kilometers from Happy Valley.

As a result of customer complaints received in the fall/winter of 2008 regarding low voltages and subsequent investigation, Hydro determined that new voltage regulation was required. An analysis identified the need to improve the system voltage regulation so that customers receive acceptable voltages within 96.7 percent to 105.4 percent of nominal at the customer's service entrance.

A voltage regulator bank has an estimated service life of 30 year.

Project Justification:

Load growth in the communities of Sheshatshiu and Northwest River has caused low voltage on the distribution Line 7. It is expected that future load growth will continue in the area as is evidenced by the planned opening of a new school in Sheshatshiu in September 2009. With increasing load growth, the present voltage on the feeder will not be sufficient to meet minimum CSA standards as specified in CAN3- C235 – 83 (R2006) Preferred Voltage Levels for AC Systems 0 – 50,000 V[3]. Table 2 illustrates the forecast load growth for the next five years.

[3] CSA Standard *CAN3-C235-83 (R2006) – Preferred Voltage Levels for AC Systems, 0 to 50 000 V*. This standard establishes a guideline for voltage standards for AC Systems in Canada, and was adopted by Hydro as the range of acceptable voltages that will be provided to customers. A standard for voltage levels is necessary because the devices connected to the electrical system are designed to operate within a certain range of voltages. When voltages supplied to the device deviate from this acceptable range, the device can be damaged or fail to function properly. The standard is meant to ensure that the devices connected to the electrical system should receive voltage within their normal operating range so that damage does not occur.

Project Title: Install New Voltage Regulators **(cont'd.)**

Project Justification: (cont'd.)

Table 2
Load Forecast for Line 7

Year	2010	2011	2012	2013	2014
Peak (kW)	10,448	10,586	10,806	11,021	11,227

Notes: Load impact of new school scheduled to open in September 2009 is included.

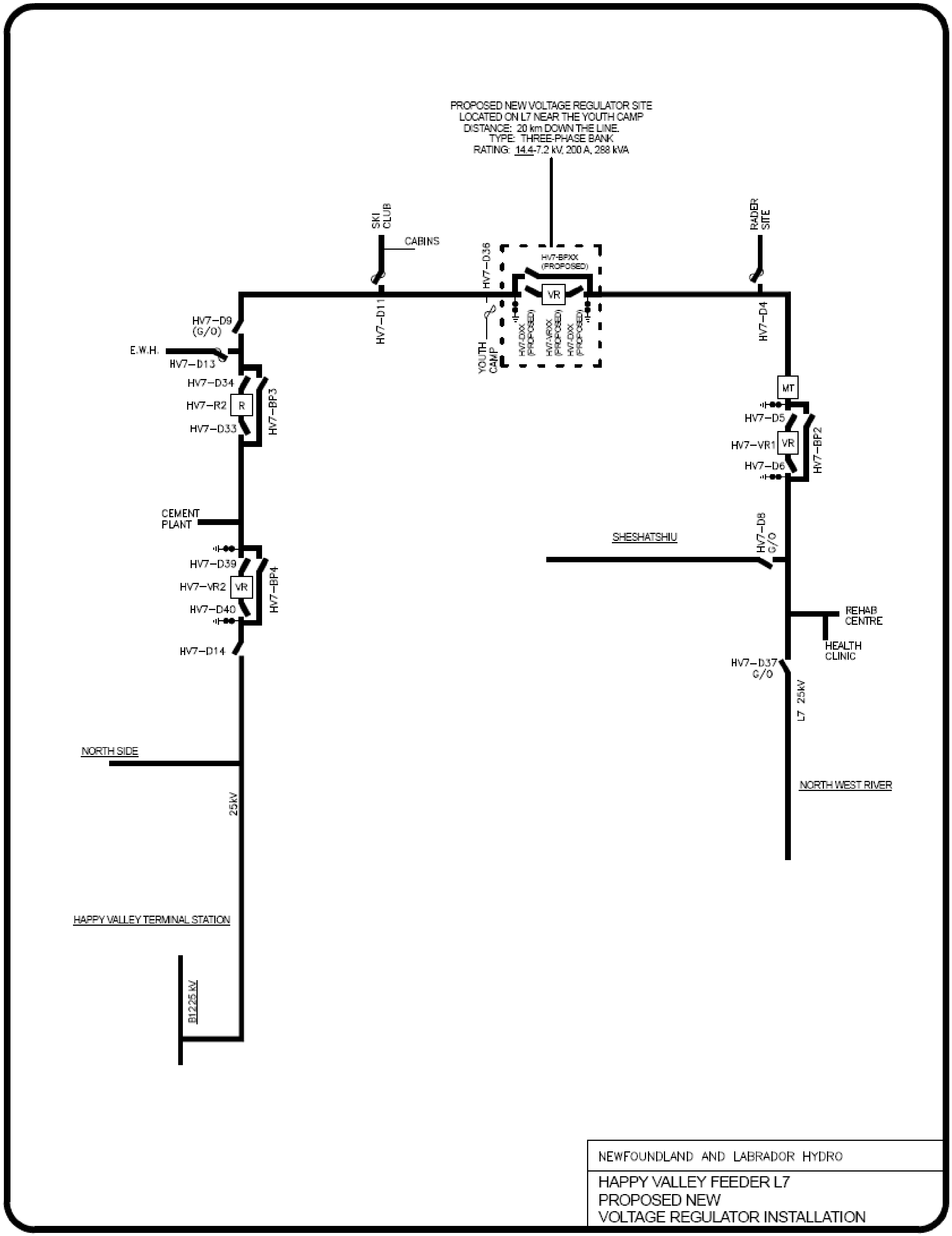
This project is justified on the need to supply acceptable voltage levels to Hydro's customers at Sheshatshiu and Northwest River. Load flow analysis has determined that the existing system is incapable of delivering voltages within standard at customers' service entrances during periods of peak load. Therefore a system upgrade is necessary to improve voltage regulation of distribution Line 7.

Future Plans:

None.

APPENDIX A

Feeder Single Line Diagram



PROPOSED NEW VOLTAGE REGULATOR SITE
LOCATED ON L7 NEAR THE YOUTH CAMP
DISTANCE: 20 km DOWN THE LINE.
TYPE: THREE-PHASE BANK
RATING: 14.4-7.2 kV, 200 A, 288 kVA
SKI CLUB
CABINS
HV7-D36
HV7-BPXX (PROPOSED)
VR
RADER SITE
HV7-D11
YOUTH CAMP
HV7-DXX (PROPOSED)
HV7-VRXX (PROPOSED)
HV7-DXX (PROPOSED)
HV7-D4
HV7-D9 (G/O)
E.W.H.
HV7-D13
HV7-D34
HV7-R2
R
HV7-BP3
HV7-D33
MT
HV7-D5
HV7-VR1
HV7-BP2
HV7-D6
CEMENT PLANT
SHESHATSHIU
HV7-D8 G/O
HV7-D39
HV7-VR2
HV7-BP4
HV7-D40
REHAB CENTRE
HEALTH CLINIC
HV7-D14
HV7-D37 G/O
L7 25kV
NORTH SIDE
NORTH WEST RIVER
25kV
HAPPY VALLEY TERMINAL STATION
B1225 kV
NEWFOUNDLAND AND LABRADOR HYDRO
HAPPY VALLEY FEEDER L7
PROPOSED NEW
VOLTAGE REGULATOR INSTALLATION

Project Title: Replace Heavy Duty Forklift- Unit 9799
Location: Bishop's Falls
Category: General Properties - Transportation
Definition: Other
Classification: Normal

Project Description:

This project involves the replacement of Unit No. 9799, a 1994 heavy duty forklift, at the warehouse located in Bishop's Falls. 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	140.0	0.0	0.0	140.0
Labour	1.0	0.0	0.0	1.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	5.0	0.0	0.0	5.0
O/H, AFUDC & Escln.	5.7	0.0	0.0	5.7
Contingency	14.6	0.0	0.0	14.6
TOTAL	**166.3**	**0.0**	**0.0**	**166.3**

Operating Experience:

There are three forklifts located at the warehouse in Bishop's Falls. A 1990 electric forklift used inside in the stores department, a 2008 diesel forklift used in salvage stores, and a 4X4 heavy duty forklift (Unit No. 9799) used in the yard. Unit No. 9799 will be 16 years old at the time of replacement. The normal life expectancy for this type of equipment is ten years depending on location and usage. The warehouse at Bishop's Falls is the main warehouse for the company, therefore, the forklift gets extensive usage and has 7,996 hours logged since it was purchased. This unit has a damaged differential with no replacement available. Therefore, it can only be used in two wheel drive mode which will be inadequate during the winter months when four wheel drive may be required to move equipment through snowy and icy conditions. Table 2 below shows the maintenance history for the heavy duty forklift to be replaced.

Project Title: Replace Heavy Duty Forklift- Unit 9799 **(cont'd.)**

Operating Experience: (cont'd.)

Table 2: Five-Year Maintenance History Unit No. 9799

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	1.0	1.8	2.8
2007	0.6	22.6	23.2
2006	1.0	7.5	8.5
2005	0.5	5.0	5.5
2004	0.9	5.5	6.4

Project Justification:

Unit No. 9799 was initially scheduled for replacement in 2011, however the replacement was moved up to 2010 due to a differential failure. Parts are not available because of the age of the unit. This equipment is essential to the operation of the warehouse in Bishop's Falls. This equipment is at the end of its life cycle and is no longer dependable.

Future Plans:

Future replacements of forklifts will be proposed in future capital budget applications.

Project Title: Install Digital Fault Recorder
Location: Deer Lake
Category: Transmission and Rural Operations - Terminal Stations
Definition: Other
Classification: Normal

Project Description:

This project involves the installation of a 32 channel digital fault recorder at the Deer Lake Terminal Station. The digital fault recorder records individual phase and equipment voltages and currents which can be reviewed after an electrical disturbance has occurred. This information helps to identify the cause of the disturbance and assess the operation of the protection relays.

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	58.1	0.0	0.0	58.1
Labour	62.1	0.0	0.0	62.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	15.9	0.0	0.0	15.9
O/H, AFUDC & Escln.	16.7	0.0	0.0	16.7
Contingency	13.6	0.0	0.0	13.6
TOTAL	**166.4**	**0.0**	**0.0**	**166.4**

Operating Experience:

The Deer Lake Terminal Station is the source of supply for the Great Northern Peninsula from the Island Interconnected System and it is connected to the Deer Lake Power Company system. The Deer Lake Power Company system has 121.4 MW of generation and four 66 kV transmission lines to the paper mill in Corner Brook. It also supplies the town of Pasadena and Marble Mountain. It is connected to the Deer Lake Terminal Station by transmission line TL-225.

This station contains the following transmission line terminations:

- TL-247, 230 kV transmission line to the Cat Arm Generating Station;
- TL-248, 230 kV transmission line to the Massey Drive Terminal Station;
- TL-239, 138 kV transmission line to the Berry Hill Terminal Station;

Project Title: Install Digital Fault Recorder **(cont'd.)**

Operating Experience: (cont'd.)

- TL-245, 138 kV transmission Line to the Howley Terminal Station; and
- TL-225, 66 kV transmission line to Deer Lake Power Company system.

The Deer Lake Terminal Station also has one 75 MVA 230/138 kV power transformer and one 41.6 MVA 138/66 kV power transformer.

The Deer Lake Terminal Station serves approximately 10,000 customers on the Northern Peninsula. This station is an important junction point on the Island Interconnected System as it is the termination of TL-247 from the Cat Arm Hydro Generating Station.

Currently, there is no digital fault recorder in the Deer Lake Terminal Station. The use of digital fault recorders in other stations has provided information for system disturbance analysis. Hydro has installed or replaced digital fault recorders in the following Terminal Stations:

Table 2: Digital Historical Information

Date Installed	Location
2008	Buchans
2005	Bottom Brook
2004	Holyrood
2004	Bay d'Espoir TS2
2002	Stoney Brook
2001	Hinds Lake
2000	Sunnyside
2000	Massey Drive
1997	Western Avalon
1995	Plum Point
1994	Hardwoods
1992	Bay d'Espoir TS1

In addition to those listed above, Hydro received approval of its 2009 Capital Budget proposal to replace digital fault recorders at the Massey Drive and Oxen Pond Terminal Stations and install a digital fault recorder at the St. Anthony Terminal Station.

Project Title: Install Digital Fault Recorder **(cont'd.)**

Operating Experience: (cont'd.)

Historical costs related to the installation of digital fault recorders in other terminal stations in the last five years are shown in Table 3.

Table 3: Historical Information

Year	Terminal Station Location	Budget ($000)	Actual ($000)	Units	Unit Cost
2009F	Massey Drive Oxen Pond and St. Anthony	461.9		3	
2008	Buchans	130.0	104.2	1	104.2
2005	Bottom Brook	122.0	91.0	1	91.0
2004	Bay d'Espoir	72.0	61.0	1	61.0

Project Justification:

The Deer Lake Terminal Station does not have disturbance monitoring capabilities. A digital fault recorder is required to assist Hydro's Protection and Control Engineering and System Operations Departments in the analysis of events and faults on transmission lines, transformers, breakers, and other station equipment at the Deer Lake Terminal Station by utilizing the recorded voltages and currents. A digital fault recorder will provide data for a complete analysis of a system disturbance.

Future Plans:

Future digital fault recorder installations/replacements will be proposed in future capital budget applications.

Project Title: Upgrade Fire Protection System
Location: Bishop's Falls
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Normal

Project Description:

This project will correct deficiencies noted during inspections completed by Newfoundland and Labrador Hydro's (Hydro) Engineering Services and FM Global, the insurance carrier for Hydro. The scope of work will include a review of the main fire pump capacity to address concerns raised by FM Global (Appendix A) regarding the inability to provide adequate water supply to the automatic sprinkler systems protecting the two main buildings in Bishop's Falls. The project will also address other noted deficiencies by replacing the fire pump pressure relief valve, piping the pressure relief to drain, re-positioning the fire pump pressure switch, replacing isolation valves, and installing a domestic water booster pump to reduce the number of false alarms caused by fluctuating town water pressure. 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	41.9	0.0	0.0	41.9
Labour	37.2	0.0	0.0	37.2
Consultant	24.5	0.0	0.0	24.5
Contract Work	20.0	0.0	0.0	20.0
Other Direct Costs	3.4	0.0	0.0	3.4
O/H, AFUDC & Escln.	18.6	0.0	0.0	18.6
Contingency	12.7	0.0	0.0	12.7
TOTAL	**158.3**	**0.0**	**0.0**	**158.3**

Operating Experience:

The Bishop's Falls Complex has experienced continuous problems with the water supply for its fire protection system. Fluctuation in water pressure has been responsible for most of the issues. Frequent drops in town water pressure causes the main fire pump at the Bishop's Falls Complex to start up causing nuisance alarms which have to be investigated by site personnel. FM Global has noted in its most recent risk report that the largest fire hazard at the Bishop's Falls Complex is the inadequate water supply feeding the existing automatic sprinkler systems protecting the main buildings.

Project Title: Upgrade Fire Protection System **(cont'd.)**

Operating Experience: (cont'd.)

In addition to the water supply problems, FM Global has reported other deficiencies associated with the fire protection system. The main fire pump pressure relief valve should be piped to a drain to prevent the pump from running hot when it re-circulates discharge water. During routine flushing of the fire hydrants the main pump sometimes fails to start due to a problem with the pressure sensing line. It was discovered that the sensing line clogs easily with debris. It was concluded that the line should be enlarged and the pressure switch repositioned to meet National Fire Protection Association (NFPA) 20 – Standard for the Installation of Stationary Pumps for Fire Protection.

Project Justification:

The project proposal will ensure that this critical system can be upgraded to meet NFPA Standards and will address the current concerns of our insurance provider and site personal.

Future Plans:

None.

Project Title: Replace Main Bus Splitter
Location: Postville
Category: Transmission and Rural Operations - Generation
Definition: Other
Classification: Normal

Project Description:

This project is required to replace the existing three phase, 400 Amp, 600 Volt main bus splitter in the Postville Diesel Plant with a three phase, 600 Amp, 600 Volt bus splitter. The work includes the installation of a new 600 Amp bus splitter and installation of a new conduit. A mobile generator will be brought on site to maintain electrical service to customers in Postville while the work to replace the bus splitter proceeds. Two short outages of approximate duration of three to four hours are expected to make the changeover to and from temporary mobile generation. 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	15.0	0.0	0.0	15.0
Labour	65.0	0.0	0.0	65.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	40.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	17.4	0.0	0.0	17.4
Contingency	12.0	0.0	0.0	12.0
TOTAL	**149.4**	**0.0**	**0.0**	**149.4**

Operating Experience:

A bus splitter is basically a low voltage (600 volts) bus, used at a diesel generating plant. It is a copper bar approximately 1.0 to 1.5 meters in length. The bar is a common point at which the cables from the generators terminate. From this termination point, other cables connect to another common point to supply station service loads or to the distribution transformer to supply customer loads. Figure 1 is a layout of the Postville Diesel Plant showing the bus splitter to be replaced. Please note that the 150 kW generating unit is being replaced with a 365 kW unit as approved in Hydro's 2009 Capital Budget.

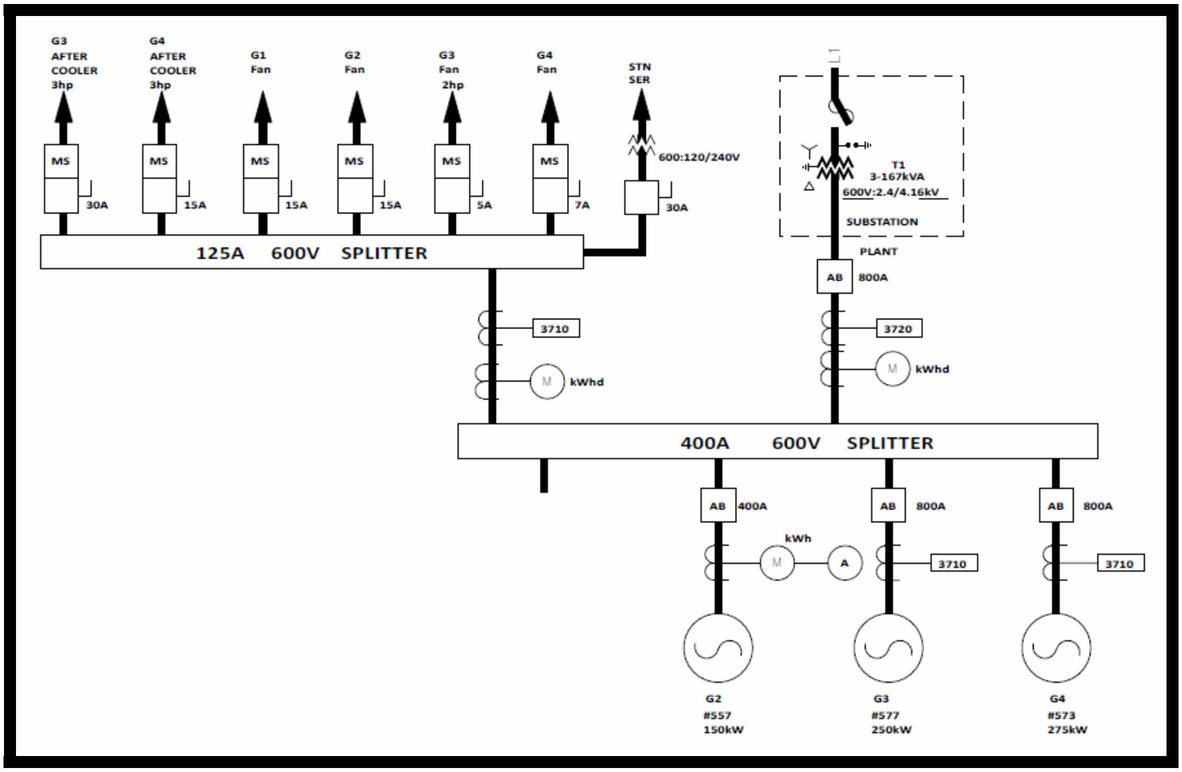


Figure 1: Postville Diesel Plant

The existing 400 Amp main bus splitter, rated at 415 kVA, has been in operation since the plant was constructed in 1976 and has reached its full capacity to meet load demand. Table 2 shows the load forecast for Postville for the period 2010 to 2014. The bus splitter is in full time continuous operation.

Table 2: Postville Load Forecast

Year	2010	2011	2012	2013	2014
Peak (kW)	412	417	422	427	432
Peak (kVA)	457	463	469	474	480
% Capacity of 400 A splitter	110%	112%	113%	114%	116%

Project Justification:

Over the five year period 2003 through 2007, the load on the Postville Distribution System grew approximately 1.4 percent annually from 339 kW in 2003 to 358 kW in 2007. In 2008, two new customer loads (a new daycare center, and a new office building for the Nunatsiavut Government)

Project Title: Replace Main Bus Splitter **(cont'd.)**

Operating Experience: (cont'd.)

were added to the system. Both of these facilities are electrically heated, and Postville's actual peak demand was 400 kW in 2008. As previously indicated in Table 2, the Postville Diesel Plant has reached its full capacity to meet load demand and the existing main bus splitter will be overloaded by 10 to 15 percent over the forecast period 2010 to 2014.

The annual compound forecast growth from 2010 through 2014 is 1.2 percent. The proposed 600 Amp bus splitter will be sufficient to address the peak demand for the foreseeable future.

Hydro has evaluated whether a conservation and demand management (CDM) program could be initiated to delay the replacement of the main bus splitter. Results of the analysis indicate that a CDM initiative would not provide a sufficient reduction in peak load to defer the splitter replacement. Therefore, CDM is not a viable alternative to this project. Customer peak demand will have exceeded the rated capacity of the existing 400 Amp main bus splitter by ten percent for 2010. CDM activities cannot achieve the required level of demand savings to defer the replacement of the main bus splitter. Results of the CDM analysis are shown in Appendix A.

Future Plans:

None.

APPENDIX A

Results of Conservation and Demand Management Program

Conservation & Demand Management (CDM) Analysis for Capital Budget Proposal

Project Title: Postville – Replace Main Bus Splitter

Description: Replace 400 Amp, 600 Volt splitter in 2010 with 600 Amp, 600 Volt Splitter

Overview:
Hydro views CDM as an opportunity to defer or postpone capital costs. The deferral can be evaluated in economic terms as the difference in the present value of the utility revenue requirement under varying commencement years for the investment. The difference represents a CDM budget constraint and is the maximum amount of money that can be expended in order to defer the investment. The analysis proceeds by determining the necessary demand or energy savings required to defer the investment and then evaluates whether the CDM budget constraint can achieve the required saving. This CDM review represents a preliminary screening to ensure there are no obvious opportunities missed.

The most economic peak demand CDM option, namely, domestic hot water load control (DLC), is evaluated against the required demand savings with the calculated CDM budget.

Conclusion:
The CDM deferral budget does not provide sufficient funds to achieve a load deferral of less than four years. The required demand savings for a four to five year project deferral is less than the achievable demand savings potential. In this circumstance, the DLC based alternative should not be further evaluated against the supply side option.

Load Forecast (HROPLF Fall 2008)	**2010**	**2011**	**2012**	**2013**	**2014**
Peak Demand Forecast (kW)	412	417	422	427	432
Domestic Customers - #	94	95	96	97	98

Required Peak to eliminate splitter upgrade	370 kW
Capital budget proposal	$149,400

	1 Yr	**2 Yr**	**3 Yr**	**4 Yr**	**5 Yr**
Targeted demand savings for capital deferral (kW)	46	51	56	61	66

(Target peak demand is 99% of firm capacity)

CDM Budget Calculation (Calculated assuming 3% escalation and 8.0% WAAC)

Capital Budget Deferral Factors*	4.6%	9.0%	13.3%	17.3%	21.1%
Total CDM Deferral Budget	$6,917	$13,506	$19,810	$25,801	$31,523
CDM Budget Per Required Demand Savings (kW)	$151	$266	$356	$425	$480

*Percentage of capital cost that can be incurred to defer project for one to five years, and still be indifferent in economic terms.

CDM Supply cost - $ per kW Achieved	$/kW
Domestic Hot Water Load Control - DLC	$403

Max. Achievable Winter Peak Demand Reduction	**1 Yr**	**2 Yr**	**3 Yr**	**4 Yr**	**5 Yr**
DLC Achievable Potential (kW)	17	29	30	30	30
Required Penetration Rate	63%	69%	75%	81%	87%
Achievable CDM to defer project (yes/no)	No	No	No	No	No

Project Title: Replace Air Compressors
Location: Western Avalon
Category: Transmission and Rural Operations - Terminal Stations
Definition: Other
Classification: Normal

Project Description:

This project is required to replace the two air compressors at the Western Avalon Terminal Station. The project will also include the replacement of the control panel which is used to operate the compressors. 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	50.0	0.0	0.0	50.0
Labour	23.7	0.0	0.0	23.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.2	0.0	0.0	4.2
O/H, AFUDC & Escln.	10.9	0.0	0.0	10.9
Contingency	7.8	0.0	0.0	7.8
TOTAL	**96.6**	**0.0**	**0.0**	**96.6**

Operating Experience:

Power circuit breakers are used to protect transformers and transmission lines from overloads. There are five air blast breakers at the Western Avalon Terminal Station. A breaker senses excessive current and uses compressed air to open the breaker contacts and cut off the power flow to the circuit. These circuit breakers operate at voltages up to 230 kV and interrupt currents up to 2,000 amperes. To withstand these voltages and interrupt the large currents, the breakers have sophisticated controls and sensing systems and large mechanical drive systems to pull the breakers contacts apart and extinguish the current arcs when the circuits are being interrupted.

The breaker contacts are housed in a sealed, pressurized chamber and the compressed air in the sealed chamber is used to extinguish the arc across the breaker contacts when the circuit is being interrupted. The compressed air supply is provided by centralized compressors and piping systems in the terminal stations.

Project Title: Replace Air Compressors **(cont'd.)**

Operating Experience: (cont'd.)

The compressed air system is critical for the operation of the air blast circuit breakers within the terminal station. If the circuit breaker does not have a compressed air supply the air pressure will eventually drop to a point where the breaker will not be able to operate during a fault condition and an outage is possible. The Western Avalon Terminal Station was constructed in 1970 and the compressed air system, including the air compressors, was installed during the original construction. Air compressors have an estimated service life of 40 years. The air compressors proposed for replacement have reached the end of their estimated service lives.

Table 2 shows the five-year maintenance history for the Compressed Air System at the Western Avalon Terminal Station.

Table 2: Maintenance History

Year	Corrective Maintenance ($000)	Preventive Maintenance ($000)	Total Maintenance ($000)
2008	4.9	4.5	9.4
2007	2.4	9.9	12.3
2006	0.0	7.4	7.4
2005	6.4	6.0	12.4
2004	4.0	3.4	7.4

This project is similar to three other terminal station air compressor projects. Table 3 shows the budget and actual costs of these projects.

Table 3: Budget History

Year	Budget ($000)	Actual ($000)	Units	Cost Per Unit	Location
2009F	95.9		2		Sunnyside Terminal Station
2008	93.5	81.2	2	40.6	Buchans Terminal Station
2007	78.0	67.0	2	33.5	Hardwoods Terminal Station

Project Title: Replace Air Compressors **(cont'd.)**

Operating Experience: (cont'd.)

The air compressors and control panel at the Sunnyside Terminal Station are scheduled to be replaced in summer 2009.

Project Justification:

The replacement of the two air compressors and the associated control panel at the Western Avalon Terminal Station is required to maintain the Island Interconnected System reliability. The compressors have reached the end of their anticipated useful lives and further operation of these compressors could lead to the failure of a circuit breaker to operate properly due to lack of compressed air. Therefore, the existing compressors at the Western Avalon Terminal Station should be replaced. Failure to ensure that reliable compressors are in service could lead to an unplanned outage disrupting customer service because of breaker inoperation.

Future Plans:

Table 4 presents the locations where air compressors are planned to be replaced within the next five years.

Table 4: Air Compressor Replacement

Year	Location
2012	Bottom Brook Terminal Station
2014	Cat Arm Hydroelectric Generating Station

Project Title: Install Pole Storage Ramps
Location: Various Sites
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Normal

Project Description:

This project is required to install pole storage ramps at the Springdale and Baie Verte Depots. Underneath each new ramp at the depots will be a 150 mm impervious backfill layer, followed by a layer of geotextile filter fabric, then a 150 mm layer of topsoil, and sod. The ramps will vary in size to accommodate the length and quantity of poles at each site. The ramps will be constructed of galvanized steel beams, fastened to reinforced concrete bases. Newfoundland and Labrador Hydro's (Hydro) Environmental Services Department will verify the suitability of each proposed location on site. 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	0.0	0.0	0.0	0.0
Labour	8.0	0.0	0.0	8.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	64.4	0.0	0.0	64.4
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	8.6	0.0	0.0	8.6
Contingency	7.4	0.0	0.0	7.4
TOTAL	**90.4**	**0.0**	**0.0**	**90.4**

Operating Experience:

Hydro owns and operates 34 line depots. Hydro must store extra poles at each of these sites. Storage ramps are constructed at the sites on a priority basis depending on an assessment by Hydro of the deterioration at the existing storage site. The poles range in length from 9 metres (30 feet) to 26 metres (85 feet). There are between ten to 225 poles stored at each site. Some of these sites require multiple ramps of various sizes to accommodate the quantity and length of poles. The majority of these poles are also treated with chromated copper arsenate (CCA), however a small quantity of pentachlorophenol (PCP) treated poles may exist at some locations.

Project Title: Install Pole Storage Ramps **(cont'd.)**

Project Justification:

This project is required to provide a safe and environmentally acceptable means of storage of wooden distribution poles. Poles are presently stored directly on the ground at one or multiple locations within each community. Contact with the ground causes poles to deteriorate at a faster rate than normal due to the harsh climate of the sites assessed; the poles are covered with snow several months of the year. Storing poles on elevated pole storage ramps will allow crews to use material handling equipment to safely and efficiently move different types and lengths of poles and will also prevent poles from deteriorating prematurely due to ground contact. Construction of these pole storage ramps will meet the federal guidelines for storing treated wood which enables Hydro to store these poles in an environmentally friendly manner.

Future Plans:

Future installation of pole storage ramps will be proposed as follows:

2011 - Construct pole storage ramps in Bay d'Espoir, Ramea, Sop's Arm and Harbour Breton line depots and Hopedale, Makkovik and Postville diesel plants

2012 - Construct pole storage ramps in St. Brendan's, Change Islands and Fogo line depots in Rigolet, Cartwright, and Black Tickle diesel plants

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

Project Title: Install Transformer Storage Ramps
Location: Various Sites
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Normal

Project Description:

This project is required to construct transformer storage ramps at Newfoundland and Labrador Hydro's (Hydro) diesel generating plants in Postville, Paradise River and Makkovik. The ramps will be constructed using pressure treated timber and will measure 2,400 millimetres (8 feet) wide and 9,600 millimetres (32 feet) long. 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	16.5	0.0	0.0	16.5
Labour	35.8	0.0	0.0	35.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	18.9	0.0	0.0	18.9
O/H, AFUDC & Escln.	10.2	0.0	0.0	10.2
Contingency	7.1	0.0	0.0	7.1
TOTAL	**88.5**	**0.0**	**0.0**	**88.5**

Operating Experience:

Transformers at the Makkovik, Paradise River and Postville Diesel Plants have been stored outdoors on wooden structures since the plants were constructed. In Makkovik, the transformers are stored on the ground on pallets. Paradise River has transformers stored on a makeshift ramp that is both too small, and not designed to carry the weight of the transformers. Postville has transformers stored on the lube oil storage ramp, which again is not designed to carry the load of the transformers (see Figures 1 to 3 for photos). The ramps are covered with snow during the winter making them difficult to see during snow clearing operations and because they are so low to the ground, inspections for potential transformer leaks are difficult to perform. Hydro has been fortunate in that there has not been an instance in which the transformers have become damaged in the course of snow clearing operations. This has been attributed to the extra precaution the snow clearing operators must

Project Title: Install Transformer Storage Ramps **(cont'd.)**

Operating Experience: (cont'd.)

exercise when operating near the storage area. Where ramps are already installed in Hydro's system, thorough inspections for transformer leaks are performed and moving transformers on and off a truck's cargo bed is easier.

Figure 1. Postville Lube Oil Storage Ramp where transformers are stored

Figure 2. Makkovik Transformer Storage

Figure 3. Paradise River Transformer Storage

Project Title: Install Transformer Storage Ramps **(cont'd.)**

Operating Experience: (cont'd.)

A project was approved by the Board in Order No. P.U. 36 (2008) for the construction of similar transformer storage ramps for Nain and Cartwright in Labrador in 2009 with a budget of $120,600. This was the first project of a three year program to construct transformer storage ramps (three per year) in Labrador. It should be noted that the budget for this project was actually for three sites (Nain, Cartwright, and Rigolet) and that project will include the construction of a transformer storage ramp in Rigolet in 2009. It should also be noted that the labour costs included in the 2009 project were overstated due to a calculation error. Furthermore, the labour cost estimate was based on the utilization of outside labour; however it is more likely that the project will be completed utilizing Hydro employees. The construction of two transformer storage ramps in Bay d'Espoir with a budget of $75,000 has also been approved for 2009.

Project Justification:

Although Hydro is not under any legislative or regulatory requirement to modify its storage structures, Hydro's Environmental Standard Operating Procedures dictate that any oil filled equipment must be placed on storage ramps, and be inspected for leaks. Having drums and transformers stored directly on the ground does not allow for this and is not in compliance with internal environmental management procedures.

The proper handling and storage of transformers and waste oil drums is an environmental concern because of the contained oil. If the transformers and/or drums become damaged, punctured or corroded then an oil spill may be imminent. When stored on the ground they become covered with snow in the winter months and there is a high risk that routine snow clearing operations could easily damage the transformers resulting in a spill. The construction of the storage ramps would eliminate the risk of damage completely. Hydro's operating procedures require that the area under the storage location for transformers be accessible for inspection to check for potential leaks. The design for the new transformer storage ramps provides enough ground clearance to allow for inspection. The height of the ramps will match the height of the truck bed used for transporting transformers and waste oil,

Project Title: Install Transformer Storage Ramps **(cont'd.)**

Project Justification: (cont'd.)

making loading and offloading easier and safer and, thus, reducing the risk of damage and potential spills. New ramp design and a carefully chosen location on site will enhance accessibility for work crews and improve inventory management.

Future Plans:

Future installations for Hopedale, Wabush and Black Tickle will be proposed in the 2011 capital budget application.

Project Title: Replace Aviation Fuel Tank and Dispensing Unit
Location: Bishop's Falls
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Mandatory

Project Description:

This project involves the replacement of the Jet A1 tank and dispensing unit at the Bishop's Falls Facility. The work will involve the repositioning of the system to avoid vehicular traffic and the construction of a new concrete pad for the tank and dispensing cabinet. The disposal of the existing aviation fuel system will be included in the scope of work. All components of the new system will be installed to meet current aviation fuel dispensing standards. 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	50.9	0.0	0.0	50.9
Labour	18.4	0.0	0.0	18.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.3	0.0	0.0	1.3
O/H, AFUDC & Escln.	9.8	0.0	0.0	9.8
Contingency	7.1	0.0	0.0	7.1
TOTAL	**87.5**	**0.0**	**0.0**	**87.5**

Operating Experience:

The 13,000 litre Jet A1 tank in Bishop's Fallls has been in operation since 1990 and the fuel dispenser was installed in 1999. Both of these components are at the end of their useful lives of 25 years. As well, the existing system has no secondary containment for the pumping system, and the tank is oversized[4]. The system has a high potential for being struck by heavy equipment, as it is located near a main thoroughfare for snow dumping where loaders are continuously passing within a few feet of it. Even though bollards are installed, there is the potential for it to be struck due to its location. As well, there is inadequate access for performing required fuel checks, since when performing weekly fuel checks the worker has to climb up onto the tank top and perform some checks (dip, fuel temp. etc.) and also has to take a fuel sample from the bottom using a fuel thief. The existing tank has nothing but a steel rung

[4] The tank was installed at a time when Hydro was refueling aircraft other than Hydro's contract aircraft.

Project Title: Replace Aviation Fuel Tank and Dispensing Unit **(cont'd.)**

Operating Experience: (cont'd.)

ladder attached to the side so especially in the winter this is a concern. The workers have been instructed to take all necessary precautions in the interim (clear ice and snow from ladder, use a second person to hand up dip stick, fuel thief, etc.) but the solution is to fabricate a work platform with a railing.

A recent review of CSA B836-05, Standard for Storage, Handling, and Dispensing of Aviation Fuel at Aerodromes, has revealed deficiencies in the system, including:

1. Section 4.3.2 - Internal Coating

   "Carbon steel fuel tank storage tanks shall have epoxy-coated internal surfaces."

2. Section 4.5.1.6

   "Piping downstream of the final filter-separator or the continuous fuel monitor shall be stainless steel, aluminum, or carbon steel internally coated with aviation - fuel-resistant epoxy".

3. Section 4.5.1.16

   "Connections shall be provided to drain water or fuel at each low point".

4. Section 4.6.1 - Isolating Valves

   "Isolating valves shall be provided at suitable locations to allow the isolation of equipment ..."

5. Section 4.13.2 - Accessories

   "Each fueling cabinet shall include the following:

   (a) a weatherproof enclosure designed to protect the cabinet contents from the elements

   (k) a pressure-relief system to relieve thermal pressure build-up in hoses exceeding normal operating pressure

6. Section 4.13.6 - Spill Pan

   "Cabinet bases shall incorporate a fuel spill pan to capture leakage within the cabinet"

Project Title: Replace Aviation Fuel Tank and Dispensing Unit **(cont'd.)**

Project Justification:

Based on the age of the system and the identified deficiencies the system needs to be replaced with one that meets all current aviation fuel standards. The existing arrangement can be reduced in size to meet the current demands of the Bishop's Falls Facility which would also reduce our environmental risk of spill. The replacement of the aviation fuel system would ensure a safe and reliable operation that meets current standards.

Future Plans:

None.

Project Title: Install Waste Oil Storage Tank
Location: Port Hope Simpson
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Mandatory

Project Description:

This project is required to purchase and install a 5,000 litre, double wall, vacuum sealed waste oil storage tank for the diesel plant in the Southern Labrador community of Port Hope Simpson. Work will also include the installation of a steel pipe header system from the waste oil storage tank to the diesel units inside the plant. The header will be constructed as a double wall system for secondary containment of the primary line, complete with a leak detection device on the secondary containment. Lube oil transfer pumps will also be purchased and installed in the header systems to pump the used oil from the engines to the storage tanks. Low oil level indication and cut-out switches will also be installed to provide pump protection. 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	12.5	0.0	0.0	12.5
Labour	27.6	0.0	0.0	27.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	13.0	0.0	0.0	13.0
Other Direct Costs	14.2	0.0	0.0	14.2
O/H, AFUDC & Escln.	10.1	0.0	0.0	10.1
Contingency	6.7	0.0	0.0	6.7
TOTAL	**84.1**	**0.0**	**0.0**	**84.1**

Operating Experience:

Hydro's preventative maintenance procedures specify that lubricating oil used in the diesel generators must be changed after every 500 hours of operation. Waste lube oil is currently pumped into steel drums, then placed in oversized plastic drums and stored on site. A certified waste oil collector travels to each site once per year to collect the used oil. The plant in Port Hope Simpson produces 2,050 litres of waste lube oil per year. As a result of being stored on ramps over the winter months, and shipping the drums, the drums become rusty and dented and do not qualify for credit when returned.

Project Title: Install Waste Oil Storage Tank **(cont'd.)**

Operating Experience: (cont'd.)

The possibility of the drums developing a leak is also a continuous environmental concern. As a protective measure to minimize the potential of an oil spill, until such time as the storage tanks are replaced, the drums are being stored inside plastic oversized drums for secondary containment.

A project was approved by the Board in Order No. P.U. 30 (2007) for a similar waste oil storage tank in 2008 for L'Anse au Loup with a budget of $45,600 and Cartwright with a budget of $53,300. The L'Anse au Loup project was later changed to Charlottetown and reforecast to $56,100. This change occurred because it was decided that from an operations and environmental perspective, Charlottetown, which operates in continuous mode and therefore produces more waste oil annually than L'anse au Loup which operates on a stand-by basis, was the more critical location to install the storage tank. The Board in Order No. P.U. 36 (2008) approved a project for a similar waste oil storage tank for Mary's Harbour in 2009 with a budget of $84,200. Table 2 provides a summary of the previously approved projects.

Table 2: Historical Information

Project Cost: *($ x1,000)*	**Year**	**(Budget)**	**(Actual)**
Mary's Harbour*	2009F	84.2	
Charlottetown	2008	45.6	54.4
Cartwright	2008	53.3	61.7

**Note: In the 2009 project to install a waste oil storage tank in Mary's Harbour the cost of the tank was included in Material Supply. In the 2010 project proposed here for Port Hope Simpson, the tank cost has been included in Contract Work as it will be purchased under a tendered contract.*

Project Justification:

There are safety and environmental concerns regarding pumping off used oil from the engines into 205 litre drums, moving drums outside the plant and placing them on the waste oil storage ramp. The drums require heavy lifting and there is a risk of spillage. The Used Oil Control Regulations, under the Environmental Protection Act (O.C. 2002-430) states in Section 21 "Used oil in a quantity that does not

Project Title: Install Waste Oil Storage Tank **(cont'd.)**

Project Justification: (cont'd.)

exceed 205 litres a site, may be stored in one 18-guage, 205 litre steel drum". The quantity of used oil generated at each of the diesel plants well exceeds that limit. Therefore, in order to comply with the regulations a storage tank should be used to hold the used oil. As part of Hydro's Environmental Management System (EMS), Hydro has initiated a program to install waste oil storage tanks at isolated diesel generating sites in Labrador.

Future Plans:

Future installations will be proposed in future capital budget applications (2010 Capital Plan Tab, Appendix A).

Project Title: Replace Surge Arresters
Location: Various Sites
Category: Transmission and Rural Operations – Terminal Stations
Definition: Other
Classification: Normal

Project Description:

This project consists of the purchase and installation of replacement surge arresters at various Hydro terminal stations on the Island Interconnected System. These units are in the 66, 138 and 230 kV classifications. 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	55.5	0.0	0.0	55.5
Labour	10.0	0.0	0.0	10.0
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.	1.3	0.0	0.0	1.3
Contingency	6.6	0.0	0.0	6.6
TOTAL	**73.4**	**0.0**	**0.0**	**73.4**

Operating Experience:

Surge arresters are used on major terminal station equipment to protect that equipment from voltage surges due to lightning and switching. The expected service life of surge arresters is approximately 20 years depending on the lightning activity in the area and the switching duty. Surge arresters fail because of the cumulative effects of lightning strikes and switching surges. Because of the wide variety of operating environments across the System, it is difficult to estimate the useful life and predict surge arrester failures. The older arrester designs have a higher incidence of failure than the newer designs. Typically, Hydro experiences approximately 14 surge arrester failures per year. Hydro has approximately 440 surge arresters in service in all three voltage classes ranging in age from one year to approximately 40 years.

Project Title: Replace Surge Arresters **(cont'd.)**

Project Justification:

Surge arresters provide critical overvoltage protection of power system equipment from lightning and switching surges. When the arresters fail they are not repairable. Replacement is the only option available. Surge arresters are regularly inspected and tested, and replacements are made based on these maintenance assessments as well as in-service failures. When a surge arrester fails, it must be replaced immediately, otherwise the major equipment is exposed to serious damage from lightning surges. Failure of any major equipment will result in major system disturbances which could result in system outages and interruption of service to customers.

Future Plans:

Future replacements will be proposed in future capital budget applications. Surge arrestor replacements are planned for the next four years as shown in the five year plan (2010 Capital Plan Tab, Appendix A)

Project Title: Replace 230 kV Breaker Controls
Location: Massey Drive and Buchans
Category: Transmission and Rural Operations - Terminal Stations
Definition: Other
Classification: Normal

Project Description:

This project is required to replace the existing control packages on three 230 kV breakers; B5L11 at the Massey Drive Terminal Station and B1L28 and L28L32 at the Buchans Terminal Station. The work will involve purchasing and programming a SEL-2411 Programmable Automation Controller for each breaker to operate in the same manner as the existing controls. The existing controls package will be removed, replaced with the new controller and tested to ensure proper functionality. 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	16.0	0.0	0.0	16.0
Labour	39.0	0.0	0.0	39.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.5	0.0	0.0	6.5
O/H, AFUDC & Escln.	8.3	0.0	0.0	8.3
Contingency	3.1	0.0	0.0	3.1
TOTAL	**72.9**	**0.0**	**0.0**	**72.9**

Operating Experience:

Circuit breakers at terminal stations are protection devices that interrupt the flow of power when an electrical disturbance such as a fault occurs. An electrical fault occurs when there is a malfunction in an electrical circuit that causes current to flow to ground or between conductors if they come into contact with each other. This current flow is sufficiently high to cause damage to electrical equipment in the terminal station. Circuit breakers react to this high current by acting like a switch to stop the current flow. Circuit breakers are complex mechanisms that have control devices that allow them to operate in a predefined manner to provide the required protection. When a fault occurs on a transmission line, circuit breakers at the terminal stations react by tripping or switching off the

Project Title: Replace 230 kV Breaker Controls **(cont'd.)**

Operating Experience: (cont'd.)

transmission line so that no damage occurs. Often the fault is cleared immediately. The breaker control will react in a timely fashion, usually within seconds, to automatically reclose the associated breaker to minimize the transmission line outage.

At the Massey Drive and Buchans Terminal Stations, some of the 230 kV breaker controls have become obsolete. Existing electromechanical breaker controls, as indicated in Table 2, are in excess of 25 years old and have reached the end of their useful lives. The controls packages on 230 kV breakers consist of electromechanical relays and timers that operate the tripping and reclosing circuits of the breaker. The controls for the three breakers are comprised of discontinued electromechanical relays. Present, functionally comparable, models of these relays are not able to be installed in these cases. Figure 1 represents an example of an obsolete system previously located at the Western Avalon Terminal Station.

Figure 1: Discontinued Electromechanical Relay

Project Justification:

This project is justified on the need to continue supplying reliable electrical power. Hydro's 230 kV breaker controls are composed of outdated and discontinued electromechanical relays. Current automation technology allows for replacements with less hardwiring and the benefit of self-diagnostic

Project Title: Replace 230 kV Breaker Controls **(cont'd.)**

Project Justification: (cont'd.)

testing and expansion of functionality for future considerations. If a failure occurs, it is anticipated that prolonged system outage or system instability could result if the breaker does not reclose normally. This project is required to continue the ongoing work to upgrade the breaker controls systems to current technology as anticipated in Table 2 below. Figure 2 is an example of a microprocessor based relay that was recently installed at the Buchans Terminal Station.

Figure 2: Microprocessor Based Relay

Future Plans:

Future replacements will be planned as necessary on the basis of age and performance. Two or three breaker systems are to be upgraded each year as a continuation of this process. Table 2 outlines the history and status of this work.

Project Title: Replace 230 kV Breaker Controls **(cont'd.)**

Future Plans: (cont'd.)

Table 2

230 kV Breaker Controls with Single Pole Reclosing

Station	Breaker	Details
STB - Stony Brook	L05L35	Upgraded 2000 with PLC
STB - Stony Brook	B1L31	Upgraded 2001 with PLC
STB - Stony Brook	B2L04	Upgraded 2001 with PLC
BUC - Buchans	B1L05	Upgraded 2002 with PLC
BDE - Bay D'Espoir	B4B5	Upgraded 2002 with PLC
SSD - Sunnyside	B1L03	Upgraded 2003 with PLC
SSD - Sunnyside	L06L07	Upgraded 2003 with PLC
HRD - Holyrood	B1L17	Upgraded 2004 with PLC
WAV - Western Avalon	B1L17	Upgraded 2004 with PLC
MDR - Massey Drive	B1L28	Upgraded 2005 with PLC
BBK - Bottom Brook	B1L11	Upgraded 2005 with PLC
BDE - Bay D'Espoir	B3B4	Upgraded 2006 with SEL-2411
BUC - Buchans	L05L33	Upgraded 2006 with SEL-2411
OPD - Oxen Pond	B1L36	Upgraded 2008 with SEL-2411
SSD - Sunnyside	L03L06	Upgraded 2008 with SEL-2411
WAV - Western Avalon	L01L03	Upgraded 2008 with SEL-2411
WAV - Western Avalon	L03L17	Upgraded 2008 with SEL-2411
OPD - Oxen Pond	B1L18	Upgraded 2009 with SEL-2411
BDE - Bay D'Espoir	B5B6	Upgraded 2009 with SEL-2411
BDE - Bay D'Espoir	L06L34	Upgraded 2009 with SEL-2411
MDR - Massey Drive	B5L11	To be upgraded in 2010; age 40 years
BUC - Buchans	L28L32	To be upgraded in 2010; age 40 years
BUC - Buchans	B1L28	To be upgraded in 2010; age 40 years
BBK - Bottom Brook	B1L09	Relays; age 31 years
DLK - Deer Lake	B3L48	Relays; age 26 years
DLK - Deer Lake	B3L47	Relays; age 24 years
HWD - Hardwoods	B1L36	Relays; age 23 years
SSD - Sunnyside	L03L06	Relays; age 19 years
SSD - Sunnyside	B1L02	Relays; age 19 years
BBK - Bottom Brook	L11L33	Old relays, no clear evidence of age but older than 25 years
BBK - Bottom Brook	L09L33	Old relays, no clear evidence of age but older than 25 years
HRD - Holyrood	B2L42	Old relays, no clear evidence of age but older than 25 years
HRD - Holyrood	B12L42	Old relays, no clear evidence of age but older than 25 years
HRD - Holyrood	B12L17	Old relays, no clear evidence of age but older than 25 years
HWD - Hardwoods	B1L01	Old relays, no clear evidence of age but older than 25 years

Project Title: Upgrade Properties
Location: Port Hope Simpson
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Normal

Project Description:

This project is required to upgrade the existing yard at the Port Hope Simpson Diesel Plant. See Figure 1. The existing yard, as illustrated by Figure 1 is approximately 2,950 m² which includes all area inside of the existing fence and a driveway which is approximately 200 m². Work will include the excavation of drainage trenches through the parking area and the installation of plastic drain tile with stone. Approximately 1,400 m² of the parking area in front and to the side of the plant will also be excavated, reshaped and graded to allow adequate surface drainage away from the site. Geotextile fabric will be installed on the new sub grade and will be topped off with 150 millimeters of Class "A" road gravel material. 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	0.0	0.0	0.0	0.0
Labour	17.2	0.0	0.0	17.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	31.6	0.0	0.0	31.6
Other Direct Costs	7.7	0.0	0.0	7.7
O/H, AFUDC & Escln.	8.7	0.0	0.0	8.7
Contingency	5.7	0.0	0.0	5.7
TOTAL	**70.9**	**0.0**	**0.0**	**70.9**

Operating Experience:

When the plant was originally built in 1994, the site was leveled and backfilled using material readily available on the site. This material consisted of a sandy and silty type soil which has proven to be unacceptable as a structural backfill material for the operations personnel and plant suppliers who have to use the yard. During spring thaw, and periods of heavy rain the soil becomes completely saturated and changes into a liquid or plastic state. The resulting mud makes it impossible to drive motorized equipment over the site. Vehicles have sunk to their axles in the muddy soil. During such times, only four-wheel drive Pick-Up trucks are able to access the plant, and on occasion, they also get stuck.

Project Title: Upgrade Properties **(cont'd.)**

Operating Experience: (cont'd.)

This problem occurs twice a year every year in the spring during spring thaw and in the fall when the soil goes through a few freeze/thaw cycles before winter sets in. The worst condition occurs in the spring when the yard becomes nearly impassable. When the yard turns to mud, operators usually opt to park their vehicles outside of the gate; they put on rubber boots and then walk through the yard choosing the best path possible to the plant. Once inside the plant, the mud gets tracked throughout the building. This problem has caused a loss in productivity for operations personnel. To date there has not been a loss of power to the community as a direct result of the muddy condition of the yard but fuel delivery trucks attempting to fill the diesel generator tanks find it extremely difficult getting through the yard when it is in this condition. Fuel truck operators have informed the plant operators that the fuel trucks are not designed to be taken through the yard under these conditions as there is a risk of damage to the undercarriage of the vehicles. On two different occasions since the plant was built, operations staff have purchased a couple of tandem truckloads of Class "A" material to spread out near the doors of the building which has somewhat helped control the problem immediately adjacent to the building.

Project Justification:

This project is justified on the need to be able to access the Port Hope Simpson Diesel Plant during spring thaw and when the yard is going through freeze/thaw cycles prior to the beginning of winter. Proper yard access will ensure that reliable power is provided to the community. Vehicular access to the power plant and general site accessibility is a basic requirement for continual plant operation. The properties of the existing soil used for backfill around the yard and for the driving surface do not allow the soil to remain solid during periods of heavy rain and during freezing and thawing cycles. This condition obstructs access to the plant especially during the spring. Plant operators have difficulty getting their vehicles to the plant due to the amount of mud. This situation also creates a problem for vehicles trying to access the site to pick up or deliver fuel, equipment and materials. The site must be accessible at all times in case of emergency and for day to day activities. Currently this is not the case and the site must be upgraded.

Project Title: Upgrade Properties **(cont'd.)**

Project Justification: (cont'd.)

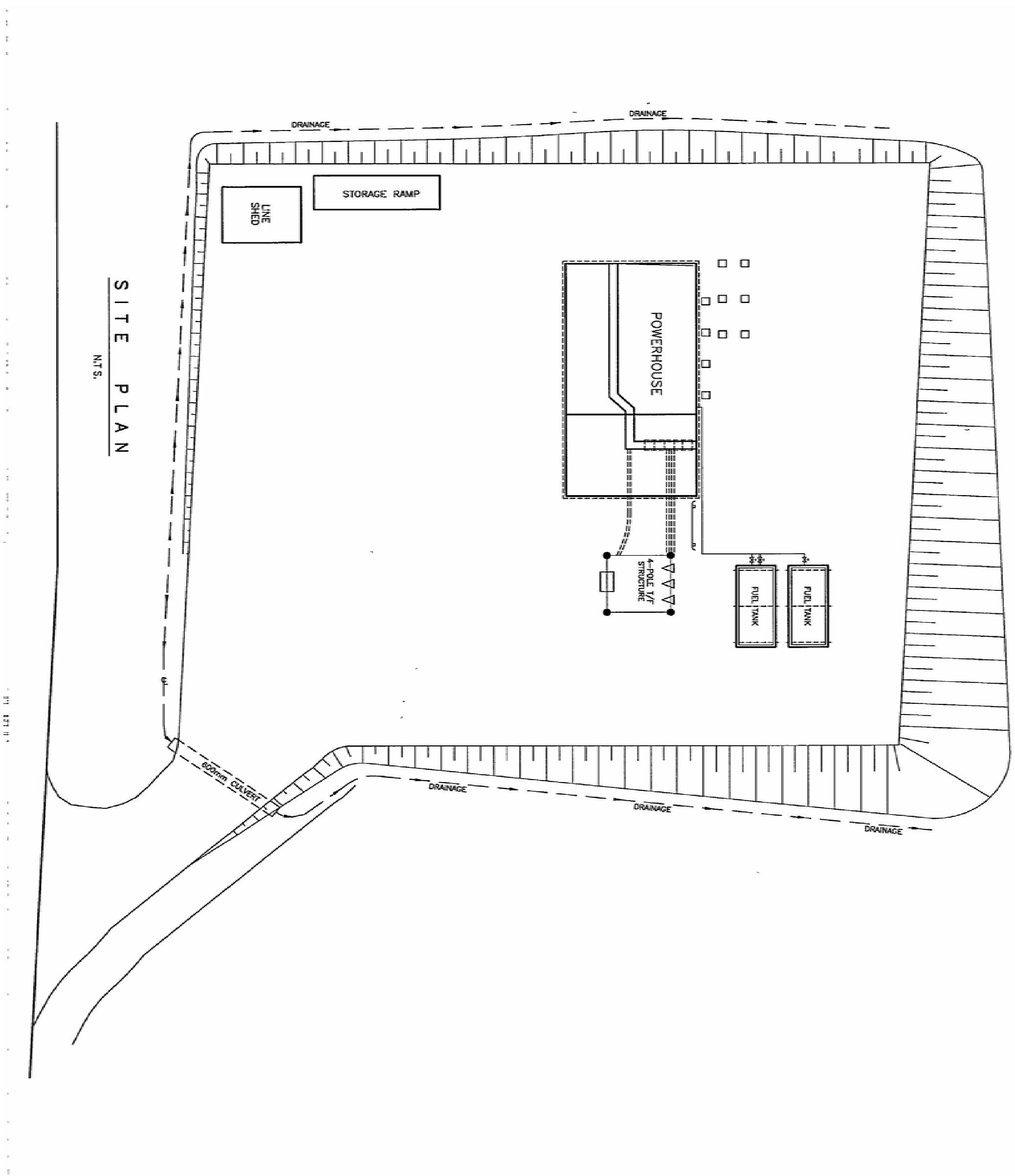


Figure 1: Port Hope Simpson Diesel Plant Yard

Future Plans:

None.

Project Title: Legal Survey of Primary Distribution Line Right of Way
Location: Various Sites
Category: Transmission and Rural Operations - Properties
Definition: Other
Classification: Normal

Project Description:

Newfoundland and Labrador Hydro (Hydro) owns and operates approximately 2,250 km of distribution lines located on Crown land, which is owned by the provincial government.

In 2004, Hydro initiated a program to obtain easements on the land on which these lines are located. Since 2004, a total of 713 km of distribution line has been surveyed and is being processed through the Department of Environment and Conservation, Lands Division (Crown Lands). Table 3 below provides the details of the length of lines surveyed to date. This project is required to continue the program to acquire legal surveys and prepare documentation to acquire Crown Land easements for approximately 160 km of primary distribution line in operation throughout the Province.

Easements are granted for a term of 50 years. Hydro can renew the easements granted for a further period of 50 years if the renewal is requested in writing before the expiration of the existing easement.

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	1.5	0.0	0.0	1.5
Labour	43.2	0.0	0.0	43.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.8	0.0	0.0	6.8
O/H, AFUDC & Escln.	8.7	0.0	0.0	8.7
Contingency	5.2	0.0	0.0	5.2
TOTAL	**65.4**	**0.0**	**0.0**	**65.4**

Project Title: Legal Survey of Primary Distribution Line Right of Way **(cont'd.)**

Operating Experience:

Older distribution lines were constructed without obtaining easements. The effort to obtain easement title to the primary distribution lines on Crown Land began in 2004. Assuming continued funding, title for the distribution systems located on Crown Land will be in place by the end of 2014.

Table 2 shows the history of expenditures for this project for the past five years and Table 3 shows the length of lines surveyed to date.

Table 2: Budget History

Year	Budget ($000)	Actual ($000)
2009F	56.0	
2008	52.0	54.0
2007	50.8	47.9
2006	49.9	51.2
2005	49.6	93.4[1]
2004	48.8	48.6

[1] Additional costs were required to obtain the surveys for Nain, Hopedale, Postville, Makkovik and Rigolet. This work was originally planned for future years.

Table 3: Length of Lines Surveyed

Year	Length (km)	Comments
2004-2006	350	Baie Verte Area (Four Distribution Systems Completed)
2007	160	Northern Distribution Lines
2008	43	Northern Distribution Lines
2009F	160	Continue with Northern Distribution Lines

In 2007, Crown Lands performed a review of the Hydro surveys, which were completed by an outside consultant during the period 2004 through 2006. Hydro's surveys required editing to comply with current Crown Lands Standards, and in 2008, Hydro spent much of the approved capital budget to have Hydro's outside consultant edit and correct these drawings for re-submission to Crown Lands. Issues included surveying roads and including them in the drawings, adding a legend on the drawings, and editing features to make them more distinctive. Due to Sections 33 and 34 of the Land Surveyors Act, 1991, Hydro could not use its own surveyors to make corrections to these drawings. The Land

Project Title: Legal Survey of Primary Distribution Line Right of Way **(cont'd.)**

Operating Experience: (cont'd.)

Surveyors Act, 1991, Section 33, Use of Seal states that "A Land Surveyor shall not affix his or her seal to a plan or document prepared in the practice of land surveying unless the plan or document was prepared by or under the personal supervision, direction or control of that Land Surveyor." Furthermore, Section 34, Survey Plan Documents, states that "(1) A master plan and duplicates of all survey plans, records and documents prepared by or under the direction of a Land Surveyor shall be retained by that Land Surveyor; (2) A person shall not, without the prior written consent of the Land Surveyor who prepared a land survey plan, alter, add to or delete from that plan or a copy or reproduction of that plan and (3) A person who contravenes subsection (2) commits an offence."

There are approximately 2,250 kilometers of distribution lines for which Hydro has no title. Applications for title to surveyed lines have been submitted to Crown Lands and are currently being processed. Since 2004, 713 kilometers of distribution line has been surveyed. The legal surveys are being completed and obtaining title is currently in progress for these surveyed lines.

Project Justification:

The distribution lines occupy Crown land without title, contrary to the Crown Lands Act. Lack of adequate title is a risk to the operation of the lines should competing requirements for the lands arise. In addition, maintenance and upgrading of the lines could be cumbersome and costly without appropriate legal easements when these lands become privately owned. Property owners are reticent to have Hydro accessing their land. The sole purpose of these surveys is to obtain easements over Crown land to prevent other parties from getting title to the land, thereby potentially complicating maintenance of the lines.

Upon purchase of Crown land, a resident receives title and it becomes private land. Although Hydro's access to Crown land has not been directly challenged, private land owners have requested Hydro to move poles and lines off private land in instances where Hydro has not acquired easements. Hydro has obliged since it has no right to cross the land to access the poles and lines.

Project Title: Legal Survey of Primary Distribution Line Right of Way **(cont'd.)**

Project Justification: (cont'd.)

Maintaining the status quo is unacceptable. In the absence of title, other parties may be able to construct, develop or otherwise use the property on which Hydro's lines are located without Hydro being consulted. Obtaining title ensures that developments do no interfere with Hydro operations.

Future Plans:

Approximately 1,537 kilometers of distribution lines remain to be surveyed. Table 4 presents Hydro's future plan for surveying lines.

Table 4: Length of Lines to be Surveyed

Year	Budget ($000's)	Length Surveyed (Km)	Length to be Surveyed (Km)
2010	65.4	160	1,377
2011	73.7	180	1,197
2012	148.3	360	937
2013	148.2	360	477
2014	152.3	360	117
2015	50.5	117	0

Future projects for legal surveys will be proposed in future capital budget applications. See five-year plan (2010 Capital Plan Tab, Appendix A).

Project Title: Install Remote Ice Growth Detector Beams
Location: Various Sites
Category: Transmission and Rural Operations - Transmission
Definition: Pooled
Classification: Normal

Project Description:

This project is required to provide ice monitoring capability in areas of Labrador that have high voltage transmission lines owned and operated by Newfoundland and Labrador Hydro (Hydro). The scope of the work includes the supply, installation and commissioning of Remote Ice Growth Detectors (RIGD) beams in Hydro terminal stations located throughout Labrador, including Happy Valley/Goose Bay, Wabush[5] and Churchill Falls[1]. This proposal is for the continuation of the original four year capital program (2006 to 2009) to establish an ice monitoring network throughout the Province. The previous stages of this program focused on the Island portion of the Province. Installation of ice monitoring equipment at the selected sites will be required for the completion of a province wide ice monitoring network. 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	12.0	0.0	0.0	12.0
Labour	26.0	0.0	0.0	26.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.0	0.0	0.0	8.0
O/H, AFUDC & Escln.	7.4	0.0	0.0	7.4
Contingency	4.6	0.0	0.0	4.6
TOTAL	**58.0**	**0.0**	**0.0**	**58.0**

Operating Experience:

A RIGD beam was initially installed at the Hawk Hill Ice Monitoring Facility approximately 15 years ago. The Hawk Hill facility is a test site, established in 1993, that contains a variety of instrumentation (meteorological as well as load sensors) to monitor the wind and ice load on a non-energized line built to 230 kV standards. The data collected from the test site has proven to be accurate and reliable. Full scale ice monitoring facilities such as Hawk Hill are costly to develop and maintain, and therefore are not typically used for ice and wind data collection. Since its installation at the Hawk Hill test site, the

[5] For monitoring transmission lines on the Labrador Interconnected System.

Project Title: Install Remote Ice Growth Detector Beams **(cont'd.)**

Operating Experience: (cont'd.)

RIGD beam has proven to be very successful and is capable of delivering results that are acceptable when compared to that of other load data from the Hawk Hill test facility. In 2006, a three year Capital Project was proposed to install RIGD ice monitoring equipment at five Terminal Stations throughout the province each year. Due to its success, Hydro continued the project to install ice monitoring equipment at five additional sites on the Island in 2009 and is applying to install Remote Ice Growth Detector Beams at three sites in Labrador in 2010.

The data received from each of the RIGD beam units are transferred through the Remote Terminal Units at each of the Terminal Stations to Hydro's Energy Control Center where they are archived in a database for future analysis. The RIGD beam is a 1 metre long x 25 millimeter in diameter hollow aluminum tube mounted as a cantilever beam that measures ice load directly through a series of strain gages mounted on the exterior of the unit. The annual maximum load at each site can be determined by analyzing this time series data. The data collected from each of the RIGD beams have proven to be reliable and valuable. Table 2 shows the locations of RIGD Beam installations.

Table 2: Past Installations of RIGD Beams

Year	Estimated Cost ($000)	Actual Cost ($000)	# of Units	Unit Cost ($000)	Location
2009F	64.7		5		Oxen Pond, Granite Canal, Roddickton, Farewell Head and Ramea
2008	46.2	49.0	5	9.8	Cat Arm, Western Avalon, Sunnyside, Doyles and Salt Pond
2007	48.0	50.4	5	10.1	Stephenville, Indian River, Buchans, Stony Brook and Bay d'Espoir
2006	27.8	30.2	5	6.0	Deer Lake, St. Anthony, Plum Point, Peter's Barren and Berry Hill

Project Justification:

The monitoring of ice accumulation on high voltage transmission lines is important for predicting long term ice loads on infrastructure. The information obtained from ice monitoring provides engineers with the knowledge to efficiently design transmission lines that have a high degree of reliability with a

Project Title: Install Remote Ice Growth Detector Beams **(cont'd.)**

Project Justification: (cont'd.)

low risk of failure. The over-design of a transmission line is uneconomical, whereas under-designing imposes a considerable risk of failure to the system, and may result in losses such as construction costs to rebuild and the potential for injury or death. Hydro has obtained a considerable amount of experience in the monitoring of ice accumulation on transmission line infrastructure. Past line failures in this Province and throughout eastern Canada show the need to develop a good database with a long term objective of reducing electrical outages caused by severe ice accumulation. Future failures could be mitigated or reduced through proper design and upgrading of transmission lines. The collection of long term data could provide early indication of these loads which would enable Hydro to take a pro-active approach into defining detailed design criteria for transmission line construction.

Future Plans:

Hydro will continue to advance the ice monitoring network by installing additional RIGD beams in other strategic locations as needs are identified in the future, to develop a regional ice map. This information, used in conjunction with existing Canadian standards, will contribute to the efficient design of transmission lines having a higher reliability and lower failure rate.

Project Title: Upgrade Remote Terminal Units
Location: Various Sites
Category: General Properties - Telecontrol
Definition: Other
Classification: Normal

Project Description:

This project is a continuation of a multiyear program to upgrade Remote Terminal Units (RTUs). RTUs are electronic devices used by the Energy Management System located in the Energy Control Centre to interface with field equipment, such as transformers, protection relays and generating units, for the purpose of controlling the power system. RTUs transmit telemetry data from a terminal station or generating plant to the Energy Management System and receive controls from the Energy Management System to operate field devices. For this year, the program consists of the installation of a new RTU at Bay d'Espoir Power House 2; and upgrades to the Hardwoods Terminal Station, Holyrood Terminal Station, and Oxen Pond Terminal Station RTUs. The upgrades to the Hardwoods Terminal Station, Holyrood Terminal Station, and Oxen Pond Terminal Station RTUs consist of replacing the microprocessor board in each unit. 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	85.0	0.0	0.0	85.0
Labour	60.4	0.0	0.0	60.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	7.0	0.0	0.0	7.0
O/H, AFUDC & Escln.	22.4	0.0	0.0	22.4
Contingency	15.2	0.0	0.0	15.2
TOTAL	**190.0**	**0.0**	**0.0**	**190.0**

Existing System:

RTUs are used in conjunction with the Energy Management Systems in the Energy Control Center to monitor and control the Island and Labrador Interconnected power systems. An RTU is located at each terminal and generating station. The RTU sends information back to the Energy Control Center regarding the status of operating equipment and receives control signals, such as starting and stopping generators and opening and closing circuit breakers, sent by the Energy Control Center to remotely controlled equipment.

Project Title: Upgrade Remote Terminal Units **(cont'd.)**

Existing System: (cont'd.)

RTUs are currently installed at the Hardwoods Terminal Station, the Holyrood Terminal Station, and the Oxen Pond Terminal Station. There is no RTU currently installed at Bay d'Espoir Power House 2 however the RTU installed at Bay d'Espoir Power House 1 is used to control all seven generating units at Bay d'Espoir. There are six 75 MW generating units in Bay d'Espoir Power House 1 and one 154 MW generating unit in Bay d'Espoir Power House 2.

Age of Equipment or System:

The Hardwoods Terminal Station and Oxen Pond Terminal Station RTUs were installed in 1998. The Holyrood Terminal Station RTU was installed in 2000. The Bay d'Espoir Power House 2 RTU is a new installation proposed for 2010.

Major Work/or Upgrades:

There have been no major upgrades since the installation of these RTUs.

Anticipated Useful Life:

RTUs are depreciated over a ten year period.

Maintenance History:

The five year maintenance history for the RTUs being upgraded is shown in Table 2 below.

Table 2: Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.0	1.1	1.1
2007	0.0	0.0	0.0
2006	0.0	1.3	1.3
2005	0.0	1.5	1.5
2004	0.0	1.1	1.1

Preventative maintenance was not required on these RTUs and has no impact on the requirement to upgrade the units.

Project Title: Upgrade Remote Terminal Units **(cont'd.)**

Existing System: (cont'd.)

Outage Statistics:

There have been no outages experienced by the RTUs being upgraded under this project.

Industry Experience:

Industry experience is not relevant to this project.

Maintenance or Support Arrangements:

Maintenance on all RTUs is performed by internal forces.

Support for issues with the operating system on the microprocessor boards was discontinued by General Electric (GE) as of December 30, 2005 and repair of any failed microprocessor boards by GE will be terminated as of December 31, 2012, or at an earlier date if electronic components are no longer available.

Vendor Recommendations:

GE recommends that the microprocessor boards be replaced with a supported model.

Availability of Replacement Parts:

Hydro currently has 25 RTUs in service that use the model of microprocessor board no longer supported by GE. Three of these RTUs are proposed for upgrading in 2010. There are four spare microprocessor boards currently in Hydro's inventory.

Safety Performance:

There are no safety performance concerns or safety code violations associated with this project.

Environmental Performance:

There are no environmental performance concerns or environmental code violations associated with this project.

Operating Regime:

This equipment is used to control and monitor the Island Interconnected power grid and operates in a continuous mode.

Project Title: Upgrade Remote Terminal Units **(cont'd.)**

Justification:

The model of microprocessor board used in the Hardwoods Terminal Station, Holyrood Terminal Station, and Oxen Pond Terminal Station RTUs being upgraded has been discontinued by the manufacturer. Although support for this model of microprocessor board is no longer provided, repairs to the microprocessor board will continue to be performed by GE until December 31, 2012 or an earlier date if electronic components are no longer available. Hydro currently has 25 RTUs in operation which use this model of microprocessor board and there are only four spare boards held in inventory. With the loss of an RTU, the Energy Control Center would lose visibility over the portion of the power grid served by that RTU and would no longer be able to monitor and control a portion of the power system. This would impact Hydro's ability to provide reliable and safe service.

A new RTU installation is required at Bay d'Espoir Power House 2 to increase reliability in the control of Hydro's largest generating plant. Currently, all equipment located at Bay d'Espoir at both power house 1 and 2 is connected to the Bay d'Espoir Power House 1 RTU. If a failure occurs in the Bay d'Espoir Power House 1 RTU, Energy Control Center will loose monitoring and control capability for all seven units at Bay d'Espoir. A separate RTU at Bay d'Espoir Power House 2 will increase reliability in Energy Control Center's control of the Bay d'Espoir Generating Station.

<u>Net Present Value:</u>

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

<u>Levelized Cost of Energy:</u>

As this project does not involve new generation sources, the levelized cost of electricity is not applicable.

<u>Cost Benefit Analysis:</u>

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

<u>Legislative or Regulatory Requirements:</u>

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

<u>Historical Information:</u>

Table 3 shows historical information for RTU replacement and upgrades.

Project Title: Upgrade Remote Terminal Units **(cont'd.)**

Justification: (cont'd.)

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2009F	278.3		4		2 replacements; 2 new installations
2008	318.8	280.8	5	56.2	3 replacements; 2 upgrades
2007	320.8	258.0	4	64.5	
2006	350.9	226.0	4	56.5	
2005	183.0	204.0	2	102.0	Costs were higher than average because of a requirement to replace large quantities of cable.
2004	313.8	325.0	4	81.3	

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits:

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

Losses During Construction:

There will be no customer outages associated with this project. While an upgrade is being performed an operator will be assigned to the terminal station in order to manually control equipment, if required.

Status Quo:

The status quo is not an acceptable alternative because it increases the risk of customer outages occurring and decreases reliability.

Alternatives:

There are no viable alternatives.

Project Title: Upgrade Remote Terminal Units **(cont'd.)**

Conclusion:

This project is necessary because of the critical nature of RTUs in controlling the Island Interconnected System. To ensure that Hydro can continue to provide reliable least-cost energy to its customers into the future, obsolete equipment which cannot be properly supported must be upgraded.

Project Schedule:

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	Milestone
Project Initiation	February 2010
Equipment Ordered	April 2010
Testing Complete	July 2010
Installation and Commissioning Complete	October 2010
Project Closed	November 2010

Future Plans:

Future plans for the upgrade of RTUs to replace microprocessor boards are summarized in Table 5.

Table 5: Future RTU Upgrades

Project Year	RTU Location	Installed Year
2011	Peter's Barren Terminal Station (PBN)	1995
	Plum Point Terminal Station (PPT)	1995
	St. Anthony Airport Terminal Station (STA)	1995
	St. Anthony Diesel Plant (SDP)	1995
	Hawke's Bay Terminal Station (HBY)	1995
	Daniel's Harbour Terminal Station (DHR)	1995
2012	Star Lake Plant (SLK)	1998
	Rattle Brook Plant (RBK)	1998
	Cat Arm Sync Remote (CAS)	1999
	Cat Arm Sync Sub (CMS)	1999
	Cat Arm Intake (CAI)	1999

Project Title: Upgrade Remote Terminal Units **(cont'd.)**

Future Plans: (cont'd.)

Table 5: Future RTU Upgrades (cont'd.)

Project Year	RTU Location	Installed Year
2013	Upper Salmon Intake (USI)	1999
	North Salmon Dam (NSD)	1999
	West Salmon Spillway (WSS)	1999
	Western Avalon Terminal Station (WAV)	2000
2014	Hinds Lake Concentrator (HLX)	2000
	Hinds Lake Spillway Sub (HMS)	2000
	Hinds Lake Control Structure Sub (HMC)	2000
	Hinds Lake Intake Sub (HMI)	2000
	Hinds Lake Spillway (HLS)	2000
	Hinds Lake Control Structure (HLC)	2000
	Hinds Lake Intake (HLI)	2000

Project Title: Upgrade Enterprise Storage Capacity
Location: Hydro Place
Category: General Properties - Information Systems
Type: Other
Classification: Normal

Project Description:

This project is to upgrade the existing Tape Library with four LTO-4 Tape Drives and to add an additional four shelves of Disk Storage, which will be approximately 15 Terabytes of storage, to the existing DS4800 Storage Area Network (SAN). The additional storage will be used to offset data growth for 2009 and 2010. A SAN is a network of storage devices which holds data for a number of servers. A tape library is a storage device which contains one or more tape drives, a number of slots to hold tape cartridges, a barcode reader to identify tape cartridges and an automated method for loading tapes (a robot). 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	182.9	0.0	0.0	182.9
Labour	15.0	0.0	0.0	15.0
Consultant	15.0	0.0	0.0	15.0
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.	7.2	0.0	0.0	7.2
Contingency	21.3	0.0	0.0	21.3
Subtotal	241.4	0.0	0.0	241.4
Cost Recoveries	(72.4)	0.0	0.0	(72.4)
TOTAL	**169.0**	**0.0**	**0.0**	**169.0**

Operating Experience:

Disk capacity has grown at a rate of approximately 30 percent per year over the last five years and is projected to grow at this rate into the future. This is slightly below the industry standard growth rates (50-70 percent per year). Storage Resource Management Tools, installed in 2007, allow Hydro to effectively manage data and disk usage.

As this budget involves the upgrade of an existing piece of software the following items are not considered relevant to the proposal:

- Outage Statistics;
- Industry Experience;
- Vendor Recommendations;

Project Title: Upgrade Enterprise Storage Capacity **(cont'd.)**

Operating Experience: (cont'd.)

- Availability of Replacement Parts;
- Safety Performance;
- Environmental Performance; and
- Operating Regime.

<u>Age of Equipment or System</u>
The Tape Library with LTO-2 Tape drives is six years old. The DS4800 SAN is two years old.

<u>Major Work/or Upgrades</u>
The upgrades listed in Table 2 have occurred since installation. Costs associated with these upgrades are shown in Table 3 of the Historical Information section of this report.

Table 2: Major Work and Upgrades

Year	Major Work/Upgrade	Comments
2008	Additional SAN installed	Additional disk storage space installed.
2007	Tivoli Productivity Center (TPC) installed	A storage management toolset was purchased and installed to allow better management of the SAN.

<u>Anticipated Useful life</u>
The new LTO-4 Tape Drives and Tapes have an estimated service life of six years. The disk capacity expansion for the DS4800 will have an estimated service life of six years also.

<u>Maintenance or Support Arrangements</u>
The LTO-4 Tape Drives and Expansion Shelves for the DS4800 will be covered by the current maintenance agreement with IBM. The maintenance agreement will cover hardware failures.

Justification:

The existing Tape drives, LTO-2, have a storage capacity of 400 GB/Tape and a maximum data transfer rate of 80 MB/sec. The proposed new LTO-4 Tape drives will have a storage capacity of 1.2 TB/Tape and a maximum data transfer rate of 320 MB/sec. The new LTO-4 Tape Drives and Tapes will increase

Project Title: Upgrade Enterprise Storage Capacity **(cont'd.)**

Project Justification: (cont'd.)

the amount of data stored per tape and also decrease the length of time it would take to transfer that data, therefore speeding up the backup. The new LTO-4 Tape drives will also allow Hydro to encrypt the data on the tapes for offsite storage to allow for better security.

The servers that are attached to the Storage Area Network are used by Hydro employees in running the business on a daily basis. A reduction in the performance of these servers due to disk space unavailability would have a negative effect on employee productivity and customer service. The additional disk capacity added to the DS4800 SAN will provide for the efficient management and growth of the disk storage for the Intel Server Infrastructure.

As this budget proposal is for an upgrade for an existing piece of software the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Energy Efficiency Benefits; and
- Losses during Construction.

Legislative or Regulatory Requirements

The Management of Information Act and Statute of Limitations Act require Hydro to retain relevant data for a six year period. This requires systems to be backed up regularly onto tapes for off-site storage. Hydro's policy is to retain this data for a period of seven years.

Forecast Growth

The projected data growth for the storage system is approximately 30 percent per year with data remaining at current anticipated levels.

Net Present Value

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

Cost Benefit Analysis

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

Project Title: Upgrade Enterprise Storage Capacity **(cont'd.)**

Project Justification: (cont'd.)

Historical Information

Table 3 shows the historical costs of the Storage Area Network.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2009			No capacity increase required
2008	261.7	260.8	Installed DS4800 SAN
2007	148.6	148.6	Management Tool Set
2006			No capacity increase required
2005	463.5	463.5	SAN Disk and Tape Library Expansion

Status Quo

The consequences of not completing this project is that the time it takes to complete a backup increases as the amount of storage increases. The systems are required during the night as well as during business hours and Hydro must insure that the computer system is available.

If the Disk capacity of the DS4800 SAN is not increased Hydro could run into disk space limits which would degrade the performance of the system and the productivity of employees.

Alternatives

There are no viable alternatives that will incorporate into the existing system. The only alternative would involve replacing the entire existing Tape system.

Project Schedule

The project is scheduled to start in February 2010 and be completed by the end of June 2010.

Future Plans:

Future upgrades will be proposed in future capital budget applications. Enterprise storage upgrades are planned for the next four years as shown in the five year plan (2010 Capital Plan Tab, Appendix A).

Project Title: Upgrade Server Technology Program
Location: Various Sites
Category: General Properties - Information Systems
Type: Other
Classification: Normal

Project Description:

This project is a part of the Server and Operating System Evergreen Program which involves the replacement, addition and upgrade of hardware components and software related to Hydro's server infrastructure and upgrades to the server-based office productivity tools.

The scope of the proposed project includes the replacement of 14 servers. 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	120.0	0.0	0.0	120.0
Labour	29.0	0.0	0.0	29.0
Consultant	24.0	0.0	0.0	24.0
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.	6.3	0.0	0.0	6.3
Contingency	17.3	0.0	0.0	17.3
Sub-Total	196.6	0.0	0.0	196.6
Cost-Recoveries	(59.0)	0.0	0.0	(59.0)
TOTAL	**137.6**	**0.0**	**0.0**	**137.6**

Operating Experience:

There are 95 servers in use which support and are used to run various applications. The applications that run on these servers include the Energy Management System, Enterprise Resource Planning and email systems. These applications are used by staff in running the business on a day to day basis.

Based on the age of existing servers, each year an appropriate number of servers will be replaced. This ensures that the Corporation has a reliable and secure infrastructure environment required to support efficient operations.

As this budget proposal is for the routine replacement of hardware and software related to the Corporations shared server infrastructure, the following items are not relevant to this proposal:

Project Title: Upgrade Server Technology Program **(cont'd.)**

Operating Experience: (cont'd.)

- Major Work / Upgrades;
- Maintenance History;
- Outage Statistics;
- Safety Performance; and
- Environmental Performance.

<u>Age of Equipment or System</u>

The age of the equipment being replaced ranges from five to eight years. The average age is six years.

<u>Anticipated Useful life</u>

Industry standards indicate that server hardware has a useful life of five years. Beyond this timeframe reliability and support may become problematic.

<u>Industry Experience</u>

Based on industry standards and operating experience, Hydro servers will be replaced at an age of five to six years based on the importance of the applications running on that server.

<u>Maintenance or Support Arrangements</u>

IBM support for the 14 servers is discontinued. Hydro has determined that the standard three year manufacturer warranty is sufficient for its Intel Server Infrastructure. After the initial three year warranty, the server is repaired on a time and material basis.

<u>Vendor Recommendations</u>

IBM recommends that servers be replaced in a five year lifecycle.

<u>Availability of Replacement Parts</u>

Parts may not be available after five years for the 14 servers to be replaced depending on the component that fails.

Project Title: Upgrade Server Technology Program **(cont'd.)**

Operating Experience: (cont'd.)

Operating Regime

Hydro's servers are used on a continuous basis. The servers are active for the life of the unit once placed in service.

Project Justification:

The factors that are driving Hydro's proposal to replace/upgrade its server environment include:

- Addressing obsolescence/maintaining vendor support;
- Providing security/managing the infrastructure; and
- Supporting current versions of applications.

Obsolescence/Vendor Support - Without vendor support, the functions and services reliant on the server infrastructure are at risk as security and support patches for the operating system will no longer be available. As a result, Hydro's ability to support and ensure continuation of these functions and services is impeded. At this time, the vendor support and inventory of spare parts are discontinued. As the servers are used by Hydro employees to provide support in running the business on a daily basis, loss of availability of these servers would have a negative effect on employee productivity by not allowing access to software applications.

Providing security/managing the infrastructure – As technology advances, there are built-in architectures and devices that improve the security of the servers and allow for better management of them.

Supporting current versions of applications – As applications are upgraded and new applications implemented throughout the organization, many are built to take advantage of technologies only present in the newer servers. An example would be an application built to take advantage of the new Hyper-threading Technology, if it is present, would have an increased processing speed.

Project Title: Upgrade Server Technology Program **(cont'd.)**

Project Justification: (cont'd.)

As this budget proposal is for the routine replacement of hardware and software related to the Corporations shared server infrastructure, the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

Net Present Value

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

Cost Benefit Analysis

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

Historical Information

Table 2 shows the historical costs of the Server and Operating System Evergreen Program.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Unit Cost ($000)(1)
2009F	272.6			
2008	249.2	249.2	21	11.9
2007	81.8	81.8	5	16.4
2006	0.0(2)	0.0	0	0.0
2005	212.0	179.0	12	14.9

(1) Server price varies on a year to year basis due to processor power and memory requirements.

(2) Server lifecycle was extended by one year, thus the refresh program was deferred by a year.

Project Title: Upgrade Server Technology Program **(cont'd.)**

Project Justification: (cont'd.)

Status Quo

Hydro must keep its servers current in order to adequately support and protect the Information Technology infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned outages, possible data loss, and data corruption. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

Alternatives

The alternative to a server refresh program is to replace servers as they fail. This would put the infrastructure at risk of unplanned outages, possible data loss, and data corruption. This alternative would also cause a significant increase in maintenance costs as repairs are undertaken and spare equipment is kept on hand. This is not a viable alternative.

Project Schedule

The project is scheduled to start in April 2010 and be completed by the end of November 2010.

Future Plans:

This is an ongoing refresh program to maintain server performance. Future replacements and upgrades will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Replace Network Communications Equipment
Location: Various Sites
Category: General Properties - Telecontrol
Definition: Other
Classification: Normal

Project Description:

Newfoundland and Labrador Hydro's (Hydro's) communications network enables employees to perform computer based administrative and operations related activities and to connect to Energy Management System data at various locations. This project is required to install new administrative network communications equipment to extend network access to the St Brendan's, Little Bay Islands and McCallum diesel plants and to the Sop's Arm and Fogo line depots.

The equipment to be installed includes routers, network switches and firewalls. A router is a device that permits network traffic to flow between different locations. A switch allows multiple computers to use a network simultaneously at a given location. A firewall blocks unauthorized access to a network at a given location.

The project is estimated to cost $130,800 as is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	33.0	0.0	0.0	33.0
Labour	41.4	0.0	0.0	41.4
Consultant	3.0	0.0	0.0	3.0
Contract Work	8.0	0.0	0.0	8.0
Other Direct Costs	20.0	0.0	0.0	20.0
O/H, AFUDC & Escln.	14.9	0.0	0.0	14.9
Contingency	10.5	0.0	0.0	10.5
TOTAL	**130.8**	**0.0**	**0.0**	**130.8**

Operating Experience:

The proposed locations do not currently have access to Hydro's communications network. Computer networks are installed at most Hydro locations, including large offices, line depots, generating stations, and terminal stations. These networks provide employees with email communication, office productivity tools such as word processing and spreadsheets, and information that employees need to perform their functions. Information can include technical information such as drawings, data sheets, corporate and industry standards, and equipment manuals; safety and health information, such as Material Safety Data Sheets (MSDS), the Corporate Health and Safety Program, and access to legislation and regulations pertaining to safety; system and equipment status information, such as

Project Title: Replace Network Communications Equipment **(cont'd.)**

Operating Experience: (cont'd.)

Hydro's Energy Management System (EMS), video camera access at remote locations, equipment monitoring, and hydrological information; and general information on Corporate policies, procedures, and initiatives.

Table 2 shows the history of expenditures in this project for the past five years.

Table 2: Budget History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Unit Cost ($000)	Comments
2009F	141.0				
2008	130.6	144.1	24	6.0	Additional training required on communications equipment.
2007	101.8	124.4	22	5.7	Project exceeded budget due to unexpected equipment failure and greater than anticipated network growth requirements.
2006	96.7	143.0	26	5.5	Department of Government Services initiated a requirement for high speed networks to be installed at diesel generating stations for access to Hydro's online Health & Safety program, Material Safety Data Sheets (MSDS) and other health and safety related information
2005	0.0	0.0	0	0.0	
2004	45.5	40.0	9	4.4	

Project Justification:

The new network equipment is required to support the anticipated requirements for new network connections for offices, terminal stations, power plants and microwave repeater sites. The demand for new services includes a mixture of office automation traffic such as e-mail, work requests and database access to substation automation functions such as remote high speed access to meters and Intelligent Electronic Devices (IEDs).

Future Plans:

Future installations will be proposed in future capital budget applications.

Project Title: Develop Learning Management System Safety Courses
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

Safety is the primary concern when work is required to be performed on Newfoundland and Labrador Hydro (Hydro) or customer equipment, or when providing a service on behalf of Hydro. The proposed project will develop online learning courses in a modular format that will educate employees in the following topics:

- Transportation of Dangerous Goods, including PCB Storage and Handling;
- Hazard and Risk Identifications (Tailboard Safety);
- Arc Flash Awareness; and
- Asbestos Awareness.

Five hours of online course material will be made available through this project. 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	0.0	0.0	0.0	0.0
Labour	20.4	0.0	0.0	20.4
Consultant	100.0	0.0	0.0	100.0
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.	5.2	0.0	0.0	5.2
Contingency	12.0	0.0	0.0	12.0
Sub-Total	137.6	0.0	0.0	137.6
Cost Recoveries	(41.3)	0.0	0.0	(41.3)
TOTAL	**96.3**	**0.0**	**0.0**	**96.3**

Operating Experience:

In the past two years Hydro has started a process of moving elements of its training program to an online (e-learning) format. Three courses were made available in 2008. A Work Protection Code course will be implemented in 2009. This project is a continuation of the effort to make courses that are critical from an operational and safety point of view, readily available to employees.

Project Title: Develop Learning Management System Safety Courses **(cont'd.)**

Project Justification:

Initial training for new hires is problematic in that often there are too few in numbers to warrant an instructor to teach a class, so they may have to wait for months before receiving any training in these topics at all. An online program would eliminate the need to wait for a critical mass to offer training and would enable employees to begin the practical part of their training much earlier.

In addition to new hires, preliminary estimates show that training will be readily available to potential audiences that number as follows (Hydro only):

- Hazard and Risk Identifications (Tailboard Safety) –600 employees;
- Transportation of Dangerous Goods – 400 employees;
- Arc Flash Awareness – 500 employees; and
- Asbestos Awareness – 500 employees.

Finally, these additional benefits may be derived from the project:

- a reduction in the amount of scheduling and coordination required to provide this training;
- a reduction in travel and accommodation requirements associated with training; and
- a consistent message delivered across all training for the courses developed.

Future Plans:

Developing training in this online format will continue for the foreseeable future. This initiative will be expanded to include core training requirements in addition to safety related ones. Future developments will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Smart Card Implementation
Location: Various Sites
Category: General Properties - Information Systems
Definition: Pooled
Classification: Normal

Project Description:

The Smart Card Implementation Project will deploy Smart Card technology to the remaining 46 percent of laptop users within the company. The Smart Card technology has four major components: (1) disk encryption for laptop computers; (2) simplified sign-on to user systems and applications; (3) a centralized management tool for smart card administrators; and (4) a combination of building and computer access via one card.

When an employee wants to use a laptop, the Smart Card is inserted into the reader and a password is also entered. The laptop is then unlocked, and the Smart Card activates any logon credentials that are securely stored on the card. It also restricts unauthorized access, since an unauthorized user would have to have both the actual card and password to unlock the laptop or application. 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	83.0	0.0	0.0	83.0
Labour	33.9	0.0	0.0	33.9
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.	4.2	0.0	0.0	4.2
Contingency	11.7	0.0	0.0	11.7
Sub-Total	132.8	0.0	0.0	132.8
Cost Recoveries	(39.9)	0.0	0.0	(39.9)
TOTAL	**92.9**	**0.0**	**0.0**	**92.9**

Operating Expenses:

Newfoundland and Labrador Hydro (Hydro) is implementing a Smart Card technology for laptop users in 2009. This implementation was after a pilot project to determine the effectiveness of the proposal. There were no major technical issues associated with the pilot project and user response to the Smart Card was positive. The Smart Card technology uses a centrally managed disk encryption system that

Project Title: Smart Card Implementation **(cont'd.)**

Operating Expenses: (cont'd.)

can be fully monitored and controlled. The server infrastructure needed to support the additional laptop users is already in place. The administrative and management expertise needed to support Smart Card technology is developed within the Information Systems (IS) Department.

Project Justification:

A Directive from the Government of Newfoundland and Labrador in January 2008 indicated that storing sensitive information on unencrypted portable storage devices was not permissible. As a Crown corporation, the same guidelines apply to Hydro. By the end of 2009, IS will have implemented Smart Card technology on 54 percent of our laptops. Increased costs for the actual Smart Cards in 2009 resulted in fewer laptops being protected with this technology than originally planned. This project will ensure that all corporate laptops have the same level of protection and are controlled and administered with consistency.

Hydro has a responsibility to protect its sensitive and confidential corporate information from accidental or targeted security exposures. Smart Card technology supplies hard disk encryption and two-tiered security – something one has (the actual Smart Card) and something one knows (a Personal Identification Number or PIN).

Without this technology, if a laptop is lost or stolen there is a high risk that any sensitive information stored on the laptop could be exposed.

Future Plans:

None.

Project Title: Upgrade Operator Training Simulator
Location: Holyrood
Category: General Properties - Telecontrol
Definition: Other
Classification: Normal

Project Description:

Newfoundland and Labrador Hydro (Hydro) has an Operator Training Simulator located in the Energy Control Centre (ECC) in St. John's. It is currently being used to train one operator at a time. This project is required to upgrade the Operator Training Simulator System to allow the Backup Control Centre at Holyrood to be used for the training of two operators at a time.

This project includes enabling the existing consoles at the Backup Control Centre to be used for operator training and providing the communication infrastructure to allow these consoles to work with the Operator Training Simulator Server located at the ECC. 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	8.6	0.0	0.0	8.6
Labour	44.6	0.0	0.0	44.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	21.0	0.0	0.0	21.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	10.7	0.0	0.0	10.7
Contingency	7.4	0.0	0.0	7.4
TOTAL	**92.3**	**0.0**	**0.0**	**92.3**

Operating Experience:

The Operator Training Simulator was commissioned in 2006 and is located at the ECC in St. John's. It is currently being used to provide ECC staff with the skills necessary to deal with abnormal conditions, disturbances or emergency conditions on the Island Interconnected and Labrador Interconnected Systems. A training program has been established for ECC staff that provides them with opportunities to gain simulated operating experience that would otherwise only be achieved through years of experience in operating the electric power system.

The current Operator Training Simulator training environment only allows the training of one operator at a time. It is difficult to simulate some outages with one person as the events and responses can be too much for one person to handle. It doesn't provide the operators with the most realistic experience as the normal operating environment is a two-person team. It also doesn't provide the

Project Title: Upgrade Operator Training Simulator **(cont'd.)**

Operating Experience: (cont'd.)
operators the opportunity to build effective teams and to discuss how they can best proceed when trying to restore the system. This aspect of creating good communication and understanding each person's role is critical in a control center environment, particularly during abnormal situations.

Project Justification:
Operators in the ECC work as a two-person team, 24 hours a day, seven days a week. However, the current simulator environment at the ECC permits training of only one operator at a time and the existing facility is not expandable to add a second console to allow training of two operators at the same time. In order to more closely simulate the actual working environment and build collaborative teams, the ability to train two operators at the same time is required.

The Backup Control Centre (BCC) in Holyrood provides the required operating consoles in which the training of a two-person team can be completed. However, the training simulator cannot presently be used on the existing consoles at the BCC. By upgrading the Operator Training Simulator to allow its use at the BCC, two operators can be trained together in order to more closely simulate actual working conditions.

The problem being experienced with completing one person training is that it is not the normal working environment. Operators are used to working in two-person teams so they can assist each other during abnormal situations and discuss appropriate actions to take. Having the capability to train a two-person team would help make the Operator Training Simulator environment as realistic as possible. In addition, it is difficult to simulate some disturbances as the system events and required responses can be too much for one person to handle.

Hydro will continue to use the Operator Training Simulator at the ECC to provide individual training for each operator as there is a benefit in having the trainer interact on a one-on-one basis with each operator. However, with this upgrade, Hydro will focus on two person training as that provides the most realistic experience.

This project is justified on the basis of providing reliable power by enabling operators to provide a more effective response to significant events on the electric power system.

Future Plans:
None.

Project Title: Perform Minor Application Enhancements
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

Newfoundland and Labrador Hydro's (Hydro) many computer applications are used daily by employees to run the business. Examples of these applications include the JD Edwards Enterprise Resources Planning Suite, the Lotus Notes Email and Collaboration Suite, the Showcase Business Intelligence and Reporting Suite, and the Microsoft Office Productivity Suite. This project is necessary to enhance these applications to support changing business requirements. The application enhancement project provides for minor enhancements to applications in response to unforeseen requirements such as regulatory and changing business needs. 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	21.0	0.0	0.0	21.0
Labour	67.2	0.0	0.0	67.2
Consultant	17.2	0.0	0.0	17.2
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.	4.8	0.0	0.0	4.8
Contingency	10.5	0.0	0.0	10.5
Sub-Total	120.7	0.0	0.0	120.7
Cost Recoveries	(36.2)	0.0	0.0	(36.2)
TOTAL	**84.5**	**0.0**	**0.0**	**84.5**

Operating Experience:

This project has been used in the past to fund enhancements to applications such as the safety and audit databases, full time equivalent reporting, and equalized billing. In 2008, the most recent year for which actual data is available, the following application enhancements were made: adjustment to the Capital Asset Projection Model System; acquisition and installation of Google Enterprise Search Licenses; upgrade of Webtrends Software; acquisition of Optical Mark Recognition Software for Customer Billing; upgrade of Audit Management Software to the latest release; Camera Software upgrade to support online meeting technology; acquisition of additional Autosketch Licenses; and acquisition of additional Microsoft Office Licenses.

Project Title: Perform Minor Application Enhancements **(cont'd.)**

Project Justification:

This project, part of normal Information Systems department work, is necessary to enhance existing applications to support changing business and regulatory requirements. Work completed as part of this project is justified on the basis of operational efficiency and response to regulatory and legislative requirements.

Table 2 shows upgrades that have occurred from 2005-2009F.

Table 2: Application Enhancements

Year	Budget ($000)	Actual ($000)	Comments[(1)]
2009F	120.2[(2)]		Upgrade
2008	372.5[(2)]	369.8	Upgrade
2007	148.5[(2)]	148.5	Upgrade
2006	780.0[(3)]	390.0	Upgrade
2005	398.0	334.0	Upgrade

(1) Upgrade refers to adding or extending functionality of applications

(2) Previous Budgets included the Intranet and/or Internet Refresh Proposals. These have now been moved to distinct proposals.

(3) The "Enhancements to the Capital and Operating Process Applications" component of this budget was cancelled. The budgeted amount for this component was $390,000.

Future Plans:

Future enhancements will be proposed in future capital budget applications. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Replace Humidifiers in Air Handling Units
Location: Hydro Place
Category: General Properties - Administrative
Definition: Other
Classification: Normal

Project Description:

In 2008, a humidifier replacement program was initiated to replace humidifiers located in air handling systems at Hydro Place. These humidifiers have reached the end of their useful lives. A total of 8 humidifiers will be replaced under the program. Two humidifiers will be replaced in 2010. 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	0.0	0.0	0.0	0.0
Labour	8.1	0.0	0.0	8.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	53.0	0.0	0.0	53.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	8.0	0.0	0.0	8.0
Contingency	6.1	0.0	0.0	6.1
TOTAL	**75.2**	**0.0**	**0.0**	**75.2**

Operating Experience:

Hydro Place is the corporate headquarters of Newfoundland and Labrador Hydro (Hydro). The Energy Control Centre, which remotely controls most of Hydro's facilities, is also located in Hydro Place. This six storey building was constructed in 1989.

Ventilation air is provided throughout Hydro Place by ten air handling systems. Each air handing system controls the temperature, humidity, and amount of air provided to a specific location. The existing humidifiers were installed in 1989 when the Hydro Place facility was constructed and are at the end of their service lives of 20 years.

Project Justification:

Johnson Controls has recommended the replacement of all humidifiers installed at Hydro Place. This recommendation is based on the following:

Project Title: Replace Humidifiers in Air Handling Units **(cont'd.)**

Project Justification: (cont'd.)

- Control system is obsolete.
- Existing units contain disposable plastic water bottles.
    - These cannot be cleaned and must be disposed of when fouled.
    - Plastic water bottles are expensive to replace.
- New humidifiers are more energy efficient than older models.
    - Improved insulation results in more heat retention.

At Hydro Place, one humidifier is currently out of service due to a control system failure. Replacement parts are not available due to the obsolescence of the control system.

Heated water is stored inside humidifiers in water bottles. Over time, mineral deposits foul the inside of the bottles. Unlike disposable plastic water bottles, stainless steel water bottles are not disposable and may be cleaned. The humidifiers at Hydro Place contain plastic water bottles that are replaced, at least annually, at a cost of $400 to $600 each. Johnson Controls has indicated that stainless steel bottles can be cleaned in about 15 minutes. The cost of cleaning a stainless steel water bottle is much less than the cost of replacing a plastic water bottle.

Due to improved insulation properties, water stored inside new humidifiers will retain its heat better than water stored inside older humidifiers. This results in energy savings.

Just like the two previous years of this five-year replacement program, the implementation of this project will maintain the air quality at Hydro Place by ensuring humidification takes place when required. Operating costs of approximately $500 per humidifier per year will be saved. In addition, by purchasing new humidifiers with stainless steel water bottles, less waste is generated from the humidification processes.

Future Plans:

In 2011, two humidifiers will be replaced at Hydro Place. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Upgrade Security SCADA Intrusion Prevention System
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

The SCADA (Supervisory Control and Data Acquisition) - Intrusion Prevention System (IPS) project will provide realtime protection for the Energy Management System's (EMS) SCADA system against computer viruses and other cyber threats by examining inbound and outbound traffic in real time. The (EMS) SCADA system is a computer system that controls the provincial power grid. Intrusion prevention technology attempts to stop attacks before they are successful thus helping to ensure network availability and uninterrupted service for users and customers. The EMS is a system of computer-aided tools used by Hydro to monitor, control and optimize the performance of the generation and/or transmission system.

A 24-hour, 7-day a week managed Security Operations Centre (SOC) will provide fast and accurate detection and response to any security threat to the EMS. The SOC will monitor all inbound and outbound traffic and take whatever steps are necessary to protect the EMS should an issue arise. 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	33.4	0.0	0.0	33.4
Labour	20.9	0.0	0.0	20.9
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.	1.9	0.0	0.0	1.9
Contingency	5.4	0.0	0.0	5.4
TOTAL	**61.6**	**0.0**	**0.0**	**61.6**

Operating Experience:

The SCADA system is the underlying electronic management system for the Island Interconnected and Labrador Interconnected Systems. The SCADA system gathers information and data from grid components, transfers the data back to a central site, conducts analysis and control, and provides

Project Title: Upgrade Security SCADA Intrusion Prevention System **(cont'd.)**

Operating Experience: (cont'd.)

alerting and reporting capabilities. The SCADA system is a critical component of the EMS. A managed IPS adds one more protective layer around the SCADA system and protects critical information and assets from existing and emerging threats.

Project Justification:

This project is justified on Hydro's responsibility to protect its critical (SCADA) control data from existing or emerging threats. As the sophistication of hackers increases, so must the effort to protect our critical systems. A managed IPS can provide continuous monitoring from a centralized SOC and add another layer of protection against unauthorized access to the SCADA system and EMS. Potential threats can be identified, monitored, reported, and responded to before they cause irrevocable damage to the SCADA system, EMS and the Provincial power grid. A managed IPS follows the philosophy of several industry standards, including the Industrial Automation and Control Systems (ISA99), the North America Electric Reliability Corporation – Critical Infrastructure Protection (NERC – CIP) standard, and the National Institute of Standards & Technology (NIST 800-83).

Future Plans:

Future upgrades will be proposed in future capital budget proposals. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Upgrade Business Intelligence Toolset Software
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

This project will update the Business Intelligence Toolset (Essbase and Analyzer products) to the latest available release. The project will implement a new user interface to the users as part of the upgrade. 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	15.3	0.0	0.0	15.3
Labour	26.0	0.0	0.0	26.0
Consultant	29.3	0.0	0.0	29.3
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.8	0.0	0.0	2.8
O/H, AFUDC & Escln.	3.1	0.0	0.0	3.1
Contingency	7.3	0.0	0.0	7.3
Sub-Total	83.8	0.0	0.0	83.8
Cost Recoveries	(25.1)	0.0	0.0	(25.1)
TOTAL	**58.7**	**0.0**	**0.0**	**58.7**

Operating Experience:

Newfoundland and Labrador Hydro has been using the Business Intelligence Toolset to support the Capital Asset Projection Model and its Key Performance Indicators systems. These systems are used on a day to day basis by staff and management in the running of the business as it presents information in a consolidated and timely manner.

Project Justification:

The project is justified on the fact that the product vendor has informed us that our existing version will no longer be supported after mid 2010.

Future Plans:

Future enhancements will be proposed in future capital budget applications. See five-year capial plan (2010 Capital Plan Tab, Appendix A).

Project Title: Upgrade Security Vulnerability Management System
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

The Managed Vulnerability Management System (VMS) project will provide realtime protection for the Information Systems (IS) Administrative network. A VMS proactively manages system vulnerabilities and helps to reduce or eliminate the potential for exploitation. A network has many components - software, hardware, peripherals - and each has identified areas that could be exploited by hackers or other cyber threats such as worms or viruses. A managed VMS continuously scans each component for the latest security updates or patches and immediately notifies IS personnel if it detects a missing patch. The VMS monitors the situation until the vulnerability has been dealt with and the issue resolved.

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	51.5	0.0	0.0	51.5
Labour	20.3	0.0	0.0	20.3
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.	2.4	0.0	0.0	2.4
Contingency	7.2	0.0	0.0	7.2
Sub-Total	81.4	0.0	0.0	81.4
Cost Recoveries	(24.4)	0.0	0.0	(24.4)
TOTAL	**57.0**	**0.0**	**0.0**	**57.0**

Operating Experience:

Newfoundland and Labrador Hydro (Hydro) does not have a managed vulnerability management system. IS staff rely on a number of external services to provide vulnerability information that may or may not pertain to our resources and environment. Applying patches and mitigating vulnerabilities is not a straightforward process. It can take hours of in-depth analysis and investigation to determine if a security patch needs to be applied to our infrastructure. The system administrator then has to ensure the security patch is deployed properly with minimal interruption to the users.

Project Title: Upgrade Security Vulnerability Management System **(cont'd.)**

Project Justification:

Hydro's critical systems and its sensitive information need to be protected. Cyber threats such as viruses and worms are becoming more numerous and complex. Computer networks including hardware, software and peripherals are becoming more intricate and challenging to manage. Hydro has implemented security measures to protect against known vulnerabilities however every day new threats (viruses, worms, and other malware) are being discovered which have to be analyzed and interpreted to see if they affect our environment. If our analysis determines our environment is at risk, real-time countermeasures must be applied. Hydro has been fortunate that, up to now, there has not been a significant loss of user productivity due to an unpatched vulnerability. Manual initiatives alone are not going to be sufficient to protect our computer systems given the infection speed of the new malware. A managed vulnerability management system will provide Hydro's computer systems with continuous protection against emerging threats and vulnerabilities before they can be exploited.

Future Plans:

Future upgrades will be proposed in future capital budgets. See five-year capital plan (2010 Capital Plan Tab, Appendix A).

Project Title: Work Protection Software Design
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

The Work Protection Code (WPC) is a complex set of rules that must be applied to help ensure that employees are provided with the safest possible work environment by standardizing the conditions under which all sources of energy must be isolated and equipment de-energized. This project is to design a specialized Work Protection Code (WPC) software application for the automation and work flow of the WPC requirements in Hydro Plants and the Energy Control Center. A separate budget will be put forward in 2011 for the implementation of the software.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2010**	**2011**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	34.0	0.0	0.0	34.0
Consultant	24.0	0.0	0.0	24.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.0	0.0	0.0	4.0
O/H, AFUDC & Escln.	2.5	0.0	0.0	2.5
Contingency	6.2	0.0	0.0	6.2
Sub-Total	70.7	0.0	0.0	70.7
Cost Recoveries	(21.2)	0.0	0.0	(21.2)
TOTAL	**49.5**	**0.0**	**0.0**	**49.5**

Operating Experience:

Work Protection Code requirements in Hydro Plants, with the exception of the Holyrood Thermal Generating Station (Holyrood), and the Energy Control Center are currently paper based. Hydro, as part of the 2008 capital budget package, applied for approval for the purchase and installation of the Work Protection Code Management Software in Holyrood at a cost of $678,100 in an effort to enhance the level of compliance with work protection standards in the area of work protection documentation. The Board approved Hydro's 2008 Capital Budget package in Order No. P.U. 30 (2007). The software was implemented successfully and has been utilized in Holyrood since 2008. It has resulted in a 20 percent increase in WPC documentation compliance in Holyrood from 2007 to 2008.

Project Title: Work Protection Software Design **(cont'd.)**

Project Justification:

Hydro's WPC was created to provide a safe work environment in which hazards can either be eliminated or controlled. It consists of important principles which, when combined with safe work practices, will provide workers with a safe work area to perform their work. WPC procedures are applicable to all individuals required to perform work on Hydro owned or operated property, circuits, or equipment. Historically, these procedures have been organized using manual paper-based processes. Since 2008, the proposed Work Protection Software has been utilized at Holyrood and has resulted in an overall 20% increase in WPC documentation compliance from 2007 to 2008.

The software will provide an effective, consistent and standard means of creating work protection documentation. This will enable adherence to work flow rules and tag management, and will permit archiving.

The benefits of this software are as follows:

- Safety - reduces chances for operating errors, which translates to less time spent analyzing errors and results in increased employee, contractor and public safety.
- Standardization – provides a standard interface for the WPC activities for the Hydro Plants and Energy Control Center.
- Efficiency – increases the efficiency of generation and checking, relieving operator workloads; potentially translates to shorter outages as the tool enables users to more quickly adapt to changes in plant status and configuration.
- Regulatory – enables work protection and plant configuration management mandates to be satisfied and provides an audit trial for conformance.
- Accuracy – allows the Hydro Plants and Energy Control Centre to complete up-to-date information for decision making. Greater accuracy of permits translates into shorter outage times.
- Configuration Control – provides the unit operator, who has responsibility for all activities on the unit, with greater control of the unit configuration. This information is also available for efficient maintenance planning.

Project Title: Work Protection Software Design **(cont'd.)**

Future Plans:

A project proposal will be submitted for 2011 for the implementation of the software in the Hydro Plants and Energy Control Centre.

Project Title: Upgrade Intranet
Location: Hydro Place
Category: General Properties - Information Systems
Definition: Other
Classification: Normal

Project Description:

A basic corporate Intranet site was implemented in 2003. In 2004 and 2005 additional departmental sites were added. Recommendations from a review of the Intranet in 2006 formed the basis for subsequent Intranet work. An update performed in 2007 refreshed the look of the main site and several secondary sites. Work continued in 2008 with an update of the Human Resources site. In 2009, the Contact Directory, Audit Management, Site Search, Site Statistics, and Web Enablement of Databases were refreshed. This project is required to continue with the upgrade of those sites in 2010. Work for 2010 includes refreshes of up to 15 sites such as Information Systems, Supply Chain Management, Performance Review Application, and Photo Library. 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	0.0	0.0	0.0	0.0
Labour	57.6	0.0	0.0	57.6
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.	2.9	0.0	0.0	2.9
Contingency	5.8	0.0	0.0	5.8
Sub-Total	66.3	0.0	0.0	66.3
Cost Recoveries	(19.9)	0.0	0.0	(19.9)
TOTAL	**46.4**	**0.0**	**0.0**	**46.4**

Operating Experience:

Newfoundland and Labrador Hydro (Hydro) has its corporate office (Hydro Place) located in the city of St. John's. Besides the corporate office, Hydro maintains other facilities such as regional offices, generating plants and line depots. Personnel at all facilities have access to databases irrespective of location. This is made possible through the corporate Intranet. The corporate Intranet is used as Hydro's primary internal information distribution system.

Project Title: Upgrade Intranet **(cont'd.)**

Project Justification:

The Intranet serves as the host for corporate and departmental information, policies and news. Departmental information specific for Human Resources, Information Systems, Corporate Communications, Supply Chain Management and the Controller's department is maintained on the Intranet. In addition to being a source of information, the Intranet is the primary distribution mechanism for key internal computer applications such as Performance Management and Safety Management. The work planned for 2010 will continue to upgrade the Intranet. This project is required to improve the effectiveness of the corporate Intranet system, ensuring that it is well organized, easy to navigate, and standardized for use as the central site for corporate information.

This project is part of normal Information Systems work to improve information flow, streamline processes and reduce manual effort associated with distributing information within the company.

Table 2 shows Intranet upgrades for 2007 – 2009. Prior to that time, this work was done under the Minor Enhancements proposal.

Table 2: Intranet Upgrades 2007-2009

Year	Major Work/Upgrade	Comments
2009	Refresh the following: Contact Directory, Audit Management, Site Search, Site Statistics, and Web Enablement of Databases	
2008	Human Resources Site Refresh	
2007	Intranet Refresh and Re-launch	Main Site Style refresh

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Retirements:

There are no retirements associated with this project.

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Type
			($000)		
MANDATORY PROJECTS					
Perform Grounding Upgrades - Various Sites	252	291		543	Pooled
TOTAL MANDADORY PROJECTS	252	291	0	543	
NORMAL PROJECTS					
New 25 kV Terminal Station - Labrador City	283	2,700	7,007	9,990	Other
Voltage Conversion - Labrador City		1,089	8,311	9,400	Other
Upgrade Gas Turbine Plant Life Extension - Hardwoods		1,305	4,690	5,995	Other
Replace and Purchase Stator Windings - Bay d'Espoir		4,687		4,687	Other
Upgrade Line 2 Distribution Feeder - Glenburnie		267	3,289	3,557	Other
Replace Programmable Logic Controllers - Holyrood		1,208	1,649	2,857	Other
Purchase Spare Stator Winding Units 2 - Bay d'Espoir	37	2,806		2,843	Other
Upgrade Distribution Systems - All Service Areas		2,572		2,572	Pooled
Refurbish Fuel Storage Facility - Holyrood		2,500		2,500	Other
Provide Service Extensions - All Service Areas		2,428		2,428	Pooled
Perform Wood Pole Line Management Program - Various Sites		2,308		2,308	Pooled
Replace Vehicles and Aerial Devices - Various Sites		2,156		2,156	Other
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	968	964		1,932	Other
Condition Assessment and Life Extension Study - Holyrood	1,210	686		1,895	Other
Replace Diesel Units - Norman Bay, Postville and Paradise River	170	1,700		1,870	Pooled
Upgrade Distribution Lines - Various Sites		218	1,645	1,863	Other
Upgrade Plant Access Road - Bay d'Espoir		1,550		1,550	Other
Upgrade System Security - Various Sites	767	702		1,469	Pooled
Upgrade Line TL-244 - Plum Point to Bear Cove		141	1,055	1,197	Other
Replace Poles - Various Sites		1,083		1,083	Pooled
Replace Pump House Motor Control Centers - Holyrood		50	999	1,049	Other
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		990		990	Other
Increase Generation Capacity - L'Anse au Loup	23	821		844	Other
Upgrade Power Transformers - Various Sites		816		816	Pooled
Replace Stationary Battery Banks and Chargers - Various Sites		717		717	Other
Install Fibre Optic Cable - Hind's Lake	209	483		692	Other
Replace Off Road Track Vehicles - Whitbourne and Bishop's Falls		685		685	Pooled
Replace Diesel Unit 2001 and Engine 566 - Francois		168	450	619	Other
Replace Recloser Control Panels - Various Sites		603		603	Pooled
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois		82	511	593	Other
Upgrade Glycol Systems - Stephenville		261	299	560	Other
Replace Light Duty Mobile Equipment - Various Sites		554		554	Other
Replace Steam Seal Regulator Unit 1 - Holyrood		335	214	548	Other
Corporate Application Environment - Upgrade Microsoft Products		526		526	Other
TOTAL NORMAL PROJECTS	3,666	40,159	30,119	73,943	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years ($000)	Total	Type
NORMAL PROJECTS					
Upgrade Trailer and Mobile Substation - Bishop's Falls		30	468	499	Other
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood		79	417	496	Other
Replace Radio Link with Fiber - Bay d'Espoir		489		489	Other
Install Meteorological Stations - Various Sites		443		443	Pooled
Replace Diesel Unit 2018 - McCallum		19	421	440	Other
PC Replacement Program - Hydro Place		407		407	Pooled
Replace Insulators - Various Terminal Stations		399		399	Pooled
Upgrade Anchors on C Structures TL-259 - Parson's Pond		353		353	Other
Upgrade Circuit Breakers - Various Terminal Stations		342		342	Pooled
Upgrade Private Automated Branch Exchange (PABX) - Various Sites		339		339	Other
Replace 50 kW Diesel Generator - Bay d'Espoir	36	289		325	Other
Replace Diesel Fire Pump - Holyrood		112	195	307	Other
Upgrade Units 5 and 6 Cooling Water Systems - Bay d'Espoir		305		305	Other
Replace Guy Wires TL-215 - Doyles to Grand Bay		301		301	Other
Upgrade Intake Gate Controls - Upper Salmon		284		284	Other
Remove Safety Hazards - Various Sites		252		252	Other
Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level - Holyrood		231		231	Other
Purchase Spare Spherical Valve Seal and Ring Assemblies - Bay d'Espoir		223		223	Other
Replace Peripheral Infrastructure -Various Sites		222		222	Pooled
Replace Radomes - Various Sites		212		212	Pooled
Install Mobile Communications - Port Hope Simpson, Charlottetown		208		208	Other
TOTAL NORMAL PROJECTS	36	5,539	1,502	7,077	
JUSTIFIABLE PROJECTS					
Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg - Bay d'Espoir		236		236	Other
TOTAL JUSTIFIABLE PROJECTS	0	236	0	236	

PROJECT DESCRIPTION	Expended to 2009	2010	Future Years	Total	Type
		($000)			
MANDATORY PROJECTS					
Install Fall Protection Equipment - Various Sites		198		198	Pooled
Upgrade Fuel Storage - Hinds Lake		149		149	Other
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls		88		88	Other
Install Waste Oil Storage Tank - Port Hope Simpson		84		84	Other
TOTAL MANDATORY PROJECTS	0	519	0	519	
NORMAL PROJECTS					
Replace Disconnects - Various Sites		199		199	Other
Replace A/C Units in Control Room and Communications Room - Upper Salmon		197		197	Other
Replace Instrument Transformers - Various Sites		197		197	Other
Upgrade Accommodations - Norman Bay		196		196	Other
Upgrade Great Northern Peninsula Protection - Various Sites	101	91		192	Other
Upgrade Remote Terminal Units - Various Sites		190		190	Other
Install Warm Air Make-up Access - Holyrood		170		170	Other
Install New Voltage Regulators - Happy Valley		170		170	Other
Upgrade Enterprise Storage Capacity - Hydro Place		169		169	Other
Install Digital Fault Recorder - Deer Lake		166		166	Other
Replace Heavy Duty Forklift - Unit 9799 - Bishop's Falls		166		166	Other
Upgrade Fire Protection System - Bishop's Falls		158		158	Other
Replace Human Machine Interface (HMI) Computer - Paradise River		158		158	Other
Replace Main Bus Splitter - Postville		149		149	Other
Upgrade Server Technology Program - Various Sites		138		138	Other
Replace Network Communications Equipment - Various Sites		131		131	Other
Replace Air Compressors - Western Avalon		97		97	Other
Develop Learning Management System Safety Courses - Hydro Place		96		96	Other
Smart Card Implementation - Various Sites		93		93	Pooled
Upgrade Operator Training Simulator - Hydro Place		92		92	Other
Install Pole Storage Ramps - Various Sites		90		90	Other
Install Transformer Storage Ramps - Various Sites		89		89	Other
Perform Minor Application Enhancements - Hydro Place		85		85	Other
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir		81		81	Other
Purchase 21 Inch Metal Cutting Lathe - Bay d'Espoir		80		80	Other
Replace Humidifiers in Air Handling Units - Hydro Place		75		75	Other
Replace Surge Arrestors - Various Sites		73		73	Other
Replace 230 kV Breaker Controls - Massey Drive and Buchans		73		73	Other
Upgrade Fuel Tank Farm Controls - Happy Valley		72		72	Other
Upgrade Properties - Port Hope Simpson		71		71	Other
Legal Survey of Primary Distribution Line Right of Way - Various Sites		65		65	Other
Upgrade Security SCADA Intrusion Prevention System - Hydro Place		62		62	Other
Improve On Site Paving and Drainage - Holyrood		59		59	Other
Upgrade Business Intelligence Toolset Software - Hydro Place		59		59	Other
Install Remote Ice Growth Detector Beams - Various Sites		58		58	Pooled
Upgrade Security Vulnerability Management System - Hydro Place		57		57	Other
Work Protection Software Design - Hydro Place		50		50	Other
Upgrade Intranet - Hydro Place		46		46	Other
TOTAL NORMAL PROJECTS	101	4,269	0	4,370	

Type	**Number**	**($000)**
Clustered	0	0
Pooled	19	16,750
Other	80	69,937
Total	**99**	**86,687**

* *Includes multi-year projects but excludes contingency fund*

2010 LEASING COSTS

THERE ARE NO ITEMS FOR THIS SECTION

	ACTUALS				BUDGET					
	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
GENERATION	9,352	7,557	9,636	13,703	10,275	18,870	18,300	18,387	9,238	20,396
TRANSMISSION AND RURAL OPERATIONS	16,691	19,249	19,150	24,711	32,098	23,904	33,814	36,179	38,083	29,144
GENERAL PROPERTIES	7,909	14,411	6,883	7,832	14,407	10,000	14,003	10,931	13,868	10,816
TOTAL CAPITAL EXPENDITURES	33,952	41,217	35,669	46,246	56,780	52,775	66,117	65,497	61,189	60,356

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures
GENERATION	3,318	8,287	1,615	8,387	100
TRANSMISSION	2,234	11,154	2,099	11,154	0
RURAL SYSTEMS	2,675	20,037	6,009	19,559	(478)
GENERAL PROPERTIES	1,227	13,980	3,009	13,924	(56)
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	500	1,000	0
PROJECTS APPROVED BY PU BOARD	0	2,309	194	2,309	0
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	0	13	8	13	0
TOTAL CAPITAL BUDGET	9,454	56,780	13,434	56,345	(435)

Approved Board Order No. P.U. 36 (2008) 2009 Capital Budget	47,856
Carryover Projects 2008 to 2009	6,609
New Project Approved by Board Order No. 4 (2009)	351
New Project Approved by Board Order No. 8 (2009)	1,093
New Project Approved by Board Order No. 10 (2009)	704
New Project Approved by Board Order No. 16 (2009)	0
New Project Approved by Board Order No. 23 (2009)	161
2009 New Projects under $50,000 Approved by Hydro	6
TOTAL APPROVED CAPITAL BUDGET	56,780

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures
GENERATION					
HYDRO PLANTS	1,469	1,712	635	1,712	0
THERMAL PLANT	1,849	5,862	933	5,962	100
GAS TURBINES	0	712	47	712	0
TOTAL GENERATION	3,318	8,287	1,615	8,387	100
TRANSMISSION					
TERMINAL STATIONS	720	5,291	1,131	5,291	0
TRANSMISSION	1,514	5,832	960	5,832	0
TOOLS AND EQUIPMENT	0	31	8	31	0
TOTAL TRANSMISSION	2,234	11,154	2,099	11,154	0
RURAL SYSTEMS					
CONSTRUCTION PROJECTS	770	11,981	4,880	11,669	(312)
GENERAL	244	6,752	655	6,586	(166)
METERING	1,661	745	151	745	0
TOOLS AND EQUIPMENT	0	560	323	560	0
TOTAL RURAL SYSTEMS	2,675	20,037	6,009	19,559	(478)

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures
GENERAL PROPERTIES					
INFORMATION SYSTEMS	740	1,760	1,111	1,760	0
TELECONTROL	291	4,683	349	4,627	(56)
TRANSPORTATION	0	4,110	1,095	4,110	0
ADMINISTRATIVE	196	3,426	454	3,426	0
TOTAL GENERAL PROPERTIES	1,227	13,980	3,009	13,924	(56)
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	500	1,000	0
PROJECTS APPROVED BY PU BOARD	0	2,309	194	2,309	0
PROJECTS APPROVED FOR LESS THAN $50,000	0	13	8	13	0
TOTAL CAPITAL BUDGET	9,454	56,780	13,434	56,345	(435)

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
HYDRAULIC PLANTS						
Replace Governor Controls Unit 2 - Cat Arm	1,096	216	28	216	0	
Replace 40 kW Diesel Generator at Spillway - Burnt Dam	148	112	123	112	0	
Install Meteorological Stations - Various Sites	225	27	48	27	0	
Replace Cooling Water Systems on Units 3 and 4 - Bay d'Espoir	0	287	151	287	0	
Install Meteorological Stations - Various Sites	0	253	27	253	0	
Replace 50 kW Diesel Generator - Bay d'Espoir	0	36	0	36	0	
Upgrade Intake Gate Controls - Hinds Lake	0	263	0	263	0	
Replace Generator Oil Level System on Units 1 and 2 - Cat Arm	0	68	0	68	0	
Purchase Spare Stator Windings Units 1 - 4 - Bay d'Espoir	0	37	85	37	0	
Replace Service Water Piping Unit 7 - Bay d'Espoir	0	144	26	144	0	
Purchase Tools and Equipment Less than $50,000	0	270	147	270	0	
TOTAL HYDRAULIC PLANTS	**1,469**	**1,712**	**635**	**1,712**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
THERMAL PLANT						
Fire Protection Upgrades	1,690	134	105	134	0	
Replace Unit 2 High Pressure Heater	62	877	553	877	0	
Environmental Effects Monitoring Study of Waste Water	31	129	26	129	0	
Install Safety Egress Lighting	20	92	5	92	0	
Construct Beta Attenuation Meter (BAM) Unit Enclosure	0	60	63	60	0	
Automatic Synchroniziation Units 1 and 2	46	47	3	147	100	H-17 (1)
Replace No. 4 and 5 Air Compressors	0	41	47	41	0	
Install Motorized Stack Winches	0	174	4	174	0	
Replace Unit 2 Air Preheater Cold End	0	320	7	320	0	
Replace Unit 1 Hydrogen Emergency Vent Valves	0	214	21	214	0	
Install Unit 1 CR Condensate Drains and HP Heater Trip Level	0	192	4	192	0	
Replace Unit 3 Steam Seal Regulator Unit 3	0	475	25	475	0	
Install Marine Terminal Capstans Lifting Frames	0	93	2	93	0	
Refurbish Fuel Storage Facility	0	2,867	65	2,867	0	
Purchase Boom Style Hydraulic Lift	0	82	0	82	0	
Purchase Tools and Equipment Less than $50,000	0	65	3	65	0	
TOTAL THERMAL PLANTS	**1,849**	**5,862**	**933**	**5,962**	**100**	
GAS TURBINES						
Upgrade Gas Turbine Plant Life Extension - Hardwoods	0	450	39	450	0	H-17 (2)
Replace Automatic Voltage Regulator on Gas Turbine - Stephenville	0	262	8	262	0	
TOTAL GAS TURBINE PLANTS	**0**	**712**	**47**	**712**	**0**	
TOTAL GENERATION	**3,318**	**8,287**	**1,615**	**8,387**	**100**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TERMINAL STATIONS						
Purchase Spare Transformer - Upper Salmon	435	1,782	342	1,782	0	
Replace Disconnect Switches - Cow Head and Daniel's Harbour	284	84	47	84	0	
Upgrade Station Services - Hardwoods	1	58	14	58	0	
Replace Insulators - Various Terminal Stations	0	391	23	391	0	
Upgrade Circuit Breakers - Various Terminal Stations	0	422	263	422	0	
Replace Air Compressors - Sunny Side	0	96	8	96	0	
Install Digital Fault Recorders - Oxen Pond, Massey Drive and St. Anthony	0	462	167	462	0	
Replace 230 kV Breaker Controls - Oxen Pond and Bay d'Espoir	0	100	31	100	0	
Upgrade Power Transformers - Various Terminal Stations	0	654	71	654	0	
Replace 69kV Breaker L51T2 - Howley	0	199	7	199	0	
Replace Drainage System - Western Avalon	0	84	2	84	0	
Perform Grounding Upgrades - Various Terminals Stations	0	252	0	252	0	
Upgrade Great Northern Peninsula Protection - Various Sites	0	101	0	101	0	
Install 138 kV Capacitive Voltage Transformer - St. Anthony Airport	0	71	0	71	0	
Install 69 kV Capacitive Voltage Transformer - St. Anthony Diesel Plant	0	67	0	67	0	
New 25 kV Terminal Station - Labrador City	0	283	0	283	0	H-17 (3)
Replace Instrument Transformers - Various Terminal Stations	0	107	102	107	0	
Replace Surge Arrestors - Various Terminal Stations	0	81	54	81	0	
TOTAL TERMINAL STATIONS	**720**	**5,291**	**1,131**	**5,291**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TRANSMISSION						
Replace Insulators on 230kV Line TL-253 - Stony Brook, Buchans	571	960	95	960	0	
Upgrade Corner Brook Frequency Converter - 2008	943	1,010	240	1,010	0	
Perform Wood Pole Line Management Program - Various Sites	0	2,256	439	2,256	0	
Construct Transmission Line Equip Off-Loading Areas - Various Locations	0	498	7	498	0	
Construct Transmission Storage Ramps - Bay d'Espoir	0	75	0	75	0	
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	0	968	158	968	0	
Install Remote Ice Growth Detector Beams - Various Sites	0	65	21	65	0	
TOTAL TRANSMISSION	**1,514**	**5,832**	**960**	**5,832**	**0**	
TOOLS AND EQUIPMENT						
Purchase and Replace Tools and Equipment Less than $50,000	0	31	8	31	0	
TOTAL TOOLS AND EQUIPMENT	**0**	**31**	**8**	**31**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
DISTRIBUTION						
Provide Service Extensions - All Service Areas	0	2,439	859	2,439	0	
Upgrade Distribution Systems - All Service Areas	0	2,526	974	2,526	0	
Replace Poles - Jackson's Arm and Hampton	0	697	188	697	0	
Replace Insulators - Jacksons Arm, Hampden and Little Bay	0	874	283	874	0	
Reconfigure Feeders - Happy Valley	76	75	74	75	0	
Recloser Assessment - Happy Valley	0	47	0	47	0	
Replace Recloser Control Panels - Various Sites	0	132	56	132	0	
Replace Submarine Cable Terminator Kit - Change Islands/Fogo Island	0	96	38	96	0	
Purchase and Install Voltage Regulator Bank - English Harbour West	0	123	79	123	0	
Upgrade L7 Distribution System - St. Anthony	0	689	151	689	0	
Replace Conductor on L2 - Rocky Harbour	0	325	484	325	0	
Replace Line L36 - Wabush	0	498	120	498	0	
Upgrade Voltage Conversion Phase 1 - Labrador City	0	189	4	189	0	
Purchase and Install Electronic Recloser - Cartwright	0	96	66	96	0	
TOTAL DISTRIBUTION	**76**	**8,807**	**3,376**	**8,807**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	8	1,265	262	1,265	0	
Replace Diesel Units - Norman Bay, Postville and Paradise River	0	170	84	170	0	
Diesel Plant Automation - Makkovik and Rigolet	259	306	264	642	336	H-17 (4)
Increase Generation Capacity - Charlottetown (Project Cancelled)	6	589	(6)	0	(589)	H-18 (5)
Replace Switchgear - Cartwright	117	435	21	435	0	
Nain Diesel Plant Rehabilitation	304	0	855	0	0	
Replace Speed Increaser - Roddickton	0	125	5	125	0	
Install Furnace Fuel Storage Tank - Williams Harbour(Project Cancelled)	0	59	0	0	(59)	H-18 (6)
Increase Generation - L'Ance Au Loup	0	23	8	23	0	
Upgrade Fuel Storage - Cartwright	0	139	11	139	0	
Install Meter Station for Fuel Reconcilation - Hawke's Bay	0	64	0	64	0	
TOTAL GENERATION	694	3,175	1,504	2,862	(312)	
TOTAL CONSTRUCTION PROJECTS	**770**	**11,981**	**4,880**	**11,669**	**(312)**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
GENERAL						
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	94	3,224	195	3,224	0	
Construct Diesel Plant Extension - William's Harbour (Project Cancelled)	11	166	(11)	0	(166)	H-18 (7)
Replace Fire Alarm System - Hopedale and Paradise River	139	29	11	29	0	
Install Fall Arrest Equipment - Various Sites	0	322	71	322	0	
Legal Survey of Primary Distribution Line Right of Ways - Various Sites	0	56	67	56	0	
Install Air Conditioning at Training Centre - Bay d'Espoir	0	34	0	34	0	
Replace Accom, Septic Sys and Upgrade Plant Commun. Sys - Cat Arm	0	1,254	21	1,254	0	
Upgrade CEMS Room Ventilation - Holyrood	0	39	1	39	0	
Build ATV/snowmobile Storage - Whitbourne	0	86	3	86	0	
Replace Dock Lighting - Holyrood	0	33	0	33	0	
Replace Explosive Storage Magazines - Various Sites	0	293	101	293	0	
Install Pole Storage Ramps - Various Sites	0	77	1	77	0	
Install Transformer Storage Ramps - Labrador	0	121	0	121	0	
Upgrade Ventilation System - Little Bay Islands Diesel Plant	0	186	8	186	0	
Build New Maintenance Shop - St. Anthony	0	429	14	429	0	
Install Waste Oil Storage Tanks - Mary's Harbour	0	84	18	84	0	
Install Water and Sewer System - Paradise River	0	77	0	77	0	
Construct Sewage Disposal Field - Makkovik	0	50	0	50	0	
Install Storage Ramp - Whitbourne	0	41	1	41	0	
Pave Parking Lots and Roadways - Bishops Falls	0	150	154	150	0	
TOTAL GENERAL	**244**	**6,752**	**655**	**6,586**	**(166)**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
METERING						
Install Automatic Meter Reading 2007 - Various Systems	1,168	108	90	108	0	
Install Automatic Meter Reading 2008 - Various Systems	493	113	61	113	0	
Install Automatic Meter Reading - Change Islands and Fogo Island	0	491	0	491	0	
Purchase Meters and Equipment - Various Locations	0	33	0	33	0	
TOTAL METERING	**1,661**	**745**	**151**	**745**	**0**	
TOOLS AND EQUIPMENT						
Replace Boom 6069 on Track Vehicle - Stephenville		236	240	236	0	
Purchase High Definition Infrared Camera - Central	0	87	57	87	0	
Tools and Equipment Less than $50,000	0	237	26	237	0	
TOTAL TOOLS AND EQUIPMENT	**0**	**560**	**323**	**560**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
NEW INFRASTRUCTURE						
Application Enhancements - Energy Systems Water Management	625	26	75	26	0	
Application Enhancements - Energy Systems Optimum Powerflow	115	101	114	101	0	
Application Enhancements - Perform Minor Application Enhancements	0	120	37	120	0	
Cost Recovery Churchill Falls	0	(35)	(12)	(35)	0	
Upgrade Intranet - Hydro Place	0	67	2	67	0	
Cost Recovery Churchill Falls	0	(19)	(6)	(19)	0	
Application Enhancements						
- Performance Management Software Budgeting Tool	0	127	130	127	0	
Purchase Protection Relay Event Report Software - Hydro Place	0	54	1	54	0	
UPGRADE OF TECHNOLOGY						
Citrix Enhancement - Hydro Place	0	118	95	118	0	
Cost Recovery Churchill Falls	0	(34)	(11)	(34)	0	
Corporate Application Environment Upgrade Showcase						
Strategy Suite - Hydro Place	0	158	41	158	0	
Cost Recovery Churchill Falls	0	(46)	(15)	(46)	0	
TOTAL SOFTWARE APPLICATIONS	**740**	**637**	**451**	**637**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
End User Evergreen Program - Various Sites	0	491	214	491	0	
Replace Peripheral Infrastructure - Hydro Place	0	161	124	161	0	
Perform Hawke Hill Improvements - Hawke Hill	0	50	0	50	0	
Replace Drafting Scanner/Plotter - Hydro Place	0	139	139	139	0	
NEW INFRASTRUCTURE						
Security Smartcard and Disk Encryption for Laptops - Hydro Place	0	125	87	125	0	
Cost Recovery Churchill Falls	0	(36)	(12)	(36)	0	
UPGRADE OF TECHNOLOGY						
Upgrade Server Technology Program - Hydro Place	0	273	134	273	0	
Cost Recovery Churchill Falls	0	(79)	(26)	(79)	0	
TOTAL COMPUTER OPERATIONS	**0**	**1,123**	**660**	**1,123**	**0**	
TOTAL INFORMATION SYSTEMS	**740**	**1,760**	**1,111**	**1,760**	**0**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Customer Service Application - Hydro Place	40	910	63	910	0	
Replace Dial Backup System - Various Sites	98	103	29	80	(23)	
Install Recloser Remote Control - Change Islands	150	44	71	44	0	
Public Address System - Holyrood	3	1,275	58	1,275	0	
Replace Remote Terminal Units - Various Sites	0	278	15	245	(33)	
Replace Radomes - Various Sites	0	130	3	130	0	
Install Fibre Optic Cable - Hinds Lake	0	209	0	209	0	
Replace Power Line Carrier on TL-250 - Bottom Brook to Grandy Brook	0	473	71	473	0	
NETWORK INFRASTRUCTURE						
Replace Network Communications Equipment - Various Sites	0	141	0	141	0	
Purchase Test Equipment - Various Sites	0	74	18	74	0	
Install Wireless Networking - Various Sites	0	45	0	45	0	
Replace Radio Tower - Ebbegunbaeg	0	179	0	179	0	
Replace Batteries and Chargers - Various Sites	0	729	21	729	0	
UPGRADE OF TECHNOLOGY						
Replace Network Management Tools - Various Sites	0	47	0	47	0	
Upgrade Site Facilities - Various Sites	0	47	0	47	0	
TOTAL TELECONTROL	**291**	**4,683**	**349**	**4,627**	**(56)**	

FOR THE QUARTER ENDING JUNE 30, 2009
($,000)

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TRANSPORATION						
Replace Vehicles and Aerial Devices 2008 - Various Sites	0	635	449	635	0	
Replace Vehicles and Aerial Devices - 2009 Various Sites	0	2,156	333	2,156	0	
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites	0	561	313	561	0	
Replace Off Road Tracked Vehicles - Whitbourne and Bishop's Falls	0	758	0	758	0	
TOTAL TRANSPORATION	**0**	**4,110**	**1,095**	**4,110**	**0**	
ADMINISTRATION						
Upgrade System Security 2008 - Various Sites	145	762	365	762	0	
Upgrade System Security 2009 - Various Sites	0	767	0	767	0	
Purchase Spare Transformer - Hydro Place	51	389	5	389	0	
Replace Humidifiers in Air Handling Units - Hydro Place	0	58	0	58	0	
Replace Air Conditioning Units 2008 - Hydro Place	0	56	0	56	0	
Replace Humidifiers in Air Handling Units - Hydro Place	0	74	0	74	0	
Replace Air Conditioning Units 2009 - Hydro Place	0	37	0	37	0	
Energy Conservation Upgrades - Hydro Place	0	833	24	833	0	
Replace Fire Protection Panels - Hydro Place	0	89	0	89	0	
Purchase and Replace Admin Office Equip less than $50,000	0	361	60	361	0	
TOTAL ADMINISTRATION	**196**	**3,426**	**454**	**3,426**	**0**	
	1,227	**13,980**	**3,009**	**13,924**	**(56)**	

	Expenditures Prior To 2009	PUB Approved Budget 2009	2009 Expenditures To June 30	Expected Total Expenditures 2009	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
ALLOCATION FOR UNFORESEEN EVENTS						
Replace Diesel Engine - Mary's Harbour	0	569	391	569	0	
TL-221 - Insulator Upgrade	0	192	109	192	0	
Allocation for Unforeseen Events		**239**	**0**	**239**	**0**	
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	**0**	**1,000**	**500**	**1,000**	**0**	
PROJECTS APPROVED BY PUB						
CARRYOVER						
TL-227/262 Upgrd Daniels Hr, Transmission Line Re-location	152	198	296	198	0	
Cost Recovery - Dept Works and Transportation	(152)	(198)	(296)	(198)	0	
Coastal Labrador Alternative Energy Study	29	221	13	221	0	
Cost Recovery - Government of Newfoundland and Labrador	(29)	(221)	(13)	(221)	0	
NEW						
Replace Programable Logic Controllers - Holyrood	0	1,093	200	1,093	0	
Upgrade Continuous Emission Monitoring System - Holyrood	0	704	0	704	0	
Replacement of Power Transformer - Wiltondale Terminal Station	0	351	0	351	0	
Work Protection Code Elearning Program	0	227	0	227	0	
Cost Recovery - Nalcor Energy, Churchill Falls	0	(66)	(9)	(66)	0	
Hydro Place Parking Lot Extension	0	93	3	93	0	
Cost Recovery - Nalcor Energy	0	(93)	0	(93)	0	
TOTAL PROJECTS APPROVED BY PUB	**0**	**2,309**	**194**	**2,309**	**0**	
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Pressure Sealer - Treasury	0	7	6	7	0	
Purchase Meters and Equipment	0	6	2	6	0	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**0**	**13**	**8**	**13**	**0**	

1. **Auto Synchronizing Units 1 and 2 - Holyrood**

   The total budget for this project has increased from $93,000 to $193,000. The contract bid was approximately $60,000 greater than anticipated due to an increase in the scope of the work to be performed. This scope change is due to the discovery that the relationship between the Units 1 and 2 systems is more complex than originally thought, and also involves Unit 3. This complexity also resulted in unplanned modifications in the terminal station switch yard as well.

2. **Upgrade Gas Turbine Plant Life Extension - Hardwoods**

   The refurbishment of the Glycol Cooler for Main Lube Oil was listed as one of the work items to be completed in 2009. When planning the project work early in 2009, new information about the condition of the underground sump drainage piping and sump pit cover as well as various pumps caused a change in priorities, therefore these items will be completed instead of the refurbishment. The refurbishment of the Glycol Cooler for Main Lube Oil will be completed in the 2010 to 2012 time frame.

3. **Upgrade Labrador City to 25 kV – Labrador City**

   This project will now take place over a four-year period rather than three years as approved in Board Order No. P.U. 36 (2008). During the early part of 2009, a study of the distribution system identified the complexity of the voltage transition plan, dictating the need to extend the duration of the project. The total budget of $9.9 million remains unchanged, however, less money will be spent in 2010 than originally anticipated. Instead of $2.7 million for 2009, $2.2 will be spent in 2009. See five-year capital plan (2010 Capital Plan tab, Appendix A).

4. **Diesel Plant Automation – Makkovik and Rigolet**

   Originally all project engineering work was to be done in-house, however due to resourcing issues within Engineering Services, the automation design portion of the project was outsourced resulting in increased labour costs of approximately $70,000. The Makkovik project was also negatively affected by the requirements of staff to address issues resulting from the Nain Plant fire. There was a significant increase in overtime hours as well as travel costs for staff who worked at both Makkovik and Nain. These two items account for approximately $200,000 of additional cost, the balance of which can be attributed to increased costs for material, travel and miscellaneous items.

5. **Increase Generation Capacity – Charlottetown (Project Cancelled)**

The primary reason for the new generation to be installed at Charlottetown was to continue supporting the high summer load associated with the operation of seasonal fish plant that was built in the community in 2000. In the fall of 2008, Hydro was advised by the owners of the fish plant that the installation of additional ice making capacity in 2009 would increase demand by 150 kW and that another similar addition could be expected in two to three years. This requires a reassessment of the long-term suitability of the existing generation plant. Hydro expects to have this assessment completed in time for the 2011 Capital Budget Application. The generation shortfall is being addressed with temporary mobile generation.

6. **Construct Diesel Plant Extension – William's Harbour**

This project has been cancelled due to negotiations taking place between the residents of the community and the Provincial Government concerning relocation.

7. **Install Furnace Fuel Storage Tank – William's Harbour**

This project has been cancelled due to negotiations taking place between the residents of the community and the Provincial Government concerning relocation.

Plan of Projected Operating

Maintenance Expenditures

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For Holyrood Generating Station

Newfoundland & Labrador Hydro

June 2009

TABLE OF CONTENTS

PAGE

INTRODUCTION

In the Decision and Order No. P. U. 14 (2004) of the Board of Commissioners of Public Utilities ("the Board"), dated May 4, 2004, ("the Order") Newfoundland and Labrador Hydro ("Hydro") is required to **"file a ten year plan of maintenance expenditures for the Holyrood Generating Station with its annual capital budget application, until otherwise directed by the Board**" (p. 64 and Paragraph 12, p. 166 of the Order).

This requirement is specifically related to system equipment maintenance costs; therefore, capital expenditures have not been included in the following report. Capital expenditures for Holyrood are submitted annually to the Board with other Hydro capital proposals as part of annual capital budget applications, and vary from year to year.

This report addresses the identified and expected maintenance expenditures for the years 2010 to 2019 inclusive. With respect to these expenditures it must be noted that Units 1 and 2, as well as two of the main fuel storage tanks and other associated ancillary equipment, are in excess of 40 years old. Unit 3 is in excess of 30 years old, along with its associated equipment, including the other two main fuel storage tanks. While many components of this equipment have been replaced and additional items added through the maintenance and capital program over the years, numerous pieces of equipment and components are original.

An accurate ten year plan of system equipment maintenance is difficult to complete given the harsh operating environment, varied production requirements and the age of the units. This report, however, outlines for the next ten years, maintenance items that are anticipated at this time. This plan, of course, will change as time progresses. The operating condition of the equipment will be continuously reviewed and, undoubtedly, events will occur that are not foreseen at this time, which will require changes in the currently anticipated annual maintenance. As can be seen from this report, there must be variation in annual operating costs for the Holyrood Generating Station. It is not possible to "levelize" the cost of maintaining a plant such as Holyrood where there are numerous components and systems integrated together to form a fossil fired thermal electric generating system.

MAINTENANCE PHILOSOPHY

The Board, in its Order as related to the Holyrood Generating Station, noted at p. 64 that **"The Board will require NLH's 10 year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances."**

It would be useful to first review the three main types or categories of maintenance undertaken at Holyrood.

1) <u>Preventive Maintenance</u>

While it is true that any plant will incur greater maintenance costs as it ages, Holyrood has used, and continues to use, up-to-date maintenance techniques and practices to maintain plant efficiency, availability and reliability. These include preventive, predictive and condition-based maintenance techniques, which are usually referred to by the overall term of "Preventive Maintenance". The basic principle underlying this approach to maintenance is timely intervention to prevent imminent or catastrophic failure, which may cause a substantial safety exposure, an increase in cost or an extended unavailability of the unit or system.

Preventive maintenance, in its specific sense, comprises routine inspections, checks, and component replacements at specific time intervals to prevent failures known, or reasonably expected, to occur within a definable time or operating hour interval during the life of the equipment, e.g. generator brush wear, air and oil filter replacements, etc. This also includes discarding equipment or components rather than repairing them when it is less expensive to do so.

Predictive maintenance involves routine testing of equipment to determine deterioration rates and initiating and carrying out repairs in a timely manner before a failure occurs, e.g. ultrasonic thickness checks on fluid lines to monitor erosion wear rates, non-destructive testing of boiler and turbine components to determine fatigue, wear or corrosion rates and remaining life. Predictive maintenance items include such things as boiler and auxiliary equipment annual overhaul, among other items, wherein an assessment is made of components or subsystems that are only accessible during these overhauls.

There is also regular or continual monitoring of equipment operating parameters with a comparison of the results with optimum conditions to determine the most economic time to intervene and perform remedial work that is intended to return the equipment to optimum performance levels, e.g. air heater washes, generator winding insulation condition, oil sampling and testing, etc.

Turbine major and minor overhauls are, effectively, long-term predictive and preventive maintenance activities. A turbine major overhaul is a major disassembly, inspection and repair of the whole turbine. Since this is a very expensive and time consuming activity, the time between these overhauls is extended to minimize the recurring cost and maximize the equipment operating time, and thus useful life of the internal wearing components. Prior to 1988, these major overhauls were carried out at four-year intervals; a subsequent assessment of the risk and cost savings resulted in extending these overhauls to six-year intervals.

In 2003, a study was undertaken by Hartford Steam Boiler Insurance Company, using their proprietary program called Turbine Overhaul Optimization Program (TOOP). This assesses the causes of failure, the risk of failure and the maintenance history of the Turbines, and then proposes the optimum frequency between major overhauls. This assessment concluded that the Turbine major overhaul interval could be extended to nine years from the major overhaul of Unit 1 in 2003, the major overhaul of Unit 2 in 2005 and the major overhaul of Unit 3 in 2007, providing that certain upgrades of internal components are made. These recommendations have been accepted and all upgrades are now completed.

Turbine valve overhauls are carried out at three-year intervals, between major overhauls. This has been found necessary, due to the critical nature of the safety and reliability aspects of these valves to the turbine operation and integrity, and will continue to be maintained on this three-year interval between major overhauls.

As of 2008, the Preventive Maintenance program has been enhanced to include the extra costs associated with plant cleaning in areas where Asbestos and Heavy Metals have been identified as potential health hazards.

2) <u>Corrective Maintenance</u>

In addition to the preventive maintenance tactics outlined in (1) above, there are also corrective maintenance requirements. These include repairs to equipment as it fails or reaches the point where preventive maintenance has identified that the equipment is approaching the end of its useful service life, such as wear and tear on pumps, pipes and valves in the main and auxiliary systems, motor rewinds due to failed or deteriorated winding insulation, or as a result of adverse conditions (humidity, salt laden atmosphere, etc), replacement of corroded piping equipment and boiler tube failure repairs etc. In 2003, Unit 2 suffered three Superheater Tube failures and an analysis indicated a common tube failure problem had developed. An approved Capital Budget proposal saw the replacement of the Unit 2 Boiler Superheater tubes in September 2007. Unit 1 Boiler Superheater tubes were replaced in 2008.

As of 2008, the Corrective Maintenance program has been enhanced to include the extra costs associated with plant cleaning in areas where Asbestos and Heavy Metals have been identified as potential health hazards.

3) <u>Projects</u>

Operating projects are those major cost repairs and inspections that are required to return structures and equipment to their original or near original condition to maintain structural integrity, possibly extend plant life, improve efficiency, improve availability and prevent or reduce environmental risks. Such projects include repairs to building structural steel, roof repairs/replacement, fuel oil tank and pipeline inspection and coating and replacement of equipment or components no longer supported by the original manufacturer. A major Asbestos Abatement program commenced in 2005 and was completed over a three-year period. Due to the significant cost ($11.3 million), Hydro was given approval to treat this as an extraordinary repair, which means an annual cost will be recovered over an additional five years, bringing the total cash flow period to eight years, 2005 to 2012.

In 2006 a major failure of the No. 2 boiler waterwall tubing resulted in three months of unexpected down time plus extensive repairs that cost $2.5 million. This cost was amortized over a five year period (2007-2011) within the plant operating budget. A root cause analysis was conducted by an external consultant which identified one of the major contributions to this failure was insufficient boiler chemical cleaning frequency (current industry practice is eight - ten years, regardless of tube loading condition). To perform future chemical cleaning of the Holyrood boilers, operating projects have been identified starting with Unit 2 in 2016, Unit 1 in 2017 and Unit 3 in 2018 with an individual cost of approximately $380,000.

In 2007 a major failure of the No. 2 nozzle block assembly steam turbine resulted in two months of extended forced outage plus extensive repairs that cost $2.4 million.

COST VARIABILITY

Preventive maintenance costs are generally incurred annually at a constant level and do not fluctuate significantly. This does not apply to corrective maintenance costs, which are unavoidable and somewhat unpredictable due to the changing energy production demands on the units from year to year. These changing demands give rise to changes in wear rates, the majority of which cannot be monitored closely enough for reasonably accurate prediction, without incurring excessive inspection costs. Excessive inspection may in itself introduce increased risk of failure and thus additional cost, so all must be considered in balancing the most appropriate amount of inspection with accepted levels of failure. These costs however, generally balance from one year to another.

The turbine and valve overhaul costs are cyclic in nature. With three units in the plant on a nine-year “major” turbine overhaul cycle interspersed with a three-year “minor” valve overhaul, this component of the system equipment maintenance cost is one of the significant reasons for the observed annual fluctuations that make normalizing annual maintenance costs difficult.

Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
No. 1			Major			Minor			Minor	
No. 2		Minor			Major			Minor		
No. 3	Minor			Minor			Major			Minor
General Cost			↑	↓	↑	↓	↑	↓		

Similarly, major operating projects, because of their extended maintenance intervals (years) or non-repeatability also add to the annual fluctuations of the system equipment maintenance costs and have to be executed when plant conditions permit.

Maintenance projects for the Holyrood Generating Station are planned on a five-year basis, but as with any plan, it is not 'fixed' or definitive, as other events can cause a shift in the prioritization of such projects. This five-year maintenance plan is regularly updated by Hydro as time progresses.

DETAILED ANALYSIS

Attached are Appendices 1 to 9, which set out the ten-year maintenance plan for the Holyrood Generating Station, as requested by the Board. Appendix 1 is a summary and indicates the expected expenditures in each of the major equipment groupings containing system equipment maintenance (SEM) costs for the years 2010 to 2019. Appendices 2 to 9, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Overhauls and Major Operating Projects for each of the major equipment groupings containing SEM costs.

This plan was prepared using the 2010 preventive, corrective and overhaul data and the current 2010 to 2014 operating project lists from Hydro's five-year plan for the Holyrood Generating Station as the base data. Considerable judgment of plant personnel had to be used to prepare a ten-year plan.

Hydro does not normally use any escalation in its five-year operating plan at the Plant or regional level. The five-year plan is primarily used for internal purposes and generation of work plans rather than detailed financial planning. However, in the attached ten-year plan, an escalation factor has been used, the source of which is the Fall 2008 Hydro forecast. A single escalation rate was used in this exercise and assumed a 50 percent weighting of Labour escalation and weighting 50 percent of Material escalation, and is as follows:

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
%	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Appendices 2 to 9 list the categories of SEM costs for the years 2010 to 2019 in each of the major equipment groupings containing SEM. The categories listed are:

Preventive – Annual	Routine preventive maintenance activities carried out every year
Corrective	Typical but unknown breakdown/emergency repairs carried out during the year
Turbine – Major	Major overhauls now planned every nine (9) years on a per Unit basis.
Turbine – Minor	Major valve overhauls currently carried out every three (3) years, between major overhauls on a per unit basis.
Boiler – Annual	Boiler overhauls carried out annually
Boiler - Amortized Cost	Five year amortized cost of repairs completed only on Unit
Operating Projects	Non-capitalized projects, justified on the basis of Safety, Environment, Reliability or Cost Benefit Analyses.

Appendices 2, 3 and 4 (for Units 1, 2 and 3 respectively) use all of the foregoing categories. Appendices 5 to 9 are for the remaining equipment groupings of Common Equipment, Building and Grounds, Water Treatment Plant, Waste Water Treatment Plant and Environmental Monitoring and use only Preventive, Corrective and Major Operating Projects.

It must be noted that the Appendices do not itemize preventive and corrective items. The preventive maintenance program consists of approximately 1,200 PM's performed on plant equipment annually. Corrective items include a large number of low cost jobs and some moderately expensive ones as well, the majority of which are largely unknown until they happen; thus, it is not practical to provide a breakout of the costs. Projects included in the headings of Operating Projects, Turbine - Major and Turbine - Minor work have been itemized in the year that the work is planned for execution.

Hydro's normal five-year plan identifies specific projects up to 2014. For the period 2015 to 2019, Hydro used an average per unit of the project budgets for the three units over the years 2010 to 2014 with escalation. This approach was taken, as it is not practical or possible to determine specific work items, which are essentially unknown for the period of 2015 to 2019.

SUMMARY

This Plan presents the best available information at this time for a ten-year forecast of the maintenance projects for the Holyrood Generating Station and is based on the 2010 system equipment maintenance budget. As with any forecast, it is subject to change depending on the operating demands of the plant, the results of inspections and assessments of changing equipment conditions.

The Plan takes into account up-to-date maintenance tactics and known restoration and inspection work. As can be seen from the Plans fluctuations in the annual cost cannot be eliminated due to the nine-year Turbine Overhauls and three-year Valve Overhauls, as well as the large but infrequent Major Operating projects.

APPENDIX 1

TOTAL HOLYROOD SEM[1] 10 YEAR MAINTENANCE EXPENDITURES ESCALATED (K)

	($000)										
	Base Year 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
UNIT 1 Total SEM	$1,803	$1,851	$3,950	$1,835	$2,114	$2,493	$2,018	$2,580	$2,560	$2,128	
UNIT 2 Total SEM	$2,262	$2,650	$1,897	$1,916	$4,057	$2,001	$2,695	$2,501	$2,280	$2,128	
UNIT 3 Total SEM	$2,064	$1,746	$1,788	$2,335	$2,035	$2,054	$4,285	$2,766	$2,488	$2,579	
Common Equipment Total SEM	$4,078	$3,338	$2,650	$2,097	$2,150	$2,203	$2,259	$2,315	$2,373	$2,432	
Buildings and Grounds Total SEM	$642	$674	$547	$560	$543	$557	$571	$585	$599	$614	
WT Plant Total SEM	$258	$189	$194	$274	$204	$238	$299	$219	$225	$324	
WWT Plant Total SEM	$133	$127	$140	$133	$147	$140	$154	$147	$163	$154	
Environmental Monitoring Total SEM	$340	$422	$323	$478	$339	$466	$394	$490	$375	$554	
Total Holyrood SEM	$11,580	$10,997	$11,489	$9,628	$11,589	$10,152	$12,675	$11,603	$11,063	$10,913	
Total Operating Projects	$3,151	$2,366	$1,411	$1,040	$1,051	$1,127	$1,547	$1,692	$1,346	$952	
Total Operating Projects Less Asbestos Abatement	$1,021	$1,024	$807	$1,040	$1,051	$1,127	$1,547	$1,692	$1,346	$952	
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

SEM[1] – System Equipment Maintenance

APPENDIX 2

HOLYROOD 10 YEAR MAINTENANCE PLAN

	($000)									
Unit No. 1	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Preventive – Yearly	$335	$344	$352	$361	$370	$379	$389	$398	$408	$418
Corrective – Yearly	$412	$422	$433	$444	$455	$466	$478	$490	$502	$515
Turbine Major Overhaul			$2,081							
Turbine Valve Overhaul						$409			$440	
Boiler Annual Overhaul	$956	$980	$1,005	$1,030	$1,056	$1,082	$1,109	$1,137	$1,165	$1,195
Operating Projects										
Boiler Chemical Clean								$390		
Overhaul Boiler Feed Pump East						$116				
Overhaul Boiler Feed Pump West	$105						$122			
Overhaul Cooling Water Pump East					$83					
Overhaul Cooling Water Pump West	$75									
Overhaul Extraction Pump North			$79							
Overhaul Vacuum Pump North	$25									
Overhaul Extraction Pump South					$83					
Overhaul Vacuum Pump South					$28					
Projects – Lump Sum for Future Years					$40	$41	$42	$43	$44	
Total – Unit No. 1	$1,803	$1,851	$3,950	$1,835	$2,114	$2,493	$2,018	$2,580	$2,560	$2,128
Total Operating Projects Unit 1	$100	$105	$79	$0	$234	$157	$42	$555	$44	$0
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

APPENDIX 3

	($000)									
Unit No. 2	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Preventive – Yearly	$335	$344	$352	$361	$370	$379	$389	$398	$408	$418
Corrective - Yearly	$412	$422	$433	$444	$455	$466	$478	$490	$502	$515
Turbine Major Overhaul					$2,133					
Turbine Valve Overhaul		$370						$430		
Boiler Annual Overhaul	$956	$980	$1,005	$1,030	$1,056	$1,082	$1,109	$1,137	$1,165	$1,195
Boiler No. 2 Amortized Repair Cost	$456	$456								
Operating Projects										
Unit No. 2 Boiler Chemical Clean							$381			
Overhaul Boiler Feed Pump East			$108						$125	
Overhaul Boiler Feed Pump West		$103						$119		
Overhaul Cooling Water Pump East							$87			
Overhaul Cooling Water Pump West		$77								
Overhaul Extraction Pump North							$87			
Overhaul Extraction Pump South				$81						
Overhaul Vacuum Pump South									$32	
Overhaul Vacuum Pump North						$29				
Projects - Lump Sum for Future Years					$43	$44	$45	$46	$47	
Total - Unit No. 2	$2,262	$2,650	$1,897	$1,916	$4,057	$2,001	$2,695	$2,501	$2,280	$2,128
Total Operating Projects Unit 2	$103	$77	$108	$81	$43	$73	$719	$46	$204	$0
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

APPENDIX 4

Unit No. 3	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
						($000)				
Preventive – Yearly	$335	$344	$352	$361	$370	$379	$389	$398	$408	$418
Corrective – Yearly	$412	$422	$433	$444	$455	$466	$478	$490	$502	$515
Turbine Major Overhaul							$2,297			
Turbine Valve Overhaul	$362			$389						$451
Boiler Annual Overhaul	$955	$979	$1,004	$1,029	$1,054	$1,081	$1,108	$1,136	$1,164	$1,195
Auxiliary Equipment Annual Overhaul										
Operating Projects										
Unit No. 3 Boiler Chemical Clean									$400	
Overhaul Cooling Water Pump East										
Overhaul Cooling Water Pump West								$89		
Overhaul Boiler Feed Pump East					$114			$120		
Overhaul Boiler Feed Pump West				$112						
Overhaul Extraction Pump North								$89		
Overhaul Extraction Pump South						$85				
Overhaul Vacuum Pump North						$29				
Overhaul Vacuum Pump South					$28					
Projects – Lump Sums for Future Years					$13	$13	$14	$14	$14	
Total - Unit No. 3	$2,064	$1,746	$1,788	$2,335	$2,035	$2,054	$4,285	$2,766	$2,488	$2,579
Total Operating Projects Unit 3	$0	$0	$0	$112	$155	$127	$14	$312	$414	$0
Total SEM for all Three Units	$6,129	$6,247	$7,635	$6,086	$8,206	$6,548	$8,998	$7,847	$7,328	$6,835
Total Project Work for Three Units	$203	$182	$187	$193	$432	$357	$775	$913	$662	$0
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

APPENDIX 5

	($000)										
Common Equipment	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Preventive – Yearly	$279	$286	$293	$300	$308	$315	$323	$331	$340	$349	
Corrective – Yearly	$1,602	$1,642	$1,683	$1,725	$1,769	$1,813	$1,858	$1,905	$1,952	$2,000	
Operating Projects											
Asbestos Abatement	$2,130	$1,342	$604								
Pipe Surveillance	$51	$53	$54	$55	$57	$58	$59	$61	$62	$64	
Plant Color Coding	$15	$16	$16	$17	$17	$17	$18	$18	$19	$19	
Total Common Equipment	$4,078	$3,338	$2,650	$2,097	$2,150	$2,203	$2,259	$2,315	$2,373	$2,432	
Total Operating Projects Common Equipment	$2,197	$1,410	$674	$72	$74	$75	$77	$79	$81	$83	
Total Operating Projects less Asbestos Abatement	$67	$68	$70	$72	$74	$75	$77	$79	$81	$83	
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

APPENDIX 6

	($000)										
Buildings Grounds	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Preventive – Yearly	$174	$179	$183	$188	$192	$197	$202	$207	$212	$217	
Corrective	$123	$126	$129	$132	$136	$139	$143	$146	$150	$154	
Operating Projects											
Coat Interior Liner Panels	$103	$105	$108	$110	$113	$116	$119	$122	$125	$128	
Repair & Repaint Structural Steel	$92	$95	$97	$99	$102	$104	$107	$110	$112	$115	
Exhaust Stack Maintenance	$150	$170	$30	$30							
Total – Buildings and Grounds	$642	$674	$547	$560	$543	$557	$571	$585	$599	$614	
Total Operating Projects Buildings and Grounds	$345	$370	$235	$240	$215	$220	$226	$231	$237	$243	
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

APPENDIX 7

	($000)										
WT Plant	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Preventive – Yearly	$54	$56	$57	$59	$60	$61	$63	$65	$66	$68	
Corrective	$82	$84	$86	$88	$91	$93	$95	$97	$100	$103	
Operating Projects											
Resin Replacement (A Train)	48						56				
Resin Replacement (B Train)		49						57			
Resin Replacement (C Train)			51						59		
Resin Replacement (Mixed Bed A)				52						$61	
Resin Replacement (Mixed Bed B)					53						
Resin Replacement (U1 Polisher)						83					
Resin Replacement (U2 Polisher)				75							
Resin Replacement (U3 Polisher)	74						85			$92	
Total WT Plant and Environmental	$258	$189	$194	$274	$204	$238	$299	$219	$225	$324	
Total Operating Projects WT Plant	$122	$49	$51	$127	$53	$83	$141	$57	$59	$153	
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

APPENDIX 8

	($000)										
Waste Water Treatment Plant	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Preventive – Yearly	$72	$74	$75	$77	$79	$81	$83	$85	$87	$89	
Corrective	$31	$32	$32	$33	$34	$35	$36	$37	$37	$38	
Operating Projects											
WWTP Periodic Basin Cleaning & Inspection		$22		$23		$24		$26		$27	
WWTP Continuous Basin Clean-Out	$22		$23		$24		$25		27		
Filter Fabric Replacement-Plate Press	$9		$10		$10		$11		11		
Total WWT Plant	$133	$127	$140	$133	$147	$140	$154	$147	$163	$154	
Total Operating Projects WWT Plant	$31	$22	$32	$23	$34	$24	$35	$26	$38	$27	
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

APPENDIX 9											
	($000)										
Environmental Monitoring	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Preventive – Yearly	$26	$26	$27	$28	$28	$29	$30	$30	$31	$31	
Corrective	$62	$63	$65	$66	$68	$70	$71	$73	$75	$77	
Operating Projects											
Emissions Monitoring	$154	$158	$162	$166	$170	$174	$178	$183	$187	$192	
Stack Emissions Testing		$107		$113		$118		$124		$130	
CEMS RATA Testing	$62	$63	$65	$66	$68	$70	$71	$73	$75	$77	
OPEP Exercise	$5	$5	$5	$6	$6	$6	$6	$6	$6	$7	
Tube Bundle Replacement – All Units	$32			$35			$37			$40	
Total Environmental Monitoring	$340	$422	$323	$478	$339	$466	$394	$490	$375	$554	
Total Operating Projects Environmental Monitoring	$253	$333	$232	$385	$243	$368	$293	$386	$269	$446	
Escalation Rate (percent)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

	2008	2007
	($000)	**($000)**
Capital Assets	2,044,398	2,016,315
Less:		
Accumulated Depreciation	603,363	570,225
Contributions in Aid of Construction	96,143	96,396
	699,506	666,621
Net Capital Assets	1,344,892	1,349,694
Balance Previous Year	1,349,694	1,345,766
Average Capital Assets	1,347,293	1,347,730
Working Capital	3,547	3,496
Fuel	34,389	25,874
Supplies Inventory	22,561	21,699
Average Deferred Charges	81,996	84,725
Average Rate Base	1,489,786	1,483,524