An Application to the

Board of Commissioners of Public Utilities

2009 Capital Budget

Application

Volume I

August 2008

HYDRO
THE POWER OF COMMITMENT

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Volume II

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 2009 capital budget pursuant to s.41(1) of the Act; (2) its 2009 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 2009 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 2007.

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

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

1. The Applicant is a corporation continued and existing under the *Hydro Corporation Act*, 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 2009 Capital Budget in the amount of approximately $47.9 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 2009 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 2009 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 2009 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 2009 capital projects by definitions, by classification and by materiality as required by the Capital Budget Application Guidelines.

7. Section F contains one new lease proposed for 2009 in excess of $5,000 per year.

8. Section G to this Application is a Schedule of Hydro's Capital Expenditures for the period 2004 to 2013.

9. Section H to this Application is a report on the status of the 2008 capital expenditures including those approved by Orders Nos. P.U. 30 (2007), projects under $50,000 not included in these Orders, and the 2007 capital expenditures carried forward to 2008.

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 2007 of $1,484,545,000.

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

13. The proposed capital expenditures for 2009 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 2009 to be approximately $275,000. The information contained in the 2009 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 2009 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2009 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 2009 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 2007 in the amount of $1,484,545,000 pursuant to section 78 of the Act.

DATED at St. John's, Newfoundland, this 11th day of August, 2008.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

Newfoundland and Labrador Hydro
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St. John's, Newfoundland and Labrador
A1B 4K7
Telephone: (709) 737-1443

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 2009 capital budget pursuant to s.41(1) of the Act; (2) its 2009 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 2009 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 2007.

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

AFFIDAVIT

I, John E. Mallam, Professional Engineer, make oath and say as follows:

1. That I am the Vice-President of Engineering Services for Newfoundland and Labrador Hydro and as such I have knowledge of the matters arising in the within matter.

2. That I have read the contents of the attached Application and those contents are correct and true to the best of my knowledge, information and belief.

SWORN TO in the City of St. John's, in the Province of Newfoundland and Labrador this 11th day of August, 2008 before me:

Geoffrey P. Young
Barrister – Newfoundland and Labrador

John E. 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. In recent years two major factors have complicated Hydro's long term planning initiatives: the possible addition of a major industrial customer in the form of a new oil refinery for Placentia Bay, and the imminent approval of the Lower Churchill Project and high voltage direct current (HVDC) infeed to the Island.

In Order P.U. 30 (2007), the Board directed Hydro to include with its 2009 Capital Budget Application:

- A five-year capital expenditure plan focusing on strategic spending priorities beginning with the current year, addressing the Provincial Energy Plan, and including a separate section on the Holyrood Thermal Generating Station; and
- A report on the System Security Upgrade program.

The five-year plan is addressed briefly in this Overview and in detail in the 2009 Capital Plan Section of this report. The report entitled "Upgrade System Security Various Hydro Locations" is located in Volume II, tab 17.

Also, in October 2007, the Board issued revised Capital Budget Guidelines, specifying information to be included in Capital Budget proposals. While the substance of the proposals contained in this Application does not differ materially from prior submissions, the format has changed somewhat to assist the Board in evaluating these proposals. Additionally, this filing is segmented by materiality, and then function, which is also a departure from prior years.

2009 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.

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 an initial 20-Year Capital Plan, which is discussed in the 2009 Capital Plan section of this submission. This plan will continue to be enhanced and adjusted driving subsequent years and capital budget submissions.

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 (for 2009 and beyond)
- Discussion between Regulated Operations and Engineering Services
- Familiarity with equipment
- Operating and Maintenance cost, and
- Professional judgment.

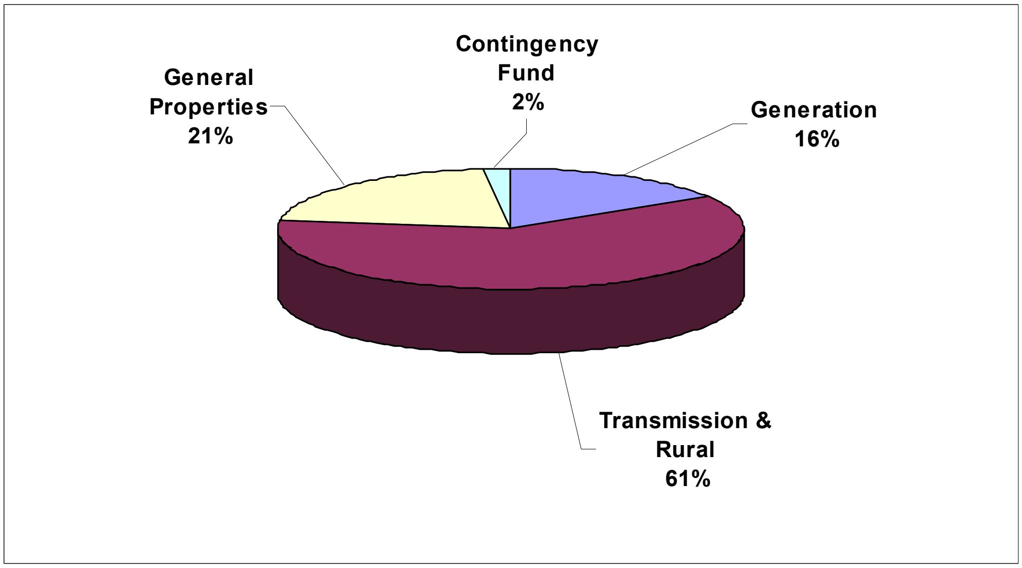
There are three broad categories of replacement criteria:

- Time 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 2009 Capital Budget by major classification. The classifications, other than the contingency fund, which represents only 2 percent of the 2009 budget, are then discussed further.

Chart 1. 2009 Capital Budget - Summary

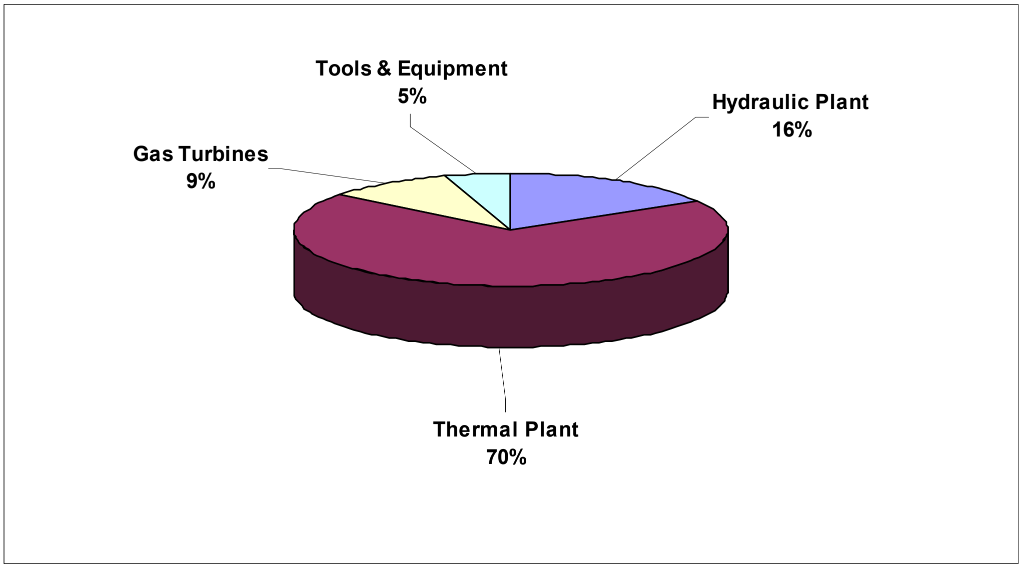


GENERATION ASSETS

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 2007, 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.

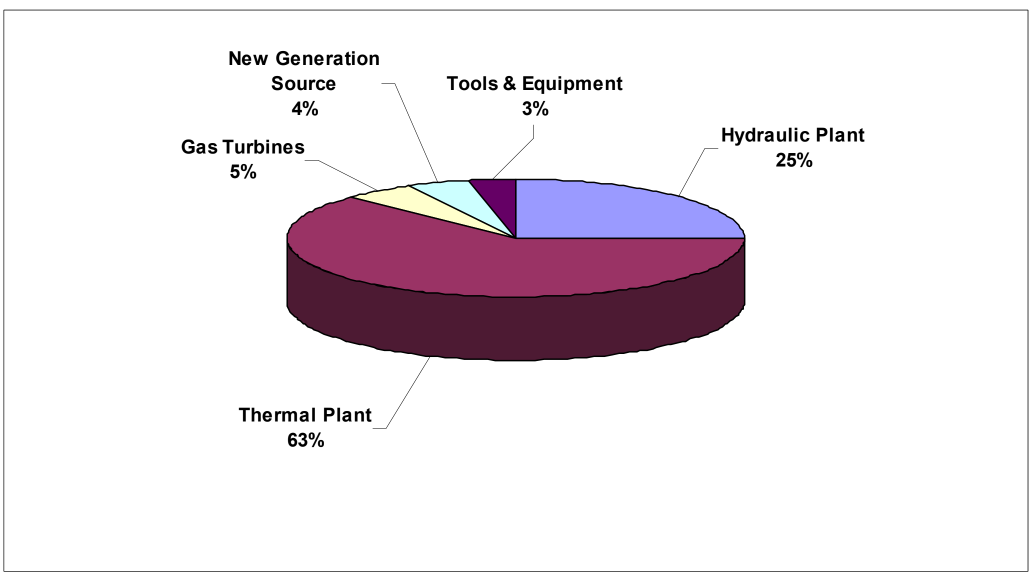
The division of the 2009 Capital Budget for Island Interconnected generation among Hydraulic Plant, Thermal Plant, Gas Turbines and Tools and Equipment expenditures is shown in Chart 2.

Chart 2: 2009 Capital Budget – Generation



The five-year (2005 to 2009) average is shown in Chart 3. For 2009, thermal plant represents 70 percent of the Island Interconnected generation budget, compared with 63 percent over the past five years. This change is indicative of the increased actual and potential asset failures at Holyrood.

Chart 3: Five-year average Capital Budget - Generation (2005 - 2009)



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 which are coming to the end of their estimated service lives. This application includes proposals for:

- Purchasing a spare stator winding to permit a unit to be restored quickly in the event of failure of the existing aged windings;
- upgrading cooling water systems at Bay d'Espoir;
- upgrading intake gate controls at Hinds Lake; and
- replacing generator oil level systems at Cat Arm.

Thermal Plant

Holyrood Thermal Generating Station Units 1 and 2 are now 39 years old while Unit 3 is 28 years old. The generally accepted life expectancy for thermal plants is 30 years, although the 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. The implications of the Lower Churchill project and the potential oil refinery are discussed in detail in the report entitled "Generation Planning Issues 2008 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 its historical average capacity factor of 40 percent to 50 percent annually and much higher through the critical winter period. If the new oil refinery is built, it will be required to operate at its maximum possible capacity factor of about 75 percent annually. The capital upgrades 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:

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

- Refurbish Fuel Storage Facility
- Replace Unit 2 High Pressure Heater
- Replace Unit 3 Steam Seal Regulator
- Replace Unit 2 Air Preheater Cold End
- Replace Unit 1 Hydrogen Emergency Vent Valves

Upgrade projects:

- Install Unit 1 Cold Reheat Condensate Drains and HP Heater Trip Level - Recommended by Insurer for reliability
- Install Motorized Stack Winches - Safety Issue
- Environmental Effects Monitoring Study of Waste Water – Environmental Issue
- Install Marine Terminal Capstans Lifting Frames - Safety Issue

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 turbine engine, 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.

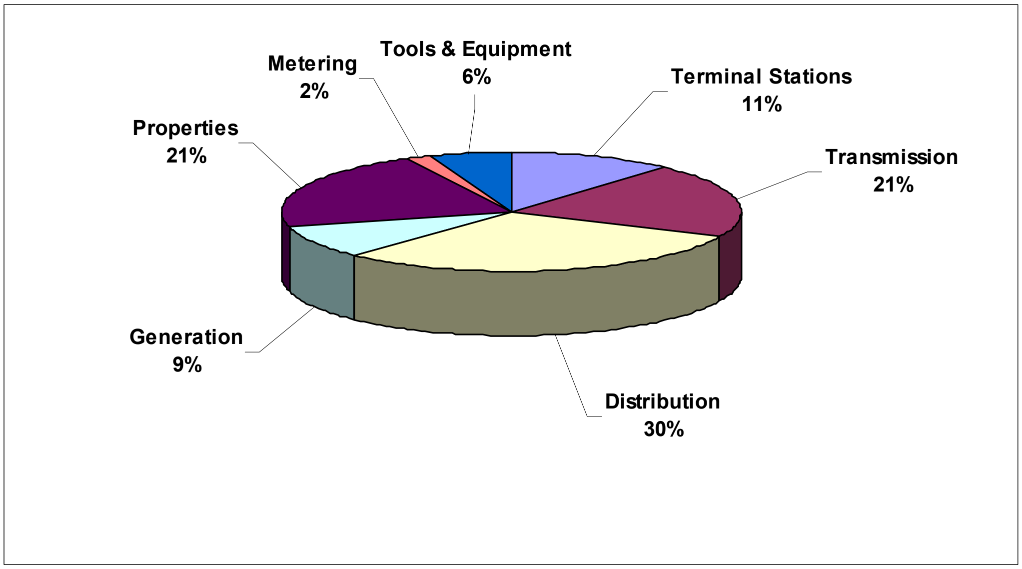
TRANSMISSION AND RURAL OPERATIONS ASSETS

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 regular 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 2009 Capital Budget for Transmission and Rural Operations is shown in Chart 4. These breakdowns are generally consistent with the five-year (2005-2009) average.

Chart 4: 2009 Capital Budget - Transmission and Rural Operations



Terminal Stations and Transmission

Many of Hydro's transmission lines were constructed in the 1960's. Because the expected useful lives of transmission assets are in the 40-year range, ongoing reconstruction and general upgrades are needed to ensure that Hydro can continue to provide our customers with reliable electrical service.

The terminal station and transmission proposals for 2009 include upgrades to the Corner Brook frequency converter, and ongoing and routine projects such as:

- upgrading power transformers in various locations in a studied and orderly manner rather than as transformers fail;
- replacing failing insulators at various locations;
- replacing breaker controls at the Bay d'Espoir and Oxen Pond terminal stations;
- replacing air compressors at the Sunnyside Terminal Station; and
- replacing a fault recorder at the Massey Drive Terminal Station.

In addition, the load growth in Labrador City will result in the construction of two new terminal stations to be completed in 2011.

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 two diesel generator units at Norman Bay; and
- increasing generating capacity at L'Anse Au Loup.

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;
- replacing poles; and
- replacing recloser control panels.

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.

During 2007 and early 2008, there were more than the usual number of outages in the Labrador West area of the Labrador Interconnected System. Meetings were held with town councils and customers, and a review of the system was undertaken to determine the causes and any required corrective action. Because of that review, the Capital Budget proposal to replace Line L36 for Wabush is included in this Application. As well, due to the age of the system and increased load, upgrade voltage conversion Phase I for the Labrador City System is included.

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 5 shows the breakdown of the General Properties Capital Budget. The Information Systems 2009 Capital Budget is 19 percent less than the five-year average (shown in Chart 6), which is indicative of the maturation of Hydro's information technology and an increasing trend to replacement rather than major upgrades.

Chart 5: 2009 Capital Budget - General Properties

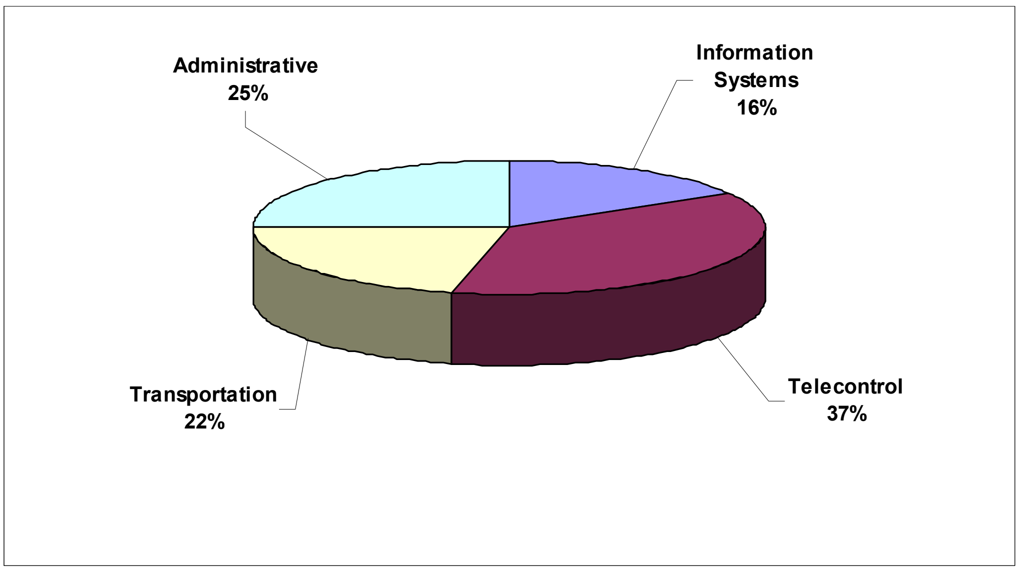
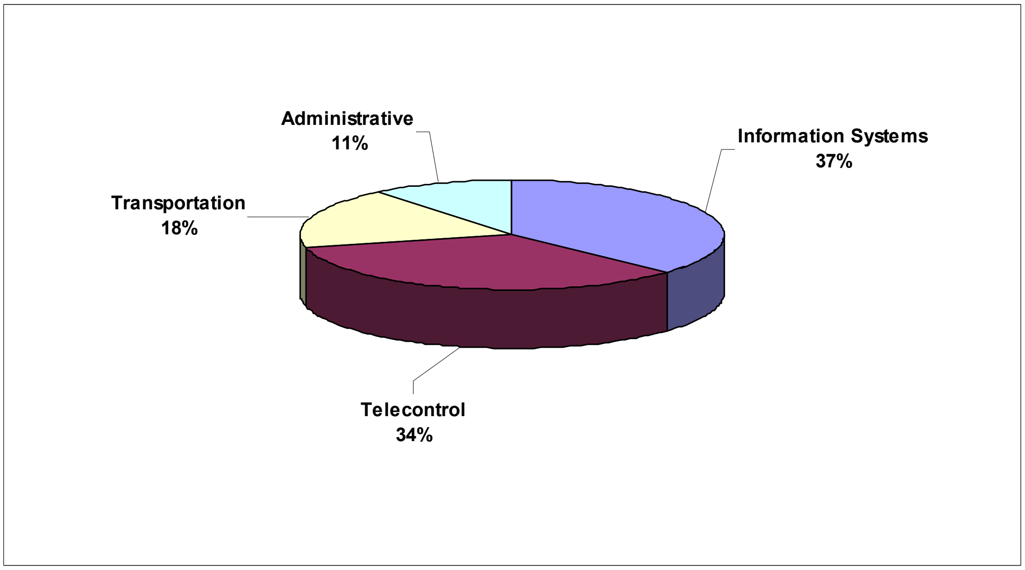


Chart 6: Five-Year Capital Budget - General Properties



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 2009 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;
- Fiber optic cable at Hinds Lake; and
- Radomes at Multiple Sites.

In summary, Hydro's Capital Budget Application for 2009 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

2009 Capital Plan

NEWFOUNDLAND AND LABRADOR HYDRO

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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.

The following sections discuss Hydro's development of a 20-year capital plan and asset maintenance philosophy, and in compliance with Board Order No. P.U. 30(2007), provides further detail concerning the five-year plan and more specifically, Holyrood.

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. This is discussed in a report entitled "Generation Planning Issues 2008 Mid Year Update", located in Volume II of this submission. The 20-Year Capital Plan does not include additional generation capacity to address future energy requirements nor does it include proposals for the Fuel Conservation and Demand Management (CDM). CDM will be the subject of a repeat filing with the Board in the fall of 2009 and will likely 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.

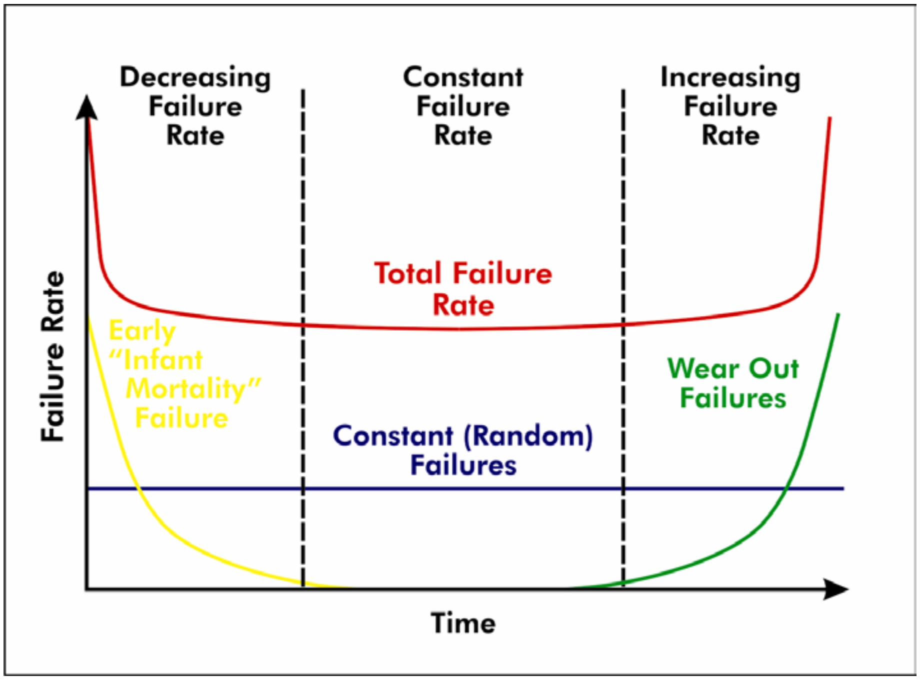
Table 2 - Age of Selected Hydro Assets

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
Terminal Stations (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.

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.

The 20-year plan is a living document and will be revised frequently as new information becomes available 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 2008 Mid Year Update" report, located in Volume II, tab 23, 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 capital expenditures to maintain the existing systems will rise to an average of $54 million over the next five-years and to an average of $58 million, expressed in 2008 dollars, over the next 20-years,. Expenditures for new generation and transmission assets are not included in these estimates.

This plan represents a first compilation of a long term capital plan for Hydro's existing assets. As such, 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.

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 (2009 and beyond)
     - 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 will begin in the last quarter of 2008. This second phase will encompass:

1. Documenting existing reliability criteria,
2. Assessing compliance with existing reliability criteria,
3. Revising reliability criteria where required,
4. Aligning reliability targets with reliability criteria, and
5. Preparing capital and operating plans to meet reliability targets.

Existing Reliability Criteria

Hydro's broad reliability targets are already defined as follows:

Island interconnected generation:

The system should have sufficient generating capability to supply firm load with firm system capability and sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) of not more than 2.8 hours per year.

Island Interconnected bulk transmission:

The bulk transmission system must sustain the single contingency loss of any element without loss of stability or overloading of remaining elements.

Transformer additions at multiple transformer terminal stations are planned on the basis of being able to withstand the loss of the largest unit.

For single transformer stations there must be a back-up plan in place.

For normal operations all voltages should be maintained between 95% and 105%. For contingency or emergency situations 90% to 110% is acceptable.

The system should be able to withstand a successful single pole reclose for a line to ground fault.

Isolated diesel generation:

The diesel system should have sufficient firm capacity to supply the peak load. Firm capacity is defined as the total installed capacity minus the largest unit.

Hydro installs a minimum of three units in each diesel system.

Distribution systems:

Distribution systems are planned based on Canadian Standards Association (CSA) standard CAN3-C235-83-"Preferred Voltage Levels for AC Systems" and Canadian Electricity Association (CEA) "Distribution Planner's Guide".

Next Steps
Hydro will complete the identification of additional specific criteria and the assessment of how well existing assets meet the reliability criteria by December 31, 2008.

Five-Year Plan

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

The five-year plan indicates an increase in expenditures from about $50 million to nearly $60 million by the end of the period. This increased spending results primarily from a need to address aging infrastructure which requires a significant increase in annual expenditures to enable electrical energy to be produced, transmitted and distributed in a reliable manner. An additional influence on the magnitude of the plan is the rapidly escalating cost of equipment, which has been increasing in cost much faster than the Consumer Price Index in recent years, primarily due to elevated demand from other markets. The costs of raw materials required for the production of the equipment, such as copper, iron and alloy steels have doubled in price, or more, in recent years and there is no reason to suspect that they will return to their former prices within the five-year planning horizon.

Generation
The requirement to invest sustaining capital in generation facilities is expected to lead capital spending during the next five-years, closely followed by other asset classes. Primary drivers for these projects are the realization of end of service lives for equipment, reductions in reliability or performance and safety considerations.

Hydraulic
Reliability maintenance is the primary five-year priority for Hydro's five-year capital plan. In 2009, Hydro proposes to replace cooling water systems at the Bay d'Espoir Generating Station, a continuation of a program to replace critical piping systems which have become corroded with age and must be replaced. Also in 2009, Hydro proposes to initiate the purchase of a spare generator stator winding for Bay d'Espoir. This generating station has four units having identical old asphalt windings which are showing indications of advanced deterioration, and having a spare will significantly reduce outage time when a failure inevitably occurs. The winding will be

ordered in 2009 for delivery in 2010. In 2011 Hydro proposes to initiate the process of replacing the penstock at Venam's Bight Generating Station. The penstock is the pipeline which supplies water to the plant. The wood stave penstock, installed in 1955, has deteriorated to the point that replacement is required. This project is estimated to cost $3 million over a two year period. Also beginning in 2009 is a proposed three year project to replace exciters at Hinds Lake and Upper Salmon.

Holyrood Thermal Generating Station

Expenditures at the Holyrood Thermal Generating Station form the majority of Generation capital expenditures over the next five-years and are discussed in detail later in this document.

Gas Turbines

Maintaining reliability of existing assets is also the priority for Hydro's gas turbines. In the past, expenditures at Hydro's gas turbine generating plants have not been significant compared to other assets, but this will need to change within the next five-years. 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. Beginning in 2009, Hydro proposes to spend in excess of $12 million to replace and overhaul components at these two sites. In 2013, Hydro proposes to replace the programmable logic control system at the Happy Valley Gas Turbine. This plant was placed in service in 1992 and some of its components are reaching the age and condition when replacement is required.

Terminal Stations

Increasing load is a significant driver for terminal station spending. The largest terminal station project proposed in the next five-years is in Labrador West. The stations in Labrador City are loaded to capacity with additional demand being placed upon them by growth in the town as a result of the expansion of mining operations. Hydro proposes to spend nearly $10 million between 2009 and 2012 to address this problem. 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.

Maintaining reliability is also a factor in the five-year capital plan. Many projects are proposed during the next five-years to address aging assets, such as insulator replacements ($2 million), upgrading circuit breakers ($2 million) and upgrading existing power transformers ($3.6 million).

The projected cost of terminal station projects will average $7 million annually, but will fluctuate widely from year to year due to the significant magnitude of some individual projects, such as the Oxen Pond transformer addition.

Transmission

Again, reliability maintenance is the primary driver for transmission investment. Capital expenditures on transmission lines will average $4.5 million over the next five-years. The single largest expenditure will be for the ongoing wood pole line management program. Under this program, the conditions of the wood components of the transmission lines are monitored. Replacements of rotted and damaged components are scheduled in a timely and planned fashion, thereby reducing the frequency and duration of unplanned outages. A similar project will see the repair and replacement of foundation structures throughout Hydro's transmission system, at a total cost of $5.4 million in 2012 and 2013.

Safety of Hydro personnel, contractors, and the public is also a factor in the five-year plan for Transmission. In 2008 Hydro began construction of highway offloading ramps. This project was proposed to eliminate a serious safety risk to Hydro employees and the public while offloading heavy equipment required for maintaining transmission lines. Hydro proposes to spend an additional $5 million over the next five-years to eliminate this serious hazard.

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 bulk of expenditures for the next five-years will consist of service extensions and upgrading 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 Plum Point Line 2 in 2013 and Line 4 in Roddickton in 2011.

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 (2013), and Little Bay Islands (2011) and at several other locations. These replacements are required to ensure that reliable service is provided to Hydro's isolated rural customers.

Compliance with Hydro's planning criteria to meet load is also a factor. In the 2009 Capital Budget, L'Anse au Loup generation must be upgraded to meet future load growth.

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, with no unusual or significant individual expenditures.

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 over $5 million per year for the next five-years. The most significant of these projects will be the West Coast microwave system, expected to cost $9 million over three years. Replacement of obsolete radio equipment will cost over $4 million during this period and the replacement of aging battery banks and chargers will cost $1.5 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 $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 $3.7 million on items such as office equipment, building energy conservation and air conditioning equipment during the next five-years. The single largest project will comprise the improvement of security systems throughout the Hydro system, at a projected cost of $1.4 million in 2009 and 2010.

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 1969/70 and has passed the normal design life for such a facility. Stage II (Unit 3) was commissioned in 1980 and is approaching the end of its normal life. Similar plants of similar age have been retired or been subjected to life assessment and life 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 or have been retired. The lack of certainty in recent years about the future of Holyrood, caused by the combination of its having reached 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 2008 Mid Year Update" report included in Volume II, tab 23, 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. It is due to this uncertainty regarding Holyrood's future deployment that Hydro re-submitted a capital proposal to the Board on June 10, 2008 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. Hydro chose to take this action in advance of a decision about the Lower Churchill project due to serious concerns about the condition of the Holyrood facility and its absolute necessity in the system. Major components of this facility have suffered serious unexpected failures in recent years (boiler superheaters, forced draft fan, turbine nozzle block), confirming Hydro's position that this facility has reached maturity. Given the long cycle time required to identify a needed refurbishment, seek approval from PUB, develop designs and specifications, tender contracts and obtain delivery of specialty components and services, which have ever increasing delivery times, Hydro feels it is crucial to begin the condition assessment process as soon as possible. The condition assessment is intended to provide Hydro with insight as to which component failures are likely and when they are likely to occur. This will provide the necessary information to determine the strategy to perform the required capital replacements in an orderly and efficient manner, thereby avoiding or mitigating the impact of failures that may occur while the plant is in service which would have a major impact on service, quality and reliability.

Five-Year Plan for Holyrood

Planning the future of this facility has been complicated by the plans to develop the Lower Churchill project and bring energy to the Island via a HVDC transmission link. This project has been proposed several times in the past and is now being actively pursued. Due to the uncertainty surrounding this project, 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 electrical system for decades to come. In the isolated case Holyrood will continue to be a generating station; in the interconnected scenario its three generating units will operate as synchronous condensers, providing 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 arrival of the HVDC infeed. Hydro also anticipates maintaining this facility to be capable of operating 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 tested and proven.

Maintaining this plant for winter reliability is the primary focus of the five-year plan. 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.

2009 Projects

The projects selected for the Holyrood Generating Station for 2009 are those required to ensure that the facility can continue to operate reliably until the completion of the Lower Churchill project and those which are associated with equipment required for synchronous condensing. Should the Lower Churchill project not be sanctioned, this facility will require extensive life assessment and life extension work over a prolonged period, to enable Hydro to continue to provide least cost electricity to our customers.

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 was assessed by consultants, serious deficiencies identified and a program identified to ensure that the facility can operate into the future.

Replace Unit 2 High Pressure Heater: The existing heater has reached the end of its useful life and has experienced a large number of leaks. Loss of this heater would degrade plant output and efficiency for a significant period as the manufacturing cycle for feed water heaters is quite long.

Replace Unit 3 Steam Seal Regulator: The existing steam seal regulator is obsolete and replacement parts cannot be obtained from the manufacturer. Failure of the regulator or one of its components could remove a generating unit from service for an extended period.

Replace Unit 2 Air Preheater Cold End: The cold end assembly is subject to high corrosion rates and a recent internal inspection indicated that it has deteriorated to the extent that it must be rebuilt. The air heater contributes to the fuel efficiency of the unit and its failure would cause an increase in fuel consumption.

Replace Unit 1 Hydrogen Emergency Vent Valves: The present valve arrangement requires that during an emergency a control room operator must travel to a lower plant level to vent hydrogen from the generator. This is both time consuming and potentially high risk. The modification will allow the venting to be accomplished quickly and remotely. Emergency hydrogen venting will be required should the plant operate as a generating or synchronous condensing facility.

Install Unit 1 Cold Reheat Piping Condensate Drains and HP Heater Trip Level: In its present configuration, the generating unit is at risk of condensate (water that has condensed from steam) induction into the turbine. The introduction of water into a spinning steam turbine can cause extensive damage which can remove the machine from service for many months. This project will provide protection to prevent such an incident from occurring.

Install Motorized Stack Winches: While performing maintenance and testing functions on the stacks, personnel are required to manually hoist heavy equipment to a height of approximately 50 meters. This is both time consuming and physically exhausting for workers. Stack winches will provide a faster, safer method for performing this work.

Environmental Effects Monitoring Study of Waste Water: This is a study of the environmental effect on Conception Bay of the cooling water plume from the plant and is required under the Compliance Agreement issued by the Department of Environment and Conservation.

Install Marine Terminal Capstans Lifting Frames: The present method of dismantling capstans exposes personnel to potentially high risk working conditions. The lifting frames will reduce the risk and reduce the labor required to perform maintenance.

Future Projects

Install Low NO_x Burners (2010 – 2013): In recent years Hydro has reduced the stack emissions from the Holyrood facility by burning fuel with lower sulphur content. This cleaner fuel does not reduce **NO_x** emissions (oxides of Nitrogen) emissions. It is anticipated that Hydro may be required to address its **NO_x** emissions regardless of whether the Lower Churchill project is sanctioned in 2009.

Replace Units 2 and 3 Hydrogen Emergency Vent Valves (2010): The present valve arrangement requires that during an emergency a control room operator must travel to a lower level to vent hydrogen from the generator. This is both potentially dangerous and time consuming. The modification will allow the venting to be accomplished quickly and remotely. Emergency hydrogen venting will be required should the plant operate as a generating or synchronous condensing facility.

Install Turbine Lube Oil Conditioners (2010): 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.

Replace Steam Seal Regulator - Unit 1 and Unit 2 (2010 – 2011): The existing steam seal regulators are obsolete and replacement parts cannot be obtained from the manufacturer. Failure of the regulator or one of its components could remove a generating unit from service for an extended period.

Construct New Carpentry Shop (2010): The current location of the carpentry shop adjacent to an operating unit is potentially dangerous, inconvenient and inefficient. A carpentry shop will be required should the plant operate as a generating or synchronous condensing facility.

Install Unit 2 and 3 Cold Reheat Condensate Drains and HP Heater Trip Level (2010 – 2011): In its present configuration, the generating units are at risk of condensate induction into the turbines. The introduction of water into a spinning steam turbine can cause extensive damage which can remove the machine from service for many months. This project will provide protection to prevent such an incident from occurring.

Install Weather Hoods for Ventilating Fans (2010): Without weather hoods the existing fans are overpowered by wind, preventing evacuation of fumes and dust from the plant. The accumulation of fumes and dust poses a health risk to personnel.

Replace Pumphouse Motor Control Centres (2012 – 2013): These electrical panels are required to operate auxiliary equipment crucial to the operation of the generating equipment. Their condition has deteriorated to the point where replacement is necessary and they will be required should the plant operate either as a generating or synchronous condensing facility.

Replace Waste Water Basin Building (2012): The building has deteriorated extensively due to corrosion which occurs in the humid interior and requires replacement. It will be required should the plant operate as a generating or synchronous condensing facility.

Install Hydrogen Gas Generator (2012): Holyrood has been at risk in the past due to uncertainty of hydrogen gas supply, which is essential for cooling the turbine generator. The hydrogen generator will be a useful addition to the plant while it operates as a generating station and will become even more important should the plant be converted to a synchronous condensing facility, as hydrogen consumption is expected to increase in that mode of operation.

Upgrade Unit 3 Relay Panel Controls (2012): Component replacement is required due to obsolescence and these controls will be required should the plant operate as a generating or synchronous condensing facility.

Upgrade Soot Blowing Controls - Units 1, 2 and 3 (2013): In recent years Hydro has reduced the stack emissions from the Holyrood facility by moving to cleaner oil, with lower sulphur content. Experience with other thermal plants has indicated that utilizing more sophisticated controls for the soot blowing equipment can reduce particulate emission concentrations. It is anticipated that Hydro may be required to address particulate emissions whether or not the Lower Churchill project is sanctioned.

Replace Gas Turbine Air Intake Structure (2013): 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.

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 is in the process of identifying the technical requirements, costs and implementation schedule for this equipment. The report will be available by the end of 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, end of life. At this time, these costs are estimated to orders of magnitude only. The table below is very preliminary in nature, 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	2,500
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 - Inside Building Fuel System	550
Unit 2 - Boiler	13,000
Unit 2 - Turbine	5,000
Unit 2 - Continuous Emission Monitoring System	2,500
Unit 2 - Steam Piping	750
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	28,500
Unit 3 - Turbine	5,000
Unit 3 - Stack and Breeching	5,000
Unit 3 - Continuous Emission Monitoring System	2,000
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

Unit and Item Description	($ 000)
Common - Fuel Unloading Equipment	425
Common - Stack and Breaching	100
Stack Emissions Cleanup Equipment	300,000
Initial Plant Life Extension	100,000
Total	**513,165**

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 will be a 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 energy produced from the plant achieves the requirement of being least cost. 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 markedly from what is presented here. The single most important point to be considered is that if the Holyrood plant is to be relied upon as a source of generation into the future, the process of assessment and remediation must begin in the very near future.

APPENDIX A

Five-Year Capital Plan

	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
GENERATION	1,225	7,711	12,625	13,457	23,256	20,624	78,898
TRANSMISSION AND RURAL OPERATIONS	2,953	29,168	24,873	27,507	19,159	28,694	132,354
GENERAL PROPERTIES	950	9,976	12,424	12,613	14,230	8,496	58,689
CONTINGENCY FUND	0	1,000	1,000	1,000	1,000	1,000	5,000
TOTAL CAPITAL BUDGET	5,128	47,856	50,922	54,577	57,644	58,814	274,942

	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
GENERATION							
Hydraulic Plant	1,132	1,265	4,964	3,192	7,877	9,084	27,514
Thermal Plant	93	5,341	4,659	7,998	10,220	6,921	35,232
Gas Turbines	0	713	2,899	2,002	5,051	4,588	15,252
Tools and Equipment	0	393	103	265	108	31	901
TOTAL GENERATION	1,225	7,711	12,625	13,457	23,256	20,624	78,898
TRANSMISSION AND RURAL OPERATIONS							
Terminal Stations	0	3,367	8,179	10,555	3,596	10,151	35,849
Transmission	1,343	5,984	4,020	3,651	4,927	5,243	25,168
Distribution	0	8,685	6,430	9,726	7,168	8,609	40,617
Generation	1,252	2,643	3,329	1,269	191	2,392	11,075
Properties	358	6,292	598	286	232	140	7,906
Metering	0	524	903	947	1,287	779	4,440
Tools and Equipment	0	1,674	1,414	1,073	1,759	1,380	7,298
TOTAL TRANSMISSION AND RURAL OPERATIONS	2,953	29,168	24,873	27,507	19,159	28,694	132,354
GENERAL PROPERTIES							
Information Systems	0	1,633	2,699	4,773	2,146	1,328	12,579
Telecontrol	864	3,716	5,844	4,056	9,462	2,600	26,543
Transportation	0	2,156	2,975	3,638	2,493	4,519	15,782
Administrative	86	2,471	906	145	128	49	3,786
TOTAL GENERAL PROPERTIES	950	9,976	12,424	12,613	14,230	8,496	58,689
CONTINGENCY FUND	0	1,000	1,000	1,000	1,000	1,000	5,000
TOTAL CAPITAL BUDGET	5,128	47,856	50,922	54,577	57,644	58,814	274,942

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
HYDRAULIC PLANT							
Purchase Spare Stator Winding Units 1 to 4 - Bay d'Espoir		37	2,806				2,843
Replace Governor Controls Unit 2 - Cat Arm	975	74					1,049
Replace 50 kW Diesel Generator - Bay d'Espoir		36	289				325
Replace Cooling Water Systems on Units 3 and 4 - Bay d'Espoir		287	293				580
Upgrade Intake Gate Controls - Hinds Lake		263	137	290			690
Replace 40 kW Diesel Generator at Spillway - Bay d'Espoir	157	103					260
Install Meteorological Stations - Various Sites		253	280	153	271		957
Replace Service Water Piping - Unit 7 - Bay d'Espoir		144					144
Replace Generator Oil Level System on Units 1 and 2 - Cat Arm		68					68
Upgrade Fuel Storage - Hinds Lake			281				281
Purchase Spherical Valve Seal & Ring Assembles - Bay d'Espoir			199				199
Design & Install Automated Diesel Monitoring Sys.at EBBE - Bay d'Espoir			180				180
Replace HMI Computer - Paradise River			171				171
Replace A/C Units in Control Room and Comm. Room - Upper Salmon			146				146
Replace Two Service Water Pumps in Powerhouse - Cat Arm			99				99
Install Air Conditioning at Burnt Spillway - Bay d'Espoir			47				47
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir			36				36
HRP#3 - Replace Exciters - Hinds Lake, Upper Salmon				80	2,124	1,179	3,383
Replace Penstock & Trashrack/Gate - Venams Bight				288	2,729		3,017
Recoat Surge Tank #3 - Bay d'Espoir				562			562
Install Trash Boom - Granite Canal				292			292
Design & Install Oil-Water Separation Systems - Units 1 to 7 - Bay d'Espoir				250			250
Install Partial Discharge Monitors - Bay d'Espoir, Hinds Lake				105	124		229
Install Dyn Air Gap Monitoring System on Units - Upper Salmon				206			206
Build Remote Computer Link Between Cat Governors and BDE - Cat Arm				175			175
Replace Automatic Transfer Switches - Bay d'Espoir, Hinds Lake				157			157

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
Replace Units 1-6 Autogreasing Systems - Bay d'Espoir				150			150
Upgrade Generating Station Service Water - Cat Arm				141			141
Replace Compressor for Frazil Ice at Intake - Upper Salmon				92			92
Replace Network Switches for ABB RTU's - Granite Canal				70			70
Replace Fire Alarm System - Hinds Lake				58			58
Replace Trash Boom at Control Structure - Hinds Lake				41			41
Replace Cooling Water Pumps 2 & 4 in Powerhouse 1 - Bay d'Espoir				40			40
Study Generator Dust Collection Systems for Units 1 to 6 - Bay d'Espoir				30			30
Replace Cooling Water Rotary Strainer - Upper Salmon				11			11
Upgrade Access Roads - Bay d'Espoir					722		722
Upgrade Road Between PH and North Salmon Spillway - Upper Salmon					719		719
Install Powerhouse, Air Circulation System - Bay d'Espoir					249		249
Replace Microscada Computers - Granite Canal					199		199
Upgrade Station Service Water System - Upper Salmon					164		164
Upgrade Unit 1 Generator Bearing - Bay d'Espoir					161		161
Construct Equipment Storage and Tool Crib Building - Bay d'Espoir					125		125
Install Gates RR Pond - Granite Canal					80		80
Install Unit 1 Governor Oil Filtration System - Bay d'Espoir					68		68
Install Trash Boom - Upper Salmon					60		60
Replace Septic System at Campsite - Bay d'Espoir					49		49
Upgrade Telephone Services at Plant - Paradise River					32		32
Rewind Generator Unit 1 - Bay d'Espoir						2,000	2,000

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
Replace Warehouse - Bay d'Espoir						1,056	1,056
Install Bridge at Noel Paul Brook - Bay d'Espoir						1,040	1,040
Upgrade Burnt Dam Access Road - Phase 2 - Bay d'Espoir						975	975
Install Road Topping and Culverts and Bin Wall - Cat Arm						895	895
Replace Runner - Snooks Arm						371	371
Replace Spherical Valve Control System - Cat Arm						350	350
Repair Roads - Upper Salmon						316	316
Install Dyn Air Gap Monitoring System on Units - Bay d'Espoir						309	309
Install Automatic Sprinkler System in Office Area - Bay d'Espoir						297	297
Upgrade Unit Relay Protection - Paradise River						158	158
Replace Runner - Venams Bight						138	138
TOTAL HYDRAULIC PLANT	1,132	1,265	4,964	3,192	7,877	9,084	27,514

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
THERMAL PLANT							
Refurbish Fuel Storage Facility - Holyrood		2,867	3,279	2,647	2,502		11,294
Replace Unit 2 High Pressure Heater - Holyrood	20	919					939
Replace Unit 3 Steam Seal Regulator - Holyrood		475					475
Replace Unit 2 Air Preheater Cold End - Holyrood		320					320
Replace Unit 1 Hydrogen Emergency Vent Valves - Holyrood		214					214
Install Unit 1 Cold Reheat Condensate Drains and HP Heater Trip Level - Holyrood		192					192
Install Motorized Stack Winches - Holyrood		174					174
Environmental Effects Monitoring Study of Waste Water - Holyrood	73	87					160
Install Marine Terminal Capstans Lifting Frames - Holyrood		93					93
Install Low Nox Burners - Holyrood			73	4,957	4,957	4,957	14,944
Replace Units 2&3 H2 Emergency Vent Valves - Holyrood			296				296
Install Turbine Lube Oil Conditioners - Holyrood			277				277
Replace Steam Seal Regulator - Unit 1 & 2 - Holyrood			237	254			491
Construct New Carpentry Shop - Holyrood			198				198
Install Weatherhoods for Ventilating Fans - Holyrood			170				170
Install Unit 2 & 3 CR Condensate Drains & HP Heater Trip Level - Holyrood			130	140			270
Replace Pumphouse Motor Control Centres - Holyrood					650	326	976
Replace Waste Water Basin Building - Holyrood					889		889
Install Hydrogen Gas Generator - Holyrood					850		850
Upgrade Unit 3 Relay Panel Controls - Holyrood					372		372
Upgrade Soot Blowing Controls - Units 1,2 & 3 - Holyrood						988	988
Replace GT Air Intake Structure - Holyrood						650	650
TOTAL THERMAL PLANT	93	5,341	4,659	7,998	10,220	6,921	35,232

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
GAS TURBINES							
Upgrade Gas Turbine Plant Life Extension - Hardwoods		450	2,519	2,002	5,051	2,706	12,728
Replace Automatic Voltage Regulator on Gas Turbine - Stephenville		262					262
Install Sprinklers System at Gas Turbine - Holyrood			191				191
Construct Gas Turbine Equipment Enclosure - Holyrood			131				131
Upgrade Fuel Tank Farm Controls - Happy Valley			58				58
Upgrade Gas Turbine PLC - Happy Valley Goose Bay						1,882	1,882
TOTAL GAS TURBINE PLANTS	0	713	2,899	2,002	5,051	4,588	15,252
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000	0	311	103	48	36	31	529
Purchase Boom Style Hydraulic Lift - Holyrood		82					82
Replace 21' Stanley Metal Cutting Lathe - Bay d'Espoir				217			217
Install Handheld Pendant to Overhead Crane - Bay d'Espoir					72		72
TOTAL TOOLS AND EQUIPMENT	0	393	103	265	108	31	901
TOTAL GENERATION	1,225	7,711	12,625	13,457	23,256	20,624	78,898

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
TERMINAL STATIONS							
New 25 kV Terminal Station - Labrador City		283	3,895	5,813			9,991
Upgrade Power Transformers - Various Sites		654	667	721	779	843	3,664
Perform Grounding Upgrades - Various Sites		252	291				543
Install Digital Fault Recorders - Massey Drive, Oxen Pond and St. Anthony		462	164	134			760
Upgrade Circuit Breakers - Various Terminal Stations		422	430	440	451	462	2,205
Replace Insulators - Various Terminal Stations		391	399	408	418	429	2,045
Replace 69 kV Breaker L51T2 - Howley		199					199
Upgrade Great Northern Peninsula Protection - Various Sites		101	91				192
Replace Instrument Transformers - Various Sites		107	109	111	114	117	557
Replace 230kV Breaker Controls - Oxen Pond, Bay d'Espoir		100	73				172
Replace Air Compressors - Various Locations		96	101	106			303
Replace Drainage System - Western Avalon		84					84
Replace Surge Arrestors - Various Sites		81	83	85	87	89	423
Install 138 kV Capacitive Voltage Transformer - St. Anthony Airport		71					71
Install 69 kV Capacitive Voltage Transformer - St. Anthony Diesel Plant		67					67
Replace Circuit Breakers - Massey Drive, Hardwoods			939	991			1,930
Install Breaker By-Pass Disconnect Switches - Various Locations			275	275	275	275	1,100
Install Bypasses for Breakers on 66kV Radial Lines - Various Locations			160	170	180	190	700
Replace Disconnects - Various Locations			197	203	209		608
Install on-line Dewpoint Monitoring - Various Locations			144	151	220		515
Install Alternate Station Services - Stony Brook, Massey Drive			164				164
Install Station Alarm Breakouts - Various Locations				948		442	1,390
Install Additional 230kV Transformer - Oxen Pond					21	4,059	4,080
Install 20 MVAR Reactor - Bottom Brook					24	2,497	2,521
Perform Site Work to Accommodate MobileTransformer - Various Locations					264	291	555
Install Control and Communications Link - Bottom Waters					542		542
Replace Trailer Mobile Substation - Bishops Falls					13	459	472
TOTAL TERMINAL STATIONS	0	3,367	8,179	10,555	3,596	10,151	35,849

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
TRANSMISSION							
Perform Wood Pole Line Management Program - Various Sites		2,256	2,106	2,677	1,691	1,843	10,572
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake		968	964				1,932
Replace Insulators on 230 kV Line - Stony Brook, Buchans	848	970					1,818
Upgrade Corner Brook Frequency Converter - Corner Brook	495	1,152					1,647
Construct Transmission Line Equip Off-Loading Areas - Various Sites		498	951	974	536		2,960
Construct Transmission Storage Ramps - Bay d'Espoir		75					75
Install Remote Ice Growth Detector Beams - Various Sites		65					65
Replace Concrete Support Structures - Various Locations					2,700	2,700	5,400
Relocate Remote Section of Line - TL220						700	700
TOTAL TRANSMISSION	1,343	5,984	4,020	3,651	4,927	5,243	25,168
DISTRIBUTION							
Upgrade Distribution Systems - All Service Areas		2,526	2,602	2,679	2,758	2,842	13,407
Provide Service Extensions - All Service Areas		2,439	2,513	2,587	2,664	2,744	12,947
Replace Insulators - Jackson's Arm, Hampden and Little Bay		874					874
Replace Poles - Various Sites		697	740	916	707	361	3,421
Upgrade L7 Distribution System - St. Anthony		689					689
Replace Line L36 - Wabush		498					498
Replace Conductor on L2 - Rocky Harbour		325					325
Upgrade Voltage Conversion Phase 1- Labrador City		189					189
Replace Recloser Control Panels - Various Sites		132	294	221	135	143	925
Purchase and Install Voltage Regulator Bank - English Harbour West		123					123
Purchase and Install Electronic Recloser - Cartwright		96					96
Replace Submarine Cable Terminator Kit - Change Islands/Fogo Island		96					96
Install Pole Storage Ramps - Various Locations			120	124	128	132	503
Replace Submarine Cable from Pilley's Island to Long Island - South Brook				635			635
Upgrade Distribution Systems - Various Sites				2,565	776	2,388	5,729
Replace Voltage Conversion - Distribution - Happy Valley			161				161
TOTAL DISTRIBUTION	0	8,685	6,430	9,726	7,168	8,609	40,617

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
GENERATION							
Replace Diesel Units - Norman Bay, Postville and Paradise River		170	1,700				1,870
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	335	938					1,273
Diesel Plant Automation - Makkovik and Rigolet	516	379					895
Increase Generation - L'Anse au Loup		23	821				844
Increase Generation Capacity - Charlottetown	18	577					595
Replace Switchgear - Cartwright	383	169					552
Upgrade Fuel Storage - Cartwright		139					139
Replace Speed Increaser - Roddickton		125					125
Install Meter Station for Fuel Reconciliation - Hawke's Bay		64					64
Install Furnace Fuel Storage Tank - Williams Harbour		59					59
Replace Unit 2001 and Unit 566 - Francois			32	801			833
Replace Genset U565 - Little Bay Islands				210			210
Replace Unit 2018 - McCallum					168	259	427
Automate Plant - Charlottetown			161	189			350
Upgrade Substation Step-Up Transformers - Charlottetown			215				215
Install Sequence of Events Monitor in Diesel Plants - Various Locations			125	69			194
Upgrade Generation - Port Hope Simpson					23	715	739
Install Nox Monitors at 2 sites - Various Locations						412	412
Install Intermediate Tank - Nain			142				142
Upgrade Main Bus Splitter - Postville			133				133
Construct Fuel Storage Tank - Nain						755	755
Upgrade Generation Transformer - Cartwright						251	251
TOTAL GENERATION	1,252	2,643	3,329	1,269	191	2,392	11,075

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
PROPERTIES							
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	358	2,960					3,318
Replace Accommodations, Septic System and Uprgade Plant Communications System - Cat Arm		1,254					1,254
Build New Maintenance Shop - St. Anthony		429					429
Install Fall Arrest Equipment - Various Sites		322					322
Replace Explosives Storage Magazines - Central and Northern Regions		293					293
Upgrade Ventilation System - Little Bay Islands Diesel Plant		186					186
Pave Parking Lots and Roadways - Bishop's Falls		150					150
Install Transformer Storage Ramps - Labrador		121	124	128			373
Build ATV/snowmobile Storage - Whitbourne		86					86
Install Waste Oil Storage Tanks - Various Sites		84	87	89	92		352
Install Pole Storage Ramps - Various Sites		77					77
Install Water and Sewer System - Paradise River		77					77
Legal Survey of Primary Distribution Line Right of Way - Various Sites		56	61	69	140	140	466
Construct Sewage Disposal Field - Makkovik		50					50
Install Storage Ramp - Whitbourne		41					41
Upgrade CEMS Room Ventilation - Holyrood		39					39
Install Air Conditioning at Training Centre - Bay d'Espoir		34					34
Replace Dock Lighting - Holyrood		33					33
Build Unheated Storage Building - Springdale			200				200
Upgrade Grounds - Port Hope Simpson			79				79
Upgrade Accomodations - Norman Bay			48				48
TOTAL PROPERTIES	358	6,292	598	286	232	140	7,906

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011 ($000)	2012	2013	Total
METERING							
Install Automatic Meter Reading - Change Islands and Fogo Island		491	779	833	1,171	779	4,053
Purchase Meters and Equipment - Various Sites		33	124	114	116		387
TOTAL METERING	0	524	903	947	1,287	779	4,440
TOOLS AND EQUIPMENT							
Replace Off Road Tracked Vehicles - Whitbourne and Bishops Falls		758					758
Replace Off Road Tracked Vehicles - Various Sites			540	514	902	1,032	2,987
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites		561	754	559	857	348	3,079
Purchase and Replace Tools and Equipment Less than $ 50,000		268	19				287
Purchase High Definition Infrared Camera - Central		87					87
Purchase High Volt Breaker Timing Sets - Bishops Falls,Stephenville,Whitbourne			101				101
TOTAL TOOLS AND EQUIPMENT	0	1,674	1,414	1,073	1,759	1,380	7,298
TOTAL TRANSMISSION AND RURAL OPERATIONS	2,953	29,168	24,873	27,507	19,159	28,694	132,354

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
INFORMATION SYSTEMS							
SOFTWARE APPLICATIONS							
New Infrastructure							
Applications Enhancements - Performance Management Software Budeting Tool - Hydro Place		127					127
Application Enhancements - Perform Minor Application Enhancements - Hydro Place		120	310	126	130	133	819
Cost Recovery CF(L)Co		(35)	(61)	(26)	(26)	(27)	(174)
Purchase Protection Relay Event Report Software - Hydro Place		54					54
Upgrade Intranet - Hydro Place		67	68	70	73	75	353
Cost Recovery CF(L)Co		(19)	(14)	(14)	(15)	(15)	(77)
Upgrade of Technology							
Corporate Application Environment - Upgrade Showcase Strategy Suite - Hydro Place		158			173		331
Cost Recovery CF(L)Co		(46)			(35)		(81)
Citrix Enhancements - Hydro Place		118					118
Cost Recovery CF(L)Co		(34)					(34)
Upgrade Microsoft Products - Hydro Place			1,177				1,177
Cost Recovery CF(L)Co			(182)				(182)
Upgrade Business Intelligence Toolset Software - Hydro Place			163				163
Cost Recovery CF(L)Co			(33)				(33)
Upgrade Citrix Suite and Lotus Notes - Hydro Place				4,341			4,341
Cost Recovery CF(L)Co				(729)			(729)
Upgrade Various Products - Hydro Place					578	133	711
Cost Recovery CF(L)Co					(85)	(20)	(105)
Upgrade Lotus - Hydro Place					283		283
Cost Recovery CF(L)Co					(57)		(57)
TOTAL SOFTWARE APPLICATIONS	0	510	1,429	3,769	1,019	279	7,006

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
COMPUTER OPERATIONS							
Infrastructure Replacement							
End User Evergreening Program - Various Sites		491	495	457	426	478	2,347
Replace Peripheral Infrastructure - Hydro Place		161	113	131	203	207	815
Replace Drafting Scanner/Plotter - Hydro Place		139					139
Perform Hawke Hill Inprovements - Hawk Hill		50					50
Upgrade Enterprise Storage Capacity - Hydro Place			233	73	75	77	458
Cost Recovery CF(L)Co			(36)	(11)	(11)	(11)	(69)
New Infrastructure							
Security Smartcard and Disk Encryption for Laptops - Hydro Place		125					125
Cost Recovery CF(L)Co		(36)					(36)
Upgrade Security SCADA Intrusion Prevention System - Hydro Place			159				159
Upgrade Security Vulnerability Management System - Hydro Place			142				142
Cost Recovery CF(L)Co			(28)				(28)
Install Password Vaulting - Hydro Place				149			149
Cost Recovery CF(L)Co				(30)			(30)
Upgrade of Technology							
Upgrade Server Technology Program - Hydro Place		273	200	249	524	358	1,604
Cost Recovery CF(L)Co		(79)	(8)	(14)	(90)	(60)	(251)
TOTAL COMPUTER OPERATIONS	0	1,123	1,270	1,004	1,127	1,049	5,573
TOTAL INFORMATION SYSTEMS	0	1,633	2,699	4,773	2,146	1,328	12,579

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
TELECONTROL							
NETWORK SERVICES							
Infrastructure Replacement							
Public Address System - Holyrood	96	1,182					1,279
Customer Service Application - Hydro Place	768	182					950
Install Fibre Optic Cable - Hinds Lake		209	549	2,707			3,465
Replace Power Line Carrier on TL-250 - Bottom Brook to Grandy Brook		473	411		437		1,321
Replace Remote Terminal Units - Various Sites		278	170	85			533
Replace Radomes - Various Sites		130	123	145	170		568
Replace MDR 4000 Microwave Radio (West) - Various Locations			2,041				2,041
Refurbish Microwave Site - Deer Lake			202				202
Expand Westcoast Microwave - Various Locations				400	6,000	2,600	9,000
Upgrade 1603 SONET Multiplexer - Various Locations				72			72
Replace MDR6000 Microwave Radio (West) - Various Locations					2,591		2,591
Network Infrastructure							
Replace Batteries and Chargers - Various Sites		729	708	281			1,718
Replace Radio Tower - Ebbegunbaeg		179					179
Replace Network Communications Equipment - Various Sites		141	95	97	119		452
Purchase Test Equipment - Various Locations		74	49	49			172
Install Wireless Networking - Various Locations		45			48		93
Install Microwave Wind Generation Hybrid - Gull Pond Hill			81				81
Upgrade of Technology							
Upgrade Site Facilities - Various Locations		47	50	49	49		195
Replace Network Management Tools - Various Locations		47					47
Upgrade Microwave Interconnect Radio System - Various Locations			365				365
Replace BDH-BDE Radio Link with Fiber - Bay d'Espoir			525				525
Upgrade PABX - Various Locations			329	66	48		443
Upgrade Operator Training Simulator - Hydro Place			147				147
Replace Telephone Keyset - Various Locations				105			105
TOTAL TELECONTROL	864	3,716	5,844	4,056	9,462	2,600	26,543

PROJECT DESCRIPTION	Expended to 2008	2009	2010	2011	2012	2013	Total
				($000)			
TRANSPORTATION							
Replace Vehicles and Aerial Devices - Various Sites		2,156	2,975	3,638	2,493	4,519	15,782
TOTAL TRANSPORTATION	0	2,156	2,975	3,638	2,493	4,519	15,782
ADMINISTRATION							
Upgrade System Security - Various Sites		767	702				1,469
Energy Conservation Upgrades - Hydro Place		833					833
Purchase Spare Transformer - Hydro Place	86	353					439
Purchase Office Equip Less than $50,000 - Hydro Place		318	128	66	47	49	608
Replace Fire Protection Panels - Hydro Place		89					89
Replace Humidifiers in Air Handling Units - Hydro Place		74	76	79	82		311
Replace Air Conditioning Units - Hydro Place		37					37
TOTAL ADMINISTRATION	86	2,471	906	145	128	49	3,786
TOTAL GENERAL PROPERTIES	950	9,976	12,424	12,613	14,230	8,496	58,689

APPENDIX B

Twenty-Year Capital Plan

20 Year Sustaining Capital
($000)

	Accuracy 10%	Accuracy 25%				Accuracy 50%				Accuracy - 50 % to order of magnitude										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Generation																				
Hydro Plants	2,875	4,964	3,192	7,877	9,084	4,292	5,487	5,142	2,329	3,773	2,385	2,515	2,186	2,185	1,945	1,660	1,605	1,740	1,880	1,510
Thermal Plant	5,414	4,659	7,998	10,220	6,921	6,975	7,975	4,800	9,350	10,600	4,700	8,400	8,700	2,500	400	975	0	250	250	3,000
Gas Turbines	713	2,899	2,002	5,051	4,588	4,245	3,315	350	3,700	200	200	2,100	1,700	2,975	5,210	4,250	3,250	3,530	3,820	1,075
Transmission and Terminals																				
Terminal Stations	3,616	8,303	10,683	3,596	10,151	8,810	7,599	6,535	5,670	8,975	4,655	5,735	5,335	5,751	4,930	4,870	4,685	5,205	5,115	5,395
Transmission	5,984	4,020	3,651	4,927	5,243	11,943	17,439	13,476	14,062	15,972	15,897	12,647	13,138	13,201	13,390	13,435	12,726	12,501	12,501	11,726
Rural Systems																				
Diesel Plants	2,643	3,455	1,269	191	2,392	6,501	6,375	5,642	4,840	4,765	3,838	2,405	2,660	1,890	1,180	875	1,630	2,935	1,240	2,195
Distribution	8,081	1,662	4,618	1,977	3,163	7,105	7,967	7,422	8,102	9,311	9,342	6,147	6,042	4,594	5,174	3,012	4,990	5,101	4,397	3,765
General Properties																				
Information Systems	1,633	2,699	4,773	2,146	1,328	2,769	2,694	6,896	2,670	2,787	3,488	2,848	6,700	1,880	2,652	2,203	6,746	1,752	1,752	2,235
Telecontrol	4,206	6,623	4,889	10,634	3,379	6,240	5,745	6,108	6,860	4,052	2,842	3,997	5,419	6,504	1,440	2,745	2,023	2,495	2,430	2,237
Transportation	3,476	4,267	4,711	4,252	5,899	3,780	3,823	4,185	2,833	5,856	3,780	3,823	4,185	2,833	5,856	3,780	3,823	4,185	2,833	5,856
Administrative	2,154	778	79	82	0	250	200	150	0	80	160	300	200	200	100	360	400	150	300	300
Routine	6,064	5,591	5,711	5,693	5,666	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064	6,064
New Projects	0	0	0	0	0	2,000	10,080	16,350	10,560	6,000	500	200	500	300	1,000	200	500	600	200	500
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	**47,856**	**50,922**	**54,577**	**57,644**	**58,814**	**71,974**	**85,763**	**84,120**	**78,040**	**79,434**	**58,851**	**58,181**	**63,829**	**51,877**	**50,340**	**45,429**	**49,442**	**47,508**	**43,782**	**46,858**
Total for 20 years	1,185,243																			
Average	59,262																			
Total Holyrood without Lower Churchill	0	25,000	75,000	120,000	121,040	36,550	31,000	28,050	25,350	21,150	20,150	3,400	1,425	1,000	0	1,500	50	0	0	2,500
Total for 20 years	513,165																			
Average	25,658																			

	Expended to 2008	2009	Future Years	Total
		($000)		
GENERATION	1,225	7,711	3,095	12,032
TRANSMISSION AND RURAL OPERATIONS	2,953	29,168	13,574	45,695
GENERAL PROPERTIES	950	9,976	1,185	12,111
CONTINGENCY FUND		1,000	0	1,000
TOTAL CAPITAL BUDGET	5,128	47,856	17,854	70,838

	Expended to 2008	2009	Future Years	Total
		($000)		
GENERATION				
Hydraulic Plant	1,132	1,265	3,095	5,492
Thermal Plant	93	5,341	0	5,434
Gas Turbines	0	713	0	713
Tools and Equipment	0	393	0	393
TOTAL GENERATION	1,225	7,711	3,095	12,032
TRANSMISSION & RURAL OPERATIONS				
Terminal Stations	0	3,367	10,090	13,457
Transmission	1,343	5,984	964	8,290
Distribution	0	8,685	0	8,685
Generation	1,252	2,643	2,521	6,416
Properties	358	6,292	0	6,650
Metering	0	524	0	524
Tools and Equipment	0	1,674	0	1,674
TOTAL TRANSMISSION AND RURAL OPERATIONS	2,953	29,168	13,574	45,695
GENERAL PROPERTIES				
Information Systems	0	1,633	0	1,633
Telecontrol	864	3,716	483	5,063
Transportation	0	2,156	0	2,156
Administrative	86	2,471	702	3,259
TOTAL GENERAL PROPERTIES	950	9,976	1,185	12,111
CONTINGENCY FUND		1,000		1,000
TOTAL CAPITAL BUDGET	5,128	47,856	17,854	70,838

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
			($000)		
HYDRAULIC PLANT					
Purchase Spare Stator Winding Units 1 to 4 - Bay d'Espoir		37	2,806	2,843	B-4
Replace Governor Controls Unit 2 - Cat Arm	975	74		1,049	
Replace 50 kW Diesel Generator - Bay d'Espoir		36	289	325	C-13
Replace Cooling Water Systems on Units 3 and 4 - Bay d'Espoir		287		287	C-30
Upgrade Intake Gate Controls - Hinds Lake		263		263	C-37
Replace 40 kW Diesel Generator at Spillway - Bay d'Espoir	157	103		260	
Install Meteorological Stations - Various Sites		253		253	C-50
Replace Service Water Piping - Unit 7 - Bay d'Espoir		144		144	D-9
Replace Generator Oil Level System on Units 1 and 2 - Cat Arm		68		68	D-15
TOTAL HYDRAULIC PLANT	1,132	1,265	3,095	5,492	
THERMAL PLANT					
Refurbish Fuel Storage Facility - Holyrood		2,867		2,867	B-2
Replace Unit 2 High Pressure Heater - Holyrood	20	919		939	
Replace Unit 3 Steam Seal Regulator - Holyrood		475		475	C-2
Replace Unit 2 Air Preheater Cold End - Holyrood		320		320	C-19
Replace Unit 1 Hydrogen Emergency Vent Valves - Holyrood		214		214	C-57
Install Unit 1 Cold Reheat Condensate Drains and HP Heater Trip Level - Holyrood		192		192	D-3
Install Motorized Stack Winches - Holyrood		174		174	D-7
Environmental Effects Monitoring Study of Waste Water - Holyrood	73	87		160	
Install Marine Terminal Capstans Lifting Frames - Holyrood		93		93	D-12
TOTAL THERMAL PLANT	93	5,341	0	5,434	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years ($000)	Total	Page Ref
GAS TURBINES					
Upgrade Gas Turbine Plant Life Extension - Hardwoods		450		450	C-12
Replace Automatic Voltage Regulator on Gas Turbine - Stephenville		262		262	C-45
TOTAL GAS TURBINE PLANTS	0	713	0	713	
TOOLS AND EQUIPMENT					
Purchase Tools and Equipment Less than $50,000	0	311		311	
Purchase Boom Style Hydraulic Lift - Holyrood		82		82	D-14
TOTAL TOOLS AND EQUIPMENT	0	393	0	393	
TOTAL GENERATION	1,225	7,711	3,095	12,032	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
			($000)		
TERMINAL STATIONS					
New 25 kV Terminal Station - Labrador City		283	9,707	9,991	B-6
Upgrade Power Transformers - Various Sites		654		654	B-28
Perform Grounding Upgrades - Various Sites		252	291	543	B-30
Install Digital Fault Recorders -					
Massey Drive, Oxen Pond and St. Anthony		462		462	C-96
Upgrade Circuit Breakers - Various Terminal Stations		422		422	C-110
Replace Insulators - Various Terminal Stations		391		391	C-118
Replace 69 kV Breaker L51T2 - Howley		199		199	D-17
Upgrade Great Northern Peninsula Protection - Various Sites		101	91	192	D-20
Replace Instrument Transformers - Various Sites		107		107	D-44
Replace 230kV Breaker Controls - Oxen Pond, Bay d'Espoir		100		100	D-46
Replace Air Compressors - Sunnyside		96		96	D-51
Replace Drainage System - Western Avalon		84		84	D-59
Replace Surge Arrestors - Various Sites		81		81	D-60
Install 138 kV Capacitive Voltage Transformer - St. Anthony Airport		71		71	D-69
Install 69 kV Capacitive Voltage Transformer - St. Anthony Diesel Plant		67		67	D-71
TOTAL TERMINAL STATIONS	0	3,367	10,090	13,457	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
			($000)		
TRANSMISSION					
Perform Wood Pole Line Management Program - Various Sites		2,256		2,256	B-13
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake		968	964	1,932	B-15
Replace Insulators on 230 kV Line - Stony Brook, Buchans	848	970		1,818	
Upgrade Corner Brook Frequency Converter - Corner Brook	495	1,152		1,647	
Construct Transmission Line Equip Off-Loading Areas - Various Sites		498		498	C-74
Construct Transmission Storage Ramps - Bay d'Espoir		75		75	D-67
Install Remote Ice Growth Detector Beams - Various Sites		65		65	D-73
TOTAL TRANSMISSION	1,343	5,984	964	8,290	
DISTRIBUTION					
Upgrade Distribution Systems - All Service Areas		2,526		2,526	B-7
Provide Service Extensions - All Service Areas		2,439		2,439	B-11
Replace Insulators - Jackson's Arm, Hampden and Little Bay		874		874	B-21
Replace Poles - Jackson's Arm and Hampden		697		697	B-25
Upgrade L7 Distribution System - St. Anthony		689		689	B-27
Replace Line L36 - Wabush		498		498	C-66
Replace Conductor on L2 - Rocky Harbour		325		325	C-124
Upgrade Voltage Conversion Phase 1- Labrador City		189		189	D-26
Replace Recloser Control Panels - Various Sites		132		132	D-33
Purchase and Install Voltage Regulator Bank - English Harbour West		123		123	D-38
Purchase and Install Electronic Recloser - Cartwright		96		96	D-48
Replace Submarine Cable Terminator Kit - Change Islands/Fogo Island		96		96	D-50
TOTAL DISTRIBUTION	0	8,685	0	8,685	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years ($000)	Total	Page Ref
GENERATION					
Replace Diesel Units - Norman Bay, Postville and Paradise River		170	1,700	1,870	B-17
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	335	938		1,273	
Diesel Plant Automation - Makkovik and Rigolet	516	379		895	
Increase Generation - L'Anse au Loup		23	821	844	B-22
Increase Generation Capacity - Charlottetown	18	577		595	
Replace Switchgear - Cartwright	383	169		552	
Upgrade Fuel Storage - Cartwright		139		139	D-31
Replace Speed Increaser - Roddickton		125		125	D-36
Install Meter Station for Fuel Reconciliation - Hawke's Bay		64		64	D-75
Install Furnace Fuel Storage Tank - Williams Harbour		59		59	D-77
TOTAL GENERATION	1,252	2,643	2,521	6,416	
PROPERTIES					
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	358	2,960		3,318	B-40
Replace Accommodations, Septic System and Uprgade Plant Communications System - Cat Arm		1,254		1,254	B-19
Build New Maintenance Shop - St. Anthony		429		429	C-103
Install Fall Arrest Equipment - Various Sites		322		322	C-130
Replace Explosives Storage Magazines - Various Sites		293		293	C-137
Upgrade Ventilation System - Little Bay Islands Diesel Plant		186		186	D-28
Pave Parking Lots and Roadways - Bishop's Falls		150		150	D-30
Install Transformer Storage Ramps - Labrador		121		121	D-41
Build ATV/snowmobile Storage - Whitbourne		86		86	D-55
Install Waste Oil Storage Tanks - Mary's Harbour		84		84	D-57
Install Pole Storage Ramps - Various Sites		77		77	D-62
Install Water and Sewer System - Paradise River		77		77	D-65
Legal Survey of Primary Distribution Line Right of Way - Various Sites		56		56	D-78
Construct Sewage Disposal Field - Makkovik		50		50	
Install Storage Ramp - Whitbourne		41		41	
Upgrade CEMS Room Ventilation - Holyrood		39		39	
Install Air Conditioning at Training Centre - Bay d'Espoir		34		34	
Replace Dock Lighting - Holyrood		33		33	
TOTAL PROPERTIES	358	6,292	0	6,650	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years ($000)	Total	Page Ref
METERING					
Install Automatic Meter Reading - Change Islands and Fogo Island		491		491	C-87
Purchase Meters and Equipment - Various Sites		33		33	
TOTAL METERING	0	524	0	524	
TOOLS & EQUIPMENT					
Replace Off Road Tracked Vehicles - Whitbourne and Bishops Falls		758		758	B-24
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites		561		561	B-29
Purchase and Replace Tools and Equipment Less than $ 50,000		268		268	
Purchase High Definition Infrared Camera - Central		87		87	D-53
TOTAL TOOLS AND EQUIPMENT	0	1,674	0	1,674	
TOTAL TRANSMISSION AND RURAL OPERATIONS	2,953	29,168	13,574	45,695	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
			($000)		
INFORMATION SYSTEMS					
SOFTWARE APPLICATIONS					
New Infrastructure					
Applications Enhancements - Performance Management					
Software Budgeting Tool - Hydro Place		127		127	D-96
Application Enhancements - Perform Minor Applications					
Enhancements - Hydro Place		120		120	D-105
Cost Recovery CF(L)Co		(35)		(35)	
Purchase Protection Relay Event Report Software - Hydro Place		54		54	D-113
Upgrade Intranet - Hydro Place		67		67	
Cost Recovery CF(L)Co		(19)		(19)	
Upgrade of Technology					
Corporate Application Environment - Upgrade Showcase					
Strategy Suite - Hydro Place		158		158	D-98
Cost Recovery CF(L)Co		(46)		(46)	
Citrix Enhancements - Hydro Place		118		118	D-107
Cost Recovery CF(L)Co		(34)		(34)	
TOTAL SOFTWARE APPLICATIONS	0	510	0	510	
COMPUTER OPERATIONS					
Infrastructure Replacement					
End User Evergreening Program - Various Sites		491		491	C-144
Replace Peripheral Infrastructure - Hydro Place		161		161	D-88
Replace Drafting Scanner/Plotter - Hydro Place		139		139	D-92
Perform Hawke Hill Inprovements - Hawk Hill		50		50	
New Infrastructure					
Security Smartcard and Disk Encryption for Laptops - Hydro Place		125		125	D-101
Cost Recovery CF(L)Co		(36)		(36)	
Upgrade of Technology					
Upgrade Server Technology Program - Hydro Place		273		273	D-80
Cost Recovery CF(L)Co		(79)		(79)	
TOTAL COMPUTER OPERATIONS	0	1,123	0	1,123	
TOTAL INFORMATION SYSTEMS	0	1,633	0	1,633	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years ($000)	Total	Page Ref
TELECONTROL					
NETWORK SERVICES					
Infrastructure Replacement					
Public Address System - Holyrood	96	1,182		1,279	
Customer Service Application - Hydro Place	768	182		950	
Install Fibre Optic Cable - Hinds Lake		209	483	692	B-38
Replace Power Line Carrier on TL-250 - Bottom Brook to Grandy Brook		473		473	C-149
Replace Remote Terminal Units - Various Sites		278		278	C-155
Replace Radomes - Various Sites		130		130	D-94
Network Infrastructure					
Replace Batteries and Chargers - Various Sites		729		729	B-36
Replace Radio Tower - Ebbegunbaeg		179		179	D-85
Replace Network Communications Equipment - Various Sites		141		141	D-90
Purchase Test Equipment - Various Sites		74		74	D-111
Install Wireless Networking - Various Sites		45		45	
Upgrade of Technology					
Upgrade Site Facilities - Various Sites		47		47	
Replace Network Management Tools - Various Sites		47		47	
TOTAL TELECONTROL	864	3,716	483	5,063	
TRANSPORTATION					
Replace Vehicles and Aerial Devices - Various Sites		2,156		2,156	B-31
TOTAL TRANSPORTATION	0	2,156	0	2,156	
ADMINISTRATION					
Upgrade System Security - Various Sites		767	702	1,469	B-32
Energy Conservation Upgrades - Hydro Place		833		833	B-34
Purchase Spare Transformer - Hydro Place	86	353		439	
Purchase Office Equip Less than $50,000 - Hydro Place		318		318	
Replace Fire Protection Panels - Hydro Place		89		89	D-100
Replace Humidifiers in Air Handling Units - Hydro Place		74		74	D-109
Replace Air Conditioning Units - Hydro Place		37		37	
TOTAL ADMINISTRATION	86	2,471	702	3,259	
TOTAL GENERAL PROPERTIES	950	9,976	1,185	12,111	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
		($000)			
GENERATION					
Refurbish Fuel Storage Facility - Holyrood		2,867		2,867	B-2
Purchase Spare Stator Winding Units 1 to 4 - Bay d'Espoir		37	2,806	2,843	B-4
Replace Governor Controls Unit 2 - Cat Arm	975	74		1,049	
Replace Unit 2 High Pressure Heater - Holyrood	20	919		939	
TOTAL GENERATION	995	3,896	2,806	7,697	
TRANSMISSION AND RURAL OPERATIONS					
New 25 kV Terminal Station - Labrador City		283	9,707	9,991	B-6
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	358	2,960		3,318	B-40
Upgrade Distribution Systems - All Service Areas		2,526		2,526	B-7
Provide Service Extensions - All Service Areas		2,439		2,439	B-11
Perform Wood Pole Line Management Program - Various Sites		2,256		2,256	B-13
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake		968	964	1,932	B-15
Replace Diesel Units - Norman Bay, Postville and Paradise River		170	1,700	1,870	B-17
Replace Insulators on 230kV Line - Stony Brook, Buchans	848	970		1,818	
Upgrade Corner Brook Frequency Converter - Corner Brook	495	1,152		1,647	
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	335	938		1,273	
Replace Accomodations, Septic System and Upgrade Plant Communication System - Cat Arm		1,254		1,254	B-19
Diesel Plant Automation - Makkovik and Rigolet	516	379		895	
Replace Insulators - Jackson's Arm, Hampden and Little Bay		874		874	B-21
Increase Generation - L'Anse au Loup		23	821	844	B-22
Replace Off-Road Tracked Vehicles - Whitbourne and Bishop's Falls		758		758	B-24
Replace Poles - Jackson's Arm and Hampden		697		697	B-25
Upgrade L7 Distribution System - St. Anthony		689		689	B-27
Upgrade Power Transformers - Various Sites		654		654	B-28
Increase Generation Capacity - Charlottetown	18	577		595	
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites		561		561	B-29
Replace Switchgear - Cartwright	383	169		552	
Perform Grounding Upgrades - Various Sites		252	291	543	B-30
TOTAL TRANSMISSION AND RURAL OPERATIONS	2,953	21,549	13,483	37,985	
GENERAL PROPERTIES					
Replace Vehicles and Aerial Devices - Various Sites		2,156		2,156	B-31
Upgrade System Security - Various Sites		767	702	1,469	B-32
Public Address System - Holyrood	96	1,182		1,279	
Customer Service Application - Hydro Place	768	182		950	
Energy Conservation Upgrades - Hydro Place		833		833	B-34
Replace Batteries and Chargers - Various Sites		729		729	B-36
Install Fibre Optic Cable - Hinds Lake		209	483	692	B-38
TOTAL GENERAL PROPERTIES	864	6,058	1,185	8,107	
TOTAL PROJECTS OVER $500,000	4,812	31,504	17,474	53,789	

Project Title: Refurbish Fuel Storage Facility

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to upgrade the drainage system and pipe supports at the Holyrood Generating Station Tank Farm. The work includes removing vegetation, site grading, supplying and installing drainage piping and an oil water separator, restoring main berm, concrete work, sand blasting and coating of pipe supports. The work will be performed under contract and engineering services will be supplied by consultants.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	48.0	0.0	0.0	48.0
Consultant	215.0	0.0	0.0	215.0
Contract Work	2,030.0	0.0	0.0	2,030.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	344.4	0.0	0.0	344.4
Contingency	229.3	0.0	0.0	229.3
TOTAL	**2,866.7**	**0.0**	**0.0**	**2,866.7**

Operating Experience:

Tanks 1 and 2 were constructed in 1968 together with the pipelines, lighting, dykes and drainage systems. Tanks 3 and 4 were added in 1979. Each of the four tanks measures 54.9 metres (180 feet) diameter by 14.6 metres (48 feet) high and has a storage capacity of approximately 216,000 barrels. The 406 millimetres (16 inches) and 457 millimetres (18 inches) diameter pipelines are heated with steam or by electrical heat trace. The tank dyke liner is constructed from glacier till. Light fixtures are mounted on eight poles situated around the dyked area.

Project Justification:

This facility must operate in accordance with industry standards and meet provincial and federal regulations. Inspection of the fuel storage facility has identified and confirmed that the dyked drainage system and the pipe supports are deteriorated and need to be upgraded. The engineering

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

Project Justification: (cont'd.)

consultant's report " Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Dyked Drainage System" is in Appendix B of the "Holyrood Thermal Generating Station Refurbishment of the Fuel Oil Storage Facility" report located in Volume II, tab 1 and it outlines the work necessary to refurbish the facilities for a further life extension of 20 years.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Attachment:

See report entitled "Holyrood Thermal Generating Station Refurbishment of the Fuel Oil Storage Facility" located in Volume II, tab 1, for further project details.

Project Title: Purchase Spare Stator Winding for Units 1 to 4

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is to purchase a spare stator winding which could replace any of the existing windings of Units 1 to 4 of the Bay d'Espoir Hydroelectric Generating Station. This winding will be installed, as required, when there is a failure of the stator winding on any of these units or when there is an imminent failure expected due to test results.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	2,110.0	0.0	2,110.0
Labour	26.0	35.8	0.0	61.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.2	6.2	0.0	12.4
O/H, AFUDC & Escln.	4.3	435.8	0.0	440.1
Contingency	0.0	218.3	0.0	218.3
TOTAL	**36.5**	**2,806.1**	**0.0**	**2,842.6**

Operating Experience:

Generating Units 1 to 4 of the Bay d'Espoir Hydroelectric Generating Station have been in service for 40 years. To ensure the unit reliability, Newfoundland and Labrador Hydro (Hydro) regularly performs a visual inspection and standard electrical tests on the stator winding of each unit. During the routine maintenance test in 2000, one coil of the Unit 1 stator windings failed. This failed coil was replaced by the original manufacturer. Similar repairs have been performed on Unit 1 in 1986 and Unit 4 in 1992.

Project Justification:

The life expectancy for asphalt insulated stator winding is 40 years. However, it varies based on operating conditions such as temperature, number of starts and stops, maintenance and care, and unit loading.

Project Title: Purchase Spare Stator Winding for Units 1 to 4 **(cont'd.)**

Project Justification: (cont'd.)

This project is justified on the requirement to provide least cost, reliable power. Failure to have a spare stator winding on hand will impair Hydro's ability to restore a Bay d'Espoir generating unit in the event of a failure of the existing stator.

Future Plans:

The windings of Units 1 to 4 have reached the end of their 40 year useful lives, and a planned replacement program is required. However, this project enables Hydro to optimize the remaining life of the windings, by running them as long as possible, without compromising an acceptable level of unit availability.

Attachment:

See report entitled "Purchase Spare Stator Winding for the Bay d'Espoir Hydroelectric Generating Station" located in Volume II, tab 2, for further project details.

Project Title: New 25 kV Terminal Station

Location: Labrador City

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to construct two new 46/25 kV terminal stations. Each station will have two new 46/25 kV, 15/20/25 MVA power transformers, new 46 kV and 25 kV electrical equipment, and new control buildings. Civil work will be completed in 2010 and the electrical equipment will be installed in 2011. Costs to dismantle old stations are not included in this estimate.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	50.0	1,919.0	3,409.0	5,378.0
Labour	83.0	231.2	200.5	514.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	83.0	890.0	800.0	1,773.0
Other Direct Costs	15.0	67.5	89.2	171.7
O/H, AFUDC & Escln.	29.1	476.3	864.0	1,369.4
Contingency	23.1	310.8	449.9	783.8
TOTAL	**283.2**	**3,894.8**	**5,812.6**	**9,990.6**

Operating Experience:

This project involves the construction of two new 46/25 kV terminal stations to replace existing 46/4.16 kV stations.

Project Justification:

This project is justified on the need to meet continued customer load growth and supply power at acceptable voltage levels as stated in Canadian Standards Association standard CAN3-C235-83.

Future Plans:

None.

Attachment:

See report entitled "Labrador City Voltage Conversion Terminals and Transmission Reconfiguration" located in Volume II, tab 3, for further project details.

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. This summarizes the total budget for the Central, Northern and Labrador regions.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	1,548.0	0.0	0.0	1,548.0
Labour	597.0	0.0	0.0	597.0
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.	143.0	0.0	0.0	143.0
Contingency	238.0	0.0	0.0	238.0
TOTAL	2,526.0	0.0	0.0	2,526.0

Operating Experience:

An analysis of historical expenditures (2003 - 2007) on distribution upgrades by region is shown in Table 1. All historical dollars were converted to 2007 dollars using the Statistics Canada Utility Distribution Line Construction index and a five year average was calculated.

Table 1. Average Annual Expenditures

Region	**Avg. Annual Expenditures (2003 - 2007) (2007 $000)**
Central	995
Northern	971
Labrador	427
All Regions	2,393

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

Operating Experience: (cont'd.)

The five year expenditures for distribution upgrades by region are shown in Table 2.

Table 2. Five Year Expenditures

Expenditures ($000)											
	2003		2004		2005		2006		2007		2008
Region	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Central	576	816	531	964	628	1,135	701	909	806	824	915
Northern	628	587	611	1,274	616	996	836	835	873	842	969
Labrador	272	255	329	432	357	364	375	404	356	558	409
Total	1,476	1,658	1,471	2,670	1,601	2,495	1,912	2,148	2,035	2,224	2,293

Other specifically approved projects for 2003 - 2008F are listed in Table 4.

Project Justification:

Based on the five year average for distribution system upgrades for the period 2003 - 2007 the budget shown in Table 3 was developed, assuming distribution line cost escalation in 2009 of approximately three percent.

Table 3. Budget for Distribution System

Region	**2009 Budget ($000)**
Central	1,050
Northern	1,026
Labrador	450
Total	2,526

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures.

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

Table 4. Annual Allotment

Year	Project Description	Budget ($000)	Actuals ($000)
2008F	Replace Distribution Line - L1 South Brook	987.4	
	Upgrade Distribution System - L1 Glenburnie	533.9	
	Upgrade Distribution System - L3 St Anthony	480.1	
	Upgrade Distribution System - Mary's Harbour	263.5	
	Upgrade Distribution System - Port Hope Simpson	205.4	
	Upgrade Distribution System - L4 Bear Cove	149.8	
	Upgrade Distribution Line - L11 Wabush	107.2	
	Replace Insulators - Upper Salmon	236.8	
	Replace Insulators - L1 Hind's Lake	168.7	
	Replace Insulators - Coney Arm	126.8	
	Replace Insulators - L2 Westport	90.2	
	Replace Poles - South Brook	377.5	
	Replace Poles - Bay d'Espoir	322.7	
2007	Replace Poles - Barachoix L4	229.9	276.0
	Insulator Replacement - Barachoix L4	120.1	123.0
	Replace Distribution Line - Brighton	192.9	230.9
	Replace Distribution Line - Seal Cove to Pass Island	547.6	552.1
	Upgrade Distribution System - L2, L3 Farewell Head	385.3	282.0
	Replace Poles - Farewell Head	355.0	295.3
	Replace Poles - St. Brendan's	159.1	175.4
	Extend Mud Lake Submarine Cable	480.9	813.6
	Upgrade Distribution System - L1, L2 St. Anthony	364.3	301.0
	Upgrade Distribution System L1, L2 Rocky Harbour	513.5	393.7
	Upgrade Distribution System - Nain	179.4	185.8
2006	Replace Insulators - L7, L8 Bottom Waters	120.0	126.5
	Replace Insulators - L4, L5 Farewell Head	260.8	270.4
	Replace Insulators - L5, L7 - South Brook	440.7	440.8
	Replace Insulators - L4, L6 - Bottom Waters	197.5	203.4
	Replace Poles - L1 Bottom Waters	152.4	166.5
	Upgrade Distribution System - Black Tickle	281.8	270.3
	Upgrade Distribution System - L6 St. Anthony	778.3	772.2
	Upgrade Distribution System - L6 Bear Cove	577.7	622.8
	Upgrade Distribution System - L1, L3 Hawke's Bay	379.6	421.1

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

Table 4. Annual Allotment (cont'd.)

Year	Project Description	Budget ($000)	Actuals ($000)
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
2003	Replace Poles - South Brook and King's Point	203.4	204.2
	Replace Poles - Farewell Head	162.5	148.4
	Replace Poles - Bay d'Espoir	222.0	184.5
	Replace Poles - L3 Goose Cove	264.1	140.4
	Replace Insulators - L1 Barachoix	146.3	69.8
	Upgrade Distribution System - Little Bay	317.2	293.8
	Replace Insulators - Bottom Waters	349.6	234.0
	Replace Insulators - L1 King's Point	299.3	231.5
	Replace Insulators and Poles - L1 St. Anthony	557.0	290.1
	Upgrade Distribution Line - Pass Island	48.0	65.9

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. This summary identifies the total budget for the Central, Northern and Labrador operating regions.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	1,177.0	0.0	0.0	1,177.0
Labour	894.0	0.0	0.0	894.0
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.	138.0	0.0	0.0	138.0
Contingency	230.0	0.0	0.0	230.0
TOTAL	2,439.0	0.0	0.0	2,439.0

Operating Experience:

An analysis of average historical expenditures (2003 - 2007) on new customer connections by region is shown in the Table 1. All historical dollars were converted to 2007 dollars using the Statistics Canada Utility Distribution Line Construction index and a five year average was calculated.

Table 1. Average Annual Expenditures

Region	**Avg. Annual Expenditures (2003 - 2007) (2007 $000)**
Central	974
Northern	718
Labrador	618
Total	2,310

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 2.

Table 2. Five Year Expenditures

	Expenditures ($000)										
	2003		2004		2005		2006		2007		2008
Region	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
Central	459	854	503	1,070	619	840	761	824	844	967	910
Northern	432	472	464	729	504	611	580	614	618	960	637
Labrador	557	473	591	484	605	556	643	535	622	873	612
Total	1,448	1,799	1,558	2,283	1,728	2,007	1,984	1,973	2,084	2,800 [1]	2,159

[1] Even though this is an annual allotment based on historical averages, some of the cost increases were due to the following: $330,000 increase from the estimate in the Labrador Interconnected system due to greater than average growth; North West Arm Cottage Development in Northern for $310,000; and, interconnection of Pine Cove in Central for $103,000.

Project Justification:

Based on the five year average of service extension expenditures for the period 2003 - 2007 the budget shown in Table 3 was developed, assuming distribution line cost escalation in 2009 of approximately 3 percent.

Table 3. Budget

Region	2009 Budget ($000)
Central	1,028
Northern	758
Labrador	653
Total	2,439

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures.

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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	610.4	0.0	0.0	610.4
Labour	903.1	0.0	0.0	903.1
Consultant	50.0	0.0	0.0	50.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	292.8	0.0	0.0	292.8
O/H, AFUDC & Escln.	214.3	0.0	0.0	214.3
Contingency	185.6	0.0	0.0	185.6
TOTAL	**2,256.2**	**0.0**	**0.0**	**2,256.2**

Operating Experience:

Hydro operates approximately 2,400 kilometres 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.

Attachment:

See report entitled "2009 Wood Pole Line Management" located in Volume II, tab 4, for further project details.

Project Title: Upgrade Transmission Line TL-212

Location: Sunnyside to Linton Lake

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

An engineering study which was completed as part of Hydro's 2008 Capital Program, determined that there are 25 locations along the tower sections of transmission line TL-212 where low conductor clearances present safety concerns whereby a member of the general public could come into contact with an energized conductor. Also, a guy wire inspection found 47 structures that require guy wire replacement because of corrosion. This inspection was completed after a deteriorated guy wire caused the failure of Structure 380 in March of 2008. This project is to upgrade the spans that are causing safety concerns.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	350.0	238.2	0.0	588.2
Labour	175.0	90.6	0.0	265.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	270.0	260.5	0.0	530.5
Other Direct Costs	56.5	31.8	0.0	88.3
O/H, AFUDC & Escln.	116.3	195.2	0.0	311.5
Contingency	0.0	147.3	0.0	147.3
TOTAL	**967.9**	**963.6**	**0.0**	**1,931.5**

Operating Experience:

Conductor clearance problems have occurred along sections of TL-212. There has been a history of outages caused by these conductor clearance problems, in addition to the safety hazards associated with the condition.

Project Justification:

The energized conductors on TL-212 come too close to the ground and pose a general public safety risk, especially along sections of the line that are used by snowmobilers. To improve the operational performance of the line and reduce the risk to the general public, it is necessary

Project Title: Upgrade Transmission Line TL-212 **(cont'd.)**

Project Justification: (cont'd.)

to correct the clearance problems associated with TL-212. Also, guy wire replacements are required because of failing or deteriorated infrastructure. Without guy wire support, a transmission structure will collapse.

Future Plans:

None.

Attachment:

See report entitled "TL-212 Upgrade" located in Volume II, tab 5, for further project details.

Project Title: Replace Diesel Units

Location: Norman Bay, Postville and Paradise River

Category: Transmission and Rural Operations - Generation

Definition: Pooled

Classification: Normal

Project Description:

This project consists of diesel generating units (genset) replacements in Norman Bay, Postville, and Paradise River. In Norman Bay, two 30 kW units will be replaced with one 30 to 50 kW unit and one 30 kW unit, and the plant will be automated. In Postville, a 150 kW unit will be replaced with a 365 kW unit. In Paradise River, a 90 kW unit will be replaced with a 25 to 35 kW unit.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	58.0	720.8	0.0	778.8
Labour	88.5	407.0	0.0	495.5
Consultant	0.0	10.0	0.0	10.0
Contract Work	0.0	65.4	0.0	65.4
Other Direct Costs	2.0	87.8	0.0	89.8
O/H, AFUDC & Escln.	21.2	264.9	0.0	286.1
Contingency	0.0	144.0	0.0	144.0
TOTAL	**169.7**	**1,699.9**	**0.0**	**1,869.6**

Operating Experience:

The existing units in Norman Bay suffer from chronic fuel pump problems. The replacement of the existing units with more modern units requires the upgrade of the existing custom automatic controls which were designed for the older units. Unit 557 in Postville is underutilized in the plant because it is unreliable and replacement parts are not readily available. Unit 2020 in Paradise River is too large for the system, which is experiencing extremely low loads and thus is underutilized resulting in increased use of the remaining units in the plant. This also results in low plant efficiency.

Project Justification:

This project is required to allow Hydro to provide reliable electrical service to the communities of Norman Bay, Postville and Paradise River. If not completed, system reliability and efficiency will be continue to be negatively impacted by individual unit unreliability and increased demand on remaining diesel units.

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

Future Plans:

None.

Attachment:

See report entitled "Replace Diesel Units Norman Bay, Postville and Paradise River" located in Volume II, tab 6, for further project details.

Project Title: Replace Accommodations, Septic System and Upgrade Plant Communications System

Location: Cat Arm

Category: Generation - Hydraulic

Type: Clustered

Classification: Normal

Project Description:

This project is required for the supply and set up of six modular units for new accommodations at the Cat Arm generating site (Cat Arm). Four units will house a total of 16 single bedrooms, each with an adjoining washroom. Two units will be used for dining, kitchen, recreation and a lounge area. The trailers will be prefabricated and measure 4.4 metres wide by 18.3 metres long. A paved parking area with street lights will be provided. A new sewage system consisting of a 4,546 litre septic tank with an ocean outfall extended to the generating station tailrace, approximately 25 metres away, will be constructed. An upgrade to the telecommunication system at the Cat Arm Generating Station will be performed along with the installation of similar equipment in the new accommodations.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	78.0	0.0	0.0	78.0
Labour	156.0	0.0	0.0	156.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	733.0	0.0	0.0	733.0
Other Direct Costs	39.5	0.0	0.0	39.5
O/H, AFUDC & Escln.	147.1	0.0	0.0	147.1
Contingency	100.7	0.0	0.0	100.7
TOTAL	**1,254.3**	**0.0**	**0.0**	**1,254.3**

Operating Experience:

The existing accommodations consist of pre-owned mobile trailers that were renovated. The trailers were brought to the site at the beginning of the construction of the Cat Arm Generating Station in 1982 to be used as temporary accommodations. The trailers require constant maintenance and have a mould problem. The sewage system, consisting of a septic tank and in-ground disposal field, was constructed in 1983-84.

Project Justification:

The existing facility poses health risks due to the presence of mould. Therefore, employees must seek off site accommodations which are up to 120 kilometres away. Travel to and

Project Title: Replace Accommodations, Septic System and Upgrade Plant Communications System **(cont'd.)**

Project Justification: (cont'd.)

from Cat Arm takes up to two hours each way. This presents safety concerns about being on public highways daily for four hours longer than necessary because suitable accommodations are not available on site. Hydro incurs increased costs through paid travel time, hotel accommodations and vehicle usage. Considering the remoteness of the Cat Arm site and the potential problems with daily accessing it during the winter months, a need for on site accommodations exists. The Cat Arm access road is not plowed during the winter months and on-site accommodations are needed to respond to outages and repairs. A new permanent accommodations facility will provide Hydro personnel with modern, safe on-site living conditions that meet all current standards and guidelines.

Future Plans:

None.

Attachment:

See report entitled "Cat Arm Hydro Generating Station Replacement of Accommodations" located in Volume II, tab 7, for further project details.

Project Title: Replace Insulators

Location: Jackson's Arm, Hampden and Little Bay

Category: Transmission and Rural Operations - Distribution Central

Type: Pooled

Classification: Normal

Project Description:

This project is required to replace insulators on Jackson's Arm distribution feeder Line 1 and Line 2, Hampden distribution feeder Line 1, and Little Bay distribution feeder Line 1.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	200.5	0.0	0.0	200.5
Labour	240.5	0.0	0.0	240.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	221.5	0.0	0.0	221.5
Other Direct Costs	44.5	0.0	0.0	44.5
O/H, AFUDC & Escln.	96.3	0.0	0.0	96.3
Contingency	70.9	0.0	0.0	70.9
TOTAL	874.2	0.0	0.0	874.2

Operating Experience:

These insulators have been in service for over 20 years and were manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP), and have been a problem throughout the Hydro system. Failure of these insulators generally occurs during adverse weather conditions and as a result impact restoration time considerably.

Project Justification:

Regular inspections have identified insulators with hairline cracks through the porcelain. These insulators have experienced industry-wide failures due to cement growth breakdown causing radial cracking that resulted in moisture intrusion. Replacement of these insulators is essential to improve system security and reliability. Mechanical breakdown of the insulators is a safety issue with line workers.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Attachment:

See report entitled "Insulator Replacement" Volume II, tab 8, for further project details.

Project Title: Increase Generation

Location: L'Anse au Loup

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This project involves the replacement of a 600 kW diesel unit with a 1,100 kW rated unit to increase the plant firm capacity in response to load growth. The project will be completed over two years, with the equipment purchases in the first year and installation in the second year. All auxiliary equipment will also be replaced due to the increase in capacity. An environmental permit will be required for the installation.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	462.3	0.0	462.3
Labour	20.0	125.7	0.0	145.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	54.1	0.0	54.1
O/H, AFUDC & Escln.	2.9	112.5	0.0	115.4
Contingency	0.0	66.2	0.0	66.2
TOTAL	**22.9**	**820.8**	**0.0**	**843.7**

Operating Experience:

The L'Anse au Loup system has experienced strong growth, primarily due to electric heat conversion, since its interconnection to the Hydro Quebec system. Based on the latest load forecast for the rural isolated system, peak load is expected to exceed plant firm capacity by 2009.

Project Justification:

This project is required to maintain Hydro's firm generation criteria which was established to maintain a reliable supply of power to customers served by isolated diesel plants. Based on the most recent load forecast for the system, the peak load for L'Anse au Loup will exceed firm capacity in 2009. The replacement of a 600 kW unit with a new 1,100 kW unit will ensure that the firm capacity criterion is met beyond the forecast period.

Project Title: Increase Generation **(cont'd.)**

Future Plans:

None.

Attachment:

See report entitled "L'Anse au Loup Increase Generation" located in Volume II, tab 9, for further project details.

Project Title: Replace Off-Road Tracked Vehicles

Location: Whitbourne and Bishop's Falls

Category: Transmission and Rural Operations - Tools and Equipment

Definition: Pooled

Classification: Normal

Project Description:

This project involves the replacement of vehicles V7676 (Whitbourne), a 1989 model heavy-duty off-road tracked vehicle, and V7941 (Bishop's Falls), a 1998 model heavy-duty off-road tracked vehicle.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	660.0	0.0	0.0	660.0
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.	31.8	0.0	0.0	31.8
Contingency	66.0	0.0	0.0	66.0
TOTAL	**757.8**	**0.0**	**0.0**	**757.8**

Operating Experience:

The heavy-duty off-road tracked vehicles have an average life expectancy which ranges from 15 to 20 years, dependant on location and usage. Unit V7676 will be 20 years old at replacement. Unit 7941 was destroyed by fire in 2007.

Project Justification:

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

Future Plans:

Future replacements will be proposed in future capital budget applications.

Attachment:

See report entitled "Replace Off-Road Track Vehicles - Whitbourne and Bishop's Falls", Volume II, tab 10, for further project details.

Project Title: Replace Poles
Location: Jackson's Arm and Hampden
Category: Transmission and Rural Operations - Distribution
Type: Pooled
Classification: Normal

Project Description:
This project is required to replace 46 deteriorated poles on Jackson’s Arm distribution feeders Line 1 and Line 2 and 30 poles on Hampden distribution feeder Line 1. Each year, during line inspections, Hydro identifies poles which are near the end of their useful lives and schedules them for replacement.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	97.0	0.0	0.0	97.0
Labour	212.5	0.0	0.0	212.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	203.5	0.0	0.0	203.5
Other Direct Costs	50.0	0.0	0.0	50.0
O/H, AFUDC & Escln.	77.3	0.0	0.0	77.3
Contingency	56.5	0.0	0.0	56.5
TOTAL	**696.8**	**0.0**	**0.0**	**696.8**

Operating Experience:
Jackson’s Arm Line 1 is a 12.5 kV three phase feeder that extends from the Jackson’s Arm Terminal Station to the community of Godfather’s Cove, covering a distance of approximately 5 kilometres and serving approximately 200 customers. Jackson’s Arm Line 2 is also a 12.5 kV three phase feeder that extends from the Jackson’s Arm Terminal Station to the community of Pollards Point covering a distance of approximately 20 kilometres and serving approximately 300 customers. Hampden Line 1 is a 12.5 kV three phase feeder that extends from the Hampden Terminal Station to the community of The Beaches and Rooms, covering a distance of 22 kilometres and serving approximately 300 customers. All three lines were built in 1968.

Project Justification:
Hydro performs regular inspections on all distribution poles classifying them using a standardized grading system. The grading system is as follows: “A” Condition: Excess of five years of life remaining, “B” Condition: one to five years of life remaining, and “C” Condition: Less than one year of life remaining. During the 2006 inspection, 46 poles on Jackson’s Arm Line 1 and Line 2 and 30

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

Project Justification: (cont'd.)

poles on Hampden Line 1 were identified as being in "B" condition and were scheduled for replacement in 2009. This project is required in order to ensure that a reliable energy supply is available for the customers served by the Jackson's Arm and Hampden distribution systems.

Future Plans:

None.

Attachment:

See report entitled "Pole Replacement" located in Volume II, tab 11, for further project details.

Project Title: Upgrade L7 Distribution System
Location: St. Anthony
Category: Transmission and Rural Operations - Distribution Northern
Definition: Other
Classification: Normal

Project Description:
This project is required to upgrade portions of St. Anthony Line 7 (L7) distribution line serving the communities of Cook's Harbour, Boat Harbour, and the Pistolet Bay cabin area. The project will include the replacement of 46 poles, 660 pin type insulators, 220 suspension insulators, 70 cutouts and 48 spans of three phase #2 ACSR primary conductor.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	147.5	0.0	0.0	147.5
Labour	131.0	0.0	0.0	131.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	248.0	0.0	0.0	248.0
Other Direct Costs	31.5	0.0	0.0	31.5
O/H, AFUDC & Escln.	75.4	0.0	0.0	75.4
Contingency	55.9	0.0	0.0	55.9
TOTAL	**689.3**	**0.0**	**0.0**	**689.3**

Operating Experience:
St. Anthony L7 is a 12.5 kV three phase feeder built in 1968, which covers a distance of approximately 25 kilometers and serves approximately 200 customers. This line has blackjack poles, old pin type and suspension type insulators, and #2 ACSR conductor that were installed when the original line was built.

Project Justification:
The poles to be replaced have been identified as close to the end of their useful lives and the insulators have a history of failure because of cement growth. The #2 ACSR conductor does not meet Hydro’s minimum standard of 1/0 AASC conductor for distribution feeders. The project is required to ensure that a reliable energy supply is available for the customers served by the St. Anthony L7 feeder.

Future Plans:
None.

Attachment:
See report entitled "Upgrade Distribution Feeder St. Anthony Line 7" located in Volume II, tab 12, 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 the upgrade of power transformers based upon condition assessments.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	316.0	0.0	0.0	316.0
Labour	184.0	0.0	0.0	184.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	28.0	0.0	0.0	28.0
O/H, AFUDC & Escln.	73.1	0.0	0.0	73.1
Contingency	52.8	0.0	0.0	52.8
TOTAL	653.9	0.0	0.0	653.9

Operating Experience:

Of Hydro's power transformers, 52 percent of all 230 kV, 138 kV and 66 kV power transformers are 30 years of age. Recent experience has shown the need to upgrade power transformers due to problems with oil quality, tap changers, gasket systems, bushings, radiators and protective devices.

Project Justification:

Power transformers are one of the single most important components on the transmission system. To maintain reliable operation of the transformer fleet it is critical to use condition assessment 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.

Future Plans:

This is an ongoing power transformer upgrading program.

Attachment:

See report entitled "Upgrade Power Transformers" located in Volume II, tab 13, for further project details.

Project Title: Replace Light Duty Mobile Equipment Less Than $50,000

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project consists of the replacement of 53 units of light duty mobile equipment.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	491.8	0.0	0.0	491.8
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.	20.2	0.0	0.0	20.2
Contingency	49.2	0.0	0.0	49.2
TOTAL	**561.2**	**0.0**	**0.0**	**561.2**

Operating Experience:

Hydro staff regularly use 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.

Attachment:

See report entitled "Replace Light Duty Mobile Equipment Less than $50,000 - Various Locations" located in Volume II, tab 14, for further project details.

Project Title: Perform Grounding Upgrades

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Mandatory

Project Description:

The Terminal Stations Grounding Upgrades Project involves modifying existing ground grids and installing or modifying gradient control mats. The ground grids to be modified are those at terminal stations where analysis has shown that hazardous step and/or touch potentials exist.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	44.6	44.6	0.0	89.2
Labour	120.2	120.2	0.0	240.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	57.7	57.7	0.0	115.4
O/H, AFUDC & Escln.	29.4	46.4	0.0	75.8
Contingency	0.0	22.3	0.0	22.3
TOTAL	**251.9**	**291.2**	**0.0**	**543.1**

Operating Experience:

This project is required in order to eliminate hazardous step and touch potentials, and also to eliminate nonconformance with Hydro's Terminals Engineering Standard.

Project Justification:

This project is justified on the requirement to eliminate unsafe step and touch potentials from terminal stations and to eliminate nonconformance with Hydro's Terminals Engineering Standards in order to allow Hydro to provide safe, least-cost, reliable electrical service to its customers.

Future Plans:

None.

Attachment:

See report entitled "Terminal Station Grounding Upgrades" located in Volume II, tab 15, for further project details.

Project Title: Replace Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Administration

Definition: Other

Classification: Normal

Project Description:

The scope of work is to replace 33 light duty transportation vehicles and six heavy duty work vehicles.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	1,884.2	0.0	0.0	1,884.2
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.	83.8	0.0	0.0	83.8
Contingency	188.4	0.0	0.0	188.4
TOTAL	2,156.4	0.0	0.0	2,156.4

Operating Experience:

The vehicles being replaced have become unreliable.

Project Justification:

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

Future Plans:

Future replacements will be proposed in future capital budget applications.

Attachment:

See report entitled "Replace Vehicles and Aerial Devices" located in Volume II, tab 16, for further project details.

Project Title: Upgrade System Security

Location: Various Sites

Category: General Properties - Administrative

Definition: Pooled

Classification: Normal

Project Description:

This project consists of the purchase and installation of equipment and infrastructure to upgrade Hydro's physical system security. Equipment and infrastructure being installed consists of high voltage warning signs, anti-climbing devices, surveillance cameras, intruder alarms, card access systems, outdoor area lighting and general property fencing upgrades. Using this equipment and infrastructure, Hydro's physical system security will be upgraded.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	87.5	147.0	0.0	234.5
Labour	139.3	140.5	0.0	279.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	381.0	254.0	0.0	635.0
Other Direct Costs	10.8	9.5	0.0	20.3
O/H, AFUDC & Escln.	86.8	95.7	0.0	182.5
Contingency	61.9	55.1	0.0	117.0
TOTAL	767.2	701.8	0.0	1,469.0

Operating Experience:

At facilities across the Hydro system, some measure of security equipment is already in place and operating effectively. However, across the majority of the Hydro system, the physical security systems are not in place to the degree that is necessary.

Project Justification:

Following September 11, 2001, the Canadian Electrical Association established the 'Critical Infrastructure Protection Group' (CIP). The mandate of this group is to promote initiatives to strengthen the protection of Canada's critical energy infrastructure and to provide a network of liaison in the utility industry to address issues related to emergency preparedness. Through the formation of this group, and Hydro's involvement in the group, Hydro recognizes that the role of its

Project Title: Upgrade System Security **(cont'd.)**

Project Justification: (cont'd.)

system security has changed dramatically in recent years. In order to comply with professional and legal standards that set an industry specific care precedent, Hydro requires a properly structured and deployed security program that will meet the industry's practices in physical and technical security countermeasures.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Attachment:

See report entitled "Upgrade System Security" located in Volume II, tab 17, for further project details.

Project Title: Energy Conservation Upgrades

Location: Hydro Place

Category: General Properties - Administrative

Definition: Pooled

Classification: Justifiable

Project Description:

This project is required to implement initiatives outlined in the Energy Audit Final Report by Energy Management Services, Ltd. to reduce the energy consumption of Hydro Place by approximately 30 percent resulting in an annual operating cost savings of approximately $148,000. The initiatives include a new energy management control system, modifications to computer and communications rooms cooling, a lighting retrofit, the installation of variable frequency drives on large motors, and heating, ventilation, and air conditioning (HVAC) system commissioning and balancing.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	0.0	0.0	0.0	0.0
Labour	16.3	0.0	0.0	16.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	650.0	0.0	0.0	650.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	99.7	0.0	0.0	99.7
Contingency	66.6	0.0	0.0	66.6
TOTAL	832.6	0.0	0.0	832.6

Operating Experience:

Hydro Place currently has an outdated HVAC control system, which results in higher energy consumption than is necessary and inadequate comfort levels for the building's occupants. The existing lighting system is obsolete and lighting levels exceed current lighting standards.

Project Justification:

A cost benefit analysis for this project indicates that the project pays for itself within nine years of completion of the proposed efficiency improvements. The analysis was made over a 15 year study period, as this is the anticipated life of the largest component of the proposed improvements, the energy management system.

Project Title: Energy Conservation Upgrades **(cont'd.)**

Future Plans:

None.

Attachment:

See report entitled "Hydro Place Energy Efficiency Improvements" located in Volume II, tab 18, for further project details.

Project Title: Replace Batteries and Chargers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

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 DC.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	285.0	0.0	0.0	285.0
Labour	206.6	0.0	0.0	206.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	46.0	0.0	0.0	46.0
Other Direct Costs	45.9	0.0	0.0	45.9
O/H, AFUDC & Escln.	86.9	0.0	0.0	86.9
Contingency	58.3	0.0	0.0	58.3
TOTAL	728.6	0.0	0.0	728.6

Operating Experience:

Hydro generally inspects its battery banks annually, however, depending on age and condition inspections may occur more often. From inspection and testing, Hydro determines which banks need to be replaced. The rate of battery deterioration increases with age and eventually reaches a point where the battery is unable to provide the 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 Institute of Electrical and Electronic Engineers 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 to ensure continued reliable operation.

Project Title: Replace Batteries and Chargers **(cont'd.)**

Future Plans:

To continue the ongoing program of monitoring and testing Hydro's battery banks to determine timely replacement.

Attachment:

See report entitled "Station Battery Replacement Program" located in Volume II, tab 19, for further project details.

Project Title: Install Fibre Optic Cable

Location: Hinds Lake

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to replace the microwave radio link between Hydro's Blue Grass Hill microwave site and Hinds Lake Generating Station with a fibre optic cable. The project involves the installation of approximately seven kilometres of fibre optic cable including poles and guy wire supports where needed. The cable will be equipped with multiplexers to provide required communications such as voice, teleprotection and Supervisory Control and Data Acquisition (SCADA).

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	45.0	37.0	0.0	82.0
Labour	120.5	37.0	0.0	157.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	270.0	0.0	270.0
Other Direct Costs	18.0	8.5	0.0	26.5
O/H, AFUDC & Escln.	25.7	76.8	0.0	102.5
Contingency	0.0	53.6	0.0	53.6
TOTAL	209.2	482.9	0.0	692.1

Operating Experience:

The existing microwave radio, purchased in 1998, has become obsolete and is not supported by the manufacturer. Hydro has similar microwave radios in its communications system and it is intended that the removed radio will provide replacement parts to prolong remaining equipment life. Microwave radio equipment requires significant maintenance. Over the five year period, 2003 to 2007, Hydro's average annual maintenance cost for this link was approximately $8,000, including $17,200 which was incurred in 2006. Approximately 66 percent of the total maintenance was corrective.

Project Title: Install Fibre Optic Cable **(cont'd.)**

Project Justification:

This project is needed to replace existing failing or deteriorated equipment. Reliable equipment is required for communications and teleprotection of Hydro's generation and transmission assets. A cost benefit analysis was performed that showed it is more cost effective to replace the existing microwave radio link with a fibre optic cable rather than replace it with microwave radio technology. The cost advantage of the fibre optic link over the microwave radio is $296,000 considering an assumed life of 30 years.

Future Plans:

None.

Attachment:

See report entitled "Hinds Lake to Blue Grass Hill Fibre Optic Cable" located in Volume II, tab 20, for project further details.

1. Construct New Office, Warehouse and Line Depot Facilities - Happy Valley

This project was approved for $1,632,200 by Board Order No. P.U. 30 (2007) of which $1,247,900 was to be spent in 2008 and the remainder, $384,300, to be spent in 2009. This project is now budgeted at $3,317,500 with $357,700 to be spent in 2008 and the remainder, $2,959,800, to be spent in 2009. The new schedule has the land purchase and project design occurring in the fall of 2008, contract tendering during the winter of 2009, commencement of construction in May 2009 and an in-service date of November 30, 2009. A detailed analysis of the cost variance is listed below.

Variance Explanation

The capital budget estimate originally submitted was based on a construction cost estimate prepared by an engineering consultant in 2005, for construction in 2006. This estimate was for construction of a building only and did not include costs such as land purchase, site development and engineering fees. This estimate was $1,019 per m^2 whereas the present estimate is $1870 per m^2. This equates to an increase of $753,000 for a building measuring 885 m^2.

Land purchase costs as well as the costs for activities associated with obtaining legal title have increased from $85,000 to $110,000. This is due to the requirement to purchase Crown Land abutting the preferred site plus the cost of surveys and legal transactions instead of leasing as originally budgeted.

Site development costs have increased from $108,000 to $208,000.

Engineering fees covering design and project management and inspection, due to the increase cost of construction, have increased from $131,000 to $173,000. These fees are based on a percentage of the cost of design and construction of the project.

Increased in-house engineering and project management costs, especially for the design and installation of computer, communications and security systems, have resulted in an increase in costs from $97,000 to $159,000.

Corporate overheads on the increases listed above result in the cost increasing from $88,000 to $133,000.

Allowance for Funds Used During Construction (AFUDC) and Escalation charges to the project are dependent on a number of factors such as the cost and duration before the project is released for service. These have increased from $89,000 to $193,000.

Contingency costs, based on a rate of 10 percent, have increased from $132,000 to $225,000.

The total extra cost documented above is $1,224,000. This does not include extra costs associated with construction of the building to a higher construction standard. This cost is addressed below.

Leadership in Energy and Environmental Design (LEED) Costs

Since the Capital Budget Proposal was submitted to the Board, initiatives outlined in the Provincial Energy Plan, September 2007, require that this building be constructed to a LEED silver standard. LEED is a rigorous approach resulting from a higher construction standard which targets environmentally sustainable construction but will add time and cost to both capital construction and engineering aspects of the project. It is estimated that this requirement will add 15 percent or $300,000 plus a $50,000 fee for a LEED coordinator. Extra engineering fees associated with this increase in cost of construction are $39,000. Corporate overhead and AFUDC charges associated with LEED construction will add another $30,000 to the cost of the project. The total basic LEED associated cost for this project is $419,000 and when the contingency portion of this estimate is added, the cost increases by $42,000 to $461,000. A summary of the cost variances are shown in Table 1 below.

Table 1. Cost Variances

Item	Original Budget ($000)	Revised Budget ($000)	Variance ($000)
Land Purchase	85	110	25
Building Construction	902	1,655	753
Site Development	108	208	100
Engineering Fees (Consultant)	131	173*	42
In-house Design/Construction	97	159	62
Corporate Overheads	88	133*	45
Interest During Construction	89	193*	104
LEED Cost	0	461	461
Contingency	132	225*	93
Total:	**1,632**	**3,317**	**1,685**

*These costs differ from those on the cash flow sheet as they have been decreased to reflect a portion of the cost which has been assigned to LEED.

Cost/Benefit Analysis

A cost benefit analysis was completed comparing the construct or lease alternatives. Based on a 30 year service life for the new facilities, the analysis shows that if Hydro constructs a new facility, it can expect to realize a benefit of approximately $453,600 and the payback period is approximately 23 years. The cumulative net present value comparison is shown in Table 2 and the cross over period is illustrated in Chart 1.

Chart 1.

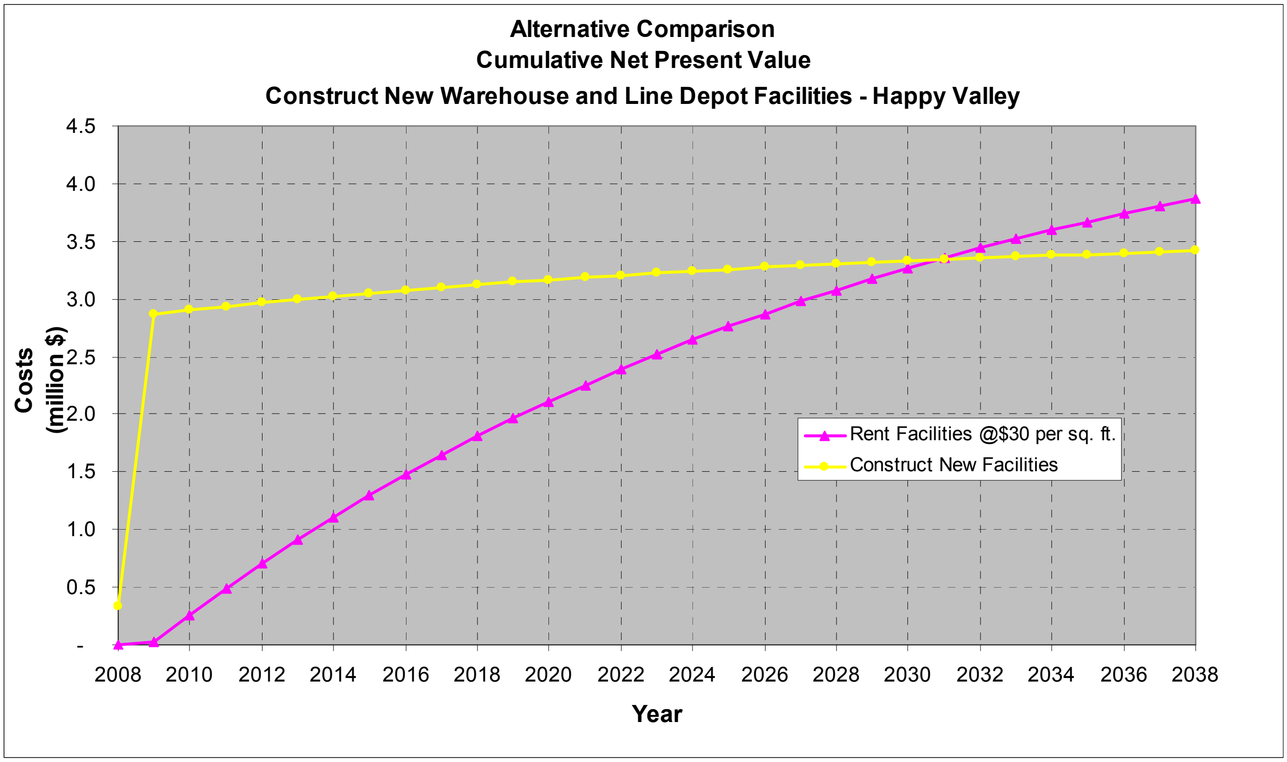


Table 2.

Construct New Warehouse and Line Depot Facilities - Happy Valley Alternative Comparison Cumulative Net Present Value to the Year 2038		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least-Cost Alternative**
Construct Accommodations	3,415,301	0
Rent Facilities @$30 per sq. ft.	3,868,917	453,616

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
		($000)			
GENERATION					
Replace Unit 3 Steam Seal Regulator - Holyrood		475		475	C-2
Upgrade Gas Turbine Plant Life Extension - Hardwoods		450		450	C-12
Replace 50 kW Diesel Generator - Bay d'Espoir		36	289	325	C-13
Replace Unit 2 Air Preheater Cold End - Holyrood		320		320	C-19
Replace Cooling Water System on Units 3 and 4 - Bay d'Espoir		287		287	C-30
Upgrade Intake Gate Controls - Hinds Lake		263		263	C-37
Replace Automatic Voltage Regulator on Gas Turbine - Stephenville		262		262	C-45
Replace 40 kW Diesel Generator at Spillway - Bay d'Espoir	157	103		260	
Install Meteorological Stations - Various Sites		253		253	C-50
Replace Unit 1 Hydrogen Emergency Vent Valves - Holyrood		214		214	C-57
TOTAL GENERATION	157	2,663	289	3,110	
TRANSMISSION AND RURAL OPERATIONS					
Replace Line L36 - Wabush		498		498	C-66
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		498		498	C-74
Install Automatic Meter Reading - Change Islands and Fogo Island		491		491	C-87
Install Digital Fault Recorders - Massey Drive, Oxen Pond and St. Anthony		462		462	C-96
Build New Maintenance Shop - St. Anthony		429		429	C-103
Upgrade Circuit Breakers - Various Terminal Stations		422		422	C-110
Replace Insulators - Various Terminal Stations		391		391	C-118
Replace Conductor on Line 2 - Rocky Harbour		325		325	C-124
Install Fall Arrest Equipment - Various Sites		322		322	C-130
Replace Explosives Storage Magazines - Various Sites		293		293	C-137
TOTAL TRANSMISSION AND RURAL OPERATIONS	0	4,129	0	4,129	
GENERAL PROPERTIES					
End User Evergreening Program - Various Sites		491		491	C-144
Replace Power Line Carrier on TL-250 - Bottom Brook to Grandy Brook		473		473	C-149
Purchase Spare Transformer - Hydro Place	86	353		439	
Replace Remote Terminal Units - Various Sites		278		278	C-155
TOTAL GENERAL PROPERTIES	86	1,595	0	1,681	
TOTAL PROJECTS OVER $200,000 AND UNDER $500,000	243	8,388	289	8,920	

Project Title: Replace Unit 3 Steam Seal Regulator

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to upgrade the Unit 3 hydraulically controlled turbine steam seal regulator to a pneumatically operated pressure control valve system at the Holyrood Thermal Generating Station.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	76.0	0.0	0.0	76.0
Labour	169.8	0.0	0.0	169.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	129.4	0.0	0.0	129.4
Other Direct Costs	3.2	0.0	0.0	3.2
O/H, AFUDC & Escln.	59.1	0.0	0.0	59.1
Contingency	37.8	0.0	0.0	37.8
TOTAL	475.3	0.0	0.0	475.3

Existing System:

The Holyrood Thermal Generating Station (Holyrood) is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW. The generating station was constructed in two stages. In 1969, Stage I was completed bringing on line two generating units, Units 1 and 2, each capable of producing 150 MW. In 1979, Stage II was completed bringing on line one additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units 1 and 2 were up-rated to 170 MW. Holyrood represents approximately one third of Newfoundland and Labrador Hydro's (Hydro) total generating capacity and each unit represents about 10 percent of that total.

The three main components of each generating unit are the boiler, turbine, and generator. A steam seal regulator is a turbine system which controls the flow of steam to and from the turbine shaft seals (See Figures 1 and 2). 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

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Existing System: (cont'd.)

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 by a common header.

The existing 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. 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 150 MW of power generation to the Island Interconnected System which represents approximately 10 percent of system capacity.

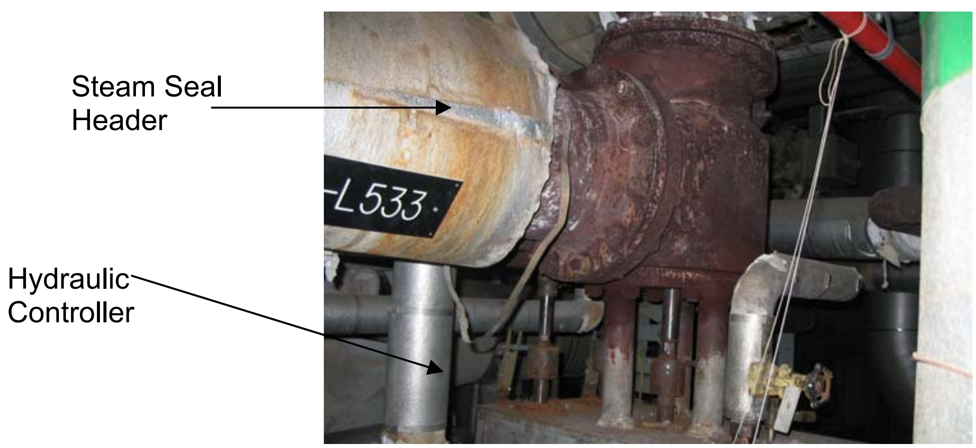


Figure 1 – Steam Seal Regulator

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Existing System: (cont'd.)

Figure 2 – Steam Seal Regulator

This project is required to convert the existing hydraulic steam seal regulator on Unit 3 to three pneumatically operated steam pressure control valves. Two of these pneumatically controlled pressure regulating valves will be used to supply steam to the steam seal header and the third will be used to relieve pressure from the steam seal header. The new system will be controlled using an existing 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.

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

Unit 3 was commissioned in 1979. The existing oil fired boiler and steam turbine are approximately 30 years old.

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

There have been no major work or upgrades performed on Unit 3 since it was commissioned in 1979.

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Existing System: (cont'd.)

Anticipated Useful Life:

The anticipated useful life of Unit 3 has been forecast to extend to the year 2020, absent an infeed from Lower Churchill.

Maintenance History:

Steam seal regulator maintenance is a component of the annual maintenance strategy for Unit 3. During the annual shutdown, Hydro uses a turbine service contractor, General Electric (GE), to perform preventative maintenance inspections on the steam seal regulator. Corrective maintenance is performed by plant internal forces during the annual shutdown. The cost of maintenance for the steam seal regulator is a component of the total maintenance cost for the whole unit. Hydro does not categorize steam seal regulator maintenance cost separately from the total unit maintenance cost. As a result, the actual preventative and corrective maintenance costs for the steam seal regulator are not available. However, the estimated total average annual maintenance cost for the steam seal regulator is $5,000.

Outage Statistics:

There have been no outages on Unit 3 caused by problems with the steam seal regulator. Operations personnel are aware of the issues surrounding the steam seal regulator and the consequences of it malfunctioning. They monitor the regulator operation daily and immediately react to binding and sticking.

Industry Experience:

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

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Existing System: (cont'd.)

<u>Maintenance or Support Arrangements:</u>

Hydro uses a combination of external contractors and internal plant resources to perform annual maintenance on Unit 3. Hydro currently has a service contract with Alstom Power, a boiler service contractor, to perform boiler maintenance during the annual scheduled outage. As stated previously, annual turbine maintenance is performed by GE in conjunction with plant internal forces.

<u>Vendor Recommendations:</u>

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

<u>Availability of Replacement Parts:</u>

Availability of spare parts for the existing steam seal regulator is an ongoing issue. The Unit 3 steam turbine was originally supplied by Hitachi Ltd. The replacement parts for the regulator are supplied out of Japan. The existing steam seal regulator is 30 years old and it is difficult to identify and order parts due to a lack of technical support from Hitachi. In recent years, any required replacement parts have been made by local machine shops by copying the original component.

<u>Safety Performance:</u>

There are no safety performance issues related to this project.

<u>Environmental Performance:</u>

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

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Existing System: (cont'd.)

Operating Regime:

The Holyrood Thermal Generating Station operates in a seasonal regime. The full plant capacity is needed to meet the winter electrical requirements on the Island Interconnected System. The steam seal regulator is an integral component of Unit 3.

Justification:

The steam seal regulator servicing Unit 3 at Holyrood is 30 years old and Hydro has been unable to secure reliable support service from the original manufacturer, Hitachi Ltd., located in Japan. In recent years, this has necessitated replacement parts being made by local machine shops by copying the original components.

Improper operation of the regulator, due to binding and sticking, allows steam to travel along the turbine rotor shaft and mix with bearing lubrication oil where it condenses to water and accelerates deterioration of the bearings. Premature failure of the turbine bearings can result in an unplanned unit outage of 10 to 12 weeks duration and a repair cost estimated to be as high as $1 million. An unscheduled unit outage during the peak winter load demand would result in a loss of 150 MW of power generation to the Island Interconnected System which represents approximately 10 percent of system capacity.

This project is required to maintain the reliability of generating Unit 3 at Holyrood.

Net Present Value:

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

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: Replace Unit 3 Steam Seal Regulator **(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 current legislative or regulatory requirements to convert the existing hydraulic steam seal regulator to a pneumatically operated pressure control valve system.

Historical Information:

There have been no capital expenditures in past years on Unit 3's steam seal regulator.

Forecast Customer Growth:

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

Energy Efficiency Benefits:

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

Losses During Construction:

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

Status Quo:

Delays to completing this project could reduce the life of Unit 3's turbine bearing system. Water contamination in bearing lubricating oil will reduce bearing life by 50 percent and can lead to catastrophic failure. A bearing failure on the turbine would result in 10 to 12 weeks of downtime on Unit 3 and repair cost as high as $1,000,000. In addition, an unscheduled failure during the peak winter load demand could result in a loss of 150 MW of power which represents approximately 10 percent of the Island Interconnected System's capacity. Moisture in the oil also requires a weekly centrifuge operation and a lot of operator involvement to monitor the quality of the lube oil system.

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Justification: (cont'd.)

Alternatives:

There are no alternatives available to the proposed project. Hydro has been unable to obtain support service for the 30 year old existing system from the manufacturer and the proposed new system is the standard design offered today by turbine service companies.

Conclusion:

This project is a conversion of the existing hydraulically controlled steam seal regulator on Unit 3 turbine to a pneumatically operated pressure control valve assembly. The steam seal regulator is 30 year old technology and has many moving parts and wear points. Improper operation of the regulator, due to binding and sticking, allows seal steam to travel along the turbine rotor shaft and mix with bearing lubrication oil where it condenses to water. Water entrainment in lubricating oil accelerates deterioration of the bearings, thereby reducing the reliability of the generating unit. The proposed pneumatic system is the standard design used today in the turbine steam seal regulating application.

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

Table 1. Project Schedule

Activity	Milestone
Project Kick-off Meeting	January 2009
Complete Design Transmittal	February 2009
Detailed Engineering Design	April 2009
Develop Installation Specification	April 2009
Issue Tender and Award Job	May 2009
Procurement of Materials	May 2009
Contract Execution	August 2009
Commissioning	September 2009
Project Final Documentation and Closeout	December 2009

Future Plans:

None.

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

GE Excerpt from Optimization and Control Report

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

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

2.2 STEAM SEAL SYSTEM UPGRADE PRODUCT OVERVIEW

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

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

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

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

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

Benefits:

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

Project Title: Replace Unit 3 Steam Seal Regulator **(cont'd.)**

Atco Power Steam Seal Regulator Conversion

ATCO Power
Alberta Power (2000) Ltd.

Turnover Package

Ref: BR3 Seal Steam Regulator Replacement

Date: April 19, 2005

From: Malcolm Boyd

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

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

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

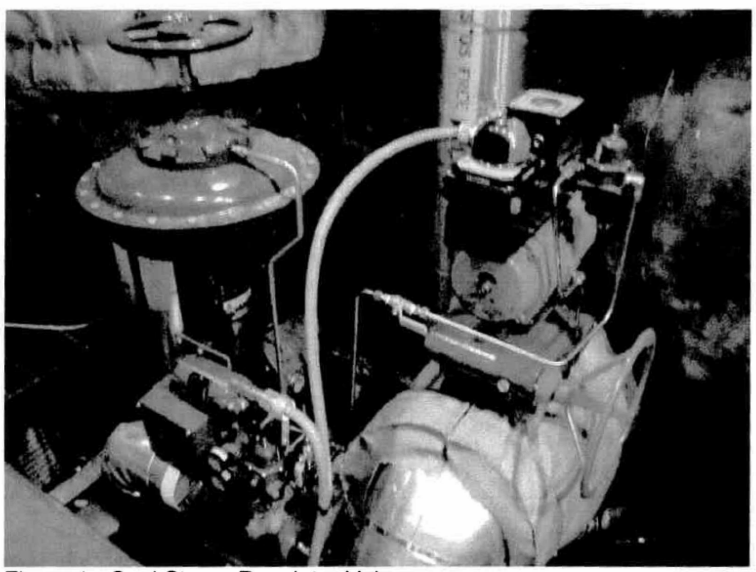


Figure 1 - Seal Steam Regulator Valves

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 first year of a four year program to implement upgrades recommended by the engineering consulting company, Stantec, Inc.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	50.0	0.0	0.0	50.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	350.0	0.0	0.0	350.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	50.3	0.0	0.0	50.3
Contingency	0.0	0.0	0.0	0.0
TOTAL	**450.3**	**0.0**	**0.0**	**450.3**

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:

To continue with years two to four refurbishment plans.

Attachments:

See report entitled "Hardwoods Gas Turbine Plant Life Extension Upgrades" located in Volume II, tab 21, containing further project details.

Project Title: Replace 50 kW Diesel Generator

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace one of two 50 kW generators at the Victoria Control Structure and to use the decommissioned generator as a source of spare parts for the remaining generator. Victoria Lake, a part of the Bay d'Espoir reservoir system, has a control structure to help regulate water levels in the reservoir. Two Dorman 50 kW diesel generators are used to power the motors that operate the gates at the control structure. The diesel generators were originally installed in 1967 and have become obsolete.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	133.0	0.0	133.0
Labour	29.3	66.3	0.0	95.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	21.8	0.0	23.8
O/H, AFUDC & Escln.	4.8	43.0	0.0	47.8
Contingency	0.0	25.2	0.0	25.2
TOTAL	**36.1**	**289.3**	**0.0**	**325.4**

Existing System:

The Bay d’Espoir Hydroelectric Generating Station (Bay d’Espoir) is the largest generating station connected to the Island Interconnected System. It has seven generating units producing a total capacity of 604 MW. The headwaters of the Bay d’Espoir system begin at Victoria Lake at an approximate elevation of 320 meters. Through an array of dams and canals, this water is directed to generating stations at Granite Canal, Upper Salmon, and finally, 150 kilometres from Victoria Lake, to its final tidewater destination at Bay d’Espoir. Water is collected, stored and diverted from a number of drainage areas between Victoria Lake and Long Pond.

The Victoria Control Structure consists of four gates which release water from the Victoria Lake Reservoir into the Burnt Pond Reservoir. The water is ultimately used to generate electricity at the

Project Title: Replace 50 kW Diesel Generator **(cont'd.)**

Existing System: (cont'd.)

Granite Canal, Upper Salmon, and Bay d'Espoir Generating Stations. The gates and site services at the Victoria Control Structure are powered by one primary 50 kW diesel generator and one back-up 50 kW diesel generator. There are no other power sources at the site. The manufacturer of the generators, Dorman, is no longer in existence and locating spare parts from a salvaged unit is difficult.

The reliability of the gate operation at the Victoria Control Structure is vital for both normal reservoir management and flood control.

Age of Equipment or System:

The existing diesel generators at the Victoria Control Structure have been in service since the site was commissioned in 1967.

Major Work/or Upgrades:

The following upgrades have occurred since installation:

Year	Major Work/Upgrade	Comments
2006	Replace Turbo Charger	Replaced due to failure
2007	Replace Starter and Ring Gear	Replaced due to failure

Anticipated Useful Life:

The anticipated useful life of a 50 kW diesel generator is 20 years.

Maintenance History:

The five-year maintenance history for the 50 kW diesel generator consists of both preventive and corrective maintenance. Preventive maintenance is a planned maintenance check that is done on the generator annually which includes an overall inspection, fluid top ups, and filter replacements. Corrective maintenance, on the other hand, is done only as needed when a component has failed.

Project Title: Replace 50 kW Diesel Generator **(cont'd.)**

Existing System: (cont'd.)

Maintenance History: (cont'd.)

The maintenance history is shown in Table 1.

Table 1. Five Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	2.0	2.0	4.0
2006	2.0	3.0	5.0
2005	2.0	2.0	4.0
2004	2.0	0.0	2.0
2003	2.0	2.0	4.0

Outage Statistics:

There are no outage statistics related to the generator.

Industry Experience:

Hydro has not researched relevant industry experience.

Maintenance or Support Arrangements:

Maintenance of the 50 kW diesel generator at the Victoria Control Structure is performed by Hydro personnel.

Vendor Recommendations:

The manufacturer of the existing generators, Dorman, is no longer in existence.

Availability of Replacement Parts:

Replacement parts for the Dorman generators are not readily available, which raises a reliability issue. The manufacturer is no longer in existence and, currently, spare parts are obtained from salvaged units. Locating these spare parts is time-consuming and difficult. As an example, Hydro

Project Title: Replace 50 kW Diesel Generator **(cont'd.)**

Existing System: (cont'd.)

Availability of Replacement Parts: **(cont'd.)**

planners performed a Google™ search and acquired a replacement ring gear from a decommissioned unit located on a farm in England.

If one generator is out of service awaiting a part search, there is no back up if the second generator also fails. If both generators fail there will be a loss of power at the site and the Energy Control Center will have no control over the gates, resulting in no control of the Victoria Reservoir. There is also no guarantee that a replacement part will be obtained when required. With the replacement of one of the generators under this project, the decommissioned generator can be used for spare parts for the back up Dorman generator still in service.

Safety Performance:

There are no safety performance issues related to the generator replacement.

Environmental Performance:

In general, by replacing the existing generator with a modern, more efficient generator a modest reduction in the amount of fuel burned and the associated emissions can be expected. No detailed analysis is available.

Operating Regime:

This generator is operated when a gate needs to be raised or lowered, when gate heating is needed prior to cold weather gate operation, and when power needs to be provided to the site during inspections and maintenance.

Justification:

This project is justified on the requirement to replace a generator that has exceeded its anticipated useful life and for which parts are no longer readily available in order to ensure the reliability of the power supply at the Victoria Control Structure. A reliable power supply will, in turn, ensure reliable gate operation and ultimately reliable reservoir management and flood control. In addition, the

Project Title: Replace 50 kW Diesel Generator **(cont'd.)**

Justification: (cont'd.)

decommissioned generator can be used as a readily available source of spare parts for the generator that will remain in operation.

Net Present Value:

A net present value calculation was not 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:

No legislative or regulatory requirements are driving this project.

Historical Information:

There is no relevant historical information; no similar diesel units have been replaced.

Forecast Customer Growth:

This project is not impacted by forecast customer growth.

Energy Efficiency Benefits:

Fuel efficiency improvements are expected from a new generator, however, they are considered to be negligible.

Losses During Construction:

As no generation outage is required to complete this project, there will be no losses during construction.

Project Title: Replace 50 kW Diesel Generator **(cont'd.)**

Justification: (cont'd.)

Status Quo:

Maintaining the status quo is unacceptable. Replacement parts for the existing generators are not readily available. Loss of power supply will result in unreliable gate operation and ultimately the inability to manage the reservoirs and control flooding.

Alternatives:

There are no viable alternatives to replacing the generator.

Conclusion:

The existing 50 kW diesel generator at the Victoria Control Structure is in need of replacement. The generator has exceeded its anticipated useful life and replacement parts are no longer readily available. A reliable power supply will ensure reliable gate operation and ultimately reliable reservoir management and flood control.

Project Schedule:

Table 2. Project Schedule

Activity	Milestone
Initiation	January 2009
Design Complete	April 2009
Equipment Ordered/Delivered	April 2009 / August 2010
Installation Commences	August 2010
Installation Complete	September 2010
Project Closeout	November 2010

Future Plans:

None.

Project Title: Replace Unit 2 Air Preheater Cold End

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to replace deteriorated components of the two air preheaters servicing the Unit 2 boiler at the Holyrood Thermal Generating Station (Holyrood). Also, rotor shaft seal covers will be fabricated and installed on Unit 2.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	16.3	0.0	0.0	16.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	240.0	0.0	0.0	240.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	37.9	0.0	0.0	37.9
Contingency	25.6	0.0	0.0	25.6
TOTAL	**319.8**	**0.0**	**0.0**	**319.8**

Existing System:

Holyrood is an essential part of the Island Interconnected System, with three units providing a total capacity of 490 MW. Holyrood was constructed in two stages. In 1969, Stage I was completed bringing on-line two generating units, Units 1 and 2, capable of producing 150 MW each. In 1979, Stage II was completed bringing on line one additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units 1 and 2 were up-rated to 170 MW. Holyrood represents approximately 33 percent of Hydro's total Island Interconnected System generating capacity and produces on average, approximately 2,996,000 MWh of energy annually.

Excluding the numerous individual and common auxiliary systems the four main components for each generating unit are the boiler, turbine, generator and transformer. During operation, combustion air is preheated before entering the boiler. The air preheaters are rotary style heat

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Existing System: (cont'd.)

exchanger systems that recapture heat from the boiler's hot flue gases to increase the temperature of the incoming air. The cold end of the air preheater is defined as the section that takes in fresh air from the outside, and the hot end of the air preheater is the section that is exposed to the hot boiler flue gases.

This project is required to replace deteriorated components of the two air preheaters that service the boiler for Unit 2. Moisture and gases such as sulphur dioxide create a corrosive operating environment for air preheater components. An internal inspection performed on both air preheaters during a 2005 outage identified extensive corrosion on the rotor shell and diaphragm at the cold end of each heater as shown in the photographs in Figures 1 and 2. This project entails replacing the corroded sections of the rotor and diaphragm with new components. In addition, seal covers will be fabricated and installed on each preheater around the rotor shaft at the hot end to reduce flue gas leaks and provide a better operating environment for the rotor shaft guide bearing by reducing moisture infiltration into the bearing.

Figure 1 – Air Preheater Cold End: Extensive Corrosion

Figure 2 – Air Preheater Cold End: Extensive Corrosion

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System:

Unit 2 was commissioned in 1970. The existing oil fired boiler and steam turbine are 38 years old.

Major Work/or Upgrades:

There have been no major upgrades on this system since its installation.

Anticipated Useful Life:

The anticipated useful life of Unit 2 has been forecast to extend to the year 2020.

Maintenance History:

Air preheater maintenance is a component of the annual maintenance strategy for Unit 2. During the annual unit shutdown, Hydro uses a boiler service contractor, Alstom Power, to perform internal inspections on both air preheaters and perform corrective maintenance as required. The cost of maintenance for the preheaters is a component of the total maintenance cost for the whole unit. Hydro does not categorize preheater maintenance costs separately from the total unit maintenance cost. The actual preventive and corrective maintenance costs are not readily available. However, the estimated average annual preventative maintenance inspection cost is $20,000 and the estimated average cost of annual corrective maintenance is $55,000 for a total estimated average annual maintenance cost of $75,000.

Outage Statistics:

There have been no outages on Unit 2 caused by the air preheaters.

Industry Experience:

According to Alstom Power, inspections and repairs on the air preheaters should be performed during a scheduled boiler outage. However, the regular maintenance program is not sufficient to cover the scope of the required repairs that were identified during the 2005 annual inspection. Extensive corrosion on the air preheater internal components, which is considered normal

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Existing System: (cont'd.)

Industry Experience: (cont'd.)

deterioration associated with operating the equipment over a long period of time, is to a point where a major replacement must take place. In the 2005 inspection, there was a long term recommendation made by Alstom Power to perform a major replacement on the preheaters (see item 5 in the Longer Term Recommendations on page C-27).

Maintenance or Support Arrangements:

Hydro currently has a service contract with Alstom Power to perform boiler maintenance during the annual scheduled outage. Maintenance repairs associated with the air preheaters are performed by Alstom Power.

Vendor Recommendations:

Following the 2005 inspection of the air preheaters, Alstom Power’s longer term recommendations included the replacement of the existing corroded rotor and diaphragm sections of the air preheaters with new components. Long term recommendations should be completed within a five year period following the recommendation and 2009 is the fourth year after the 2005 recommendations (see item 5 in Alstrom Power's Longer Term Recommendations on page C-27). This is beyond the scope of the normal annual maintenance strategy. Installation of rotor shaft seal covers, which will improve the mechanical reliability of the air preheaters by preventing air leakages around the rotor shaft, was also recommended. Air leakage around the rotor shaft causes moisture to enter the guide bearing which sharply reduces the life of the bearing (see item 18 in the Longer Term Recommendations page C-28).

Availability of Replacement Parts:

Replacement parts for the air preheaters are readily available. Spare components are inventoried on site at the generating station’s warehouse. The rotor shaft seal covers must be designed and fabricated by Alstom Power. It will take approximately two months to design and fabricate the rotor shaft seal covers.

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Existing System: (cont'd.)

Safety Performance:

There are no safety code violations associated with the operation of the Unit 2 air preheaters. However, flue gas leakage around the rotor shaft reduces the quality of air inside the Holyrood plant.

Environmental Performance:

There are no environmental performance concerns or environmental code violations associated with the operation of the Unit 2 air preheaters.

Operating Regime:

Holyrood operates in a seasonal regime. The full plant capacity is needed to meet the winter electrical requirements on the Island Interconnected System. The air preheaters are an integral component of Unit 2.

Justification:

This project is justified on the requirement to replace the deteriorated components of the two preheaters servicing the Unit 2 boiler. Failure to perform the replacements recommended by Alstom Power increases the risk of a major unit failure and unscheduled downtime. Reliable electrical service at the least cost to the customer may be interrupted. If a unit at Holyrood is lost during peak load periods, then a more costly power supply, such as operating gas turbines, would have to be found. Prevention of a major failure of the air preheaters through a strategic rebuild will allow Hydro to maintain its commitment to supply least cost power. Also, the installation of rotor shaft seal covers increases the reliability of the preheater guide bearing.

Net Present Value:

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

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: Replace Unit 2 Air Preheater Cold End **(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.

Historical Information:

There have been no capital expenditures on any of the generating unit air preheaters at Holyrood.

Forecast Customer Growth:

Customer load growth does not affect this project since the scope of the project is to replace and upgrade existing equipment.

Energy Efficiency Benefits:

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

Losses During Construction:

No losses during construction will be incurred. The project will be completed during the scheduled annual unit shutdown.

Status Quo:

Maintaining the status quo is unacceptable. Delays in the completion of this project could result in a major mechanical failure of both air preheaters. An unscheduled outage caused by the failure would result in four to six weeks of downtime on Unit 2. In addition, an unscheduled failure during the peak winter load demand could result in a loss of 170 MW of power which represents approximately 10 percent of the Island Interconnected System capacity.

Alternatives:

There are no viable alternatives available to the proposed project.

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Conclusion:

This project is required to make major repairs to the two air preheaters servicing the Unit 2 boiler, as recommended from an inspection performed by the boiler service contractor, Alstom Power. The project will replace corroded sections of the existing rotor and diaphragm with new components. In addition, rotor shaft seal covers will be installed. Failure to execute the repairs recommended by Alstom increases the likelihood of unscheduled mechanical downtime on the boiler and increases the risk of being unable to meet customer demands during the winter peak. The proposed repairs to the air preheater infrastructure are beyond the scope of the normal annual maintenance program.

Project Schedule:

Table 1. Project Schedule

Activity	Milestone
Project Kick-off Meeting	January 2009
Complete Design Transmittal	February 2009
Procurement of Materials	May 2009
Contract Execution	August 2009
Commissioning	September 2009
Project Final Documentation and Closeout	December 2009

Future Plans:

None.

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Alstom Power Recommendations

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5 Recommendations

This section is divided into recommendations that should be considered for 2006 and longer term recommendations.

Recommendations for 2006

1) Replace breaching expansion joints.

2) Be aware that asbestos is, or may be, contained in the boiler access door frames and in the west airheater guide bearing packing. These items should be removed as part of the asbestos abatement planned for 2006.

3) Replace the east hot-end baskets in 2006 (except for the inner row).

4) Replace the cold-end radial seals in the east air heater.

5) Repair the holes in the east air heater diaphragm plates.

6) Replace three sections of angle in the east air heater hot-end.

7) Install thermal drains in the air heater sootblower steam supply.

8) Pressure wash the furnace tubes to allow a detailed furnace wall inspection.

9) Complete a detailed inspection of the furnace for blisters and other damage.

10) Modify the casing attachment to the west sidewall tube in the north bottom vestibule.

11) Monitor the pitting in the boiler tubes around the burners and in the crevices formed by the ignitor horns.

12) Replace the ignitor fin plates at 2A and 2D burners.

13) Change the 2A ignitor horn and bottom buckets at D corner.

14) Tighten loose VIVs in the FD fans by drilling the lever-arms and installing set screws.

15) Have spare VIV bearings on hand for future repairs as required.

16) Purchase the windbox damper bearing upgrade to have on hand when it is required.

17) Check burner gun lengths after each repair and during each cleaning. This should be added to the burner gun maintenance procedure.

18) Repair the refractory on the 5th floor furnace access door.

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Alstom Power Recommendations

19) Replace the refractory at the 8th floor west side behind the reference line crotch plates.

20) Monitor the performance of the replaced fabric expansion joints. Budget for additional repairs for 2006.

21) Monitor the condition of the refractory around the economiser outlet tube penetrations.

22) Regular checks should be done on the airheater sootblowers to verify that the poppet valve are not passing. Passing valves must be corrected immediately to minimize damage to the airheaters and breaching.

23) Repair the 8th floor buckstay near south east corner if required.

24) Rebuild the economizer hopper access doors.

Longer Term Recommendations

1. A full Condition Assessment is recommended to allow the plant to anticipate and budget for any necessary future repairs.
2. Prepare for replacement of the final secondary superheater section. This will likely be required in the next few years.
3. Establish a budget for replacing all remaining fabric expansion joints.
4. Budget for west air heater hot end basket replacement in 2007.
5. Budget for a complete re-build of the air heater cold ends. Include run-out measurements and angle adjustments, shaft alignment, sector plate liners, and diaphragm and rotor shell plate re-build.
6. Replace the repaired tube in the west sidewall at the bottom vestibule.
7. Budget for chemical cleaning, which might be required if blisters continue to form.
8. Once the blister problem has been resolved, remove the repaired blisters in the furnace and replace with new tube.
9. Repeat DA shell thickness measurements at regular intervals to monitor corrosion.
10. Extend the 9th floor catwalk to create a walkway between the hoist way and the 17L sootblower on Unit 2 and the 17R sootblower on Unit 1.
11. Replace the 17R sootblower air seal aspirator in the near future.

Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Alstom Power Recommendations

ALSTOM
Power Service

Maintenance Outage Report - 2005
Newfoundland & Labrador Hydro - Holyrood Unit #2

12. The thermoprobe should be refurbished or a replacement purchased.
13. Burner upgrades including low NOx technology, replaceable tipped buckets, and bulbous buckets should be considered.
14. Repeat economiser inlet header inspection in future with better equipment.
15. Consideration should be given to upgrading the air heater wash headers to the new standard, which should give better cleaning.
16. Rebuild the penthouse access doors and frames.
17. Replace the air lines from the I/P panel on the 4th floor up to and including the air headers at the burner corners.
18. Install hot-end seal covers on both airheaters.
19. Consider building permanent access platforms to the airheater hopper valves to facilitate cost-effective repairs.
20. Budget for repair of the anti-vibration baffles in the primary superheater.
21. Repairs to the refractory in the front wall at the reheater inlet and outlet tube will be required in the near future.
22. New bull gear covers should be fabricated for the air heaters – particularly the west.

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Project Title: Replace Unit 2 Air Preheater Cold End **(cont'd.)**

Alstom Power Recommendations

ALSTOM
Power Service

Maintenance Outage Report - 2005
Newfoundland & Labrador Hydro - Holyrood Unit #2

12. The thermoprobe should be refurbished or a replacement purchased.

13. Burner upgrades including low NOx technology, replaceable tipped buckets, and bulbous buckets should be considered.

14. Repeat economiser inlet header inspection in future with better equipment.

15. Consideration should be given to upgrading the air heater wash headers to the new standard, which should give better cleaning.

16. Rebuild the penthouse access doors and frames.

17. Replace the air lines from the I/P panel on the 4th floor up to and including the air headers at the burner corners.

18. Install hot-end seal covers on both airheaters.

19. Consider building permanent access platforms to the airheater hopper valves to facilitate cost-effective repairs.

20. Budget for repair of the anti-vibration baffles in the primary superheater.

21. Repairs to the refractory in the front wall at the reheater inlet and outlet tube will be required in the near future.

22. New bull gear covers should be fabricated for the air heaters – particularly the west.

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Project Title: Replace Cooling Water System on Units 3 and 4

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the supply and discharge surface air cooler water piping, associated components, and a strainer on Units 3 and 4 at the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir). The four inch diameter piping will be replaced with stainless steel schedule 10 piping, which is corrosion and foul resistant. The six inch diameter piping will be replaced with standard mild steel schedule 40 pipe. The system will be equipped with Victaulic fittings to allow ease of inspection and maintenance. The strainer will be replaced with a stainless steel manual backwash basket strainer unit.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	147.7	0.0	0.0	147.7
Labour	79.3	0.0	0.0	79.3
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.	37.4	0.0	0.0	37.4
Contingency	22.7	0.0	0.0	22.7
TOTAL	287.1	0.0	0.0	287.1

Existing System:

Bay d'Espoir is Hydro's largest hydroelectric station on 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 generator components, consisting of supply and discharge surface air cooler water piping, a strainer, and associated components. Each cooling system is fabricated completely from carbon steel which is highly susceptible to corrosion. In fact, the system has experienced fouling and corrosion approximately every five years resulting in the need for cleaning. See Figure 1 for a picture of fouled piping. This corrosion has progressed to such a point that if cleaning is performed then leaks occur. The leaks can potentially damage the generators, thus, replacement of the system is required.

Project Title: Replace Cooling Water System on Units 3 and 4 **(cont'd.)**

Existing System: (cont'd.)

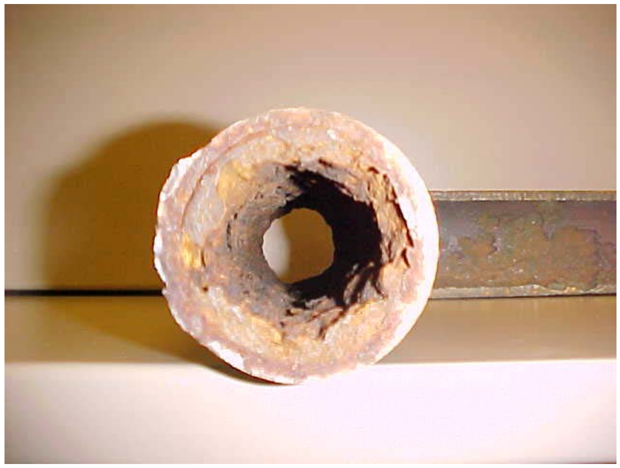

Figure 1. Fouled cooling water pipe, Bay d'Espoir

Upgrading of the cooling water systems for Units 3 and 4 at Bay d'Espoir is required to increase the reliability of the hydroelectric generating units. By upgrading the components of this system with corrosion resistant piping the potential for corrosion and fouling of the piping will be significantly less, thus reducing the potential for generator over heating and unit outages.

Age of Equipment or System:
The cooling water systems for Units 3 and 4 are the original systems installed when the units were put in service in 1968.

Major Work/or Upgrades:
There have been no major work/upgrades performed on the cooling water systems for Units 3 and 4 since installation, however there is a capital budget proposal for 2008 to replace the cooling water systems on Units 1 and 2 that the Board approved in Order No. P.U. 30 (2007) with a budget of $264,000.

Anticipated Useful Life:
A cooling water system has an estimated service life of 25 years.

Project Title: Replace Cooling Water System on Units 3 and 4 **(cont'd.)**

Existing System: (cont'd.)

Maintenance History:

Over the last five years there have been numerous problems associated with the cooling water systems for Units 3 and 4 at Bay d'Espoir. Several valves have been replaced, including two Singer control valves and eight isolation valves. When inspected in 2008, these valves have again degraded to the point where replacement is required. There are also cases of smaller pressure sensing lines being completely clogged with organic materials which required cleaning. The costs associated with these items are presented in Table 1.

Table 1. Five Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	0.6	0.0	0.6
2006	0.6	0.0	0.6
2005	0.6	0.2	0.8
2004	0.6	0.0	0.6
2003	0.6	4.9	5.5

Outage Statistics:

No outage statistics can be attributed to this system due to the redundancy inherent in the system design.

Industry Experience:

Hydro Quebec installed stainless steel piping on Unit 3 in Menihek during the refurbishment of that unit in 2007.

Maintenance or Support Arrangements:

Maintenance of the cooling water systems at Bay d'Espoir is conducted by the mechanical maintenance staff at the plant. Inspections are conducted on an annual basis, with cleaning and other repairs performed as required.

Project Title: Replace Cooling Water System on Units 3 and 4 **(cont'd.)**

Existing System: (cont'd.)

Vendor Recommendations:

There are no vendor recommendations.

Availability of Replacement Parts:

Replacement parts are readily available for many of the components of the cooling water system. However, the major components, such as strainers, are no longer available or supported by the 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 water cooling systems are operated as needed. Typically, the cooling water system for a unit is operated when that unit is generating.

Justification:

This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. An internal cooling water system 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 under PUB NLH 610 Attachment 1 from 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, this corrosion fouling problem 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.

Project Title: Replace Cooling Water System on Units 3 and 4 **(cont'd.)**

Justification: (cont'd.)

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:

No legislative or regulatory requirements apply to this project.

Historical Information:

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 $264,000 in Board Order No. P.U. 30 (2007). The costs for the 2009 project are 8.7 percent higher due to the increase in material costs.

Forecast Customer Growth:

Forecast customer load has no affect on this project.

Energy Efficiency Benefits:

This project will not have an effect on energy efficiency.

Losses During Construction:

No losses during construction will be incurred. This work will be completed during a planned unit outage. The remaining five units at Bay d'Espoir will remain in service and be capable of compensating for this outage.

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 the joints can not be sealed. This is an unsatisfactory condition that could potentially damage the generators.

Project Title: Replace Cooling Water System on Units 3 and 4 **(cont'd.)**

Justification: (cont'd.)
Alternatives:

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

The first alternative was to replace the existing pipe with 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 five 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 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 is required because of the deteriorated piping currently installed on Units 3 and 4 at Bay d'Espoir. The existing piping is 40 years old and has become fouled and corroded to such a point that leaks occur if cleaning is conducted. A cooling water study, performed in 2002, determined that all existing carbon steel piping smaller than four inches in diameter should be replaced with corrosion and fouling resistant piping.

Project Title: Replace Cooling Water System on Units 3 and 4 **(cont'd.)**

Conclusion: (cont'd.)

Project Schedule:

This project will be completed during the scheduled unit outages associated with each unit. Project milestones are included in Table 2 below.

Table 2. Project Schedule

Activity	Milestone
Initiation	January 2009
Design Complete	February 2009
Equipment Ordered/Delivered	May 2009
Installation Commences	June 2009
Installation Complete	July 2009
Project Closeout	September 2009

Future Plans:

None.

Project Title: Upgrade Intake Gate Controls

Location: Hinds Lake

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to upgrade the electrical controls at the Hinds Lake intake gate. The new system will use a programmable logic controller (PLC) with a cable reel sensor to precisely control the position of the current intake gate. This system will offer accurate gate position feedback. A backup penstock-priming device will also be employed to address all safety concerns arising from filling the penstock after partial or complete dewatering.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	75.0	0.0	0.0	75.0
Labour	101.4	0.0	0.0	101.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	32.3	0.0	0.0	32.3
O/H, AFUDC & Escln.	33.5	0.0	0.0	33.5
Contingency	20.9	0.0	0.0	20.9
TOTAL	263.1	0.0	0.0	263.1

Existing System:

The Hinds Lake Generating Station (Hinds Lake) is one of nine hydroelectric generating sites owned and operated by Hydro connected to the Island Interconnected System. Hinds Lake is located in the western part of the Island near Grand Lake, about 55 kilometers southeast of the Town of Deer Lake. Hinds Lake has one generating unit rated at a capacity of 75 MW. Figure 1 shows Hinds Lake. The upper right part of the picture indicates where the penstock is laid. The penstock brings water from the reservoir to the station.

Figure 1. Hinds Lake Generating Station

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

Existing System: (cont'd.)

An intake gate at the end of the penstock in the reservoir controls the passage of water into the penstock. The intake gate is equipped with a single wire type electric hoist equipped with an electromagnetic brake to control the lowering of the gate. It also has a mechanical brake that is used during emergency lowering of the intake gate.

In the generating station, there is no shut off valve on the generating unit to isolate the generator from the penstock. Therefore, the intake gate is used to provide isolation and unit protection in the event of a sustained, unit over speed condition. An over speed condition occurs when there is a loss of electrical load on the generating unit. When an over speed condition occurs, the protection circuitry gives the intake gate an emergency drop command, which releases the hoist brake and causes the gate to close under its own weight.

The current intake gate hoisting system is equipped with a gearing arrangement that directly couples the hoist motor to the wire wound drum. Another small gearbox couples the drum to a set of mechanical switches and a dial indicator. The intake gate is equipped with five interrupters or limit switches that enable the desired control of the gate. These include slack rope switches, a manual brake operation switch, cam switches, cracking proximity switches and an extreme upper limit power disconnect switch. Figure 2 is a rough sketch of the intake gate hoisting system.

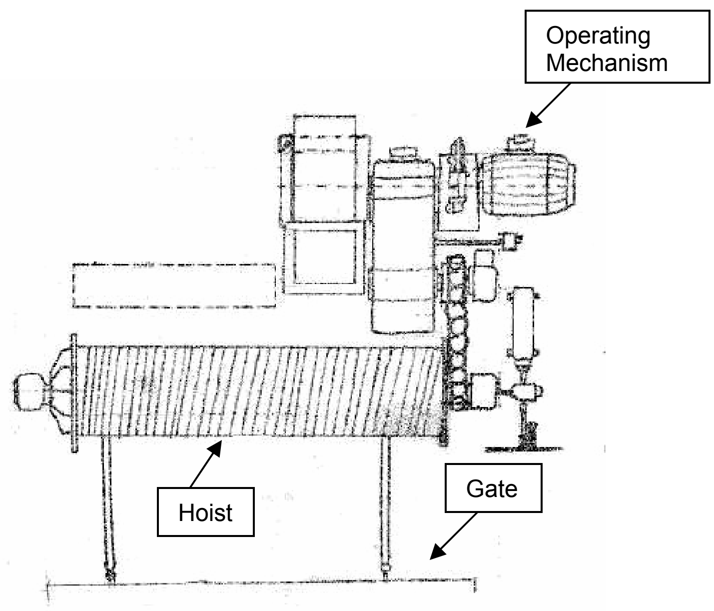

Figure 2. Intake Gate Hoisting System

The hoisting operation is currently achieved through a wall mounted pushbutton station equipped with five pushbuttons (stop, prime, raise, lower and maintenance raise) and one selector switch for local or remote operation. The intake gate is also equipped with heaters that prevent the gate from freezing up in the winter.

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

Existing System: (cont'd.)

Age of Equipment or System:

The Hinds Lake intake gate controls were installed in 1988 when the generating unit was originally commissioned.

Major Work/or Upgrades:

There have been no major upgrades on this system since its installation.

Anticipated Useful Life:

The controls that are currently on this system have an anticipated useful life of 25 years. These controls are composed predominately of relays and solid state contactors and are, thus, fairly maintenance free devices.

Maintenance History:

This control system has required very little maintenance over the last five years. Once a year this system is fully inspected and calibrated as part of Hydro's preventative maintenance program.

Outage Statistics:

No generation outages have been attributed to the intake gate system at Hind's Lake.

Industry Experience:

The Hydroelectric Generating Station at Churchill Falls has eleven generating units. Each generating unit has its own penstock with an intake gate. Churchill Falls Engineering was contacted for information about the plant's intake gate control system. A similar design is being proposed in this study as is used in the Churchill Falls Plant.

Maintenance or Support Arrangements:

No external support arrangements are currently in place to maintain this system. All maintenance is completed by Hydro Operations personnel.

Vendor Recommendations:

No vendor recommendations were evaluated for this proposal.

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

Existing System: (cont'd.)

<u>Availability of Replacement Parts:</u>

The existing intake gate controls consist of relays, contactors, and limit and proximity switches, therefore, spare parts are still available for this system. This proposal is to upgrade the existing controls to a Programmable Logic Controller (PLC) based system that consists of constant gate position feedback and a backup penstock priming device.

<u>Safety Performance:</u>

The prime position is the location of the intake gate when it is raised to 6.4 cm above the sill. This position is determined using a set of two proximity switches that are mounted directly on the gate/guide interface on the base of the intake gate. This allows for the gate to stop precisely at 6.4 cm during a raise command, thereby filling the penstock slowly. This prevents the formation of a pressure bubble from trapped air that could rise up through the penstock and potentially destroy the vent house and/or injure personnel in the process. These proximity switches are located under water, are unreliable in that they do not operate consistently, and fail to indicate the gate’s position. They are difficult to maintain or replace because the penstock has to be dewatered to perform maintenance. Also there is no backup device to prevent the gate from traveling past the prime position and filling the penstock too quickly. Because of this, there is a safety 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 the intake vent house and presented the possibility for personnel injury. An incident in 1984 destroyed intake gate 4 at Bay d'Espoir. Figure 3 shows several pictures taken by Bay d’Espoir employees after a failure in July, 2000 at the Bay d’Espoir generating site. They illustrate the destructiveness of the event and the potential safety risk. The pictures show the destruction of intake gate 2.

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

Existing System: (cont'd.)

Safety Performance: **(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

Environmental Performance:

There are no environmental concerns with the existing intake gate system.

Operating Regime:

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

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

Justification:

This project is required to enhance safety at the intake gate controls at Hinds Lake. 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 Hydroelectric Generating Station on intake Gate 4 in the early 1980's and on intake Gate 2 in July 2000. The incidents occurred when the penstock was being refilled after a complete dewatering. During both of these incidents, Hydro personnel and equipment were in the path of danger and personnel involved narrowly escaped without serious injury or death. Pictures of the Gate 2 incident are included in Figure 3. In addition to these major incidents, in July 2005, the Bay d'Espoir intake Gate 4 was once again opened beyond the prime limit, thus causing the penstock to be filled too quickly. As a result, operators were forced to give the gate an emergency drop command before further destruction occurred.

Since there is no spiral case shut off valve on the generating unit at the Hinds Lake Hydroelectric Generating Station, the intake gate must be lowered at least once a year to isolate the generating unit 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. This avoids the formation of a large pressure bubble that could rise up through the penstock and potentially destroy the vent house and/or injure personnel in the process.

To stop the gate at the prime position, the intake gate is currently equipped with a set of proximity limit switches. These proximity switches are extremely difficult to maintain or replace and are found not to be reliable in service. In addition, there is currently no backup device to prevent the gate from traveling past the prime position. As a result, there is a risk every time the intake gate is opened after a complete or partial dewatering of the penstock.

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

Justification: (cont'd.)

Net Present Value:

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

Levelized Cost of Energy:

As this project does not relate to a 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.

Legislative or Regulatory Requirements:

No legislative or regulatory requirements apply to this project.

Historical Information:

The intake gate controls on Unit 7 in Bay d'Espoir are being upgraded in 2008, as approved with a budget of $115,500 in Board Order No. P.U. 30 (2007). This project has been reforecast to $144,000. The upgrade of the intake gate controls for Hinds Lake will be more expensive because of additional travel costs to the remote site. As well, the Hinds Lake project requires additional components, such as a PLC, that already existed at Bay d'Espoir.

Forecast Customer Growth:

This project is not impacted by forecast customer growth.

Energy Efficiency Benefits:

This project will not have an effect on energy efficiency.

Losses During Construction:

No losses will be experienced during the construction phase. This upgrade will take place during the annual unit outage on the generating unit.

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

Justification: (cont'd.)

Status Quo:

The status quo option is not a viable option for Hydro because there is a safety hazard associated with the continued operation of the existing equipment.

Alternatives:

There are no viable alternatives for this proposal.

Conclusion:

This upgrade is necessary due to the safety concerns that surround the Hinds Lake facility given past failure events. Over the next three years, a similar project will be proposed on all hydro generating units that are not equipped with spherical valves. The intake Gate controls at Hinds Lake will be upgraded before those on other units because they are the only source of unit isolation and are, thus, operated more frequently. It is Hydro's plan to complete all units in the system within the next 10 years.

Project Schedule:

Table 1 presents the anticipated project schedule.

Table 1. Project Schedule

Activity	Milestone
Project Initiation	January 2009
Engineering Design	May 2009
Installation and Commissioning	August 2009
Project Closeout	October, 2009

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Replace Automatic Voltage Regulator on Gas Turbine

Location: Stephenville

Category: Generation - Gas Turbines

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the Automatic Voltage Regulator (AVR) for the exciter on the gas turbine in Stephenville and to provide the necessary training in the use of the new AVR.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	98.0	0.0	0.0	98.0
Labour	65.6	0.0	0.0	65.6
Consultant	36.0	0.0	0.0	36.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.4	0.0	0.0	10.4
O/H, AFUDC & Escln.	31.3	0.0	0.0	31.3
Contingency	21.0	0.0	0.0	21.0
TOTAL	**262.3**	**0.0**	**0.0**	**262.3**

Existing System:

Hydro owns and operates a gas turbine plant located in Stephenville to support the western part of the Island Interconnected System. The Stephenville Gas Turbine has a rated capacity of 50 MW. It operates approximately 60 percent of the time as a synchronous condenser. In this mode of operation, the gas turbine responds to constant fluctuations in system voltage levels to maintain voltage stability. It operates to maintain nominal voltage levels of 230, 138 or 66 kV and to limit voltage drop to no more than five percent below the nominal level. The gas turbine is used less than one percent of the time as a generator. In this mode of operation, the gas turbine supports system generation during peak load periods which occur during the winter months. Also, the gas turbine is required at times when other generation is unavailable because of a forced outage and at times when transmission line TL-214 from Bottom Brook to Doyles is taken out of service.

Part of the control system of the gas turbine is the AVR. The AVR is used to regulate input voltage to the gas turbine excitation system. The excitation system is used to regulate generator output voltage. The existing AVR is obsolete.

Project Title: Replace Automatic Voltage Regulator on Gas Turbine **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System:

The AVR was commissioned in 1976. Therefore, it is over 30 years old.

Major Work/or Upgrades:

There have been no major upgrades or significant work done on the AVR since installation.

Anticipated Useful Life:

The anticipated useful life of the gas turbine and components is 25 years.

Maintenance History:

Maintenance on the AVR is part of the overall maintenance plan for the gas turbine plant. This includes daily and weekly operator visual inspection checks. Once every five years, maintenance personnel test the AVR settings and relays. The latest test was conducted in February 2008 and no problems were found with the settings and relays.

Outage Statistics:

There were no outages to the Stephenville Gas Turbine attributed to AVR during the past five years.

Industry Experience:

There is no industry experience available for this proposal.

Maintenance or Support Arrangements:

Maintenance of the AVR is performed by Hydro's internal resources.

Vendor Recommendations:

ASEA Brown Boveri Company Inc. (ABB), the supplier of another AVR that was purchased for the Hardwoods Gas Turbine (Hardwoods), recommends the replacement of the existing AVR with the latest technology as obsolete parts can no longer be obtained.

Project Title: Replace Automatic Voltage Regulator on Gas Turbine **(cont'd.)**

Existing System: (cont'd.)

Availability of Replacement Parts:

Hydro is unable to locate spare parts or obtain technical support for this equipment as it is no longer supported by the manufacturer, Brush Electrical Machines Limited. The only source of replacement parts is the AVR removed from Hardwoods in 2006. These spare parts have not yet been used. The Hardwoods AVR is also over 30 years old and, although parts could be used if a failure of the AVR at Stephenville occurs, it is a temporary solution.

Safety Performance:

There is no obvious safety issue with this project.

Environmental Performance:

This project does not have any environmental impact.

Operating Regime:

The AVR is in continuous use.

Justification:

The AVR at Stephenville is more than 30 years old and replacement parts and technical support are no longer available. The only source of spare parts is the AVR removed from Hardwoods in 2006. The AVR is required for the gas turbine to function. Failures of the similarly aged unit at Hardwoods have resulted in difficulty in sourcing parts. Although the Stephenville AVR has not failed in the past five years, a failure will result in the gas turbine not being available for generation or voltage support for the west coast portion of the Island Interconnected System. Also, the loss of the gas turbine would adversely impact Hydro's maintenance planning schedule. To prevent an extended outage to the Stephenville Gas Turbine, the AVR must be replaced.

Net Present Value:

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

Project Title: Replace Automatic Voltage Regulator on Gas Turbine **(cont'd.)**

Justification: (cont'd.)

Levelized Cost of Energy:

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

Cost Benefit Analysis:

A cost benefit study is not required as this project has no quantifiable benefits.

Legislative or Regulatory Requirements:

There are no legislative or regulatory requirements for this project.

Historical Information:

A gas turbine AVR was replaced at Hardwoods in 2006 with a budget of $200,900. The actual cost was $174,400. Due to the increase in material and labour costs, the current project is budgeted at approximately $90,000 more than the 2006 project.

Forecast Customer Growth:

This project has no impact on customer load growth nor is it affected by it.

Energy Efficiency Benefits:

There are no energy efficiency benefits that can be attributed to replacing the AVR.

Losses During Construction:

A four week gas turbine outage is required to replace the AVR. However, the replacement will be scheduled during a planned outage. Therefore, there are no anticipated losses during the installation and commissioning periods.

Status Quo:

The status quo is not acceptable because a failure of the AVR would cause the gas turbine to be inoperable. The AVR is obsolete and spare parts are not available.

Alternatives:

No viable alternative exists. Replacement of the existing AVR is required.

Project Title: Replace Automatic Voltage Regulator on Gas Turbine **(cont'd.)**

Conclusion:

This project is necessary to maintain the reliability of the Stephenville gas turbine. The gas turbine is required for voltage support and, at times, generation for the western part of the Interconnected Grid. Without an AVR, the gas turbine cannot operate. The existing AVR has reached the end of its useful life.

Project Schedule:

Table 1 provides the anticipated project schedule.

Table 1. Project Schedule

Activity	Milestone
Specifications and Ordering	March 2009
Design and Manufacture	July 2009
Installation and Commissioning	September 2009

Future Plans:

None.

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 only collects meteorological data from two of the 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 project is required to purchase and install meteorological stations at the Burnt Dam Spillway, the Victoria Reservoir and at the Hinds Lake Control Structure in 2009. All stations will be equipped to provide precipitation data, air temperature, humidity, wind speed and wind direction. Additionally, the station at Burnt Dam Spillway will be equipped to provide reservoir elevations and the station at Victoria Reservoir will be equipped to record snow pack. Also, wind speed and direction sensors will be installed at the Long Pond Intake and then Ebbegunbaeg Control Structure. Hydro already receives reservoir elevation data from the Hinds Lake Control Structure, and there is no requirement for snow pack data at this site. The project involves identifying the measurement sites and the means of returning the data to the Energy Control Centre.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	69.0	0.0	0.0	69.0
Labour	91.2	0.0	0.0	91.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	11.0	0.0	0.0	11.0
Other Direct Costs	29.0	0.0	0.0	29.0
O/H, AFUDC & Escln.	32.3	0.0	0.0	32.3
Contingency	20.0	0.0	0.0	20.0
TOTAL	**252.5**	**0.0**	**0.0**	**252.5**

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

Existing System:

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

The Bay d'Espoir system is a multi reservoir system comprised of the following six reservoirs:

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

The Hinds Lake and Cat Arm systems are single reservoir systems.

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 timeframe within the runoff season. Inflows can rise rapidly from a typical 20 m3/s to 200 m3/s within this

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

Existing System: (cont'd.)

timeframe. The plant only consumes 40 m3/s 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 two locations where Hydro currently receives meteorological data. These include temperature, precipitation and humidity from the Granite Lake Reservoir and temperature and precipitation data from a third party station near the Hinds Lake Reservoir.

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, 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.
Last year Hydro received approval from the Board or Commissioners of Public Utilities (the Board) to install meteorological stations at four locations in 2008. This project is the second year of a five year program. Stations will be installed at Burnt Dam Spillway and Victoria Reservoir on the Bay d'Espoir System and at Hinds Lake Control Structure on the Hinds Lake System in 2009.

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

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

Existing System: (cont'd.)

- Age of equipment
- Major work or upgrades
- Maintenance history
- Outage statistics
- Safety performance
- Environmental performance
- Vendor recommendations
- 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.

Availability of Replacement Parts:

As this will be a new installation, availability of replacement parts is not an issue.

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 $100,000 based upon a $70/bbl fuel price and 630 kWh/bbl 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

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

Justification: (cont'd.)

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.

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:

Work has already been approved by Board Order P.U. 30 (2007) to install four meteorological stations at a budgeted cost of $222,000 in 2008, the first year of a five year program. Most of the equipment has been ordered and work has begun.

Increases have been forecast in the 2009 estimate to reflect increased labour costs, the addition of wind speed and direction sensors at the Long Pond Intake and the Ebbegunbaeg Control Structure, and more up to date information on equipment costs.

Forecast Customer Growth:

Customer load growth does not affect this project.

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

Justification: (cont'd.)

Energy Efficiency Benefits:

There are no energy efficiency benefits that can be attributed to the installation of meteorological stations. However, though better data availability, better scheduling decisions are 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 two of its eight reservoirs. This makes predicting inflows into Hydro's reservoirs difficult and the results inadequate. 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 1 presents the anticipated project schedule.

Table 1. Project Schedule

Activity	Milestone
Project Initiation	February 2009
Complete Design Transmittal	March 2009
Develop Equipment Specification	April 2009
Issue Equipment Specification	April 2009
Procure Equipment and Materials	June 2009
Installation and Commissioning - Hinds Lake Control Structure	July 2009
Installation and Commissioning - Burnt Dam Reservoir	August 2009
Installation and Commissioning - Victoria Reservoir	September 2009
Project Completion and Close Out	November 2009

Future Plans:

Future installations will be proposed in future capital budget applications. Table 2 shows a list of installation and/or upgrades.

Table 2. Installation/Upgrades

Activity		Milestone
Installation at:	Long Pond Reservoir Hinds Lake Reservoir Meelpaeg Reservoir	2010
Upgrade at:	Victoria Spillway Granite Lake RR Pond	2011
Installation at:	Victoria Control Structure Burnt Pond Reservoir Granite lake Reservoir	2012

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to modify the existing manual valve station for the emergency venting of hydrogen from the turbine generator of Unit 1 at the Holyrood Thermal Generating Station (Holyrood). This will enable the valve station to be actuated remotely from the control room. Existing manual valves that are actuated during the Unit 1 emergency degassing procedure will be replaced with new valves equipped with electric actuators and manual overrides.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	32.8	0.0	0.0	32.8
Labour	133.4	0.0	0.0	133.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	4.0	0.0	0.0	4.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	26.7	0.0	0.0	26.7
Contingency	17.0	0.0	0.0	17.0
TOTAL	213.9	0.0	0.0	213.9

Existing System:

Holyrood is an essential part of the Island Interconnected System, with three units producing a total capacity of 490 MW. The generating station was constructed in two stages. In 1969, Stage I was completed bringing on line two generating units, Units 1 and 2, each capable of producing 150 MW. In 1979, Stage II was completed bringing on line an additional generating unit, Unit 3, capable of producing 150 MW. In 1988 and 1989, Units 1 and 2 were up-rated to 170 MW. Holyrood represents approximately one third of Newfoundland and Labrador Hydro's (Hydro) total Island Interconnected System generating capacity and each unit represents approximately 10 percent of that total.

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Existing System: (cont'd.)

Four main components of each generating unit are the boiler, turbine, generator, and transformer. During operation, the generator is cooled using a hydrogen cooling system. Hydrogen is piped to the generator casing where it circulates throughout the machine through a series of slots and coils in the rotor and stator. Hydrogen is also purged from the generator casing using carbon dioxide gas which utilizes the same piping system. A valve station (Figure 1) located directly below the generator is used to either add hydrogen gas to the generator casing during normal operation, dump hydrogen gas from the casing and purge with carbon dioxide gas, or quickly vent hydrogen gas from the generator casing in the event of an emergency situation.

In the event of an emergency that requires the dumping of hydrogen gas from the turbine generator, an operator has to leave the control room and go to the valve station to manually operate the valves. This is potentially dangerous for the operator. Hydrogen gas is flammable and a fire on the generator may cause an explosion.

Figure 1. Unit 1 Hydrogen Valve Station

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System:

Unit 1 was commissioned in 1970. The Unit's 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 1987, it was upgraded to a capacity of 170 MW. No modifications or upgrades have been made to the Unit 1 hydrogen emergency vent valves.

Anticipated Useful Life:

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

Maintenance History:

Plant records indicate that there has been no maintenance performed on the existing Unit 1 generator degassing manual valve station since the original construction in 1970.

Outage Statistics:

There have been no outages on Unit 1 caused by problems with the emergency venting of hydrogen from the generator casing.

Industry Experience:

Hydro has no knowledge of cases in industry where the lack of a rapid response for the emergency venting of hydrogen from a generator casing has resulted in either major equipment damage from a hydrogen fire or operator injury.

Maintenance or Support Arrangements:

Hydro uses a combination of external contractors and internal plant resources to perform annual maintenance on Unit 1.

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Existing System: (cont'd.)

Vendor Recommendations:

There are no vendor recommendations to modify the existing manual valve station for the emergency venting of hydrogen from Unit 1's generator so that it can be activated remotely from the control room. Completion of this project is based on safety considerations and a recommendation from FM Global to minimize the risk of damage to the turbine from a hydrogen fire (see page C-64 and C-65, Section 00-11-004 Provide remote hydrogen venting capability).

Availability of Replacement Parts:

Replacement parts for the manual vent valves are readily available. Also, replacement motorized valves are readily available and will be inventoried at the Holyrood warehouse.

Safety Performance:

There are no specific safety code violations associated with the operation of the existing manual valve station for the emergency venting of hydrogen from Unit 1's turbine generator. However, the current standard operating procedure can be a dangerous function for the operator in the event of a fire on the generator, given the location of the manual valve station in relation to the generator. To operate the system as it presently exists, an operator would have to come in close proximity of a fire and a potentially explosive work area.

Environmental Performance:

There are no environmental performance concerns or environmental code violations associated with the operation of the existing manual valve station.

Operating Regime:

Holyrood operates in a seasonal regime. The full plant capacity is needed to meet the winter electrical requirements on the Island Interconnected System. Operation of Unit 1's turbine generator emergency hydrogen vent valves is only required for rapid emergency response.

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Justification:

This project is required to eliminate safety issues with the existing manually operated vent valves. The existing design of Unit 1's turbine generator emergency hydrogen vent valves is a concern from a personal safety standpoint and also does not allow a rapid emergency response in the event of fire. It has been cited by FM Global as a hazard that must be eliminated. A means for remote hydrogen venting from the generator will ensure that the unit is secured as quickly as possible and will minimize equipment damage.

<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 the 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>

A cost benefit analysis for this project is not required. The project is a recommendation by FM Global to reduce the likelihood of damage in the event of a generator fire.

<u>Legislative or Regulatory Requirements:</u>

There are no current legislative or regulatory requirements to provide a means of remote emergency venting of hydrogen from the Unit 1 turbine generator.

<u>Historical Information:</u>

This is a new one year project and, as a result, there have been no similar capital expenditures. A similar modification will be budgeted for each of Units 2 and 3 following the proposed modification on Unit 1.

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Justification: (cont'd.)

Forecast Customer Growth:

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

Energy Efficiency Benefits:

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

Losses During Construction:

No losses during construction will be incurred. The project will be scheduled during the annual planned unit outage.

Status Quo:

Delays in completing this project, could result in major damage on the Unit 1 turbine generator in the event of a fire. Damages caused by a fire would result in 10 to 12 weeks of downtime on Unit 1. In addition, an unscheduled failure during the peak winter load demand could result in a loss of 170 MW of power, which represents approximately 10 percent of the Island Interconnected System generating capacity. The existing design of Unit 1's turbine generator emergency hydrogen vent valves is also a concern from a personal safety standpoint for the operator in the event of a generator fire.

Alternatives:

There are no viable alternatives available to the proposed project.

Conclusion:

In an emergency situation, operating the existing Unit 1 manual valve station, located directly below the generator, poses potential risk for the operator. In addition, emergency response time using the existing manually operated valves is greater than if the venting could be activated remotely from the control room, which in turn increases the likelihood of equipment damage. Failure to install the new vent valves may result in unscheduled downtime on the turbine generator and poses the risk of being unable to meet customer demands during the peak winter load requirement. This project is

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Conclusion: (cont'd.)

required to improve the existing emergency response procedure for a fire at Unit 1. It is recommended by FM Global to minimize generator damage in the event of a fire.

Project Schedule:

Table 1 presents the anticipated project schedule.

Table 1. Project Schedule

Activity	Milestone
Project Kick-off Meeting	January 2009
Complete Design Transmittal	February 2009
Detailed Engineering Design	April 2009
Develop Installation Specification	April 2009
Issue Tender and Award Job	May 2009
Procurement of Materials	May 2009
Contract Execution	August 2009
Commissioning	September 2009
Project Final Documentation and Closeout	December 2009

Future Plans:

Future replacements for Units 2 and 3 will be proposed in future capital budget applications.

Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Excerpt from "FM Global Risk Report"

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

04-10-001 continued

Technical Detail	The new pre-action valves on the operating floor of the turbine-generator should be locked in the wide open position with non breakable locks and chains. A full recorded program is now being conducted. Without the recommended frequency of monthly physical checks of the outside valves, the following partial solutions should be considered to minimize the possibility of a shut valve: 1. Be vigilant about following the FM Global Red Tag Permit System procedures in the event of valve closures. 2. Be aware that snow removal operations should be considered a priority around these curb box valves in the event that operation of these valves is necessary in an emergency. This was discussed and was reported to sometimes be difficult as snow removal is also a priority for safety purposes as well. However, these partial solutions will be taken into account.
Status	Last year, efforts were made to physically verify outside valves monthly. However, this was time consuming. The frequency of these checks will only be considered every three months at this time. Snow should be cleared around valves always.

00-11-004

Provide remote hydrogen venting capability.

A means for remote hydrogen venting and purge from the generator (preferably from the control room) should be provided to ensure that the unit can be secured as quickly as possible.

The Hazard	The panel containing the hydrogen vent is located directly below the unit and would be inaccessible in the event of a fire in the area. The shutdown for the DC lube oil pumps is located on a mid-mezzanine below the operating floor but would not be considered accessible in the event of a serious fire. Remotely venting and purging hydrogen from the generator could minimize the damage from a hydrogen fire at the bearing in the event of a seal failure. Management indicated that this work will be done. Financial considerations have delayed implementation, but Unit Nos. 2 and 3 remote hydrogen venting capabilities should be completed by the end of 2007.
Technical Detail	Several discussions were previously held on site about remote venting and purging of hydrogen in the event of a fire. It was reported that it is possible to vent the hydrogen remotely, however, full purging with CO2 could take up to 20 hours, which far exceeds the time where it would be beneficial to reduce the severity of a fire. It was concluded that the priority is to provide the capability of remote venting of hydrogen via a motorized valve operated from within or near the control room. A fire-rated cable would be required for this motorized valve and operation should be on battery back-up in the event that electricity is shut off to

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Project Title: Replace Unit 1 Hydrogen Emergency Vent Valves **(cont'd.)**

Excerpt from "FM Global Risk Report"

00-11-004 continued

Technical Detail	isolate electrical equipment in the fire area. The insured stated that this will be considered.
Status	This will be done by motorizing the valve and fire rating the cable to this valve. The valve will be capable of being operated from the control room. This should be completed by the end of the year 2008.

07-10-003

Conduct flushing investigations of all dry pipe sprinkler systems & keep records of amount of scale.

Dry pipe systems should be thoroughly investigated for obstructions from corrosion after they have been in service for 10 years, 20 years and every 5 years thereafter. The dry pipe systems servicing the Pipeshop, Warehouses, Training Centre, etc. have been in service since 1970.

In addition, all dry pipe trip test records should be available for review. The trip tests are reportedly conducted annually but records were not available. Ensure that water reaches the most remote point of the sprinkler system (i.e. Inspector's Test Connections) within 60 seconds.

The Hazard	For effective control and extinguishment of fire, automatic sprinklers must receive an unobstructed flow of water. Although the overall performance record of automatic sprinklers has been very satisfactory, there have been numerous instances of impaired efficiency because sprinkler piping or sprinklers were plugged with pipe scale, mud, stones, or other foreign material. If a fire occurs and the sprinklers are plugged, the fire may not be extinguished or controlled. In such a situation, the fire may grow to uncontrollable size resulting in greater fire damage, causing excessive sprinkler operations and threatening the structural integrity of the building. In a worst case, the building may be completely destroyed. A flushing will ensure piping is free of scale, silt, etc.
Technical Detail	It is reported that annual dry pipe trip tests are conducted by Tyco with the last tests carried out on September 25, 2007. Records were not available and it is unknown if dry pipe trip tests were done. Mr. Cochrane will request all information from Tyco and inquire about the flushing investigations.
Status	Mr. Cochrane stated that records will be obtained from the contractor who conducts the annual tests. A quote for a flushing investigations will be obtained if this has not already been completed.

Project Title: Replace Line L36

Location: Wabush

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

This project proposes that a 4 kilometre line be constructed from the Churchill Falls (Labrador) Corporation (CF(L)Co.) substation to the Wabush Substation. The proposed new line will follow the Labrador City to Wabush road right-of-way from the CF(L)Co. substation to the Wabush Substation which will allow it to be more accessible for line crews during regular maintenance, upgrading, and line outages. The new line will be constructed to meet Hydro's current standards for supplying a voltage of 46 kV. The project will consist of the installation of approximately 53 poles, 12,000 meters of 4/0 AASC conductor, 168 46 kV line post clamp top insulators, and any other hardware associated with new line construction.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	92.5	0.0	0.0	92.5
Labour	114.0	0.0	0.0	114.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	135.0	0.0	0.0	135.0
Other Direct Costs	58.5	0.0	0.0	58.5
O/H, AFUDC & Escln.	57.9	0.0	0.0	57.9
Contingency	40.1	0.0	0.0	40.1
TOTAL	498.0	0.0	0.0	498.0

Existing System:

The distribution system for the community of Wabush consists of Line 36 (L36), a single source 46 kV line that supplies power from the CF(L)Co substation to the Wabush substation. The Wabush substation supplies the community of Wabush via six distribution feeders; four 12.5 kV feeders (L3, L9, L11, and L12) and two 4.16 kV feeders (L7 and L8). Sections of the existing line are inaccessible to Hydro maintenance vehicles.

Project Title: Replace Line L36 **(cont'd.)**

Existing System: (cont'd.)

Examples of substandard equipment on the existing line are shown in Figures 1, 2 and 3.

Figure 1. Substandard 46 kV E Type Structure

Figure 2. Substandard Guying of E Type Structure

Figure 3. Damaged Pole Requiring Replacement

Project Title: Replace Line L36 **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System:

The Wabush L36 sole source feeder was originally constructed by the mining company and was taken over in 1985 by Hydro.

Major Work/or Upgrades:

There has been no major work on Wabush L36 since 1985.

Anticipated Useful Life:

The estimated service life of a distribution/sub-transmission line, for depreciation purposes, is 30 years.

Maintenance History:

Maintenance records for the Wabush L36 feeder are grouped with general maintenance records for the Wabush distribution system and are not readily available.

Outage Statistics:

Hydro tracks all distribution 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.

Project Title: Replace Line L36 **(cont'd.)**

Existing System: (cont'd.)

Outage Statistics: (cont'd.)

Because L36 is a sub-transmission line outages are not tracked separately but are included in the overall statistics for Wabush. Table 1 shows the 2003 - 2007 average SAIDI and SAIFI Indices for the Wabush System in comparison to Hydro Corporate Values and the latest CEA five year average (2002 - 2006).

Table 1. SAIDI and SAIFI indices for the Wabush system.

	All Causes	
	SAIFI	**SAIDI**
Wabush System	7.39	11.82
Hydro Corporate	6.24	9.72
CEA (2002-2006)	2.35	6.43

Over the last five years, the Wabush System has been less reliable than both Hydro Corporate and CEA Averages, in terms of both frequency and duration of outages.

Industry Experience:

Industry experience is not a consideration for the project.

Maintenance or Support Arrangements:

A visual inspection of the Wabush L36 feeder is scheduled every two years, however because this is the sole source feeder for Wabush, a visual inspection is also performed after every major storm. This inspection is completed by regulated operations personnel and any corrective maintenance required is reported, scheduled and performed.

Vendor Recommendations:

There are no vendor recommendations for this project.

Project Title: Replace Line L36 **(cont'd.)**

Existing System: (cont'd.)

Availability of Replacement Parts:

Availability of replacement parts is not a consideration for this project.

Safety Performance:

Safety performance is not an issue for this project.

Environmental Performance:

Environmental performance is not an issue for this project.

Operating Regime:

Wabush L36 feeder is in continuous operation providing power to the town of Wabush.

Justification:

A new sub-transmission line is required to provide a reliable power source for the customers in Wabush. The existing line was assessed in February of 2008 and it was determined that various upgrades were required, including replacing the conductor, re-guying of substandard structures, and replacing various poles.

Outages are required to upgrade the existing L36 sole source feeder, which would result in a complete shut down of all power to Wabush. Alternate generation from mobile diesel units, would be the only alternative for supplying the customers with power during the upgrading. Alternate generation is a very expensive option due to the current cost of fuel, rental of equipment, and mobilization. Therefore, a second estimate, as indicated in the alternatives section on page C-72 for a new line to be constructed was completed and was determined to be the more cost effective alternative.

Net Present Value:

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

Project Title: Replace Line L36 **(cont'd.)**

Justification: (cont'd.)

Levelized Cost of Energy:

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

Cost Benefit Analysis:

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

Forecast Customer Growth:

Customer load growth does not affect this project.

Energy Efficient Benefits:

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

Legislative or Regulatory Requirements:

There are no applicable legislative or regulatory requirements.

Historical Information:

No historical information exists for the new line construction of 46 kV sub-transmission feeders.

Losses During Construction:

There are no anticipated energy losses during construction.

Status Quo:

The status quo is not an acceptable alternative. The existing system currently needs to be upgraded, and failure to do so could result in continuing outages of varying durations for the community of Wabush.

Project Title: Replace Line L36 **(cont'd.)**

Justification: (cont'd.)

Alternatives:

Various alternatives were reviewed to upgrade of the existing Wabush L36 feeder. An alternate generation source, mobile diesel units, would be needed to supply the town with power during a lengthy upgrade. Construction of a new line is the most cost effective solution. As Table 1 indicates, the required upgrades with alternate generation is double the cost of constructing a new line. The option of new line construction also allows the new feeder to be constructed closer to the main road. The construction in the road right-of-ways will provide for more efficient maintenance to the line, and, in the event of a power outage, reduce outage durations.

Table 2 shows alternative costs. Included in Other Direct Costs for upgrading the line is the rental of mobile diesel units, and Material Supply includes fuel costs.

Table 2. Wabush L36 Alternatives

Activity	New 46 kV Line Cost ($000)	Upgrade with Alternate Generation Cost ($000)
Material Supply	92.5	389.0
Labour	114.0	55.0
Contract Work	135.0	69.0
Other Direct Costs	58.5	332.5
O/H, AFUDC and Escalation	57.9	116.8
Contingency	40.1	84.6
Total	**498.0**	**1046.9**

Conclusion:

L36 is a sub-transmission line which supplies power to the entire community of Wabush. This project is required to ensure a reliable energy supply is available for Hydro's customers in Wabush.

Project Title: Replace Line L36 **(cont'd.)**

Conclusion: (cont'd.)

The alternative to constructing a new line is to upgrade the existing line. The cost of upgrading the existing line is the more expensive of the two options. A new 46 kV sub-transmission feeder built to current Hydro standards will provide the most cost effective and reliable solution.

Project Schedule:

Table 3 presents the anticipated Project Schedule.

Table 3. Project Milestones

Activity	Milestone
Initiation	January 2009
Design Complete	March 2009
Equipment Ordered	May 2009
Installation Commences	June/July 2009
Installation Complete	August 2009
Project Closeout	September 2009

Future Plans:

None.

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 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.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	0.0	0.0	0.0	0.0
Labour	43.4	0.0	0.0	43.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	335.8	0.0	0.0	335.8
Other Direct Costs	23.4	0.0	0.0	23.4
O/H, AFUDC & Escln.	55.0	0.0	0.0	55.0
Contingency	40.3	0.0	0.0	40.3
TOTAL	**497.9**	**0.0**	**0.0**	**497.9**

Existing System:

Hydro's Transmission and Rural Operations Central Region is responsible for the maintenance of 46 transmission lines which have a combined length of 2,817 kilometres or approximately 75 percent of the total length of the Island Transmission lines. Transmission lines are constructed of wood, steel or aluminum and range in age from three to 40 years. Approximately 1,610 kilometres of the transmission lines in the Central Region are 230 kV lines used to transmit electricity from the Bay d'Espoir Hydroelectric Generating Station through the Island Interconnected System. There are also 915 kilometres of 138 kV and 292 kilometres of 69 kV transmission lines in the Central Region.

In order to provide a high level of 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.

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

Existing System: (cont'd.)

Secondary highways in this province are constructed to a standard which allows very narrow shoulders and steep embankments. Crews must also contend with increasing levels of both traffic and speed on secondary highways. Safety is further compromised in adverse weather conditions with reduced visibility. Flag persons and signage are often required to divert traffic or shut down traffic lanes altogether while off-loading equipment operations take place in a portion of one of the traffic lanes. Crews also have difficulty negotiating steep embankments while simultaneously attempting to stay clear of adjacent highway traffic and avoid damaging existing highway shouldering.

Current off-loading procedures are often an inefficient use of time, equipment and personnel. Once crews are finished their off-loading operations along secondary highways, they often have to park their work vehicles at distances up to 3 kilometres away to secure safe and legal parking. Crew members must then be shuttled back to the work area, thereby causing delays in the execution of transmission line work. The steep embankment slopes in some areas also cause delays to crews as they are often unable to negotiate their way down to trail level. Crews are forced to use alternate approved trails which are not located adjacent to the work area. Alternate approved trails are used to access the transmission lines and then the transmission line equipment is slowly traveled back along the transmission line to access the work area.

This project is required to build new off-loading areas at various locations along the Burin Peninsula Highway in 2009. Specific locations of proposed off-loading areas are shown on the maps on pages C-84 to C-86. The off-loading areas will allow Hydro work crews to safely park away from existing traffic lanes and will facilitate transmission line equipment access to approved trails. The construction of new off-loading areas will consist of grubbing, excavating of unsuitable material, and supplying, placing and compacting of granular and Class A backfill. Supply and installation of culverts and signage will also be required based on site-specific conditions. A sketch is provided on Page C-83.

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

Existing System: (cont'd.)

Major Work or Upgrades:

In Order No. P.U. 30 (2007) the Board directed Hydro to report on the progress of the 2008 planned sites in terms of the approval and design process. Hydro has made site visits to both the Buchans and Burgeo highways with officials from the Department of Transportation and Works (DOTW). Draft specifications for off-loading ramps (see page C-83) for 2008 off-loading work on both highways have been prepared. The DOTW has approved Hydro's design of the transmission line equipment off-loading areas. However, individual off-loading areas are evaluated on a site by site basis and will be considered for secondary highways only. Individual site approval from the DOTW is based on the available sight distance from both directions when approaching the off-loading area. Sight distance is the distance from the point where a vehicle is first able to spot the off-loading area to the off-loading area itself. Only sites with a sight distance of 250 metres in both directions will be approved. Based on these criteria, 14 possible sites on the Buchans highway and 13 possible sites on the Burgeo highway have been approved by DOTW for construction in 2008. Hydro is waiting for a response from DOTW regarding sight distances for two more possible sites along the Burgeo highway. Not all sites approved by the Department of Transportation and Works will be constructed.

In response to the Board's query about whether any proposal changes or additional safety measures are required, Hydro has determined that no changes or additional safety measures are required to Hydro's original proposal. The DOTW sight distance standard applied to the off loading ramps is the same that is applied to any point of access to a highway. This should provide safe highway access for Hydro and for any members of the public who use the ramps for an unauthorized purpose.

Five Year Strategy:

Hydro proposes to construct approximately 100 off-loading areas as a multi-year project. Construction is planned for 20 sites per year over a five year period starting in 2008. Sites will be selected on a priority basis, with the highest hazard areas addressed first. Scheduling will be optimized so that mobilization and construction are at least cost.

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

Existing System: (cont'd.)

Five Year Strategy: (cont'd.)

Table 1 displays the number and locations of ramps to be constructed in the five year plan. Map locations are provided on pages C-84 to C-86 for the potential locations for 2009.

Table 1. Locations and Proposed Schedule for Off-Loading Areas

Highway	**2008**	**2009**	**2010**	**2011**	**2012**
Burin Peninsula		20		20	9
Bay d'Espoir					1
Buchans	8				
Springdale					1
Hampden					5
Jackson's Arm			15		
Howley					4
Burgeo	12		5		
Total Sites	20	20	20	20	20

Safety Performance:

A roll over accident on Friday, October 12, 2007 on the Trans Canada Highway (TCH) near the Hawke Hill access road is indicative of problems faced by Hydro work crews. A Go-Track unit was being loaded onto a low bed trailer by backing the unit onto the trailer deck. While the operator attempted to straighten the Go-Track with the trailer, the rear of the Go-Track starting sliding towards the ditch. The right track slid off the trailer to the road shoulder, which gave way slightly and with its own weight, the machine toppled onto its right side resting on the outriggers and boom in the ditch by the roadside. The operator remained in the machine but there were no injuries. The deck was clear and dry at the time of the incident. Direct and indirect costs to Hydro arising from this incident totaled $56,000. Figures 1 and 2 show pictures of this incident.

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

Existing System: (cont'd.)

<u>Safety Performance</u>: (cont'd.)

Figure 1. Go-Track unit resting on damaged outriggers and boom.

Figure 2. Low bed trailer parked close to the edge of the ditch to maintain clearance to the driving lane as Go-Track unit overhangs trailer deck on both sides when loaded. Note the tilt of the trailer and the shape of the tracks on the Go-Track unit.

This incident raises several issues. The shape of the D-Dent track used on the Go-Track leaves very little metal in contact with the bed of the trailer and in fact acts much like a ski when the vehicle is moving in the transverse direction. The width of the Go-Track is 3.05 metres. This dictates that the trailer must be parked as close to the edge of the shoulder's embankment as possible to avoid highway traffic. This arrangement causes the trailer to be tilted significantly in the direction of the ditch. This creates a significant risk of injury to workers and bystanders, as well as the possibility of environmental contamination. Safe loading operations on narrow shoulders require traffic to be stopped in adjacent traffic lanes including those on divided highways.

Shoulders on the Trans Canada Highway (TCH) are designed to accommodate the full width of a typical parked vehicle. Despite the higher standards to which the TCH is built, shoulder width is still inadequate for the safe and efficient loading and unloading of transmission line equipment which is

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

Existing System: (cont'd.)

Safety Performance: **(cont'd.)**

much wider than the typical vehicle traveling the TCH. The DOTW has to date rejected Hydro's requests to build off loading ramps along the TCH.

As this is a new construction of off-loading ramps, the following items related to Existing System do not apply to this project:

- Age of Equipment
- Anticipated Useful life
- Maintenance History
- Outage Statistics
- Industry Experience
- Maintenance or Support Arrangements
- Vendor Recommendations
- Availability of Replacements Parts
- Environmental Performance
- Operating Regime

Justification:

This project is justified on the requirement to provide safety to Hydro work crews and the motoring public. This project will also provide efficient access to transmission lines by transmission line equipment crews during responses to emergencies and for regular maintenance. System reliability will also be improved in emergency situations.

Workplace safety and public safety are the predominant reasons for the construction of off-loading ramps. Hydro is committed to ensuring that our customers, employees, and the public are protected against the hazards of our facilities and operations. Transmission line equipment off-loading areas will facilitate the safe loading and unloading of equipment used to access government approved

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

Justification: (cont'd.)

trails along secondary highways. The current procedure for the off-loading of transmission line equipment constitutes a hazardous operation with Hydro work crews working directly in active traffic lanes of highways with increasing levels of both traffic and speed. Hydro work crews have difficulty negotiating steep highway embankments while simultaneously attempting to stay out of adjacent highway traffic lanes. Safety is particularly compromised during adverse weather conditions such as fog, snow, rain, or sleet, which reduces visibility in high traffic areas. Construction of the off-loading areas will increase the level of safety associated with off-loading operations as the potential of vehicular incidents will be reduced, resulting in safer working conditions for our employees and less danger for the motoring public.

Current off-loading operations are time consuming processes which affect the efficiency of Hydro work crews during roadside off-loading and loading operations. When Hydro work crews access transmission lines their vehicles are parked at safe and legal parking areas which may not be close to the delivery points. During actual off-loading operations, partial or complete closure of a highway lane may be required which involves the use of signage, flag persons, or other precautionary measures, depending on the site-specific conditions. Eliminating the requirement for closed lanes on public roads, especially on highways, will reduce the danger created for the public. Furthermore, in some cases approved trails are currently inaccessible due to steep embankment slopes and delays are encountered when alternate approved trails must be used to get to the transmission lines. The new ramps will eliminate the need for lane closures and will facilitate easy access to approved trails for transmission line equipment, resulting in increased functionality and improved efficiency to Hydro work crews.

In addition to regular planned operations by maintenance crews, the off-loading ramps will be used during unplanned outage situations. The installation of these sites will permit faster mobilization and shorter response times during forced outage situations, thus reducing customer outage time.

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

Justification: (cont'd.)

Net Present Value:

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

Levelized Cost of Energy:

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

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 pertaining to the construction of transmission line equipment off-loading areas.

Historical Information:

2009 will be the second year of a five year recurring project. The approved budget for 2008 is $301,800. At the time of the writing of this report, preliminary work has been initiated on the Buchans and Burgeo highways for 2008.

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 construction of transmission line equipment off-loading areas.

Losses During Construction:

This project will have no effect on normal operations of generating facilities and will not cause any interruptions or system outages. Therefore, there will be no losses during construction.

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

Justification: (cont'd.)

Status Quo:

If transmission line equipment off-loading areas are not constructed, the safety of both Hydro work crews and the traveling public will continue to be at risk during off-loading and loading operations in which heavy equipment is moved in active highway traffic lanes. Furthermore, access to transmission lines by Hydro work crews will continue to be impeded, decreasing productivity in the performance of maintenance and emergency repairs.

Alternatives:

There are no viable alternatives available to the construction of transmission line equipment off-loading areas.

Conclusion:

Transmission line equipment off-loading areas are needed to improve the safety of both Hydro work crews and the public. This project will allow Hydro's work crews to perform transmission line work more efficiently by providing a dedicated area for off-loading operations and parking. System reliability will also be improved in emergency situations as response times for mobilization will be reduced. This project demonstrates Hydro's continued commitment to employee and public safety.

Project Schedule:

Table 2 provides the anticipated project schedule.

Table 2. Project Schedule

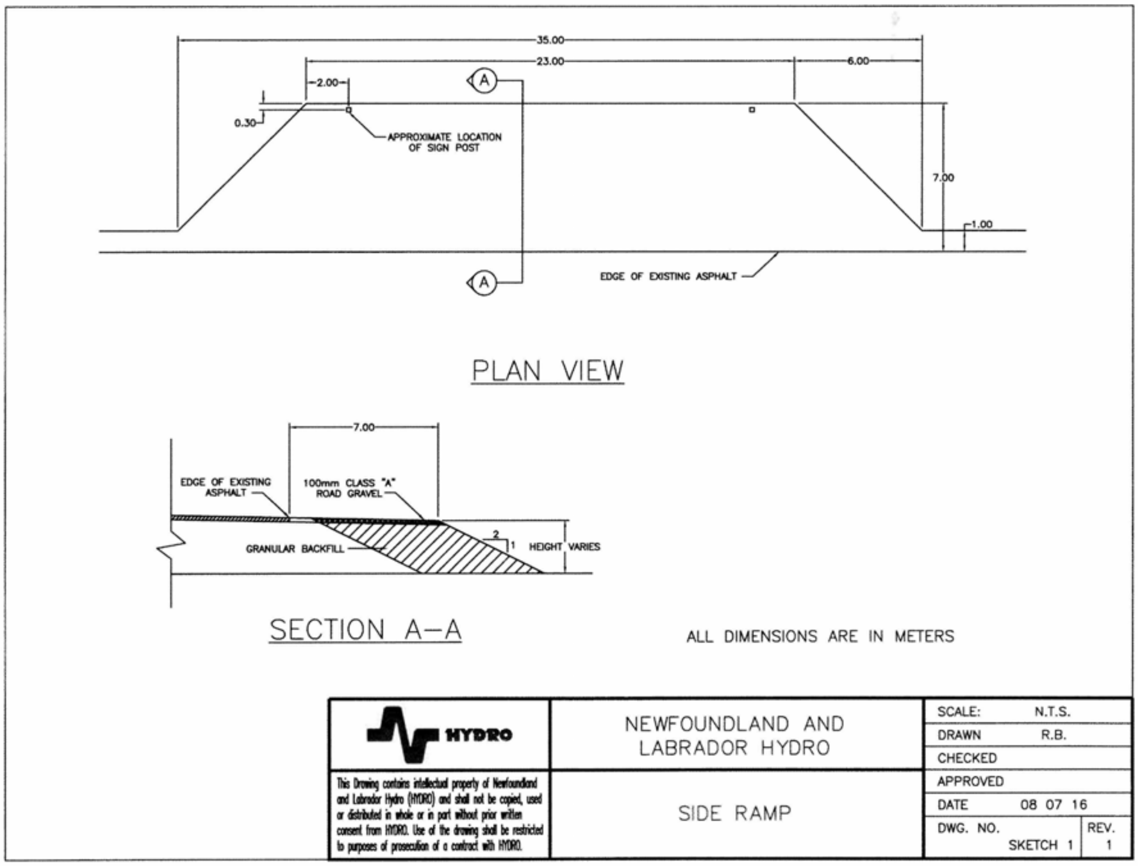
Activity	**Milestone**
Project Initiation	February 2009
Design and Planning	May 2009
Tendering	July 2009
Construct Transmission Line Equipment Off Loading Ramps	September 2009
Close Out and Documentation	November 2009

Future Plans:

Future construction projects will be proposed in future capital budget applications.

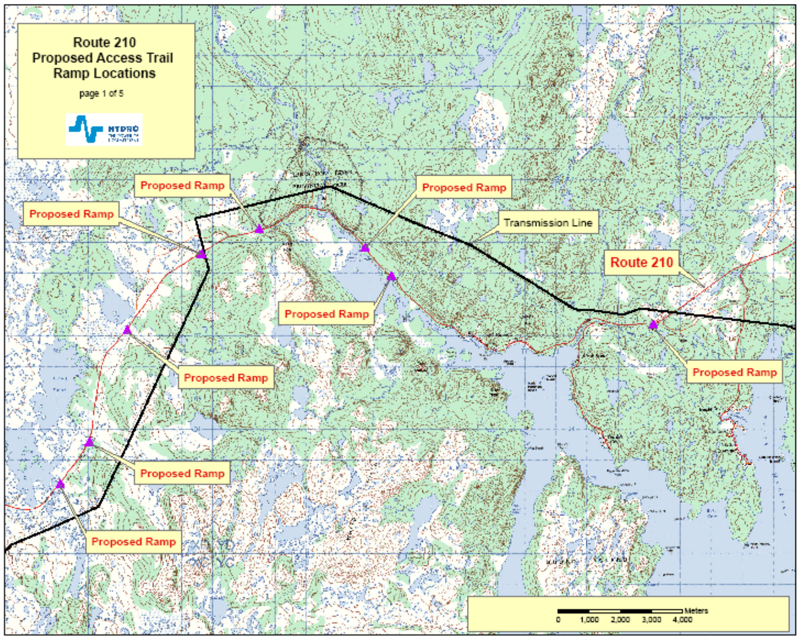
Project Title: Construct Transmission Line Equipment Off-Loading Areas **(cont'd.)**

Off-Loading Ramps Specifications

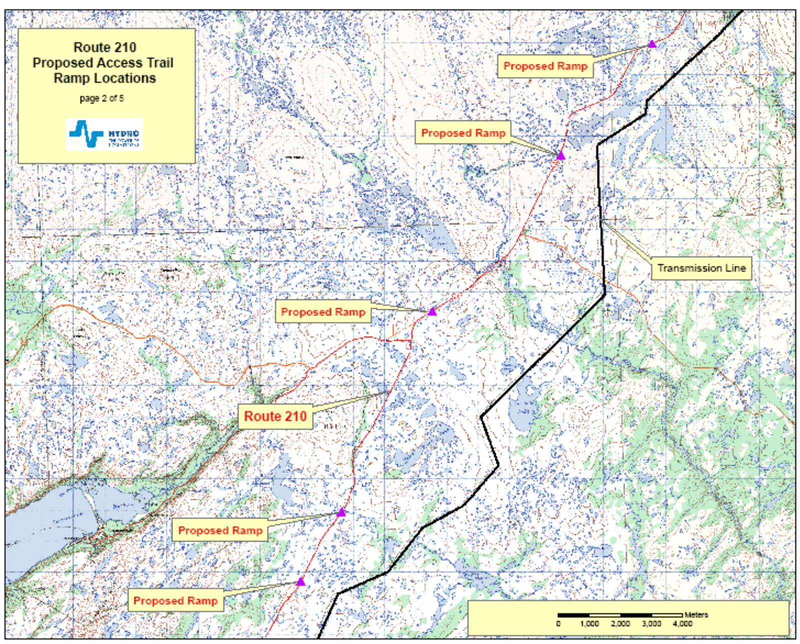


Project Title: Construct Transmission Line Equipment Off-Loading Areas **(cont'd.)**

Maps Showing Specific Locations of Proposed Off-Loading Areas



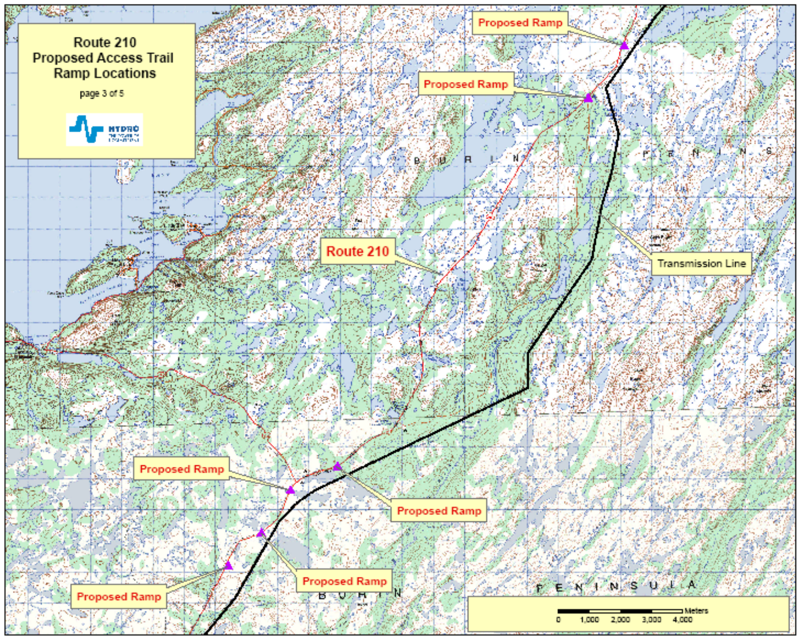
Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway



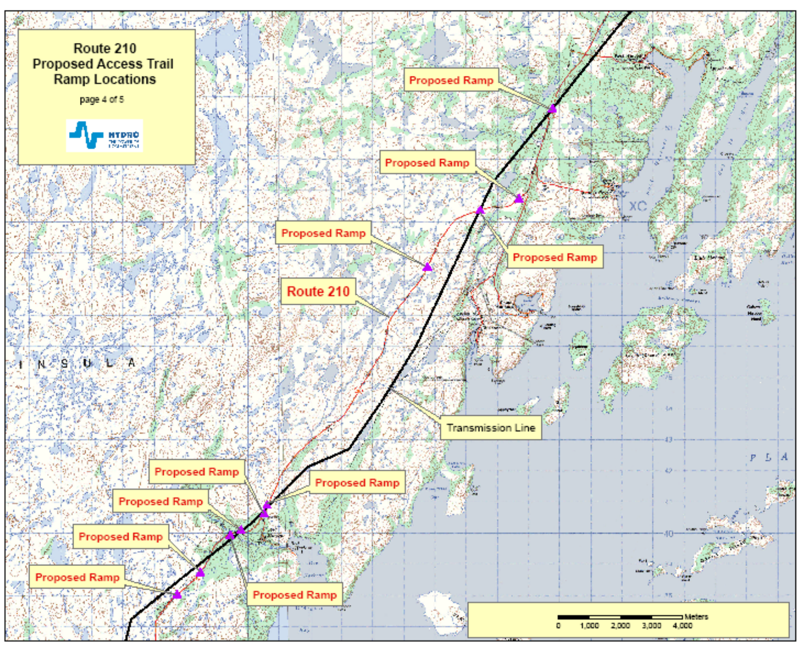
Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway

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

Maps Showing Specific Locations of Proposed Off-Loading Areas



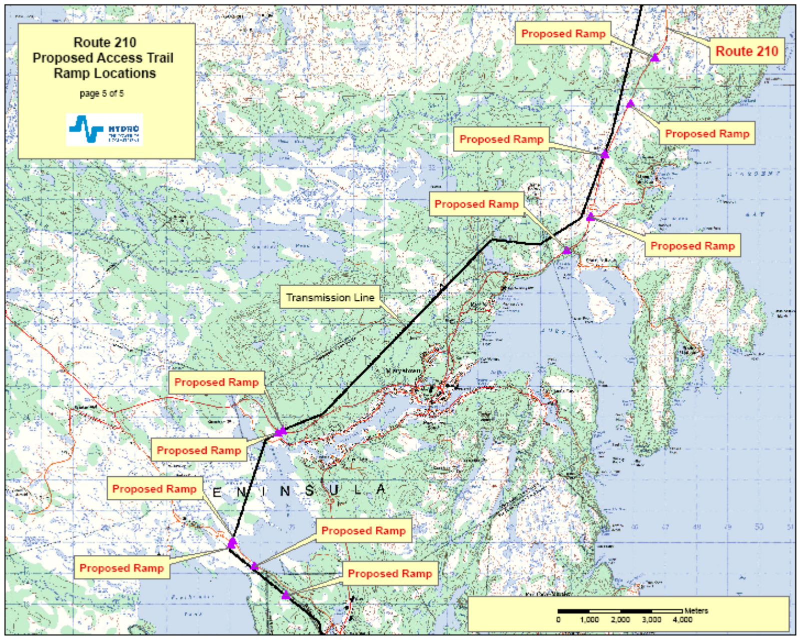
Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway



Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway

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

Maps Showing Specific Locations of Proposed Off-Loading Areas



Transmission Lines TL 212, TL 219 - along Burin Peninsula Highway

Project Title: Install Automatic Meter Reading

Location: Change Islands and Fogo Island

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Justifiable

Project Description:

This project is required to implement Automatic Meter Reading (AMR) in Hydro's customer service area of Farewell Head (Change Islands and Fogo Island). The AMR system utilizes a one-way power line carrier communications system that is designed for rural area applications. The term power line carrier refers to the method of transmitting data through a transmission or distribution line. The work includes (i) replacement of all customer service meters with AMR equipped meters; (ii) installation of a data collector in the Farewell Head substation to receive the meter readings from Hydro's customers via the distribution line; (iii) telephone communications to a central server located at Hydro's head office in St. John's; and (iv) configuring the AMR central server at head office to include customers in Farewell Head.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	250.0	0.0	0.0	250.0
Labour	129.1	0.0	0.0	129.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.1	0.0	0.0	14.1
O/H, AFUDC & Escln.	58.0	0.0	0.0	58.0
Contingency	39.3	0.0	0.0	39.3
TOTAL	**490.5**	**0.0**	**0.0**	**490.5**

Existing System:

Hydro provides electrical service to 31 areas connected to the Island Interconnected System and to 20 isolated areas served by diesel generation. An area is a group of communities served by a common distribution line(s). In 2003-2004 Hydro initiated a pilot program for automatic customer meter reading in St. Brendan’s. This pilot program proved successful and Hydro extended the program to other service areas.

This project is required to implement AMR in the Farewell Head service area. This project is a continuation in the deployment of AMR initially approved in the 2007 and 2008 capital budget proposals for eight service areas.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Existing System: (cont'd.)

The current meter reading system used in the Farewell Head service area is the Radix system. This system involves the following process for reading meters:

- The meter reading information is transferred from the Customer Information/Billing System at Hydro's head office to the Radix system and then loaded into a handheld device in the local area.

- A meter reader visits each customer's meter and manually enters the meter reading into the handheld device.

- After the meter readings have been taken, the handheld device is connected to a local computer and the readings are transferred to the Radix system.

- The meter readings are transferred from the Radix system to the Customer Information/Billing System at Hydro's head office.

For 2009, Hydro is proposing to deploy AMR in the Farewell Head service area. The AMR system being deployed is Cellnet+Hunt's TS1 System. This is a one-way power line carrier communications based system where data is transferred from a customer's meter to a data collector located in a terminal station; communications to a customer's meter is not supported. As the existing distribution lines are used to carry the meter data signals, implementation of this AMR system only requires installation of an AMR equipped meter at each customer's site and a data collector in the service area terminal station.

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

The existing Radix system was implemented for all of Hydro's service areas in 1999 and includes approximately 30 hand held devices.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Existing System: (cont'd.)

Major Work/or Upgrades:

Table 1 shows the upgrade that have occurred since installation:

Table 1. Major Work Upgrades

Year	Major Work/Upgrade	Comments
2005	Replace hand held devices	Devices worn out from use. Cost/Unit=$2,800.

Anticipated Useful Life:

The handheld units for the Radix system have a service life of five years. The data collectors, which are located in the terminal stations, have an estimated service life of 15 years.

Maintenance History:

The five year maintenance history for the entire Radix system is shown in Table 2.

Table 2. Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	12.5	7.4	19.9
2006	0.0	0.3	0.3
2005	0.0	67.1	67.1
2004	0.0	4.8	4.8
2003	0.0	1.8	1.8

To date there has been $12,500 in preventative maintenance costs and $4,800 in corrective maintenance costs in 2008. There is no maintenance history for the AMR system as the first service areas will only become operational in 2008.

Outage Statistics:

No outages are attributable to meter reading.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Existing System: (cont'd.)

Industry Experience:

The TS1 System, Cellnet+Hunt's power-line carrier, was introduced in 1995. There are currently over 400 utilities using TS1 Systems and over four million AMR equipped meters deployed. Most of these installations are in North America, but are also in Sweden, Finland and Costa Rica.

Maintenance or Support Arrangements:

Hydro has a maintenance agreement in place with Radix Micro Devices for the Radix System. The cost is approximately $12,000 per year and it covers software support and maintenance and repair services on equipment.

Hydro has a maintenance agreement in place with Cellnet+Hunt for the AMR System. The cost of the support agreement in 2009 will be approximately $9,000. The maintenance agreement includes software and hardware support, software updates from Cellnet+Hunt, and full replacement of any defective modules integrated into the meters to provide AMR functionality. Under the Support Agreement, any defective end points that are under warranty (18 months from date of purchase) are replaced free of charge.

Vendor Recommendations:

Cellnet+Hunt's estimated life expectancy for the data collectors used in the AMR system, which are located in terminal stations to capture meter readings, is 15 years and this is used as the time period for the cost-benefit analysis, which is shown on page C-92.

For the Radix system, Radix's expectations are that the handheld models average about 18 months or 500 charges on a set of batteries before requiring return to the factory for replacement. The devices are supported for a period of seven to nine years.

Availability of Replacement Parts:

Replacement handheld devices are purchased from Radix Micro Devices when the units are no longer operational.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Existing System: (cont'd.)

Availability of Replacement Parts: (cont'd.)

For the AMR System, Cellnet+Hunt states that the modules integrated into meters to provide AMR functionality are returned for full replacement under the support agreement. If in the future, a product is discontinued by Cellnet+Hunt, product support/replacement is offered for a minimum of 18 months following the discontinuation.

Safety Performance:

There are no safety non-compliance issues related to meter reading devices.

Environmental Performance:

There is no environmental non-compliance issues associated with this project. Hydro is investigating whether meters that are taken out of service can be recycled.

Operating Regime:

Meters are in continuous operation.

Justification:

This project is justified on the results from a cost-benefit analysis which shows that the new AMR system has economic benefit over the existing system. With respect to improvements in customer service:

- Meter reading errors will be eliminated;
- Estimated readings will be eliminated;
- More detailed energy usage information will be available to help customers track consumption patterns; and,
- More flexible billing options will be available to customers such as consolidated bills and customer selected billing dates. This functionality is not being implemented as part of this project, however, this capability will be available for future use.

Replacement handheld devices are purchased from Radix Micro Devices when the units are no longer operational. In addition to the above, implementation of AMR will enhance safety by reducing employee risk exposure and will provide a benefit to the environment as a result of less vehicle usage.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Justification: (cont'd.)

Net Present Value:

See below for discussion of the cost-benefit analysis.

Levelized Cost of Energy:

This project will have no effect on the levelized cost of electricity as it does not involve comparison of costs of new generation sources.

Cost Benefit Analysis:

The cumulative present worth analysis was performed considering two alternatives: AMR or the current system. A period of 15 years was chosen for the analysis. The results show a positive net present value after 10 years (2019) and total savings of $128,190 by 2023 as shown in Tables 3 and 4. The savings result primarily from the reduction in labour costs associated with manual meter reading.

Table 3. Cost Benefit Analysis

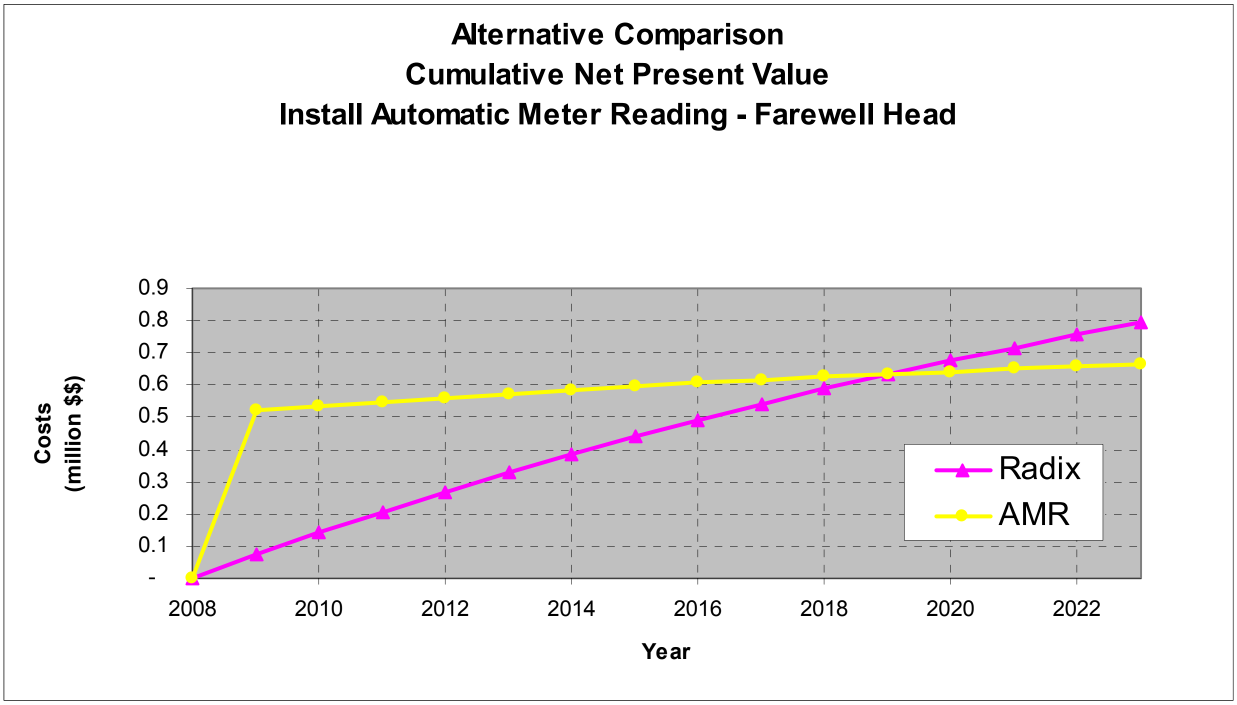
Install Automatic Meter Reading - Farewell Head		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year*** **2023**		
Alternatives	**Cumulative Net Present Value (CPW)** $	**CPW Difference between Alternative and the Least Cost Alternative** $
AMR 2009	663,990	0
Current Radix System	792,180	128,190

Project Title: Install Automatic Meter Reading **(cont'd.)**

Justification: (cont'd.)

Cost Benefit Analysis: (cont'd.)

Table 4. Alternative Comparison



Legislative or Regulatory Requirements:

There are no legislative or regulatory requirements to initiate this project.

Historical Information:

This is a recurring project which started in 2007. Historical information is shown in Table 5.

Table 5. Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2008	566.6	92.7	Not completed.
2007[1]	1,135.2	604.1	Not completed.

[1] Although the 2007 project was approved by Board Order No. P.U. 35 (2006) for $696,000 as a one year project, the project was reforecast to occur over two years for $1,135,000.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Justification: (cont'd.)

Forecast Customer Growth:

Customer load growth does not affect this project.

Energy Efficiency Benefits:

There are no direct energy efficiency benefits that can be attributed to the implementation of AMR. However, the capability to provide more detailed energy usage statistics enables customers to track consumption patterns. This helps promote energy efficiency.

Losses During Construction:

There is no construction involved in the implementation of the AMR system.

Status Quo:

As described in the cost-benefit analysis, the economic benefit from the new AMR system results primarily from labour savings. If the Radix system is kept in-service, manual readings will still be required and, therefore, operating costs will be higher. In addition, difficulty getting relief meter readers results in more estimated meter readings.

Alternatives:

Three alternatives were considered:

- Maintain the existing Radix system.
- Deploy Cellnet+Hunt's TS1 AMR System. This is a one-way power line carrier communications AMR system in which a customer's meter sends information to a local data collector.
- Deploy Cellnet+Hunt's TS2 AMR System. This is a two-way power line carrier communications AMR system in which a customer's meter can send information to a data collector and, also, the data collector can send information or instructions to a customer's meter.

Although Alternative 3 provides more functionality, Hydro does not foresee a requirement for the additional functionality and is unable to justify the additional expense.

Project Title: Install Automatic Meter Reading **(cont'd.)**

Justification: (cont'd.)

Alternatives: (cont'd.)

Alternative 1 is labour intensive and meter reading costs will continue to increase over time.

Alternative 2 has been selected by Hydro for the following reasons:

- As shown by the cost-benefit analysis, it results in lower meter reading costs and a savings to Hydro.
- The payback period is 10 years with net savings of approximately $128,000 in 15 years.
- It eliminates incorrect and estimated meter readings.
- It provides a future opportunity to allow more detailed energy usage statistics to be available to Hydro’s customers.

Conclusion:

Implementation of Cellnet+Hunt’s TS1 AMR System is the chosen alternative for the reasons discussed in the Alternatives Section of this document.

Project Schedule:

Table 6 provides the anticipated project schedule.

Table 6. Project Schedule

Activity	Milestone
Approval of Design Transmittal	February 2009
Meters Tendered	March 2009
AMR Collector Ordered	March 2009
AMR Collector Received	April 2009
Meters Received	July 2009
Farewell Head Collector Installation Complete	July 2009
Farewell Head Meter Installation Complete	October 2009
Farewell Head In-Service	November 2009
Project Completion and Closeout	December 2009

Future Plans:

Future AMR projects will be proposed in future capital budget applications.

Project Title: Install Digital Fault Recorders

Location: Massey Drive, Oxen Pond and St. Anthony

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing 32 channel Digital Fault Recorder (DFR) with a new 32 channel unit at Hydro's Massey Drive Terminal Station (Massey Drive), and install a 32 channel DFR at both the Oxen Pond Terminal Station (Oxen Pond) and St. Anthony Airport Terminal Station (STA). The digital fault recorder provides individual phase and equipment voltages which can be viewed after a disturbance has occurred. By looking at the information, the disturbance can be readily identified and a solution can be formulated. Without the fault recorder, the nature of the problem (the reason for the fault) is unknown and cannot be identified unless there is obvious physical damage to equipment or other pieces of information, such as sequence of events records or relay targets, are known.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	172.0	0.0	0.0	172.0
Labour	159.0	0.0	0.0	159.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	39.3	0.0	0.0	39.3
O/H, AFUDC & Escln.	54.6	0.0	0.0	54.6
Contingency	37.0	0.0	0.0	37.0
TOTAL	**461.9**	**0.0**	**0.0**	**461.9**

Existing System:

Hydro’s Massey Drive is located near Corner Brook. It plays a vital role in the supply of power to the southwestern part of the Island Interconnected System and to the Corner Brook area. Three 230 kV transmission lines terminate at this station; TL-248 from the Deer Lake Terminal Station, TL-211 from the Bottom Brook Terminal Station, and TL-228 from the Buchans Terminal Station. Generally, power flows to Massey Drive from the Buchan’s Terminal Station. This power is transformed to 66 kV and sold to Newfoundland Power and the Corner Brook Pulp and Paper mill.

Hydro also owns and operates two major Terminal Stations in the St. John’s area. One is the Hardwoods Terminal Station (Hardwoods) and the other is Oxen Pond. Oxen Pond has two

Project Title: Install Digital Fault Recorder **(cont'd.)**

Existing System: (cont'd.)

incoming 230 kV transmission lines, one from the Holyrood Thermal Generating Station (Holyrood) switchyard and one from Hardwoods. Oxen Pond is a major supplier of electrical power to the St. John's area. Normally, about 56 percent of that power flows through Oxen Pond and 44 percent flows through Hardwoods. These percentages can fluctuate because one station can pick up load normally served by the other if the need arises as they are connected by a 230 kV transmission line. This power is transformed from 230 kV to 66 kV, sold to Newfoundland Power, and subsequently distributed to the customers of the St. John's region.

STA is a major point of supply of electrical power to the St. Anthony area. It has one incoming 138 kV line from the Bear Cove Terminal Station and two incoming 66 kV transmission lines, one from the Main Brook Terminal Station switchyard and one from the St. Anthony Diesel Generating Station Switchyard. This energy is then distributed to the customers of the St. Anthony region.

Age of Equipment or System:

The present digital fault recording system in Massey Drive was installed in February of 1993. This system is from a different manufacturer than most of the other DFRs in the system today. Hydro is currently installing Mehta Tech DFRs in its terminal stations. The following are the stations that have been outfitted with Mehta Tech DFRs:

- Hardwoods (1993)
- Western Avalon (1995)
- Sunnyside (1999)
- Stony Brook (2002)
- Holyrood (2003)
- Bay d'Espoir (2004)
- Bottom Brook (2005)

Project Title: Install Digital Fault Recorder **(cont'd.)**

Existing System: (cont'd.)

Major Work/or Upgrades:

Table 1 shows upgrades that have occurred at Massey Drive since installation

Table 1. Upgrades

Year	Major Work/Upgrade	Comments
2006	Investigate DFR, unable to retrieve data	Reinstalled network card
2003	New power supply	Installed new +5VDC power supply
2002	Trouble shoot	Installed new power supply
2001	Communications from DFR and Master station not working	Installation of Modem

Anticipated Useful Life:

The existing DFR at Massey Drive has reached the end of its useful life. The manufacturer suggests that the useful life of a new Digital Fault Recorder is approximately 15 years. However, some components will need to be replaced after 5-12 years, including batteries and hard drives, as this type of equipment has a limited shelf life.

Maintenance History:

Table 2 presents the Maintenance History of the DFR at Massey Drive.

Table 2. Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2006	0	1.167	1.167
2004	0	0.370	0.370
2001	0	0.685	0.685

Outage Statistics:

DFRs are monitoring devices and do not initiate the tripping of breakers. As such, no outages can be attributed to a DFR.

Project Title: Install Digital Fault Recorder **(cont'd.)**

Existing System: (cont'd.)

Industry Experience:

As per “The World Market for Substation Automation and Integration Programs in Electric Utilities: 2005-2007” the North American Summary for 2005, the following has been stated:

> “Transmission Substations - Seventy-five utility officials took the time to indicate which of 15 specific equipment types were or were planned to be part of their utility’s transmission substation-wide automation programs. RTUs, digital relays, redundant protection schemes and digital fault recorders were all indicated by more than one half of the respondents as component parts of their utility substation automation programs.”

The above statement indicates that the trend in the utility industry is to install DFRs as part of terminal or substation automation.

Maintenance or Support Arrangements:

This equipment is maintained by Hydro personnel.

Vendor Recommendations:

No recommendations have been sought from vendors.

Availability of Replacement Parts:

The present DFR contains outdated technology and no longer has parts readily available. Damaged parts must be sent back to the original manufacturer for repairs. This causes the equipment to be out of service for two to three months. This has occurred at the Massey Drive and Buchans Terminal Stations.

Safety Performance:

As this is a monitoring device only, there are no safety concerns surrounding this equipment.

Environmental Performance:

Environmental non-compliance is not an issue for the DFR installation.

Project Title: Install Digital Fault Recorder **(cont'd.)**

Existing System: (cont'd.)

Operating Regime:

The DFR is in service at all times.

Justification:

The DFR is required to provide assistance to Protection and Control, System Operations and field personnel in analyzing faults on transmission lines, transformers, breakers, and other station equipment at the Massey Drive, Oxen Pond and STA Stations. The information provided by DFRs aid in the return of service to our customers caused by faults and disturbances on the system. The reliability of the Massey Drive, Oxen Pond and STA are key factors in providing service to Hydro's Island Interconnected customers.

Replacement parts are no longer available for outdated digital recording equipment. Hydro personnel have to troubleshoot the equipment and, if possible, send the part away to the manufacturer to be fixed. The DFR can be out of service for approximately two to three months while the part is shipped, repaired and returned to the station.

Net Present Value:

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

Levelized Cost of Energy:

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

Cost Benefit Analysis:

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

Legislative or Regulatory Requirements:

There are no legislative or regulatory requirements.

Project Title: Install Digital Fault Recorder **(cont'd.)**

Justification: (cont'd.)

Historical Information:

The five year history of expenditures for the installation or replacement of DFR units is shown in Table 3 below. No DFRs were installed in 2006 or 2007:

Table 3. Five Year History

Year	Location	Budget ($000)	Actual ($000)
2008	Buchans Terminal Station	130.0	-
2005	Bottom Brook Terminal Station	122.0	91.0
2004	Bay d'Espoir Terminal Station	72.0	61.0
2003	Holyrood Terminal Station	76.0	10.0

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 the DFR.

Losses During Construction:

No losses occur during construction as outages are not needed.

Status Quo:

The current system at the Massey Drive is no longer maintained by the manufacturer and replacement parts do not exist. It is at the end of its useful life. A reliable digital fault recorder is needed for continued fault analysis efficiency. There are no DFRs in the STA or Oxen Pond.

Alternatives:

There are no alternatives available to the proposed project.

Project Title: Install Digital Fault Recorder **(cont'd.)**

Conclusion:

A DFR provides data for a complete analysis of a system disturbance. General utility experience indicates that DFRs are important to system automation. The current DFR at Massey Drive can no longer be properly maintained, as replacement parts are not available. The replacement of the DFR in Massey Drive and installation of a new DFR at the Oxen Pond and STA are required for fault disturbance analysis.

Project Schedule:

Table 4 provides the anticipated project schedule.

Table 4. Project Schedule

Activity	Milestone
Project Initiation, Design and Equipment Ordering	April 2009
Project Safety Plan	April 2009
Field Construction/Installations	October 2009
Operations Installations	October 2009
Commissioning	October 2009
In Service	October 2009
Project Completion and Close Out	November 2009

Future Plans:

None.

Project Title: Build New Maintenance Shop

Location: St. Anthony

Category: Transmission and Rural Operations - Properties Northern

Definition: Other

Classification: Normal

Project Description:

This project consists of the construction of a new 9.1 metres wide x 15.2 metres long x 8.5 metres high (30 feet x 50 feet x 28 feet high) pre-engineered metal building at approximately 1.2 meters from the existing maintenance building. The building will have a service pit, a 5 metre high x 3.6 wide roll up door and a fall arrest system. The building will be equipped with a 120/240 distribution panel, high bay lighting, fan forced heaters, and mechanical ventilation. A covered corridor will be provided between the existing and new building. All work will be carried out by contractors with supervision by Hydro forces.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	57.0	0.0	0.0	57.0
Consultant	3.0	0.0	0.0	3.0
Contract Work	265.0	0.0	0.0	265.0
Other Direct Costs	22.0	0.0	0.0	22.0
O/H, AFUDC & Escln.	47.0	0.0	0.0	47.0
Contingency	34.7	0.0	0.0	34.7
TOTAL	428.7	0.0	0.0	428.7

Existing System:

Hydro owns and operates transmission and distribution lines throughout Newfoundland and Labrador. In order to provide reliable service to its customers Hydro must maintain these lines. Maintaining these lines requires the use of heavy equipment that must be maintained. This proposal is required to construct a new pre-engineered metal building to be used as a maintenance shop to maintain the line maintenance equipment in St. Anthony.

Project Title: Build New Maintenance Shop **(cont'd.)**

Existing System: (cont'd.)

Equipment that will be maintained consists of the following:

- Five Posi-Plus, which are bucket trucks or cherry pickers consisting of a boom with attached bucket to allow for a person to be lifted and perform work at heights,
- Two Altexs (similar to Posi-Plus).
- Three Versa Lifts (similar to Posi-Plus).
- Three Hiabs, which are articulating cranes, two of which are installed on a flatbed and one on a Go-Track.
- One Pitman Boom installed on a Power Trax similar to a Hiab crane.
- Three excavators.
- Four Digger Derricks, which are boom trucks with an auger bit attachment to facilitate digging for utility pole placement.
- Two Go-Tracks, which are heavy-duty, all-terrain, track vehicles. They have tracks instead of wheels to facilitate work in areas where wheeled vehicles cannot go, such as transmission lines.
- One Power Trax, which is similar to a Go-Track only a larger, heavier version.

The existing maintenance building is used to maintain electrical and mechanical equipment and provides offices and lunchroom facilities but it is too small for the large equipment (see photos on page C-109). To maintain the larger equipment, Hydro leases a garage located approximately 500 metres from the existing St. Anthony site.

As this project relates to the construction of a new building, there is no relevant data related to:

- Age of equipment
- Major work or upgrades
- Maintenance history
- Outage statistics
- Industry experience
- Maintenance or support arrangement

Project Title: Build New Maintenance Shop **(cont'd.)**

Existing System: (cont'd.)

- Vendor recommendations
- Availability of replacement parts
- Safety performance
- Environmental performance
- Operating regime

Anticipated Useful Life:

A building has an estimated service life of 20 years.

Justification:

Construction of a new maintenance garage located next to the existing maintenance garage is the best alternative for maintaining the heavy equipment. The existing maintenance garage is not large enough to service the equipment as shown in the photos on page C-109. The present arrangement of leasing a larger garage at a cost of $3,750 a month is not cost effective. Heavy equipment is maintained by Hydro's mechanics and requires regular inspections of the lifting mechanisms as mandated by the manufacturer, as well as all applicable standards, such as Canadian Standard Association (CSA) requirements. An adequate facility to carry out these inspections and maintenance work is essential.

Net Present Value:

The net present value to construct a new maintenance building is $369,294 compared to the net present value of leasing the garage at $482,511.

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.

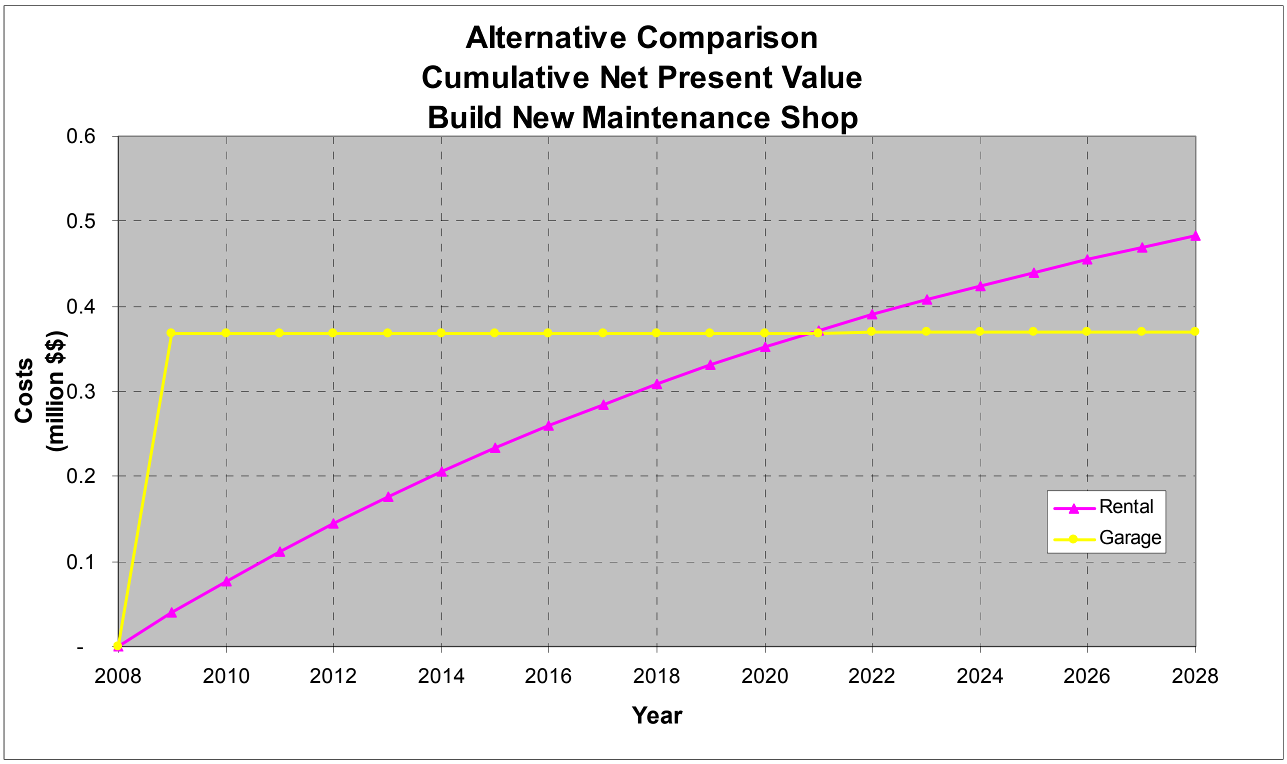
Project Title: Build New Maintenance Shop **(cont'd.)**

Justification: (cont'd.)

Cost Benefit Analysis:

A cost benefit analysis (see Table 1) demonstrates that the least cost alternative is to construct a new garage providing a benefit of $113,218 over a twenty year analysis period. Chart 1 provides a comparison of the two alternatives used in the Cost Benefit Analysis.

Chart 1.



Project Title: Build New Maintenance Shop **(cont'd.)**

Justification: (cont'd.)

Cost Benefit Analysis: (cont'd.)

Table 1. Cost Benefit Analysis

St Anthony **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2028**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Construct Garage	369,294	0
Lease Garage	482,511	113,218

Legislative or Regulatory Requirements:

The maintenance shop will be constructed in compliance with all applicable legislative and regulatory requirements.

Historical Information:

There is no historical information as this is a new construction.

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 construction of a new maintenance building.

Project Title: Build New Maintenance Shop **(cont'd.)**

Justification: (cont'd.)

Losses During Construction:

This project will have no effect on normal operations so there will be no losses during construction.

Status Quo:

Leasing the garage is not cost effective in the long term. Also, having the maintenance facilities in another location is not as secure as having them on Hydro property, which had a chain link fence installed in 2001.

Alternatives:

The two alternatives evaluated, leasing versus construction of a new garage, are the only viable alternatives.

Conclusion:

The construction of a new facility is the best alternative as leasing the garage at $45,000 per year is not cost effective. Having this building next to the other facilities in St. Anthony will make maintaining the equipment more efficient and more secure.

Project Schedule:

Table 2 provides the anticipated project schedule.

Table 2. Project Schedule

Activity	Milestone
Design	April 2009
Tender	May 2009
Award Tender	June 2009
Construct Maintenance Shop	September 2009
Closeout Project	November 2009

Future Plans:

None.

Project Title: Build New Maintenance Shop **(cont'd.)**

Figure 1. Existing Maintenance Shop

Posi-Plus is too high for door

Figure 2. Existing Maintenance Shop

Hiab is too long for building

Project Title: Upgrade Circuit Breakers

Location: Various Terminal Stations

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project is required as part of an upgrading program to refurbish all Brown Boveri DCVF, DCF and DLF styles 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 will 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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	220.0	0.0	0.0	220.0
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.	49.4	0.0	0.0	49.4
Contingency	33.9	0.0	0.0	33.9
TOTAL	**421.8**	**0.0**	**0.0**	**421.8**

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 and economic 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.

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.

At 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

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Maintenance History: (cont'd.)
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.

Outage Statistics:
Table 1 below lists the 15 and five year averages for the performance of Air Blast Circuit Breakers. 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 1. 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.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

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.

Hydro consulted with other Canadian utilities and their experiences were the same as Hydro's.

In addition, Hydro consulted with 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.

Maintenance or Support Arrangements:

Normal operation and maintenance work is performed by Hydro staff.

Vendor Recommendations:

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.

Availability of Replacement Parts:

Replacement parts for the existing breakers are generally readily available.

Safety Performance:

The safety performance of the air blast breakers has been good. The breakers meet all applicable codes and standards for the industry. However, failure to properly maintain and refurbish the breakers may cause a safety risk by allowing pressure to increase sufficiently to forcefully spread porcelain pieces throughout the station.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Existing System: (cont'd.)

Environmental Performance:

There are no specific environmental issues regarding the air blast breakers other than the proper disposal of the retired parts.

Operating Regime:

The breakers are employed in full time continuous operation on the system, feeding the transmission and sub-transmission networks.

Justification:

The Brown Boveri air blast circuit breakers are the first generation air blast breakers in use by Hydro. These breakers are generally reliable but as they age they tend to create operational problems. The highlights of these problems are summarized in the Maintenance History Section.

The upgrades are the least cost alternative to replacement of the breakers with newer models.

Other utilities with air blast breakers of the same style and vintage as Hydro's, and with similar experiences, have taken or are taking, the same course of action.

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.)**

Justification: (cont'd.)

Net Present Value:

There are two solutions to the problems described with the air blast beakers. 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 2, 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. These upgrades are estimated to extend the life of the breakers to that equivalent to a replacement.

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:

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 2 shows the summary costs for each year.

Table 2. Budget

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2008F	$315.2	-	4		Work in preliminary stages
2007	$257.8	$146.4	2	$73.2	-

Project Title: Upgrade Circuit Breakers **(cont'd.)**

Justification: (cont'd.)

Historical Information: (cont'd.)

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 divided by the number of breakers upgraded.

Forecast Customer Growth:

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

Energy Efficiency Benefits:

There are no issues related to energy efficiencies associated with this project.

Losses During Construction:

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.

Status Quo:

The status quo is not an option as the breakers must be upgraded to maintain system reliability.

Alternatives:

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.

Project Title: Upgrade Circuit Breakers **(cont'd.)**

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.

Project Schedule:

Table 3 presents the anticipated project schedule.

Table 3. Project Schedule

Activity	Milestone
Project Start	January 2009
Initial Planning and Equipment Ordering Tendering	February 2009
Equipment Delivery	July 2009
Equipment installations and Commissioning	November 2009
Project In Service	November 2009
Project Completion and Close Out	December 2009

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Replace Insulators

Location: Various Terminal Stations

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project is required to purchase and install 230, 138, 69, and 25 kV station post and suspension insulators at various terminal stations in the Island Interconnected System. 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 can be shipped from this central location for installation in the particular stations.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	180.0	0.0	0.0	180.0
Labour	119.0	0.0	0.0	119.0
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.	42.2	0.0	0.0	42.2
Contingency	31.7	0.0	0.0	31.7
TOTAL	390.9	0.0	0.0	390.9

Existing System:

The insulators in use on the Island Interconnected System range in age from one to forty years. The insulators targeted for replacement under this project were manufactured before the mid 1970's.

Insulators are an integral part of the transmission system. They serve to 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 the insulators ages, it grows and cracks. As this growth progresses, the insulators fail. For instance, tops of cap and pin top insulators are failing, and the rings on multi-cone insulators are breaking down as the cement deteriorates.

Major Work/or Upgrades:

There has been no major work or upgrades on terminal station insulators since they were installed. Replacements have been made as failures occurred.

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

Existing System: (cont'd.)

Anticipated Useful Life:

The anticipated service life of the new insulators is 40 years, depending on the service environment.

Maintenance History:

The normal maintenance tactic 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 1 lists the 2003 to 2007 system average transmission (T) T-SAIFI and T-SAIDI data and the latest CEA five year averages (2002 to 2006).

Table 1. SAIFI/SAIDI Average

Five Year Averages (2003-2007)		
	T-SAIFI	T-SAIDI
Hydro System	1.38	83.63
CEA (2002-2006)	0.86	127.92

These outage statistics cannot be directly linked to insulator failures.

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

Existing System: (cont'd.)

Industry Experience:

The industry experience with the older insulators manufactured prior to the mid 1970's is the same as Hydro's.

Maintenance or Support Arrangements:

The 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. 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.

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 short circuits are created and when broken insulator parts fall to the ground.

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.

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

Justification:

This project is justified on the requirement for Hydro to provide safe and reliable power. When insulators fail they create a short circuit to ground and result in loose and falling parts. Both create safety hazards to personnel and system outages. "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.

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

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

Justification: (cont'd.)

Historical Information:

This is the fourth year of a five-year plan to replace terminal station insulators. Table 2 contains the historical information for insulator replacements.

Table 2. Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2008F	294.3				
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.

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.

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

Justification: (cont'd.)

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 3 presents the anticipated project schedule.

Table 3. Project Schedule

Activity	Milestone
Project Start	January 2009
Initial Planning and Equipment Ordering Tendering	February 2009
Equipment Delivery	July 2009
Equipment Installations and Commissioning	November 2009
Project In Service	November 2009
Project Completion and Close Out	December 2009

Future Plans:

None.

Project Title: Replace Conductor on Line 2

Location: Rocky Harbour

Category: Transmission and Rural Operations - Distribution Northern

Definition: Other

Classification: Normal

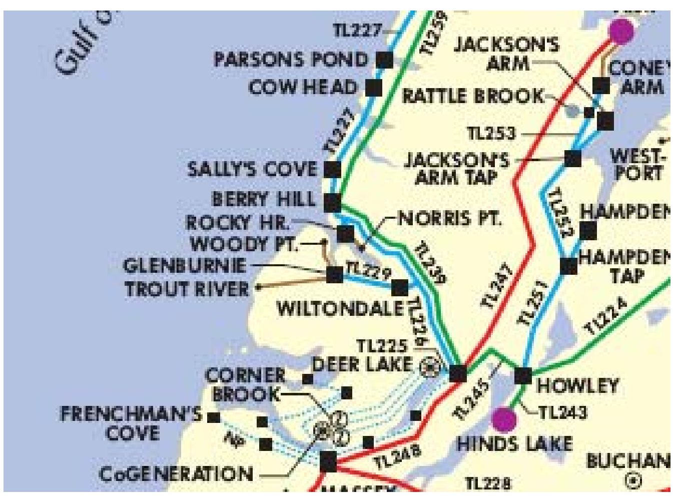
Project Description:

This project is required to replace nine kilometres of #2 ACSR conductor with 4/0 AASC conductor on Line 2 (L2) in Rocky Harbour.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	61.0	0.0	0.0	61.0
Labour	64.5	0.0	0.0	64.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	118.0	0.0	0.0	118.0
Other Direct Costs	18.3	0.0	0.0	18.3
O/H, AFUDC & Escln.	36.5	0.0	0.0	36.5
Contingency	26.2	0.0	0.0	26.2
TOTAL	324.5	0.0	0.0	324.5

Existing System:

Rocky Harbour distribution L2 is a nine kilometer 12.5 kV three phase feeder serving approximately 440 customers in the communities of Neddie's Harbour, Norris Point and Wild Cove located in the Bonne Bay area on the West Coast of the Island of Newfoundland (see Figure)



Project Title: Replace Conductor on Line 2 **(cont'd.)**

Existing System: (cont'd.)

Age of Equipment or System:

Rocky Harbour L2 was constructed in 1978 and the conductor was installed at that time.

Major Work/or Upgrades:

There has been no major work on the conductor since the installation of the line.

Anticipated Useful Life:

For depreciation purposes, a distribution feeder has a service life of 30 years.

Maintenance History:

Table 1 contains the five year maintenance history for Rocky Harbour L2.

Table 1. Maintenance History

Rocky Harbour L2	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	12.0	4.5	16.5
2006	3.2	5.4	8.6
2005	8.3	8.3	16.6
2004	6.5	8.0	14.5
2003	9.2	10.4	19.6

Outage Statistics:

Hydro tracks all distribution 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.

Project Title: Replace Conductor on Line 2 **(cont'd.)**

Existing System: (cont'd.)

Outage Statistics: (cont'd.)

SAIFI - Indicates the system average Interruption Frequency Index 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 2003 to 2007 average SAIFI and SAIDI data for the Rocky Harbour System, the 2003 to 2007 corporate values, and the latest CEA five-year average (2002 to 2006) for comparison. A number of factors contribute to the statistics for L2 indicating better performance than the overall Rocky Harbour System. Approximately one percent of line outages are caused by conductor failure. Also, L2 had new crossarms and 29 poles replaced in 2007. Therefore, the line has a strong infrastructure that supports the conductor. However, the conductor is below Hydro's standards and replacement completes the upgrade of L2.

Table 2. Five Year Average

Five Year averages (2003 to 2007)				
	All Causes		Defective Equipment	
	SAIFI	SAIDI	SAIFI	SAIDI
Rocky Harbour	3.06	3.55	0.58	0.85
L2	1.42	1.71	0.32	0.46
Hydro Corporate	6.24	9.72	0.66	1.14
CEA (2002-2006)	2.64	7.61	0.98	2.14

Maintenance or Support Arrangements:

A visual inspection of the Rocky Harbour L2 feeder is performed every nine years to evaluate the condition of the line. This inspection is completed by internal forces and any corrective maintenance required is reported, scheduled, and performed.

Operating Regime:

The Rocky Harbour L2 feeder is in continuous operation providing power to the communities of Neddie's Harbour, Norris Point, and Wild Cove.

Project Title: Replace Conductor on Line 2 **(cont'd.)**

Justification:

The existing conductor no longer meets Hydro's distribution standards and is required to be replaced with a larger conductor. A larger standard conductor will also decrease the voltage drop on the L2 feeder, reduce energy losses, and provide a more reliable system.

<u>Net Present Value:</u>

See the Cost Benefit Analysis Section below.

<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 performed to decide between Alternative #1: using 1/0 AASC conductor and Alternative #2 - using 4/0 AASC conductor. Alternative #2 was proven to be the most cost effective solution. See Table 3, page C-129 for the cumulative net present value comparison.

<u>Forecast Customer Growth:</u>

Customer load growth does not affect this project.

<u>Energy Efficient Benefits:</u>

Replacing the sub-standard conductor on Rocky Harbour L2 with the larger 4/0 conductor will reduce annual line losses by approximately 75,400 kWh which is equivalent to displacing 120 barrels of fuel at the Holyrood Thermal Generating Station.

<u>Legislative or Regulatory Requirements:</u>

There are no applicable legislative or regulatory requirements.

<u>Historical Information:</u>

There is no applicable historical information with regards to a line reconductoring.

Project Title: Replace Conductor on Line 2 **(cont'd.)**

Justification: (cont'd.)

Losses During Construction:

There are no anticipated energy losses during construction.

Status Quo:

The #2 ACSR conductor that exists on the line is currently a substandard material, even though the SAIDI and SAIFI's from years 2003-07 do not indicate a large number of interruptions. Upgrading the line with 4/0 conductor brings the line to Hydro standards, improves the mechanical integrity of the line, and will provide energy savings.

Alternatives:

Two alternatives were considered. These alternatives and their capital costs of the alternatives are:

Reconductoring with 1/0 AASC Conductor - $307,100

Reconductoring with 4/0 AASC Conductor – $324,500

From a technical point of view, either conductor is acceptable; however, it was decided to evaluate the economic impact of using 4/0 AASC rather than 1/0 AASC. The capital cost of using 4/0 AASC is $16,300 greater than using 1/0 AASC but will reduce line losses by 75,400 kWh annually. Assuming that the Holyrood Thermal Generating Station is the marginal energy supplier, this will result in payback by 2011 and a cumulative present worth (CPW) savings of $104,199 from 2009 to 2038 (see Table 3). Therefore, using 4/0 AASC Conductor is the most cost-effective alternative.

Cumulative Present Worth Analysis:

Table 3 contains the cumulative present worth analysis of the two alternatives.

Table 3.

Alternative Comparison Cumulative Net Present Value to the Year 2038		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least-Cost Alternative**
Rocky Harbour Reconductoring - 4/0 AASC	159,090	0
Rocky Harbour Reconductoring - 1/0 AASC	263,289	104,199

Project Title: Replace Conductor on Line 2 **(cont'd.)**

Conclusion:

This project is required to ensure that a reliable energy supply is available for the customers served by the Rocky Harbour L2 feeder.

Project Schedule:

Table 4 presents the anticipated project schedule.

Table 4. Project Schedule

Activity	Milestone
Initiation	February 2009
Design Complete	March 2009
Equipment Ordered	April 2009
Installation Commences	June 2009
Installation Complete	July 2009
Project Closeout	August 2009

Future Plans:

None.

Project Title: Install Fall Arrest Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Tools and Equipment

Definition: Pooled

Classification: Mandatory

Project Description:

This project is the last year of a five-year fall protection program for Hydro facilities. This project is to design, supply and install fall protection systems at several Hydro facilities. It includes installing ladder systems where needed, hand rails and cat walks at the Holyrood Generating site, anchor plates for transformers where needed, replacement of safety track at the Stephenville Gas Turbine, cat walks for the Cat Arm Terminal Station insulators, hand rail and cat walks at the Happy Valley Gas Turbine and cable systems at the Black Tickle, Cartwright, and Hopedale diesel plants. The work will be completed by external contractors and Hydro personnel. Inspection and certification will performed by a qualified engineering consultant.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	80.0	0.0	0.0	80.0
Labour	95.0	0.0	0.0	95.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	59.0	0.0	0.0	59.0
Other Direct Costs	5.0	0.0	0.0	5.0
O/H, AFUDC & Escln.	36.8	0.0	0.0	36.8
Contingency	25.9	0.0	0.0	25.9
TOTAL	**321.7**	**0.0**	**0.0**	**321.7**

Existing System:

Hydro owns and operates generating facilities including the Holyrood Thermal Generating Station, ten hydroelectric plants, four gas turbines, and 26 diesel plants. In order to meet provincial safety regulations, Hydro must install fall arrest systems on buildings, tanks and transformers located at various Hydro facilities. In 2005, Hydro started a fall arrest program to be completed in 2009. This proposal is the last year of that program to complete additional fall arrest systems in facilities which were identified over the last four years. All new tanks, buildings and transformers will have fall arrest systems incorporated into their original designs.

Project Title: Install Fall Arrest Equipment **(cont'd.)**

Existing System: (cont'd.)

This proposal is required to install:

- ladder systems at various Hydro facilities,
- hand rails and catwalks at the Holyrood Thermal Generating Station, Cat Arm Hydroelectric Generating Station and Happy Valley Gas Turbine Plant,
- anchor plates on transformers, and
- cable systems at Black Tickle, Cartwright, and Hopedale Diesel Plants.

Below is a discussion of the three basic types of fall arrest systems installed by Hydro. The photographs illustrate how each system is used.

Figure 1. Roof Fall Arrest Protection System

Generally, a fall arrest 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 Arrest Equipment **(cont'd.)**

Existing System: (cont'd.)

In this Fall Arrest system, a safety track is installed vertically in the middle of the ladder as shown in Figure 2. The worker on the ladder is securing himself to the ladder fall arrest system by attaching himself to a small trolley that rides on the safety track. The trolley allows the worker to move with ease up the ladder but in the event of a sudden downward movement, as in a fall, the trolley is designed to abruptly brake, securing the worker and preventing a fall. This action is similar to the behavior of a seat belt in a car.

Figure 2. Safety Track

Figure 3 illustrates a transformer fall arrest system used by the three workers standing on top of a transformer. This system is portable and is mounted on a fixed anchor plate welded to the top of the transformer. When work is completed, it can be taken to another site.

The three basic types of fall arrest 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.

Figure 3. Transformer Fall Arrest System

Project Title: Install Fall Arrest Equipment **(cont'd.)**

Existing System: (cont'd.)

As this project relates to installation of new fall arrest systems there is no relevant data related to:

- Age of the equipment
- Major work/or upgrades
- Maintenance history
- Outage statistics
- Industry experience
- Maintenance or support arrangements
- Vendor recommendations
- Availability of replacement parts
- Operating regime

Anticipated Useful Life:

There are three basic types of fall arrest systems proposed to be installed and with annual inspections and proper maintenance it is anticipated that these systems will last 20 years.

Safety Performance:

Hydro must conform with Section 60 “Safety Belts and Lifelines “ of the Occupational Health and Safety (OH and S) Regulations (see page C-136) which 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”. Without proper fall arrest systems in place, a worker can refuse to perform his/her assigned duties.

Environmental Performance:

There are no environmental issues associated with fall arrest.

Justification:

This project is justified on the requirement to provide a safe work environment to Hydro employees and to comply with section 60 “Safety Belts and Life lines“ of the Occupational Health and Safety

Project Title: Install Fall Arrest Equipment **(cont'd.)**

Justification: (cont'd.)

Regulations. In order for Hydro to be in compliance with provincial regulations, fall arrest systems must be installed at various locations throughout Hydro properties. Employees can refuse to work in areas where there are no fall protection systems which can impede Hydro's normal operations.

Net Present Value:

Net present value is not applicable for this project as only one viable alternative exists to meet safety regulations and that is to install fall arrest systems.

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.

Cost Benefit Analysis:

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

Legislative or Regulatory Requirements:

Please refer to the Safety Performance section.

Historical Information:

Hydro has been installing fall arrest systems on roofs, fuel tanks and transformers over the last four years (see Table 1 for a three year history). The cost for 2008 has a higher contractor component than in other years.

Table 1. Three Year History

Year	Capital Budget ($000)	Actual Expenditures ($000)
2008F	404.5	
2007	250.9	245.2
2006	268.1	241.9
2005	206.2	208.7

Project Title: Install Fall Arrest Equipment **(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 installation of fall arrest systems.

Losses During Construction:

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

Alternatives:

There are no viable alternatives to this project.

Conclusion:

To comply with provincial Health and Safety Regulations, Hydro must install fall arrest systems in locations where employees work at a height above 3.05 meters.

Project Schedule:

Table 2 presents the anticipated project schedule.

Table 2. Project Schedule

Activity	Milestone
Design	April 2009
Material Acquisition	June 2009
Install Systems	September 2009
Project Closeout	October 2009

Future Plans:

None.

Project Title: Install Fall Arrest Equipment **(cont'd.)**

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.

Project Title: Replace Explosives Storage Magazines

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Type: Pooled

Classification: Mandatory

Project Description:

This project is to replace existing explosive storage magazines with new government approved ones. Type 6 dynamite storage magazines, and Type 6 detonator storage magazines at Hydro will be replaced with Type 4 storage magazines. Each magazine will be capable of holding 250 kilograms of dynamite and 1000 detonators.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	215.0	0.0	0.0	215.0
Labour	16.0	0.0	0.0	16.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.2	0.0	0.0	2.2
O/H, AFUDC & Escln.	36.1	0.0	0.0	36.1
Contingency	23.4	0.0	0.0	23.4
TOTAL	**292.7**	**0.0**	**0.0**	**292.7**

Existing System:

Hydro uses explosives when there is a requirement for blasting at a location for a newly installed pole or replacement poles that were installed inadequately at time of construction. The explosives and detonators are currently stored in magazines that do not meet Natural Resources Canada (NRC) regulations that will become effective May 2009. The current Type 6 dynamite storage magazines, and Type 6 detonator storage magazines at Hydro facilities at Burgeo, Springdale, Fogo Island, Norris Point, Port Saunders, Flowers Cove, Roddickton, St. Anthony, L'Anse-Au-Loup, and Mary's Harbour will be replaced with Type 4 storage magazines as per NRC directive. Pages C-141 - 143 contains the Directive Letter #58 from the Explosives Regulatory Division of NRC.

Project Title: Replace Explosives Storage Magazines **(cont'd.)**

Existing System: (cont'd.)

The following items are not applicable because the project is directed by government:

- Maintenance History
- Outage Statistics
- Industry Experience
- Vendor Recommendations
- Availability of Replacement Parts
- Environmental Performance
- Operating Regime
- Net Present Value
- Levelized Cost of Energy
- Cost Benefit Analysis
- Historical Information
- Forecast Customer Growth
- Energy Efficiency Benefits
- Losses During Construction

<u>Age of Equipment:</u>

The existing Type 6 dynamite storage magazines, and Type 6 detonator storage magazines were installed in 1995.

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

There have been no major upgrades on this system since its installation.

<u>Anticipated Useful Life:</u>

Dynamite storage magazines and detonator storage magazines have an anticipated service life of 10 years.

<u>Maintenance or Support Arrangements:</u>

All maintenance is completed by Hydro personnel.

Project Title: Replace Explosives Storage Magazines **(cont'd.)**

Existing System: (cont'd.)

Safety Performance:

NRC states that safety could be compromised because the existing storage magazines are at risk to break-ins through the use of modern powerful portable tools, thus, increasing the risk of theft. Explosives in the hands of untrained persons are a safety hazard.

Justification:

As per Directive Letter # 58 from the Explosives Regulatory Division of NRC, Hydro will no longer be permitted to store explosives in Type 6 magazines for stand alone, overnight and unattended storage after May 31, 2009. There is still a need to store explosives at all currently licensed locations in Hydro's facilities. To conform to the new regulations, the existing magazines must be replaced with an approved Type 4 magazine.

Legislative or Regulatory Requirements:

Please see page C-141 - 143 containing NRC Explosives Branch Directive Letter # 58 for restricted usage of Type 6 magazines for stand alone, overnight and unattended storage.

Status Quo:

After May 31, 2009 Hydro will no longer be allowed to store explosives used for rock blasting often required for the installation of utility poles in distribution systems. As a result, Hydro will be restricted from installing poles where blasting is necessary for both planned and emergency work.

Conclusion:

Hydro has been given a directive from the Explosives Regulatory Division of NRC to discontinue the storage of explosives in Type 6 magazines by May 31, 2009 because of heightened security requirements. Rock blasting is often required when Hydro installs utility poles in its distribution systems and explosives must be on hand for both planned and emergency work. Therefore, in order for Hydro to continue with this work, the Type 6 dynamite storage magazines and Type 6 detonator storage magazines must be replaced with approved secure Type 4 explosives storage magazines as directed by NRC.

Project Title: Replace Explosives Storage Magazines **(cont'd.)**

Conclusion: (cont'd.)

Project Schedule:

Table 1 presents the anticipated project schedule.

Table 1. Project Schedule

Activity	Milestone
Tender Preparation	January 2009
Tender Period	February 2009
Tender Award	February 2009
Fabrication	April 2009
Delivery	May 2009
Installation	May 2009
Commissioning	May 2009

Future Plans:

None.

Project Title: Replace Explosives Storage Magazines **(cont'd.)**

Excerpt from Directive Letter #58

Natural Resources Canada / Ressources naturelles Canada

Canada

Explosives Regulatory Division

Directive Letter # 58

December 2007

Restricted Usage of Type 6 Magazines for Stand-Alone, Overnight and Unattended Storage

In Part 3, section 6.0.1, of the 2001 *Storage Standards for Industrial Explosives* (Magazine Standards), the Explosives Regulatory Division (ERD) stated that additional requirements may be needed to the policy on the usage of Type 6 magazines related to stand-alone, overnight and unattended storage.

Additionally, the June 2002 Version II *Proposals for Enhanced Explosives Security* document, produced following the events of 9/11, also mentioned that these magazines, more than any other type, warranted a review. This review was required not just because of the reported thefts but, more importantly, also because of the containers' inherently simplistic design, coupled with a padlock locking system, which by its very nature is more accessible and vulnerable to an attack. The overall design lends itself to a greater risk from break-ins by modern-day, battery-powered and more powerful portable tools as these can easily penetrate in minutes. These powerful tools have reduced the security of these magazines to the extent that they now only provide protection against casual theft.

Unfortunately, the prescribed upgrades in the May 2001 Magazine Standards have not been effective, to any great extent, in deterring a determined challenge by those with the intent of acquiring explosives by illicit means. They, like other magazine types, do store the desirable initiating components of the explosives train, such as boosters and detonators, currently in quantities up to 250 kg in weight, much of which cannot be readily produced by activists intent on doing harm. It is these concerns that have prompted the review and that have been the driving force behind the changes.

With the ongoing global terrorist acts, security has obviously taken on more prominence, particularly within this industry, thus making it more difficult to defend the outdated technology. As a result, a Type 6 magazine is no longer secure enough for stand-alone, overnight and unattended storage for many sectors of the industry, as is currently required under Quebec statute.

Page 1 of 3

Project Title: Replace Explosives Storage Magazines **(cont'd.)**

Excerpt from Directive Letter #58

The changes affecting Type 6 magazines for stand-alone, overnight and unattended storage are:

- limited areas of use or elimination in affected industries; and
- reduced storage quantities for all industries.

1.0 What are the affected industries?

1.0.1 The following affected industries will require a more secured Type 4 or smaller Type 4S magazine, instead of a Type 6, for overnight, unattended storage:

Construction:	Zone licences, unattended
Forestry:	Zone licences, unattended
Communities/municipalities:	Beaver dam control, unattended
Rail:	Unattended

Note: For fixed facilities in the affected industries listed above, such as a home base, a Type 6 magazine may be permitted within a secured building[1], or compound with a monitored alarm system that would get a response from authorities having jurisdiction (AHJ) within 30 minutes of being activated, i.e., they give it a top priority to respond; otherwise, video surveillance with appropriate lighting may be imposed as an additional requirement.

2.0 What are the quantity changes?

2.0.1 As a general requirement for all industries, the current maximum limit of 250 kg will be reduced to 100 kg for all Type 6 explosives magazines, plus an upper limit of 500 detonators will be imposed for all Type 6 detonator magazines. For some applications and industries, other lower quantity limitations will match usage.

2.0.2 For all industries, there will be a limit of one (1) Type 6 detonator magazine and one (1) Type 6 explosives magazine when used on a site, i.e., more than two (2) magazines per site is unacceptable.

3.0 When will the changes come into effect?

3.0.1 For the affected industries listed in 1.0.1 above, no new Type 6 magazine licences for overnight, unattended storage have been issued since **May 31, 2006**.

3.0.2 For the affected industries listed in 1.0.1 above, existing Type 6 magazines will not be permitted for overnight, unattended storage after **May 31, 2009**. The *Note* to 1.0.1 explains the exception. This means, for example, that Type 6 magazines will not be allowed on zone licences.

3.0.3 The quantity limits in section 2.0 will come into effect on **May 31, 2007**.

Page 2 of 3

Project Title: Replace Explosives Storage Magazines **(cont'd.)**

Excerpt from Directive Letter #58

3.0.4 The Winter Olympic Games, which will be held in Vancouver in February 2010, require significant additional security requirements from the host nation. As a result, ERD is taking a proactive stand leading up to and including the Olympics, to improve the security of explosives storage, in order to lessen access to explosives and reduce the threat from an explosives related event. Effective **1 October 2008**, no Type 6 and/or Type 10 portable magazines will be permitted to store blasting explosives and detonators in any stand-alone, overnight or unattended situation in the province of British Columbia in all of the high risk area below the 57th degree latitude line.

For all industries, Type 6 magazines may continue to be used as a "day box" under provincial legislation or for transportation usage only. Magazines on vehicles will be permitted under s. 63.(s.1) of the *Explosives Regulations*.

Further bulletins will explain limitations on other industries.

Contact your regional office for more detailed information.

Chris Watson, Ph.D.
Chief Inspector of Explosives

Note:
[1] Contact ERD for the appropriate minimum attributes for a secure building.

Page 3 of 3

Project Title: End User Evergreening Program

Location: Various Sites

Category: General Properties - Information Systems

Definition: Pooled

Classification: Normal

Project Description:

The End User project is required to enhance the efficiency of Hydro employees by replacing the personal computers (PCs) used for their day to day requirements.

This project will enable Hydro to replace 230 personal computers; 130 desktop PCs that were deployed in 2004 and 120 laptops that were deployed in 2005.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	340.0	0.0	0.0	340.0
Labour	90.0	0.0	0.0	90.0
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 & Escalation	18.4	0.0	0.0	18.4
Contingency	43.0	0.0	0.0	43.0
Total	**491.4**	**0.0**	**0.0**	**491.4**

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. A refresh is defined as 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 of the refresh program refined the replacement life cycle for laptops to be every four years and desktops every five years. This change in life cycle allowed Hydro to defer expenditures in 2006 for the End User Evergreening Program.

Project Title: End User Evergreening 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
- Operating Regime

Age of Equipment or System:

The existing PCs that are to be replaced under this project will have been in service between four and six years depending on the hardware platform used. If the end-user is using a laptop then it will have been in service for four years; if using a desktop, five or six years.

Anticipated Useful Life:

According to Gartner[1], 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.

[1] Gartner Inc. is the leading provider 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: End User Evergreening Program **(cont'd.)**

Existing System: (cont'd.)

Maintenance or Support Arrangements:

Hydro has purchased maintenance agreements with Lenovo 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.

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:

Project Title: End User Evergreening Program **(cont'd.)**

Justification: (cont'd.)

- Levelized Cost of Energy
- Legislative or Regulatory Requirements
- Forecast Customer Growth
- Energy Efficiency Benefits
- 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 1.

Table 1. Maintenance History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2008F	451		185		
2007	395	393	102	3.9	Laptops only replaced
2006	0	0	0	0	
2005	711	663	280	2.4	
2004	793	796	354	2.2	

Project Title: End User Evergreening 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.
- 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:

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 2009 and be completed before December 31, 2009.

Future Plans:

None.

Project Title: Replace Power Line Carrier on TL-250

Location: Bottom Brook to Grandy Brook

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project is required to supply, install and commission communications equipment to replace the existing Power Line Carrier and associated equipment on TL-250 between the Bottom Brook and Grandy Brook Terminal Stations.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	246.9	0.0	0.0	246.9
Labour	110.1	0.0	0.0	110.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	23.4	0.0	0.0	23.4
O/H, AFUDC & Escln.	54.1	0.0	0.0	54.1
Contingency	38.0	0.0	0.0	38.0
TOTAL	**472.5**	**0.0**	**0.0**	**472.5**

Existing System:

A Power Line Carrier is essentially a radio transmitter/receiver (transceiver) system which transmits information using the cables of the high voltage transmission line instead of free space. It has been used by utilities for decades to provide communications to remote locations. It operates at a much higher frequency than power transmission, which is why it can share the power line without interference. Electrical filters are used at each end of a Power Line Carrier system to trap the communications signal and separate it from the power being transmitted.

A Power Line Carrier is a low bandwidth communication system; that is to say it has extremely limited communications capacity. It is used when other higher speed communications systems are prohibitively expensive or where there is insufficient justification to install them. Power Line Carriers are used throughout Hydro's transmission system on its 138 kV and 230 kV transmission lines to provide communications to remote locations.

Project Title: Replace Power Line Carrier on TL-250 **(cont'd.)**

Existing System: (cont'd.)

The existing Power Line Carrier provides communications for the following:

- Teleprotection for high speed, automatic transmission line protection;
- Supervisory Control and Data Acquisition (SCADA) for manual remote control of terminal station equipment from the Energy Control Center;
- Voice Circuit for communications to the Energy Control Center; and
- Network Management for remote monitoring of communications equipment.

The following equipment will be replaced inside the control building at each terminal station:

- Asea Brown Boveri (ABB) ETI Power Line Carrier Terminal; and
- ABB NSD60 Teleprotection Unit.

The following high voltage (138 kV) auxiliary equipment will be replaced outside the control building at each terminal station on TL-250. This equipment allows the Power Line Carrier signal to be transmitted on the transmission line conductor, and includes:

- Line Matching Unit (LMU);
- Current Voltage Transformer (CVT); and
- Wavetrap (WT).

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

The existing Power Line Carrier equipment was installed in 1987 and has been in service for 21 years.

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

There have been no major upgrades to the Power Line Carrier since its initial installation.

<u>Anticipated Useful Life:</u>

The Power Line Carrier has a service life of 15 years.

<u>Maintenance History:</u>

The maintenance history from 2003 to 2007 for the TL-250 Power Line Carrier is shown in the Table 1.

Project Title: Replace Power Line Carrier on TL-250 **(cont'd.)**

Existing System: (cont'd.)

Maintenance History:

Table 1. Maintenance History

Year	Preventive Maintenance ($)	Corrective Maintenance ($)	Total Maintenance ($)
2007	0	0	0
2006	300	0	300
2005	2,000	4,800	6,800
2004	1,900	3,900	5,800
2003	700	0	700

In 2008, $2,600 has been spent on preventative maintenance.

Outage Statistics:

Since 2003, the existing equipment had one recorded failure which occurred in 2005. The duration of the outage was not recorded. Replacements for such equipment are required before significant outages occur.

Industry Experience:

There is no known industry experience available with regards to the failure rate of Power Line Carrier.

Maintenance or Support Arrangements:

All preventative and corrective maintenance on Power Line Carrier equipment is completed by Hydro operations personnel.

Vendor Recommendations:

The existing Power Line Carrier model has been phased out since the mid-1990s and spares are no longer available. The vendor, Asea Brown Boveri, recommends replacement due to unavailability of replacement parts.

Project Title: Replace Power Line Carrier on TL-250 **(cont'd.)**

Existing System: (cont'd.)

Availability of Replacement Parts:

The existing Power Line Carrier model has been phased out and modules cannot be repaired, due to the unavailability of components.

Safety Performance:

There have been no safety performance issues attributed to the operation of Power Line Carrier communication equipment. Safety procedures for working with this equipment are the same as for working with high voltage equipment.

Environmental Performance:

As Power Line Carrier equipment consists of electronic equipment housed inside the terminal station building and electromechanical components housed in the terminal station yard and connected to the power line, environmental non-compliance is not an issue for the Power Line Carrier.

Operating Regime:

This Power Line Carrier communications equipment is critical to the operation of the power grid and must operate continuously, 24 hours/day.

Justification:

This project is justified on the requirement to replace obsolete deteriorating equipment in order for Hydro to provide least-cost, reliable electrical service. The existing Power Line Carrier has exceeded its useful life and replacement parts are no longer available.

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.

Project Title: Replace Power Line Carrier on TL-250 **(cont'd.)**

Justification: (cont'd.)

Cost Benefit Analysis:

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

Legislative or Regulatory Requirements:

There are no legislative or regulatory requirements.

Historical Information:

In the past five years only one Power Line Carrier replacement has been performed. The replacement of the Power Line Carrier on TL-212 from the Sunnyside Terminal Station to the Paradise River Hydraulic Generating Station was approved by the Board in Order No. P.U. 30 (2007) for $466,000.

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:

A planned outage of eight hours is required on TL-250 to install the high voltage components of the communications equipment on the line. During this time approximately 950 customers in the Burgeo area will be affected. Depending on the actual outage date, the load loss during the outage is expected to be approximately 1.5 to 2.5 MW.

Status Quo:

Voice, SCADA data and teleprotection communication is essential for the operation of TL-250 and the Grandy Brook Terminal Station. Aging equipment, prone to failure, does not provide the reliability needed for control of Hydro's Island Interconnected System. In particular, high speed,

Project Title: Replace Power Line Carrier on TL-250 **(cont'd.)**

Justification: (cont’d.)

Status Quo: (cont’d.)

reliable teleprotection on the Power Line Carrier is required continuously, and even short communication outages are unacceptable. The failure of a teleprotection command to be transmitted over the Power Line Carrier, when required, could cause significant equipment damage, unacceptable outages or even affect the stability of the System.

Alternatives:

Only one viable alternative exists and that is to replace the power line carrier on TL-250. Note that occasionally there is some misunderstanding surrounding Power Line Carrier and other higher bandwidth applications. In recent years much publicity has been given to the benefits of high speed communications over power lines, known as “Broadband over Power Line” (BPL). BPL is quite different than the equipment being replaced here, and is suitable only for very short distances, such as on distribution lines to households for Internet access. BPL cannot be used on transmission lines to provide the types of service required by Hydro in this application.

Conclusion:

This project is necessary to maintain reliable communications associated with the automatic and manual control of the power grid.

Project Schedule:

Project Start: January 1, 2009

Project Completion: December 31, 2009

Future Plans:

None.

Project Title: Replace Remote Terminal Units

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This is a continuation of a program to replace obsolete Remote Terminal Units (RTUs).

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	116.5	0.0	0.0	116.5
Labour	94.8	0.0	0.0	94.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.1	0.0	0.0	12.1
O/H, AFUDC & Escln.	32.6	0.0	0.0	32.6
Contingency	22.3	0.0	0.0	22.3
TOTAL	278.3	0.0	0.0	278.3

Existing System:

This project is required to replace obsolete RTUs at Long Harbour and the Energy Control Center (ECC). RTUs are used in conjunction with the Energy Management System (EMS) to control the delivery of power to our customers. An RTU is located at each terminal and generating station in Hydro's power system. The RTU translates control signals sent by the ECC to remotely controlled equipment in the station; examples include starting and stopping generators, opening and closing circuit breakers, and so on. It also sends information back to ECC on the status of operating equipment.

Age of Equipment or System:

All RTUs being replaced under this project were installed in 1990.

Major Work/or Upgrades:

There have been no major upgrades since the installation of these RTUs.

Anticipated Useful Life:

RTUs have a depreciation period of 10 years and are typically replaced after 15 years.

Project Title: Replace Remote Terminal Units **(cont'd.)**

Existing System: (cont'd.)

Maintenance History:

The five year maintenance history for the RTUs being replaced is shown in Table 1 below.

Table 1. Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2008	0.5	0.0	0.5
2007	0.0	0.0	0.0
2006	0.0	0.0	0.0
2005	0.2	0.0	0.2
2004	0.0	0.1	0.1

Outage Statistics:

There have been no outages experienced by the RTUs being replaced under this project.

Industry Experience:

Industry experience is not relevant in this instance. The RTUs are being replaced based on their age and the unavailability of replacement parts and manufacturer support.

Maintenance or Support Arrangements:

This equipment is no longer supported by the manufacturer and parts are no longer in production. Maintenance is performed by internal forces.

Vendor Recommendations:

There are no vendor recommendations regarding this equipment.

Availability of Replacement Parts:

Replacement parts are no longer in production for this equipment, so spare parts are limited to existing inventory.

Project Title: Replace Remote Terminal Units **(cont'd.)**

Existing System: (cont'd.)

Safety Performance:

There are no safety performance concerns or safety code violations associated with the operation of this equipment. It consists of standard industrial-grade electronics operating in a controlled environment.

Environmental Performance:

There are no environmental performance concerns or environmental code violations associated with the operation of this equipment. It consists of standard industrial-grade electronics operating in a controlled environment.

Operating Regime:

This equipment is used to control and monitor the power grid and is in operation continuously, 24 hrs/day, and 365 days/year.

Justification:

This is a continuation of a program to replace obsolete RTUs. The existing RTUs have been discontinued by the manufacturer and spare parts and repair services are no longer available. The loss of an RTU due to the unavailability of parts or repair services would result in the loss of the Energy Control Centre's ability to monitor and control that portion of the power grid. This would increase the probability of an outage affecting customers, and increase operating costs due to the requirement to have personnel in the station continuously.

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.

Cost Benefit Analysis:

No cost benefit analysis was done because only one viable alternative exists.

Project Title: Replace Remote Terminal Units **(cont'd.)**

Justification: (cont'd.)

Legislative or Regulatory Requirements:

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

Historical Information:

Table 2 shows historical information for RTU replacements.

Table 2. Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
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	313.80	325.0	4	81.3	
2003	285.2	288.0	4	72.0	

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 work. When installation is being performed an operator will be assigned to the terminal station in order to manually control equipment, if required.

Project Title: Replace Remote Terminal Units **(cont'd.)**

Justification: (cont'd.)

Status Quo:

The status quo is not an acceptable alternative because it increases the risk of customer outages occurring as the equipment gets older, reliability decreases, and the limited inventory of spare parts becomes exhausted.

Alternatives:

There are no viable alternatives.

Conclusion:

This project is necessary because of the critical nature of RTUs. To ensure that Hydro can continue to provide reliable least-cost energy to its customers into the future, obsolete equipment that will soon be difficult, if not impossible to properly maintain, must be replaced.

Project Schedule:

The project schedule is shown in Table 3.

Table 3. Project Schedule

Activity	Milestone
Project Initiation	February 2009
Equipment Ordered	March 2009
Configurations Complete	April 2009
Testing Complete	May 2009
Installation and Commissioning Complete	July 2009
Project Closed	August 2009

Future Plans:

None.

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
			($000)		
GENERATION					
Install Unit 1 Cold Reheat Condensate Drains and HP Heater Trip Level - Holyrood		192		192	D-3
Install Motorized Stack Winches - Holyrood		174		174	D-7
Environmental Effects Monitoring Study of Waste Water - Holyrood	73	87		160	
Replace Service Water Piping - Unit 7 - Bay d'Espoir		144		144	D-9
Install Marine Terminal Capstan Lifting Frame - Holyrood		93		93	D-12
Purchase Boom Style Hydraulic Lift - Holyrood		82		82	D-14
Replace Generator Oil Level System on Units 1 and 2 - Cat Arm		68		68	D-15
TOTAL GENERATION	73	841	0	914	
TRANSMISSION AND RURAL OPERATIONS					
Replace 69 kV Breaker L51T2 - Howley		199		199	D-17
Upgrade Great Northern Peninsula Protection - Various Sites		101	91	192	D-20
Upgrade Voltage Conversion Phase 1- Labrador City		189		189	D-26
Upgrade Ventilation System - Little Bay Islands Diesel Plant		186		186	D-28
Pave Parking Lots and Roadways - Bishop's Falls		150		150	D-30
Upgrade Fuel Storage - Cartwright		139		139	D-31
Replace Recloser Control Panels - Various Sites		132		132	D-33
Replace Speed Increaser - Roddickton		125		125	D-36
Purchase and Install a Voltage Regulator Bank - English Harbour West		123		123	D-38
Install Transformer Storage Ramps - Labrador		121		121	D-41
Replace Instrument Transformers - Various Sites		107		107	D-44
Replace 230 kV Breaker Controls - Oxen Pond and Bay d'Espoir		100		100	D-46
Purchase and Install Electronic Recloser - Cartwright		96		96	D-48
Replace Submarine Cable Terminator Kit - Change Islands and Fogo Island		96		96	D-50
Replace Air Compressors - Sunnyside		96		96	D-51
Purchase High Definition Infrared Camera - Central		87		87	D-53
Construct ATV/Snowmobile Storage Building - Whitbourne		86		86	D-55
Install Waste Oil Storage Tanks - Mary's Harbour		84		84	D-57
Replace Drainage System - Western Avalon		84		84	D-59
Replace Surge Arrestors - Various Sites		81		81	D-60
Install Pole Storage Ramps - Various Sites		77		77	D-62
Install Water and Sewer System - Paradise River		77		77	D-65
Construct Transmission Storage Ramps - Bay d'Espoir		75		75	D-67
Install 138 kV Capacitive Voltage Transformer - St. Anthony Airport		71		71	D-69
Install 69 kV Capacitive Voltage Transformer - St. Anthony Diesel Plant		67		67	D-71
Install Remote Ice Growth Detector Beams - Various Sites		65		65	D-73
Install Meter Station for Fuel Reconciliation - Hawke's Bay		64		64	D-75
Install Furnace Fuel Storage Tank - William's Harbour		59		59	D-77
Legal Survey of Primary Distribution Line Right of Way - Various Locations		56		56	D-78
TOTAL TRANSMISSION AND RURAL OPERATIONS	0	2,991	91	3,082	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Page Ref
			($000)		
GENERAL PROPERTIES					
Upgrade Server Technology Program - Hydro Place		194		194	D-80
Replace Radio Tower - Ebbegunbaeg		179		179	D-85
Replace Peripheral Infrastructure - Hydro Place		161		161	D-88
Replace Network Communications Equipment - Various Sites		141		141	D-90
Replace Drafting Scanner/Plotter - Hydro Place		139		139	D-92
Replace Radomes - Various Sites		130		130	D-94
Application Enhancements - Performance Management Software Budgeting Tool - Hydro Place		127		127	D-96
Corp. Application Environment - Upgrade Showcase Strategy Suite - Hydro Place		112		112	D-98
Replace Fire Protection Panels - Hydro Place		89		89	D-100
Security Smartcard and Disk Encryption for Laptops - Hydro Place		89		89	D-101
Application Enhancements - Perform Minor Application Enhancements - Hydro Place		85		85	D-105
Citrix Enhancement - Hydro Place		84		84	D-107
Replace Humidifiers in Air Handling Units - Hydro Place		74		74	D-109
Purchase Test Equipment - Various Sites		74		74	D-111
Purchase Protective Relay Event Report Software - Hydro Place		54		54	D-113
TOTAL GENERAL PROPERTIES	0	1,732	0	1,732	
TOTAL PROJECTS OVER $50,000 AND UNDER $200,000	73	5,563	91	5,727	

Project Title: Install Unit 1 Cold Reheat Condensate Drains and High Pressure Heater Trip Level
Location: Holyrood
Category: Generation - Thermal
Definition: 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 (see Figure 1). 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 heater. Both of these conditions can allow the induction of condensate into the high pressure turbine and cause damage to the turbine blades.

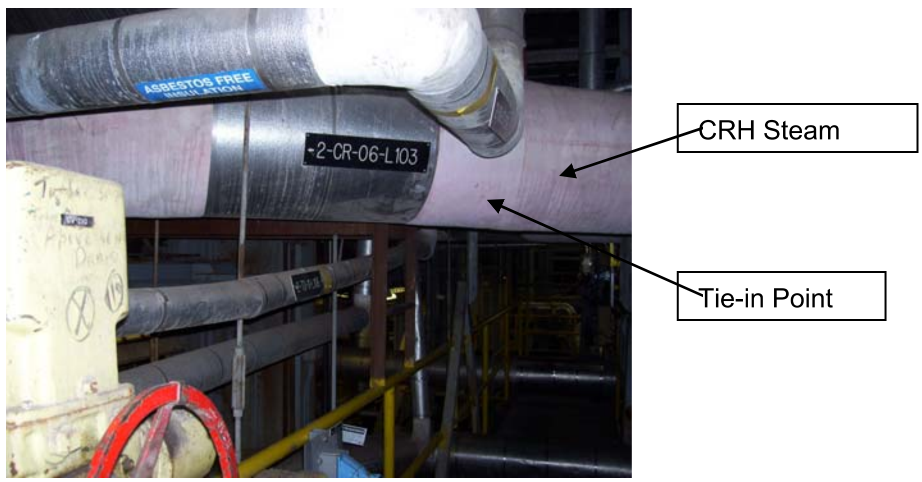


Figure 1 – Tie-in Point for CRH Drain Pot

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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	9.0	0.0	0.0	9.0
Labour	70.9	0.0	0.0	70.9
Consultant	12.0	0.0	0.0	12.0
Contract Work	60.5	0.0	0.0	60.5
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	24.0	0.0	0.0	24.0
Contingency	15.2	0.0	0.0	15.2
TOTAL	**191.6**	**0.0**	**0.0**	**191.6**

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

Operating Experience:

The four main components of each generating unit are the boiler, turbine, generator, and transformer. 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. This new condensate collection system will be installed on the lowest point of elevation on the CRH steam line between the boiler and turbine. The lowest point of elevation is selected because water collects at the lowest point of elevation in a piping system. It is necessary to prevent water induction into the steam turbine to preventing damage to the turbine caused by condensate ingression.

Project Justification:

FM Global, Hydro’s insurance company, indicates that there have been numerous 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 heater high condensate level trip system is essential for reliable operation of the turbine.

A major mechanical failure of the Unit 1 turbine could result if this project, which is based on recommendations by FM Global (see pages D-5 and D-6), is delayed. An unscheduled outage caused by the failure would result in eight to 10 weeks of downtime on Unit 1. In addition, an unscheduled failure during the peak winter load demand could result in a loss of 170 MW of power which represents approximately 10 percent of the Island Interconnected System capacity.

Future Plans:

To perform a similar installation on Unit 2 in 2010 and Unit 3 in 2011.

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

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.

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

FM Global Recommendations

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.

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Project Title: Install Motorized Stack Winches

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to install motorized stack winches on each of the three stacks at the Holyrood Thermal Generating Station (Holyrood).

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	40.4	0.0	0.0	40.4
Labour	52.4	0.0	0.0	52.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	45.8	0.0	0.0	45.8
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	21.8	0.0	0.0	21.8
Contingency	13.9	0.0	0.0	13.9
TOTAL	**174.3**	**0.0**	**0.0**	**174.3**

Operating Experience:

Each of the three stacks is equipped with a davit arm and pulley system that requires hand-lifting and lowering of equipment weighing up to 130 kilograms between the ground and the stack mid-platform, a height of approximately 175 ft (53 m) above ground level.

A considerable amount of physical exertion is required when lifting heavy loads of up to 130 kilograms to a height of more than 50 meters. The effect of wind acting on the loads being lifted during regular maintenance increases the safety risk. Wind makes it substantially harder to control the suspended loads. Wind also increases the forces acting on the load which results in increased risk of equipment failure. In addition, the emergency high angle rescue team utilizes the current lifting system to lift rescue equipment to the mid platform level. This equipment weighs approximately 45 kilograms. Lifting this equipment by hand using the current lifting system can fatigue the rescue team before they can attempt a rescue. There are no recorded incidents or near misses that have occurred in relation to the existing pulley system.

Project Title: Install Motorized Stack Winches **(cont'd.)**

Operating Experience: (cont'd.)

This system is adequate for light-duty lifting but inadequate for lifting in an emergency response situation and for transporting heavier tools and equipment. Operations personnel at Holyrood have worked with the current manual equipment since 1990.

Project Justification:

The recent installation of a Continuous Emissions Monitoring System (CEMS) and the formation of a high angle rescue team have created a need that is not met by the existing system. The increased workload and climbing requirements is beyond the capabilities of the existing equipment. An upgrade is required for enhanced safety and improved emergency response times.

Lifting equipment with the current system usually takes 30 minutes or longer. Due to the speed of than electric winch, this time will be reduced to 15 minutes or less. This reduction in time will be beneficial to the rescue team as they will be able to respond to an emergency more quickly. The current system is inadequate for lifting emergency response equipment, which weighs approximately 45 kilograms, and for lifting heavier tools and equipment with weights of up to 130 kilograms. Also, during lifts the loads may be subject to high wind forces, increasing the risk of a potential failure or loss incident.

Future Plans:

None.

Project Title: Replace Service Water Piping - Unit 7

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the service water piping on Unit 7 at the Bay d'Espoir Generating Station. The piping will be replaced with stainless steel pipe to reduce corrosion and fouling of the piping. The system will also be equipped with Victaulic couplings to allow ease of inspection and maintenance.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	65.0	0.0	0.0	65.0
Labour	50.1	0.0	0.0	50.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	15.6	0.0	0.0	15.6
Contingency	11.7	0.0	0.0	11.7
TOTAL	144.4	0.0	0.0	144.4

Operating Experience:

Each unit at the Bay d'Espoir Generating Station is equipped with a cooling water system, used to maintain the temperature of generator components, consisting of surface air coolers, turbine bearing coolers, piping, and associated components. Each cooling system is fabricated completely from carbon steel which is susceptible to corrosion. In fact, the system has experienced fouling and corrosion approximately every five years resulting in the need for cleaning (see Figure 1 for a picture of fouled piping). This corrosion has progressed to the point that if cleaning is performed then leaks will occur. The leaks can potentially damage the generators, thus, replacement of the system is required.

Upgrading of the service water systems for Unit 7 at Bay d'Espoir is required to increase the reliability of this hydroelectric generating unit. By upgrading the components of this system with corrosion resistant piping, the potential for corrosion and fouling of the piping will be significantly less thus, reducing the potential for generator over heating and unit outages.

Project Title: Replace Service Water Piping - Unit 7 **(cont'd.)**

Operating Experience: (cont'd.)

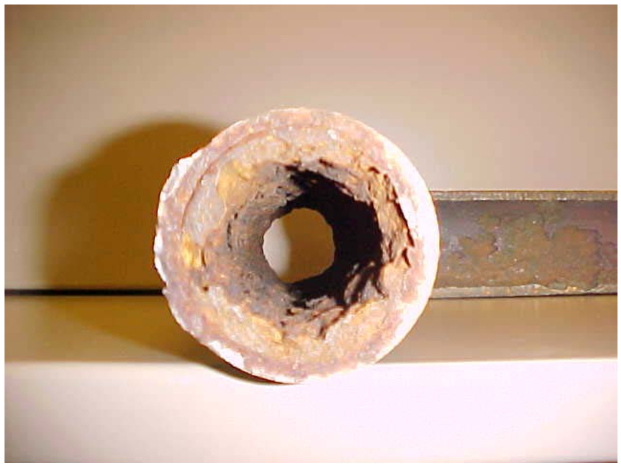

Figure 1. Fouled Cooling Water Pipe, Bay d'Espoir

The service water system has an estimated service life of 25 years and has been in service since 1977.

The five year maintenance history for the service water system is shown in Table 1.

Table 1. Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2007	0.8	0.0	0.8
2006	0.5	0.0	0.5
2005	0.5	0.5	1.0
2004	1.2	0.0	1.2
2003	1.3	0.9	2.2

Project Title: Replace Service Water Piping - Unit 7 **(cont'd.)**

Project Justification:

The piping and its components, as confirmed in preventive maintenance inspections, is extensively fouled and corroded to the extent that the only option is to replace the piping system with new components. This has to be done to avoid forced unit outages or capacity de-rating of the units.

A service water system study was performed in 2002 for all hydroelectric generating stations. This study concluded that all piping 4 inches in diameter piping and smaller should be replaced with stainless steel schedule 10 for corrosion and fouling protection. This reduces future maintenance costs of cleaning out piping, on average, every five years because of fouling. Changing the piping material from mild steel to stainless steel eliminates the corrosion fouling problem, thereby improving the efficiency of the cooling system. This lowers the risk of having to de-rate the unit or take a forced outage because of high temperatures.

It is not possible to change the complete service water piping system during a typical outage for Unit 7. Therefore, only the service water piping less than 4 inches in diameter will be replaced in 2009. Due to it's large size (8 inches) the supply and discharge headers will be inspected during the installation of the surface air cooler piping to determine if replacement is required.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Install Marine Terminal Capstan Lifting Frame

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to install four lifting frames over four capstans located along the shoreline at the Holyrood Thermal Generating Station (Holyrood).

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	25.7	0.0	0.0	25.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	50.2	0.0	0.0	50.2
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	9.8	0.0	0.0	9.8
Contingency	7.6	0.0	0.0	7.6
TOTAL	93.3	0.0	0.0	93.3

Operating Experience:

Holyrood burns No. 6 heavy fuel oil (Bunker C) at a rate of up to 3.7 million barrels per year. This fuel is received at the plant via tanker approximately 14 times per year. The tankers are moored to the shoreline at four locations. Each mooring location is equipped with a capstan which a rotating drum used to haul heavy lines and cables, that assists in the mooring of the tankers to the shoreline (see Figure 1). Removal of the capstan is required in order to perform maintenance on its gear reducer and motor. This maintenance is performed once or twice a year. A proper lifting frame to remove the capstan does not exist. At present, when such maintenance is required scaffolding is erected around the capstan as a temporary lifting device. A steel beam is laid across the top of the scaffolding. A hoist is then attached to the beam to lift the capstans. This unconventional use of scaffolding is an unsafe practice as it has the potential to collapse and result in personal injury and/or loss of equipment.

Figure 1. A Marine Capstan

Project Title: Install Marine Terminal Capstan Lifting Frame **(cont'd.)**

Project Justification:

The project is justified on the need to install permanent marine capstan lifting frames as required to safely maintain the capstans at Holyrood. Each marine terminal capstans, weigh approximately two tons. The current use of scaffolding when maintaining the marine terminal capstans is not conventional. Scaffolding is designed to be a means for workers to access work areas. They are not normally designed to support structural loads. Also, by installing these lifting frames, the required maintenance time will be reduced from the current three to four days to one to two days.

Future Plans:

None.

Project Title: Purchase Boom Style Hydraulic Lift

Location: Holyrood

Category: Generation - Tools & Equipment - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase a new hydraulic lift capable of safely lifting people to high work areas.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	65.0	0.0	0.0	65.0
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.	10.7	0.0	0.0	10.7
Contingency	6.5	0.0	0.0	6.5
TOTAL	82.2	0.0	0.0	82.2

Operating Experience:

The various Maintenance Shop Personnel have to, from time to time, work at heights which require the use of ladders and scaffolds.

Project Justification:

When using ladders, there is risk of falling causing injury to the worker. To build a scaffold takes time and effort thereby slowing down the work flow. Four men are required for one and a half days to build a scaffold and then half day to take it down. Scaffolding is required to access the two pumphouse cranes for servicing and to perform routine maintenance in the dock loading area. The gas turbine stack and snow door assemblies require scaffolding for work to be performed. It is also required to install or repair building siding, eaves trough and windows. A portable hydraulic lift will minimize exposure to fall hazards during the day to day activities performed by the maintenance staff. This machine would be used to safely lift maintenance personnel to working heights and increase the safety for outdoor activities.

Future Plans:

None.

Project Title: Replace Generator Oil Level System on Units 1 and 2

Location: Cat Arm

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the current generator oil level system on Units 1 and 2 of the Cat Arm Hydraulic Generating Station. The generator oil level system is used to monitor the generator and turbine bearing oil levels. Bearings allow rotating components, such as the turbine shaft and rotor, to rotate relative to the stationary components, such as the stator. The hydraulic turbines derive their mechanical power from the moving water to turn the electric generators. The turbine – generator combination has two types of bearings. A guide bearing constrains the radial movement of the rotor or shaft and a thrust bearing supports the weight of the generator and transmits the weight into the powerhouse structure. These bearings use a thin film of oil to reduce friction between the moving parts, thereby preventing overheating. The oil level system monitors the oil used by the bearings. If the oil is lost, either due to a leak or improper oil level indication, it is possible that the stationary and moving components will rub causing extensive damage and require repair or replacement of the bearing, depending on the severity of the damage.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	11.3	0.0	0.0	11.3
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	6.7	0.0	0.0	6.7
O/H, AFUDC & Escln.	8.6	0.0	0.0	8.6
Contingency	5.4	0.0	0.0	5.4
TOTAL	67.8	0.0	0.0	67.8

Operating Experience:

The current system is unreliable in that the low level alarm will never be triggered. As the oil level goes down, residual oil is left in the piping to the sight glass, which never decreases to show the actual oil level. This residual level remains high enough that it will never trip the low level alarm. The oil level system is used to indicate the oil level of the turbine and generator bearings. If the

Project Title: Replace Generator Oil Level System on Units 1 and 2 **(cont'd.)**

Operating Experience: (cont'd.)

oil level in either of these bearings becomes too low, the bearings will start to make contact with the spinning turbine shaft and generator rotor. This will cause destruction of the bearings and also harm the spinning components.

The existing system cannot provide reliable information on oil levels due to the residual oil left in the piping. The proposed system will include new piping, a differential pressure oil level sensor, a guided wave radar level sensor, and digital displays from which oil levels can be observed. Similar types of systems are currently being used in the Bay d'Espoir and Upper Salmon Hydroelectric generating plants. The two plants have not experienced problems with the systems. They are reliable and provide accurate information.

Project Justification:

This project is justified on the need for a reliable generator bearing and turbine bearing oil level monitoring system. Without a reliable monitoring system, the generator and turbine units are at risk of damage due to the loss of oil pressure. Low oil pressure leads to increased friction that damages the generator and turbine bearings. Failure of an alarm system to annunciate this condition can result in costly repairs.

Future Plans:

None.

Project Title: Replace 69 kV Breaker L51T2

Location: Howley

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing 66 kV Sulfur hexaflouride (SF_6) gas circuit breaker at the Howley Terminal Station. The scope of the work involves providing a new foundation, installing new protection equipment and control cable, and wiring connections to the station control systems. A mobile substation will be used to maintain service to customers and minimize outages while the work on replacing the breaker proceeds.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	74.0	0.0	0.0	74.0
Labour	69.5	0.0	0.0	69.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	17.0	0.0	0.0	17.0
O/H, AFUDC & Escln.	21.9	0.0	0.0	21.9
Contingency	16.1	0.0	0.0	16.1
TOTAL	198.5	0.0	0.0	198.5

Operating Experience:

The existing breaker is a Westinghouse SF6 gas breaker which was installed in 1981. The anticipated service life of this type of breaker is 30 years. Depending on environmental conditions and service duty, actual service life can be less than 30 years, as is the case with this breaker. There has been an increase in preventive and corrective maintenance, and an increased number of service interruptions on transmission line TL-251, which delivers power from the Howley Terminal Station over a distance of approximately 47 kilometers to the Hampden and Jackson's Arm distribution systems. Table 1 shows the maintenance history, and Table 2 shows reliability statistics.

This breaker is a 69 kV Westinghouse SF_6 SP breaker and this vintage (1981) and type (6905P2500) has a history of problems at other locations. For example, prior to being replaced in 2007, breaker B7C1 at Hardwoods had many problems relating to SF_6 gas leaks (11 events),

Project Title: Replace 69 kV Breaker L51T2 **(cont'd.)**

Operating Experience: (cont'd.

operating rods breaking (2 events) and, as well, an air receiver tank failure. L51T2 at Howley has also had SF_6 gas leaks (11 events) and a receiver tank failure. In fact, to maintain system reliability, a temporary receiver tank has been installed on this breaker in August 2007.

Table 1. Maintenance History

Year	Preventative Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	0.3	3.3	3.6
2006	1.1	2.5	3.6
2005	0.4	0.3	0.7
2004	0.2	0.6	0.8
2003	0.2	0.3	0.5

There are 790 customers in the Hampden and Jackson's Arm area serviced by TL-251. A failure of breaker L51T2 will result in a major outage to these customers, until installation of a replacement breaker.

Project Justification:

The Breaker L51T2 is the main protective device servicing the transmission line TL-251 to the Hampden and Jackson's Arm distribution systems. These breakers have a history of problems as described in Operating Experience and this one needs to be replaced in order to provide reliable power to the customers in Hampden and Jackson's Arm.

Table 2 lists the 2003 to 2007 average Transmission (T) System Average Interruption Frequency Index (SAIFI) T-SAIFI and System Average Interruption Duration Index (SAIDI) T-SAIDI for the three delivery points (Hampden, Jackson's Arm and Coney Arm) in the White Bay area served by transmission line TL-251 and circuit breaker L51T2 in the Howley Terminal Station. The average of the three are compared to the Hydro System and the latest CEA five year average (2002 to 2006).

Project Title: Replace 69 kV Breaker L51T2 **(cont'd.)**

Project Justification: (cont'd.)

SAIDI and SAIFI are defined 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. Average T-SAIFI and T-SAIDI

Area	T-SAIFI	T-SAIDI
Hampden	1.80	224.20
Jackson Arm	1.40	397.40
Coney Arm	1.40	378.00
White Bay System	1.53	333.20
Hydro System	1.38	83.63
CEA (2002-2006)	0.86	127.92

While the frequency of interruptions is only slightly higher than the Hydro average, the durations are more extensive than average. However, the outage statistics cannot be solely attributed to this breaker.

Future Plans:

None.

Project Title: Upgrade Great Northern Peninsula Protection

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace five distance protective relays and eight phase over-current protective relays with new microprocessor based relays on Hydro's 69 kV and 138 kV transmission lines at the following six terminal stations on the Great Northern Peninsula (GNP): TL-259 at Berry Hill, TL-241 at Peter's Barren, TL-221 at Hawke's Bay, TL-244 at Plum Point, TL-256 at Bear Cove, and TL-257 at Roddickton.

All new protective relays will interface with Hydro's Supervisory Control and Data Acquisition (SCADA) network for recording system trips and fault occurrences in order to establish the Sequence Of Events (SOE) for analysis of system disturbances and outages.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	47.8	4.0	0.0	51.8
Labour	33.2	43.3	0.0	76.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	9.0	15.4	0.0	24.4
O/H, AFUDC & Escln.	10.6	13.1	0.0	23.7
Contingency	0.0	15.3	0.0	15.3
TOTAL	100.6	91.1	0.0	191.7

Operating Experience:

The Great Northern Peninsula (GNP) is serviced by the following transmission lines:

Line	Location
TL-259	Berry Hill to Peter’s Barren
TL-241	Peter’s Barren to Plum Point
TL-221	Peter’s Barren to Hawkes Bay
TL-244	Plum Point to Bear Cove
TL-256	Bear Cove to St. Anthony Airport
TL-257	St. Anthony Airport to Roddickton

Project Title: Upgrade Great Northern Peninsula Protection **(cont'd.)**

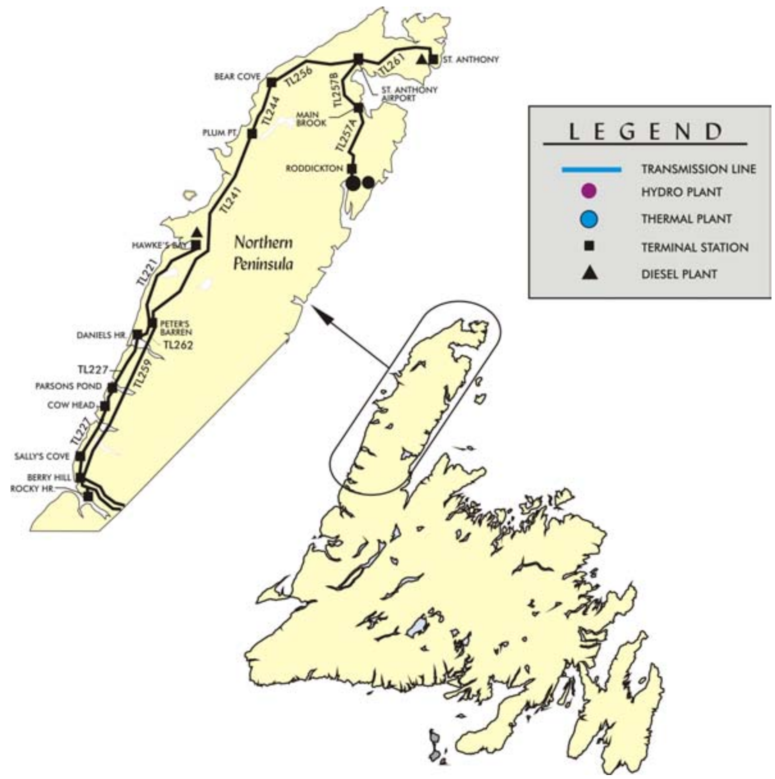

Figure 1. GNP Transmission Lines

Operating Experience: (cont'd.)

Figure 1 provides an Island map which highlights the GNP transmission lines. Each of these lines has protective relays to detect faults such as a tree falling onto the conductors or conductors slapping together during windy conditions. These relays will trip the line breakers to protect the lines from damage.

The lines are protected by relays that determine whether the fault is within a certain distance from the terminal station. These are called distance relays and they are the primary fault protection. They operate very quickly to isolate the faulted line. The primary distance relays are backed up by a secondary relay called an overcurrent relay. This relay will operate once a defined current level has been exceeded and has a time delay to prevent it from operating for faults on adjacent lines. Some of the relays are of an electronic design and others are of an electro-mechanical design, which involves moving mechanical parts.

The various relay designs are as shown in Table 1.

Table 1. Relay Designs

Line	Relay	Design	Model	Installation Year
TL-259	Primary Distance	Electronic	Areva Optimho	1996
TL-241	Primary Distance	Electronic	Areva Optimho	1995
TL-221	Primary Distance	Electro-mechanical	Westinghouse KD	1970
TL-221	Secondary Overcurrent	Electro-mechanical	General Electric IAC	1970
TL-244	Secondary Overcurrent	Electro-mechanical	General Electric IAC	1983
TL-256	Primary Distance	Electronic	Areva Optimho	1996
TL-257	Primary Distance	Electro-mechanical	Westinghouse KD	1989

Project Title: Upgrade Great Northern Peninsula Protection **(cont'd.)**

Operating Experience: (cont'd.)

Customers on the GNP have experienced power outages due to distance relay failures. Additionally, fault protection coordination is not possible with the existing overcurrent electro-mechanical relays, resulting in a larger customer outage area following power system disturbances. The GNP Transmission System outage statistics are located in Table 4.

The General Electric electro-mechanical overcurrent relay, the Westinghouse electro-mechanical distance relay, and the Optimho digital distance relay are no longer in production. Original parts for the electro-mechanical relays are no longer available and original parts for the Optimho digital distance relay have at least a two-three month delivery time. As well, the Optimho distance relay has to be removed from service and sent back to the manufacturer for repair of any internal circuit failures.

Protective relay failure events and related issues are listed in Table 2.

Table 2. Protective Relay Failure Events

Date	Line	Description
2007/10/19	TL-221	Distance Relay Westinghouse KD10 fails under test
2007/09/20	TL-244	Optimho LFZP111S relay failed in service
2007/09/24	TL-244	Optimho LFZP111S relay replaced by SEL-311C
2007/09/28	TL-244	Distance Relay Westinghouse KD10 trip contact issue
2007/09/28	TL-244	Overcurrent Relays GE IAC53 time dial setting issue
2001/05/17	TL-256	Optimho LFZP111S relay failed in service
2001/10/09	TL-256	Optimho LFZP111S repaired and returned to service

Temporary repairs have been made to those protective relays that failed during function testing in 2007. The Areva Optimho is an electronic distance relay design, however, there have already been two failures of this type of relay on the GNP since 2001. Following the second failure in 2007 on Plum Point TL-244, which resulted in a system outage, this relay was replaced with a Schweitzer type distance relay. Therefore, the remaining Optimho relays on the GNP are also included for replacement.

Project Title: Upgrade Great Northern Peninsula Protection **(cont'd.)**

Operating Experience: (cont'd.)

GNP Transmission System Outage Statistics

Terminal equipment outage statistics are provided in two tables. The first table (Table 3) lists the transmission line performance for the previous five years on transmission lines TL-259, TL-221, TL-241, TL-244, TL-256, and TL-257 compared to the latest available five year average (2001-2005) for all of the Hydro System and CEA.

The second table (Table 4) details the effect of trips on these transmission lines to delivery points. The table lists the transmission line and the delivery points it supplies. In this table, it can be seen that some delivery points are affected by more than one transmission tripping.

Table 3. Transmission Delivery Points

Listing of Transmission Line Terminal Equipment Performance		
Transmission System	**Frequency[1] (per terminal year)**	**Unavailability (%)[2]**
138 kV		
TL-259	2.40	0.0202
TL-241	1.30	0.0004
TL-244	2.10	0.0101
TL-256	0.90	0.0009
Hydro 138 kV (2001-2005)	0.57	0.1054
CEA 138 kV (2001-2005)	0.14	0.0381
66 kV		
TL-221	27.60	0.0052
TL-257	2.20	0.0385
Hydro 66 kV (2001-2005)	0.57	0.0537
CEA 66 kV (2001-2005)	0.27	0.0896
[1] Frequency is number lines outages per line terminal.		
[2] Unavailability is amount of time the line is not available for terminal related causes.		

Project Title: Upgrade Great Northern Peninsula Protection **(cont'd.)**

Operating Experience: (cont'd.)

The average Transmission (T) System Average Interruption Duration Index (T-SAIDI) and the System Average Interruption Frequency Index (T-SAIFI) is defined as follows:

SAIDI - Indicates the system average interruption duration for customers served per year or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - Indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 4. Five Year Average

(2003-2007) Forced Outages Only			
Transmission Line	**Delivery Point Affected**	**T-SAIFI**	**T-SAIDI**
TL-259	**Total**	**3.40**	**100.89**
	Bear Cove	2.20	116.80
	Daniels Harbour	2.20	54.00
	Hawkes Bay	4.60	63.20
	Main Brook	4.80	174.80
	Parsons Pond	2.40	31.60
	Plum Point	1.60	49.20
	Roddickton	4.80	262.20
	St. Anthony	4.60	55.34
TL-221	Hawkes Bay	**4.60**	**63.20**
TL-241	**Total**	**3.00**	**131.67**
	Bear Cove	2.20	116.80
	Main Brook	4.80	174.80
	Plum Point	1.60	49.20
	Roddickton	4.80	262.20
	St. Anthony	4.60	55.34
TL-244	**Total**	**4.10**	**152.29**
	Bear Cove	2.20	116.80
	Main Brook	4.80	174.80
	Roddickton	4.80	262.20
	St. Anthony	4.60	55.34
TL-256	**Total**	**2.03**	**164.11**

Project Title: Upgrade Great Northern Peninsula Protection **(cont'd.)**

Operating Experience: (cont'd.)

Table 4. Five Year History (cont'd.)

	Main Brook	4.80	174.80
	Roddickton	4.80	262.20
	St. Anthony	4.60	55.34
TL-257	Roddickton	**4.80**	**262.20**
	TRO Northern Region	3.37	114.42
	Hydro System	1.38	83.63
	CEA (2002-2006)	0.86	127.92

Project Justification:

The outage statistics indicate transmission lines on the GNP have experienced protection trips due to obsolete equipment. This project is justified on the requirement to replace outdated protective relays that have a high risk of failure in order for Hydro to provide safe, least-cost, reliable electrical service to customers on the GNP.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Upgrade Voltage Conversion Phase I

Location: Labrador City

Category: Transmission and Rural Operations - Distribution Labrador

Definition: Other

Classification: Normal

Project Description:

This project includes the first phase of conversion of the distribution system in Labrador City from 4.16 kV to 25 kV as detailed in the Labrador City Distribution System Upgrading Study Located in Volume II, tab 3, Appendix B. The project involves preliminary engineering to confirm the scope of work and the cost estimate for Phase II, a multi-year proposal that will be submitted to the Board as part of the 2010 Capital Program.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	3.0	0.0	0.0	3.0
Labour	115.0	0.0	0.0	115.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	34.0	0.0	0.0	34.0
O/H, AFUDC & Escln.	21.6	0.0	0.0	21.6
Contingency	15.2	0.0	0.0	15.2
TOTAL	188.8	0.0	0.0	188.8

Operating Experience:

The Labrador City Distribution System was owned and operated by The Iron Ore Company of Canada (IOCC) until acquired by Hydro in 1992. At that time, the system was upgraded to have the capacity to supply a local load of approximately 52 MW. By 2009, the Labrador City load will reach the 52 MW level and continue to grow as a result of expansions at IOCC.

Project Justification:

The Labrador City Distribution System Upgrading Study has determined a voltage conversion to 25 kV to be the preferred technical and economic alternative to address load growth in Labrador City. The upgrade of the Labrador City Distribution System involves the reconfiguration of the substations and 46 kV sub-transmission lines supplying power to the area, and a voltage conversion to the distribution lines that supply Hydro's customers. The study investigated both 12.5 kV and 25 kV conversion alternatives, however, because Hydro uses identical standards for both

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

Project Justification: (cont'd.)

12.5 kV and 25 kV distribution construction, the only differences between the alternatives are those associated with the substation and 46 kV sub-transmission expansion plans. The distribution plan is common to both alternatives. The reconfiguration of the substations and 46 kV lines are addressed in a separate 2009 capital proposal, "Upgrade Labrador City to 25 kV". The distribution system conversion is in two phases; Phase I is the preliminary engineering to be completed in 2009 and Phase II is a multi-year conversion program starting in 2010.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Upgrade Ventilation System

Location: Little Bay Islands Diesel Plant

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

This project is required to increase ventilation air flow and improve air movement through the engine hall in order to provide temperature control in the Little Bay Islands diesel plant. Two new supply and exhaust fans will be installed in locations which will provide for cooling efficiency, particularly during the summer. System control panels will be installed and a thermostat will be mounted in the engine hall for system control.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	68.9	0.0	0.0	68.9
Labour	63.2	0.0	0.0	63.2
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.	23.5	0.0	0.0	23.5
Contingency	14.8	0.0	0.0	14.8
TOTAL	**186.3**	**0.0**	**0.0**	**186.3**

Operating Experience:

The existing system provides only half of the airflow necessary for effective engine hall cooling during peak periods. High combustion air temperatures reduce the available power of the diesel engines and high engine hall ambient temperatures can cause heat stress on maintenance and operating personnel, which increases health risks. This is managed by reducing time in the engine hall, which increases the time to complete maintenance tasks. With the existing ventilation system, temperatures in the engine hall can be expected to regularly exceed 40° C during the summer. Operations personnel have reported temperatures in the engine hall of 67° C during the summer.

Project Title: Upgrade Ventilation System **(cont'd.)**

Project Justification:

The current ventilation flow rate of 12,000 cfm (cubic feet per minute) cannot supply the air flow necessary to keep the temperature in the engine hall at a level that is acceptable for worker safety. High engine hall temperatures also limit the power output of the diesel engines. Review of the ventilation requirements indicates that 24,000 cfm is required to keep the engine hall temperature within the 10°C of ambient temperature during summer operation. This will limit the engine hall temperature to approximately 40°C during peak summer operating periods.

Future Plans:

None.

Project Title: Pave Parking Lots and Roadways

Location: Bishop's Falls

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project is required to supply and install approximately 7,000 square meters of asphalt pavement at Bishop's Falls to cover the parking areas at the Service Building, the Helicopter Hanger and the roadway to the Diesel/Network Services shop.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	0.0	0.0	0.0	0.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	132.0	0.0	0.0	132.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	5.0	0.0	0.0	5.0
Contingency	13.2	0.0	0.0	13.2
TOTAL	**150.2**	**0.0**	**0.0**	**150.2**

Operating Experience:

These areas of the Bishop's Falls complex are currently gravel surfaced. The gravel surface results in a build up of snow and ice during the snow clearing season which contributes to increased incidents of slippery driving and walking surfaces. These areas become very muddy during spring thaw. The rough surface created from the ice build up causes damage to the plow truck when it is operating in these areas.

Project Justification:

Paving will enhance the ability to keep these areas ice free in winter and improve safety for vehicles and pedestrians using these areas. On gravel surfaces, snow becomes compacted through vehicle and pedestrian use and easily turns to ice through temperature changes. On paved surfaces, snow is easier to plow and clean off. The pavement will provide a standard surface material throughout the complex and reduce the levels of ice control material needed. As well, less salt is required to maintain paved surfaces.

Future Plans:

None.

Project Title: Upgrade Fuel Storage

Location: Cartwright

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase and install a 45,400 litre double wall, vacuum sealed fuel storage tank for the existing diesel plant in Cartwright, Labrador. Work includes modifications to the existing fuel header system to accommodate the new tank. This includes installation of pipe supports, painting, pressure testing of the new piping system, and installation of a new pressure treated timber foundation.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	54.0	0.0	0.0	54.0
Labour	33.3	0.0	0.0	33.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	7.0	0.0	0.0	7.0
Other Direct Costs	17.4	0.0	0.0	17.4
O/H, AFUDC & Escln.	16.2	0.0	0.0	16.2
Contingency	11.2	0.0	0.0	11.2
TOTAL	139.1	0.0	0.0	139.1

Operating Experience:

When the Storage and Handling of Gasoline and Associated Products (GAP) Regulations were enacted, there was a requirement for all fuel storage tanks to have a method of secondary containment. At that time it proved both practical and economical for Hydro to deliver open steel dykes to sites and place the existing tanks within the dykes. Since that time secondary containment has progressed to covered steel dykes and now to double wall, vacuum sealed tanks which eliminate the need for steel dykes. The existing open dyke requires continual monitoring and maintenance to ensure it does not fill up with rain or snow.

A visual inspection was carried out on the structural supports on the inside of the dyke and it was concluded that the supports were not structurally adequate. The saddles that support the tank inside the dyke are starting to protrude into the tank causing denting of the tank. This results from metal fatigue over time. The tank is now 33 years old, well past its useful life of 20 years, and show signs of deterioration and heavy rusting. It is necessary to replace the tank.

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

Operating Experience: (cont'd.)

There was a 45,400 litre fuel storage tank installed in Paradise River in 2005 at a cost of $75,600. The increase in costs for the current project is mainly due to the increase of steel and transportation costs since 2005.

Project Justification:

The existing tank was fabricated in 1975. It was used in Rigolet for 11 years and then installed in Cartwright in 1986. The steel dyke is of the old design, with no covers, which allows for accumulation of rain, snow, and ice in the dyke. Any accumulation reduces the capacity of the dyke and makes it in non-conformance with GAP regulations.

The regulations state in Section 27.(8)(a) "where a dyked area contains only one storage tank, the dyked area shall retain not less than 110 percent of the capacity of the tank". This situation currently requires observation and remedial action, as needed, which will be eliminated with the installation of the new double wall tank.

Future Plans:

None.

Project Title: Replace Recloser Control Panels

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project involves the purchase and installation of five stainless steel control panels for distribution reclosers: three for Burgeo (BU2-R1, BU3-R1 and BU4-R1) and two for Bottom Waters (BW2-R3 and BW4-R1).

These distribution reclosers will also require an upgrade for their sensing current transformers (CTs) in order to be compatible with the latest version digital control. The recloser control panel would be in compliance with Hydro Engineering Distribution Standard D1-06-01 which is 'Three Phase Electronic Recloser Specification'. Remote Supervisory Control and Data Acquisition (SCADA) access capability is also included in the upgrade.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	50.0	0.0	0.0	50.0
Labour	51.0	0.0	0.0	51.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	19.2	0.0	0.0	19.2
O/H, AFUDC & Escln.	12.2	0.0	0.0	12.2
Contingency	0.0	0.0	0.0	0.0
TOTAL	132.4	0.0	0.0	132.4

Operating Experience:

Electronic recloser control panels (illustrated in Figures 1 and 2) are mounted outdoors and are therefore exposed to all weather conditions, including severe salt contamination in rural coastal communities. The existing Cooper Form 3 and 3A recloser control panels are a painted steel design, which have been in service for about 35 years. Maintenance crews have patched and repaired these panels over the years, however, within the last several years many of these recloser control panels have deteriorated beyond repair and parts are no longer readily available from the manufacturers. The cost of retrofits is prohibitive since it can amount to 80 percent of the price for a new stainless steel recloser control panel. The stainless steel recloser panels have long service

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

Operating Experience: (cont'd.)

lives in adverse conditions; this is especially important in the rural coastal locations in which Hydro provides service. Any replacement parts that may be available for these older Cooper Form 3/3A recloser control panels now require reverse engineering by the manufacturer, which has resulted in long delivery times, typically 16 - 18 weeks.

The reclosers contained within the control panels are considered the most important fault protection device for the various distribution systems that Hydro services. It is also a critical protection device as it relates to the safety and protection of our line crews when performing routine hot line work and other power system repairs.

This is the second year of a four year program to replace recloser control panels. Board Order No. P.U.30 (2007) approved the replacement of eight control panels in the 2008 capital budget for $222,500.

Project Justification:

The distribution recloser is a key protective device for detection of various types of system faults and the automatic restoration of power when these line faults are only temporary in nature. It also enables isolation of the faulted line section should the system fault be permanent. Therefore, the operating integrity of this key protective device must not be compromised by the failure of an internal electronic component due to severe rusting of the recloser control panel. The replacement recloser control cabinet shall be stainless steel construction, which is now the standard design requirement for new installations in order to protect against severe salt contamination. The new recloser control panel will also have remote control capability should a future telecommunications network be established at these sites.

Future Plans:

Future replacements will be proposed in future capital budget applications.

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

Figure 1. Inside of Recloser Control Panel

Figure 2. Outside of Recloser Control Panel

Project Title: Replace Speed Increaser

Location: Roddickton

Category: Transmission and Rural Operations - Generation Northern

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the speed increaser at the Roddickton Mini-Hydroelectric Plant. The speed increaser is a gear box that increases the turbine operation speed of 450 rpm to the generator operation speed of 1,200 rpm.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	77.0	0.0	0.0	77.0
Labour	20.0	0.0	0.0	20.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	16.0	0.0	0.0	16.0
Contingency	9.9	0.0	0.0	9.9
TOTAL	**124.9**	**0.0**	**0.0**	**124.9**

Operating Experience:

The speed increaser gear box is physically coupled to the turbine output shaft and the generator input shaft, and is essential for the proper operation of the mini-hydro plant to produce electricity at the required 60 Hertz. The speed increaser has reached the end of its useful operating life of 15 to 20 years. It was originally installed in 1980 and was rebuilt three times. In 1991, the gear box was rebuilt at a cost of $3,810. In 1997, it was rebuilt at a cost of $5,000. In 2006, it was rebuilt at a cost of $13,665. In order to rebuild the gear box it must be removed and shipped away. This down time can take approximately four months due to delays in obtaining obsolete parts for the gear box, and two months longer if there is damage to the gear box housing. The maintenance philosophy is to run the speed increaser to failure before a rebuild.

Project Title: Replace Speed Increaser **(cont'd.)**

Project Justification:

The speed increaser is vital for power generation. The existing speed increaser is obsolete and, its useful life has been extended through a number of rebuilds. After the last rebuild in 2006, Siemens, who repaired the gearbox, recommended that Hydro consider replacing the speed increaser because of obsolete technology and the unavailability of replacement parts from the vendor.

Future Plans:

None.

Project Title: Purchase and Install a Voltage Regulator Bank

Location: English Harbour West

Category: Transmission and Rural Operations - Distribution Central

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase and install three single-phase 7.2/14.4 kV, 200 AMP voltage regulators on the English Harbour West Distribution System. The new regulator bank will be installed on a new three-pole structure at the start of distribution line L1 near the English Harbour West Terminal Station.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	69.0	0.0	0.0	69.0
Labour	19.0	0.0	0.0	19.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	10.0	0.0	0.0	10.0
Other Direct Costs	3.0	0.0	0.0	3.0
O/H, AFUDC & Escln.	12.1	0.0	0.0	12.1
Contingency	10.2	0.0	0.0	10.2
TOTAL	123.3	0.0	0.0	123.3

Operating Experience:

The English Harbour West Distribution System is located on the Connaigre Peninsula and is supplied from the English Harbour West Terminal Station. The distribution system consists of a single radial medium-voltage 25 kV distribution feeder L1. Feeder L1 is approximately 53 kilometers in length and supplies power to 802 customers in the communities of Poole’s Cove, St Jacque’s, Belloram, English Harbour West, Mose Ambrose, Boxey, Coomb’s Cove, Wreck Cove, and Rencontre East. The community of Rencontre East was part of the isolated diesel system until the spring of 2006 when it was interconnected to the English Harbour West distribution system.

The existing English Harbour West Terminal Station includes a 69/25 kV, 5/6.7 MVA power transformer. The transformer has an off load tap changer which provides an approximate 2.5 percent boost to the voltage on the distribution system, because there is no automatic voltage regulation at the station. Voltage regulation for the existing system is via the transmission system to which it is connected.

Project Title: Purchase and Install a Voltage Regulator Bank **(cont'd.)**

Operating Experience: (cont'd)

As a result of customer complaints and a subsequent investigation of the distribution and transmission systems, it was determined that the voltage regulation, due to load variations on both systems, was negatively impacting customers on the distribution system. The analysis identified the need to improve the system voltage regulation so that customers receive acceptable voltages.

This is the first installation of a voltage regulator bank at the English Harbour West Terminal Station. A bank of voltage regulators was installed on this system in 1980 at a location 33 kilometers from the station. That installation was to prevent low voltages from occurring at the end of the line. A voltage regulator bank has an estimated service life of 30 years.

The five year maintenance history for the English Harbour West Distribution System is shown in Table 1.

Table 1: Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	0.3	15.4	15.7
2006	0.6	16.6	17.1
2005	0.3	14.2	14.5
2004	0.3	21.3	21.5
2003	0.0	27.1	27.1

Project Justification:

This project is required to provide quality power and voltage to the customers served on the English Harbour West Distribution System.

Project Title: Purchase and Install a Voltage Regulator Bank **(cont'd.)**

Project Justification: (cont'd.)

Due to steadily increasing load on the distribution system over the past number of years, voltage levels at customers' services during light load and peak load are exceeding the recommended voltage levels outlined in CSA Standard CAN3-C235-83 (R2006) - Preferred Voltage Levels for AC Systems, 0 to 50 000 V[1].

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. The present method of using the transmission system, along with the fixed taps on the substation power transformer to regulate the voltage on the distribution system, is causing high voltages on the distribution system during off peak periods. Therefore, a system upgrade is necessary to improve the voltage regulation on the distribution system.

Future Plans:
None.

[1] 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 Transformer Storage Ramps

Location: Labrador

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

This project is required to construct transformer storage ramps at Hydro's diesel generating plants in Nain and Cartwright. 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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	16.5	0.0	0.0	16.5
Labour	52.7	0.0	0.0	52.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	27.6	0.0	0.0	27.6
O/H, AFUDC & Escln.	14.1	0.0	0.0	14.1
Contingency	9.7	0.0	0.0	9.7
TOTAL	120.6	0.0	0.0	120.6

Operating Experience:

In Nain and Rigolet, the transformers are stored on their shipping pallets resting on the ground. Cartwright has transformers stored on makeshift ramps that are both too small, and not designed to carry the weight 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 making inspections for potential transformer leaks difficult. 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. Transformer storage ramp is being installed in Port Saunders in 2008 for $15,000. Construction costs for isolated communities in Labrador, as well as increases in the freight and trucking costs, contribute to the higher costs for this proposal.

Project Title: Install Transformer Storage Ramps **(cont'd.)**

Figure 1. Nain Transformer Storage

Figure 2. Nain Transformer Storage

Figure 3. Cartwright Transformer Storage

Project Justification:

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. 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

Project Title: Install Transformer Storage Ramps **(cont'd.)**

Project Justification: (cont'd.)

inspection. The height of the ramps will match the height of the truck bed used for transporting transformers and waste oil, 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 will be proposed in future capital budget applications.

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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	81.5	0.0	0.0	81.5
Labour	4.5	0.0	0.0	4.5
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.	12.0	0.0	0.0	12.0
Contingency	8.6	0.0	0.0	8.6
TOTAL	106.6	0.0	0.0	106.6

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. In the last two years there were 13 instrument transformers replaced and, as the remaining instrument transformers age, it is expected the number of failures will increase. As a result, in future years, the capital budget for instrument transformer replacements may increase. This proposal provides for an allowance of capital dollars for replacements on an as required basis.

Project Title: Replace Instrument Transformers **(cont'd.)**

Operating Experience: (cont'd.)

Table 1 shows the history of expenditures for this project for the past five years.

Table 1. Budget History

Year	Budget ($000)	Actual ($000)	Units	Average Unit Cost ($000)
2008F	73.7			
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
2003	73.8	60.4	5	12.1

The unit cost of instrument transformers vary with voltage class. For example, a 230 kV current transformer will cost approximately $18,000 while a 69 kV potential transformer costs $7,000. As a result, in any given year, the quantity of units replaced varies and, as a result, the annual average cost can be considerably different.

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. Project estimates are 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.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace 230 kV Breaker Controls

Location: Oxen Pond and Bay d'Espoir

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing controls on 230 kV breakers B1L28 at the Oxen Pond Terminal Station and B5B6 and L06L34 at the Bay d'Espoir Terminal Station.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	15.0	0.0	0.0	15.0
Labour	37.0	0.0	0.0	37.0
Consultant	15.0	0.0	0.0	15.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	13.0	0.0	0.0	13.0
O/H, AFUDC & Escln.	11.6	0.0	0.0	11.6
Contingency	8.0	0.0	0.0	8.0
TOTAL	**99.6**	**0.0**	**0.0**	**99.6**

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 it to operate in a predefined manner to provide the required protection. When a fault occurs on a transmission line, circuit breakers at the terminal station react by tripping or switching off the 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 Hydro terminal stations at Oxen Pond and Bay d’Espoir some of the 230 kV breaker controls have become obsolete. Oxen Pond breaker B1L28 and Bay d’Espoir breakers B5B6 and L06L34

Project Title: Replace 230 kV Breaker Controls **(cont'd.)**

Operating Experience: (cont'd.)

are comprised of outdated and discontinued electromechanical relays. This project is required to continue the ongoing work to upgrade the breaker controls systems to current technology. Hydro has replaced circuit breaker controls as shown in Table 2.

Table 2. Replacement of Circuit Breaker Controls

Year	Location	Budget ($000)	Actual ($000)	Average Unit Cost ($000)
2006	Bay d'Espoir, Buchans	39.1	32.5	16.3
2005	Bottom Brook, Massey Drive	33.2	35.5	17.8
2004	Western Avalon, Holyrood	30.0	43.0	21.5

Project Justification:

Hydro's 230 kV breaker controls are composed of outdated and discontinued electromechanical relays. Current automation technology offers replacements with less hardwiring and the benefit of self-diagnostic testing. Existing electromechanical breaker controls are in excess of 25 years old and have reached the end of their useful lives. If a failure occurs, prolonged system outage and/or system instability could result if the breaker does not reclose normally within seconds. This project is required to continue the ongoing work to upgrade the breaker controls systems to current technology.

Future Plans:

Future replacements will be submitted in future capital budget applications.

Project Title: Purchase and Install Electronic Recloser

Location: Cartwright

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

This project consists of the installation of a platform mounted, three-phase electronic recloser at the Cartwright diesel plant. The recloser will be mounted on a new two pole structure constructed adjacent to the diesel plant. The recloser control panel will be located inside the diesel plant and will allow remote access to data such as recloser events, the number of operations, monthly peak loads and maintenance flags.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	48.0	0.0	0.0	48.0
Labour	29.0	0.0	0.0	29.0
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.	11.6	0.0	0.0	11.6
Contingency	7.7	0.0	0.0	7.7
TOTAL	**96.3**	**0.0**	**0.0**	**96.3**

Operating Experience:

In 2003 electronic reclosers where installed on the isolated systems listed in Table 1.

Table 1. Electronic Recloser Installations

Year	Location	Budget ($000)	Actual ($000)
2003	Postville	86.4	84.0
2003	St. Lewis	76.3	84.0
2003	St. Brendan's	77.1	65.8
2003	Black Tickle	88.7	105.0
2003	Little Bay Islands	72.1	76.0

The 4.16 kV distribution system for this community is presently protected by high voltage fuses (fused cutouts located in the substation) and a 600 V main breaker (located in the plant). At

Project Title: Purchase and Install Electronic Recloser **(cont'd.)**

Operating Experience: (cont'd.)

present, a temporary fault will result in an outage because the existing overcurrent protective devices do not include reclosing capabilities. A recloser has the ability to detect and clear temporary faults and quickly re-energize the circuit, restoring service to the system.

Project Justification:

The detection and isolation of three-phase, phase-to-phase and bolted line-to ground faults on the distribution system are not an issue for the existing high voltage fuses, however, the loss of supply for one or two phases will cause operating problems for three phase customers such as the fish plant located in Cartwright. A recloser would eliminate this problem.

The detection and isolation of a line-to-ground fault, which has a significant fault impedance (i.e. > 20 ohms), is an issue for both the high voltage fuses and the plant's main breaker. This fault impedance limits the available fault current, and may limit it to a level which cannot be detected by these existing devices. The neutral overcurrent feature of the recloser allows better detection of line-to-ground fault through a significant fault impedance.

Future Plans:

None.

Project Title: Replace Submarine Cable Terminator Kit

Location: Change Islands and Fogo Island

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

This project is required to replace 16 cable terminators on the Farewell Head Distribution System submarine cable that provides electrical service to approximately 1,730 Hydro customers on Change Islands and Fogo Island.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	32.5	0.0	0.0	32.5
Labour	37.6	0.0	0.0	37.6
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.	10.2	0.0	0.0	10.2
Contingency	7.8	0.0	0.0	7.8
TOTAL	**96.1**	**0.0**	**0.0**	**96.1**

Operating Experience:

The existing cable was installed in 1988 and it has an anticipated useful life of 20 years. Hydro completes an annual visual inspection of the cable terminators and associated equipment to identify cracked porcelain, leaking polybutene fluid from the sealed terminators, and to detect insulation defects. Maintenance records for the cable terminators are part of the overall maintenance for the distribution line feeder, L1, of which the submarine cable is a part. Detailed information on the cable terminator maintenance is not readily available. To date, some outages have resulted from a cable terminator failure, however because of a backup submarine cable for reliability, the outages have been of short duration. Without a backup, an outage could last up to 24 hours.

Project Justification:

The existing cable terminators and associated equipment have reached the end of their useful lives. A failure of the terminators will take the submarine cable out of service leaving approximately 1,730 customers without electrical service. The submarine cable is part of the 25 kV distribution line feeder, L1, that is the sole electrical power provider to Change Islands and Fogo Island.

Future Plans:

None.

Project Title: Replace Air Compressors

Location: Sunnyside

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 Sunnyside Terminal Station. The project will also include the replacement of the control panel, which is used to operate the compressors.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	50.0	0.0	0.0	50.0
Labour	23.8	0.0	0.0	23.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.2	0.0	0.0	3.2
O/H, AFUDC & Escln.	11.2	0.0	0.0	11.2
Contingency	7.7	0.0	0.0	7.7
TOTAL	95.9	0.0	0.0	95.9

Operating Experience:

Power circuit breakers are used to protect transformers and transmission lines from overloads. The breaker senses excessive current and uses a compressed spring arrangement 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 4,000 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 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.

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

Project Title: Replace Air Compressors **(cont'd.)**

Operating Experience: (cont'd.)

eventually drop to a point where the breaker will not be able to operate during a fault condition and an outage is possible. The Sunnyside Terminal Station was constructed in 1966. The compressed air system, including the air compressors, was installed during the original construction. The air compressors have an estimated service life of 40 years.

Table 1 shows the five year maintenance history for the Compressed Air System.

Table 1. Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2007	4.8	0.6	5.4
2006	2.1	2.5	4.6
2005	3.4	3.1	6.5
2004	2.9	4.5	7.4
2003	0.3	0.4	0.7

This project is similar to two other Terminal Station air compressor projects. In 2007, the two air compressors at the Hardwoods Terminal Station were replaced. The budget was $78,000 and the actual cost was $67,000. In 2008, two air compressors along with the control panel at the Buchans Terminal Station are scheduled to be replaced at a budgeted cost of $93,500.

Project Justification:

The replacement of the two air compressors and the associated control panel at the Sunnyside Terminal Station is required to maintain the Island Interconnected System reliability. Without compressed air, circuit breakers will not operate when needed during a fault condition. 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 Sunnyside 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:

None.

Project Title: Purchase High Definition Infrared Camera

Location: Central

Category: Transmission and Rural Operations - Tools & Equipment - Transmission

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase a high definition 16X digital zoom, minimum 640 x 480 infrared resolution camera to be used in the inspection of transmission lines. The camera will be used to detect line connection hot spots that can eventually lead to forced outages if left uncorrected. The purchase of the high definition infrared camera includes the necessary software, accessories, telelens, and level 1 thermographer certification training.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	70.5	0.0	0.0	70.5
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.	9.3	0.0	0.0	9.3
Contingency	7.1	0.0	0.0	7.1
TOTAL	86.9	0.0	0.0	86.9

Operating Experience:

Infrared cameras are used to determine locations of defective connections called hot spots in terminal stations, and on distribution and transmission lines. In particular, these cameras are used to detect line and bus connection hot spots. Upon detection, a scheduled outage would be planned to investigate the underlying problem and make the necessary corrections. For example, an overheated conductor splice on TL-201 on February 7, 2006 was discovered by an infrared camera during a helicopter patrol. A scheduled outage was made to correct the problem. If the overheated condition had gone undetected, there would have been a failure at the hot spot and loss of service to Hydro's customers. Hydro has been using infrared technology for the past 20 years and has found it to be an effective maintenance and trouble shooting tool. Prior to 2006, Hydro used an infrared camera for more than 15 years for various field applications. This camera was retired due to obsolescence. In 2006, Hydro purchased five cameras with 2X digital zoom and 160 x 120 infrared resolution for use in terminal stations. This project was budgeted for $82,000 and the actual

Project Title: Purchase High Definition Infrared Camera **(cont'd.)**

Operating Experience: (cont'd.)

cost was $65,200. In 2008, Hydro will purchase two cameras with 8X digital zoom and 320 x 240 infrared resolution for use on distribution lines at a budgeted cost of $45,700.

Project Justification:

A high definition 16X digital zoom, minimum 640 x 480 infrared resolution camera, which is more powerful than those used for the distribution system, is required for transmission line inspections because of the greater distances between the camera, user and transmission equipment. Since Hydro does not own a high definition infrared camera, the inspection services (camera and operator) are contracted to Newfoundland Power at an average cost of $1,000 per line. Hydro will schedule the inspection of 58 transmission lines in a two year cycle. Within four years, the cost of the camera will be recovered.

Future Plans:

None.

Project Title: Construct ATV/Snowmobile Storage Building

Location: Whitbourne

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project is required to construct a 7.3 metre wide x 9.8 metre long pre-engineered steel storage building at Hydro's Whitbourne line depot. The building will be constructed on a concrete frost wall and have an interior concrete floor. The building will be used for the storage of eight snowmobiles and eight all-terrain vehicles. In addition, transmission line materials, tools, and vehicle tires will be stored in this facility. Shelving will be constructed to accommodate tools and equipment. The building will not have heating, running water, washroom facilities or windows. However, lighting and 120 V AC electrical service will be provided. Design is to start in April 2009, and work is to be completed by September 2009.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	3.0	0.0	0.0	3.0
Labour	8.0	0.0	0.0	8.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	58.0	0.0	0.0	58.0
Other Direct Costs	1.6	0.0	0.0	1.6
O/H, AFUDC & Escln.	8.5	0.0	0.0	8.5
Contingency	7.1	0.0	0.0	7.1
TOTAL	**86.2**	**0.0**	**0.0**	**86.2**

Operating Experience:

The existing 3.0 metre wide x 3.7 metre long wooden storage shed that contains transmission line materials was built in the 1970's when the depot was constructed. In addition, snowmobiles, all-terrain vehicles, and vehicle tires are currently stored outside in the yard making them susceptible to theft and weather exposure.

Project Justification:

In 1999 and 2007, a total of five all-terrain vehicles were stolen from the Whitbourne line depot yard. Currently, snowmobiles, all-terrain vehicles, and vehicle tires are stored outside in the yard in plain view of the public. In addition, the existing 3.0 metre wide x 3.7 metre long storage

Project Title: Construct ATV/Snowmobile Storage Building **(cont'd.)**

Project Justification: (cont'd.)

shed that contains transmission line materials and tools has deteriorated beyond repair. The new steel storage building will provide sufficient space to store snowmobiles, all-terrain vehicles, tools, and materials in a secure and weatherproof environment concealed from view of the general public.

Future Plans:

None.

Project Title: Install Waste Oil Storage Tanks

Location: Mary's Harbour

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Mandatory

Project Description:

This project is required to purchase and install 5,000 litre, double wall, vacuum sealed waste oil storage tanks for the diesel plant in the Southern Labrador community of Mary's Harbour. Work shall also include the installation of steel pipe header systems from the waste oil storage tank to the diesel units inside the plant. The header systems shall be double wall systems for secondary containment of the primary line, complete with leak detection devices on the secondary containments. Lube oil transfer pumps shall also be purchased and installed in the header systems to pump the used oil from the engines to the storage tanks.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	25.5	0.0	0.0	25.5
Labour	27.6	0.0	0.0	27.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	14.2	0.0	0.0	14.2
O/H, AFUDC & Escln.	10.2	0.0	0.0	10.2
Contingency	6.7	0.0	0.0	6.7
TOTAL	84.2	0.0	0.0	84.2

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 Mary's Harbour produces 2,250 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. 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.

Project Title: Install Waste Oil Storage Tanks **(cont'd.)**

Operating Experience:

A project was approved by the Board in Order P.U. 30 (2007) for a similar waste oil storage tank for L'Anse au Loup with a budget of $46,000. This project has been changed to Charlottetown and reforecast to $56,000. The current project is budgeted higher due to expected increases in the price of steel and increased costs for labour and travel.

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 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.

Project Title: Replace Drainage System

Location: Western Avalon

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to remove an existing drainage system at the Hydro Western Avalon Terminal Station and install a new system. The new drainage system will consist of approximately 300 metres of 150 mm diameter perforated pipe wrapped in a filter fabric and installed in a bed of crushed stone. The work will be performed under contract with supervision by Hydro personnel.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	0.0	0.0	0.0	0.0
Labour	16.0	0.0	0.0	16.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	50.0	0.0	0.0	50.0
Other Direct Costs	3.0	0.0	0.0	3.0
O/H, AFUDC & Escln.	8.0	0.0	0.0	8.0
Contingency	6.9	0.0	0.0	6.9
TOTAL	**83.9**	**0.0**	**0.0**	**83.9**

Operating Experience:

The existing drainage system was constructed in 1993 and is no longer working. Silt has migrated, over the last 15 years from the existing bank and plugged the holes in the drainage system. It would not be cost effective, because of labor costs, to dig up the existing pipe without damaging it and then to clean out the hundreds of drainage perforations.

Project Justification:

The existing drainage system is has exceeded its service life of 20 years. Over a period of 15 years, silt has plugged the perforations in the drain pipe preventing water from entering. This causes water to form a pond in the yard after heavy rainfalls. This presents a safety hazard in the terminal station as water is a conductor of electricity. Filter fabric, which was not used back in 1993, will be part of this new drainage system. This material will reduce the infiltration of silt and crushed stone into the pipe, resulting in a predicted 20 year life.

Future Plans:

None.

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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**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.	9.0	0.0	0.0	9.0
Contingency	6.6	0.0	0.0	6.6
TOTAL	81.1	0.0	0.0	81.1

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.)**

Operating Experience: (cont'd.)

Table 1 shows the history of expenditures for this project for the past four years.

Table 1. Maintenance History

Year	Budget ($000)	Actual ($000)	Units	Unit Cost ($000)
2008F	67.1			
2007	71.3	84.8	9	9.4
2006	70.0	66.9	24	2.8
2005	68.4	79.7	21	3.8
2004	70.3	65.1	10	6.5

The unit cost for surge arresters vary with voltage class. For example a 23 kV surge arrester installed cost is approximately $4,300 each or $12,900 for a set of three, while a 69 kV surge arrester costs approximately $2,500 or $7,500 for a set of three. As a result, in any given year the quantity of units replaced vary with voltage class and the annual average cost can be considerably different.

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.

Project Title: Install Pole Storage Ramps

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

This project involves the construction of two 10 metre long by 4 metre wide pole storage ramps at the Nain and Postville Diesel Plants. Underneath each ramp will be a 150 millimetre layer of impervious backfill, followed by a layer of filter fabric and then grass. The poles will be covered with an 18 ounce PVC tarpaulin which will be held in place with tie down straps. The ramps will be constructed from wooden utility poles. Hydro's Environmental Services Department will verify the suitability of each proposed location.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	20.0	0.0	0.0	20.0
Labour	24.0	0.0	0.0	24.0
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.	8.7	0.0	0.0	8.7
Contingency	6.2	0.0	0.0	6.2
TOTAL	76.9	0.0	0.0	76.9

Operating Experience:

In order to provide reliable service to its customers, Hydro must store extra poles at each of its diesel plant sites. The poles range in length from 9 metres (30 feet) to 14 metres (45 feet). There are typically between 15 to 30 poles stored at each site. The majority of these poles are treated with chromated copper arsenate (CCA), however a small quantity of pentachlorophenol (PCP) treated poles may exist at some locations.

Figure 1 shows photos of Nain and Postville, pole storage and a photo showing a completed pole storage ramp at Holyrood. Figure 2 shows a sketch of a storage.

Project Title: Install Pole Storage Ramps **(cont'd.)**

Nain Pole Storage **Postville Pole Storage**

Holyrood Pole Storage Ramp

Figure 1. Photos of Pole Storage at Nain Postville and Holyrood

Project Title: Install Pole Storage Ramps **(cont'd.)**

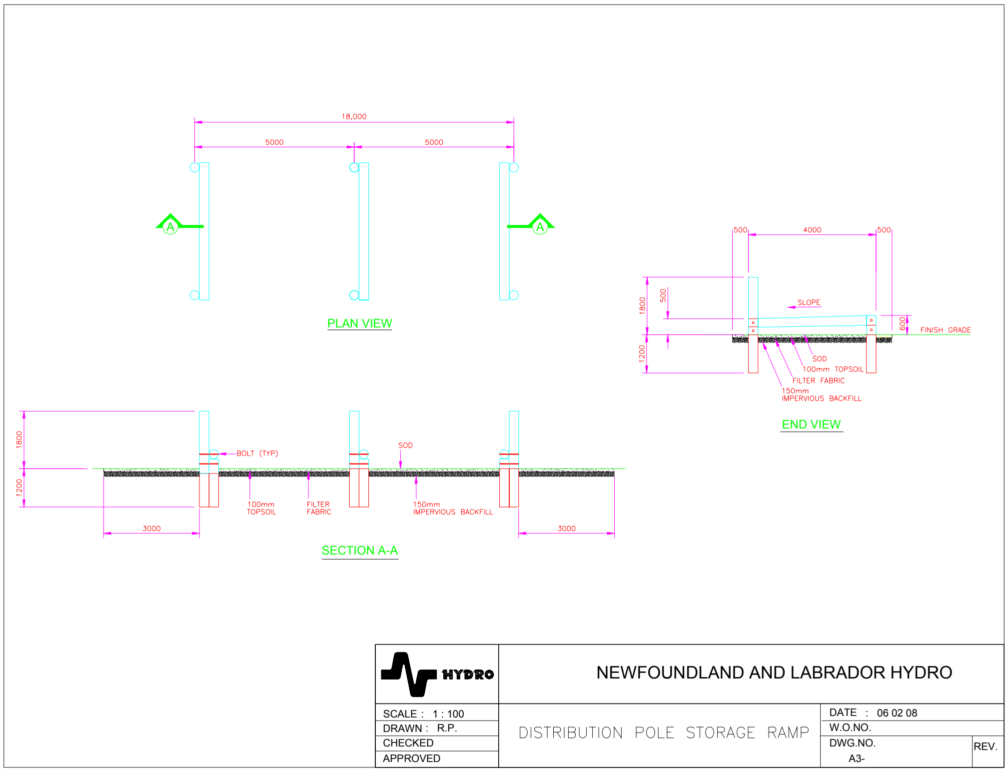

Figure 2. Storage Ramp Sketch

Project Justification:

Storing poles on elevated ramps will make it safer and easier to sort, select, and handle different types and lengths of poles. Storage ramps will also prevent poles from deteriorating early due to ground contact. The ramps will be constructed to meet the federal requirements as outlined in the March 2002 report "Guidelines for Treated Wood Storage Facilities" prepared by Earth Tech (Canada) Incorporated. This enables Hydro to be more environmentally friendly.

Future Plans:

Future installations will be proposed in future capital budget applications.

Project Title: Install Water and Sewer System
Location: Paradise River
Category: Transmission and Rural Operations - Generation
Definition: Other
Classification: Normal

Project Description:

This project is required to drill an artesian well, install a deep well pump and connect to the diesel plant. This project is to include pressure tank, cable and controls. Work also includes the installation of a biogreen sewer system that limits the amount of effluent flowing towards the river. A biogreen septic system is an environmentally friendly system where no suction is needed for the septic tank, as it is able to degrade contents using special chambers and bacterial action.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	2.1	0.0	0.0	2.1
Labour	22.7	0.0	0.0	22.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	31.5	0.0	0.0	31.5
Other Direct Costs	5.8	0.0	0.0	5.8
O/H, AFUDC & Escln.	8.5	0.0	0.0	8.5
Contingency	6.2	0.0	0.0	6.2
TOTAL	76.8	0.0	0.0	76.8

Operating Experience:

Hydro owns and operates the Paradise River diesel plant. The plant was constructed in 1971 and is of wood frame construction. The plant provides electricity to the residents of Paradise River and houses three diesel generators ranging in size from 48 kW to 135 kW. Paradise River is located approximately 45 kilometers from the Town of Cartwright along the Trans Labrador Highway. Currently, there are no running water or sewer facilities in the plant. Maintenance crews assigned to do work at Paradise River typically stay in hotels located at Cartwright. While working in Paradise River, crews must leave the job site and drive for approximately a half hour to Cartwright to use hotel washroom facilities. Also, there is no running water for general housekeeping and cleaning of the plant.

Project Title: Install Water and Sewer System **(cont'd.)**

Project Justification:

This project is required on the basis of health and sanitation needs. Currently, there are no washroom facilities at the Paradise River Diesel Plant. The time required for workers to reach washroom facilities is unacceptable as a round trip to Cartwright takes about an hour. Workers are currently expected to wait until they arrive at the hotel in Cartwright before they can clean up for the day. Some of the maintenance work performed on the diesel generators can get quite messy. Periodic clean up throughout the day is not possible and there is no hot water available for floor cleaning and general housekeeping.

Future Plans:

None.

Project Title: Construct Transmission Storage Ramps

Location: Bay d'Espoir

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

This proposal is required to install two transmission storage ramps at the Camp Boggy pole yard which is located at the main Hydro site in Bay d'Espoir, across from Hydro's main warehouse. The two ramps will be constructed using pressure treated timber and each will measure 2.4 meters (8 feet) wide and 9.6 meters (32 feet) long.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	11.0	0.0	0.0	11.0
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	10.1	0.0	0.0	10.1
O/H, AFUDC & Escln.	8.9	0.0	0.0	8.9
Contingency	6.0	0.0	0.0	6.0
TOTAL	75.0	0.0	0.0	75.0

Operating Experience:

Transformers, which contain oil, are being stored on shipping pallets resting on the ground or directly on the ground itself. Similarly, drums of waste oil are stored directly on the ground. These storage methods make it very difficult to detect leaks and can contribute to corrosion and leaks in metal containers. Transformers and waste oil must be handled and stored properly. The current method of storage allows transformers and waste oil to be buried under snow which makes them susceptible to damage from snow clearing equipment. These storage methods are unacceptable because of the potential environmental risks of spills resulting from damage of the transformer casings and drums. The existing deteriorated storage platform is approximately 25 years old and can no longer be used to support loads imposed by heavier items such as transformers and drums of waste oil. Currently, the storage platform is being used for storing lightweight items such as smaller transmission line hardware and cross members. As the existing storage ramp is rotting and in disrepair, new properly designed transmission storage ramps should be constructed. These ramps have an anticipated useful life of 20 years.

Project Title: Construct Transmission Storage Ramps **(cont'd.)**

Project Justification:

The storage of oil filled equipment is part of Hydro’s day to day operation and the existing storage methods for transformers and waste oil at the Camp Boggy pole yard site is inadequate. Transformers and waste oil drums are at risk of damage that could cause an oil spill, and the current method of storage makes it difficult to detect leakage. In order to mitigate any environmental consequences, transformers and waste oil need to be stored on a raised platform to allow for inspection of the area underneath and must be in a location which prevents the possibility of being struck by mobile equipment. Transformers and waste oil stored on a standardized transmission storage ramp will meet these requirements. New ramp design and a carefully chosen location on site will enhance accessibility for the loading and off-loading of cargo to and from a truck's cargo bed, as well as improve inventory management.

Future Plans:

None.

Project Title: Install 138 kV Capacitive Voltage Transformer

Location: St. Anthony Airport

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project consists of the purchase and installation of a 138kV capacitive voltage transformer (CVT) in the St. Anthony Airport Terminal Station. The new CVT will be installed on phase 'A' of transmission line TL-256. The work involves installation of a new concrete foundation and steel structure to mount the CVT. New control cables will be installed to connect the CVT to the existing protection and control systems. All installations and commissioning will be done by Hydro personnel.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	16.6	0.0	0.0	16.6
Labour	33.0	0.0	0.0	33.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	2.0	0.0	0.0	2.0
Other Direct Costs	5.6	0.0	0.0	5.6
O/H, AFUDC & Escln.	7.6	0.0	0.0	7.6
Contingency	5.7	0.0	0.0	5.7
TOTAL	70.5	0.0	0.0	70.5

Operating Experience:

The CVT is one component of a series of voltage and current sensing devices used for protection and control of the transmission system. Currently, there are two CVTs on TL-256 at the St. Anthony Airport Terminal Station, phases 'B' and 'C' of the transmission line. When the St. Anthony diesel plant is generating power, the protection scheme using two CVTs is manually deactivated to prevent interruptions to customers. Consequently, the line has to be operated without the proper protection.

Project Justification:

The transmission line protection circuits on line TL-256 malfunctions and causes outages to customers on the St. Anthony, Roddickton and Main Brook systems when the St. Anthony Diesel Plant operates. Consequently, the line protection circuits have been de-activated, leaving TL-256

Project Title: Install 138 kV Capacitive Voltage Transformer **(cont'd.)**

Project Justification: (cont'd.)

without protection. This diminishes the overall reliability and security of supply to customers. This project is required to upgrade the transmission line protection by adding the third phase CVT, and to provide system reliability and security during all operating scenarios.

Future Plans:

None.

Project Title: Install 69 kV Capacitive Voltage Transformer

Location: St. Anthony Diesel Plant

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project consists of the purchase and installation of a 69kV capacitive voltage transformer (CVT) in the St. Anthony Diesel Plant Terminal Station. The new CVT will be installed on phase 'A' of transmission line TL-261. The work involves installation of the new CVT on the existing steel structure adjacent to the existing CVTs. New control cables will be installed to connect the new CVT to the existing protection and control systems. All installations and commissioning will be done by Hydro personnel.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	13.6	0.0	0.0	13.6
Labour	33.0	0.0	0.0	33.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	2.0	0.0	0.0	2.0
Other Direct Costs	5.6	0.0	0.0	5.6
O/H, AFUDC & Escln.	7.2	0.0	0.0	7.2
Contingency	5.4	0.0	0.0	5.4
TOTAL	66.8	0.0	0.0	66.8

Operating Experience:

The CVT is one component of a series of voltage and current sensing devices used for protection and control of the transmission system. Currently, there are two CVTs on TL-261 at the St Anthony Diesel Plant Terminal Station on phases 'B' and 'C' of the line. When the St. Anthony Diesel Plant is generating power, the protection scheme using two CVTs is manually deactivated to prevent interruptions to customers. Consequently, the line has to be operated without the proper protection.

Project Justification:

Since the line protection circuits have been de-activated, the transmission line TL-261 has no protection against electrical faults. This diminishes the overall reliability and security of supply to customers. This project is required to upgrade the transmission line protection by adding the third

Project Title: Install 69 kV Capacitive Voltage Transformer

Project Justification: (cont'd.)

CVT to the line protection circuits to provide system reliability and security during all operating scenarios.

Future Plans:

None.

Project Title: Install Remote Ice Growth Detector Beams
Location: Various Sites
Category: Transmission and Rural Operations - Terminal Stations
Definition: Pooled
Classification: Normal

Project Description:

This project is required to purchase and install five Remote Ice Growth Detector (RIGD) beams in Hydro Terminal Stations. This is the continuation of a three year capital program (2006 to 2008) to establish an ice monitoring network throughout the Island Interconnected System. The earlier capital program installed RIGD beams in 15 terminal stations. This project will install RIGD beams in five more stations at Oxen Pond, Granite Canal, Roddickton, Farwell Head and Ramea. However, these sites may change depending on further review.

Project Cost: *($ x1,000)*	2009	2010	BEYOND	TOTAL
Material Supply	18.0	0.0	0.0	18.0
Labour	25.0	0.0	0.0	25.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.5	0.0	0.0	8.5
O/H, AFUDC & Escln.	8.0	0.0	0.0	8.0
Contingency	5.2	0.0	0.0	5.2
TOTAL	**64.7**	**0.0**	**0.0**	**64.7**

Operating Experience:

A RIGD was initially installed at the Hawk Hill Ice Monitoring Facility approximately 14 years ago. The Hawk Hill site is a test facility established in 1993 and contains instrumentation 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. As a result of its success, and the low implementation costs, a second and third beam were later installed at St. John's airport and in the Goose Bay Terminal Station. In 2006, a three year Capital Project was proposed to install RIGD ice monitoring equipment at five Terminal Stations throughout the province each year. 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 database network. A network has been created at Hydro Place to monitor and archive the data for later analysis. The RIGD beam is a 1 metre long x 25 millimeter diameter hollow aluminum tube mounted as a cantilever beam that measures ice load

Project Title: Install Remote Ice Growth Detector Beams **(cont'd.)**

Operating Experience: (cont'd.)

directly through a series of strain gauges mounted to the exterior of the unit. The annual maximum load at each site can be determined by analyzing the time series data. The data collected from each of the RIGD beams have proven to be reliable and valuable engineering data.

Table 1. Budget History

Year	Budget ($000)	Actual ($000)	Units	Unit Cost ($000)
2008F	46.2		5	
2007	30.2	50.4	5	10.1
2006	27.8	30.2	6	5.0

Due to limited labour availability, the calibration of the 2006 sites did not get completed until 2007. In addition, the labour costs for 2007 were higher than expected due to the inability to coordinate this work with other work requirements at the time of installation.

The costs for 2009 have increased because of increased travel costs due to the varied locations of the proposed installations.

Project Justification:

The monitoring of ice accumulation on transmission lines is important for predicting long term ice loads on transmission line infrastructure. The loading information from ice monitoring assists engineers to efficiently design transmission lines that have a high degree of reliability with low failure risk. Over-designing a transmission line is uneconomical, whereas under-designing imposes a considerable risk of failure to the system. Hydro has obtained a considerable amount of experience and knowledge on the effects of ice accumulation on transmission line infrastructure within the past 15 years through line failures in this province and other parts of eastern Canada. A database on ice accumulation does contribute to defining detailed design criteria that is used to efficiently design transmission lines.

Future Plans:

Hydro will continue to advance the ice monitoring network by installing additional RIGD beams in other strategic locations to develop a regional ice accumulation map using this data.

Project Title: Install Meter Station for Fuel Reconciliation

Location: Hawke's Bay

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Mandatory

Project Description:

This project is required to install metering on fuel lines at the Hawke's Bay Standby diesel site.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	23.4	0.0	0.0	23.4
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	7.0	0.0	0.0	7.0
O/H, AFUDC & Escln.	6.3	0.0	0.0	6.3
Contingency	5.2	0.0	0.0	5.2
TOTAL	**63.7**	**0.0**	**0.0**	**63.7**

Operating Experience:

The Hawke’s Bay Diesel Plant, located on the Northern Peninsula, is a 5 MW plant comprised of two 2.5 MW generating units. The plant is utilized primarily as a stand-by plant but is also utilized to provide local power during planned outages in the area. Fuel reconciliation is the process of accounting for addition and removal of fuel in a system. This is done to detect fuel leaks, if they occur, which mitigates environmental damage. Fuel reconciliation is a reporting requirement of Part 18 of the Storage and Handling of Gasoline and Associated Products Regulations under the Environment Protection Act which states:

> The operator of an above-ground tank system shall:
>
> *18.(2)(b) reconcile gauge or dip readings with receipt and withdrawal records at least weekly.*

Project Justification:

In order to perform fuel reconciliation as required by the Storage and Handling of Gasoline and Associated Products Regulations under the Environment Act it is necessary to install a meter station in Hawke's Bay. Presently, only dip readings are taken at the fuel storage tanks. They

Project Title: Install Meter Station for Fuel Reconciliation **(cont'd.)**

Project Justification: (cont'd.)

indicate the amount of fuel in the tank but do not tell whether the fuel was purposely withdrawn or lost through leakage. There is no method to meter the actual fuel consumed by the gensets. A metering system will show the amount of fuel entered and withdrawn from the tank. The system will reconcile its readings with the weekly dip readings to detect possible fuel leaks. Dip readings alone do not meet the requirements of the Environment Protection Act.

Future Plans:

None.

Project Title: Install Furnace Fuel Storage Tank

Location: William's Harbour

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase a new 9,000 litre double wall fuel storage tank for installation at the William's Harbour Diesel Plant to service the personnel accommodation trailer furnace. Work will include cleaning and disposal of the existing residential tank, installing the new tank on a timber foundation, installing new piping to the accommodation trailer and pipe pressure testing and painting.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	20.3	0.0	0.0	20.3
Labour	19.0	0.0	0.0	19.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	2.0	0.0	0.0	2.0
Other Direct Costs	7.1	0.0	0.0	7.1
O/H, AFUDC & Escln.	6.2	0.0	0.0	6.2
Contingency	4.8	0.0	0.0	4.8
TOTAL	**59.4**	**0.0**	**0.0**	**59.4**

Operating Experience:

With the delivery of fuel by marine tanker, the existing residential type tank used to supply fuel to the furnace in the accommodation trailer has to be filled by hand numerous times a year. This requires that fuel be pumped from the plant bulk storage tanks into drums, that the drums be transported to the smaller residential size tank, and that the fuel be pumped from the drums into the smaller tank. This operation is carried out by the diesel plant operator approximately five or six times per year.

Project Justification:

With no roads in the community and fuel delivery being made twice a year by marine tanker, the new 9,000 litre storage tank could be filled from the tanker, eliminating the handling of fuel by the operators, and reducing the environmental risk of spills as a result of multiple manual fuel transfers.

Future Plans:

None.

Project Title: Legal Survey of Primary Distribution Line Right of Way
Location: Various Locations
Category: Transmission and Rural Operations - Properties Northern
Definition: Other
Classification: Normal

Project Description:
This project is required to perform legal surveys and prepare documentation to acquire Crown Land easements for approximately 160 kilometers of primary distribution line in operation throughout the Province.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	1.5	0.0	0.0	1.5
Labour	40.4	0.0	0.0	40.4
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.	2.4	0.0	0.0	2.4
Contingency	4.9	0.0	0.0	4.9
TOTAL	56.0	0.0	0.0	56.0

Operating Experience:
Many of the 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 acquired by Hydro by the end of 2014.

Table 1 shows the history of expenditures for this project for the past four years.

Table 1. Budget History

Year	Budget ($000)	Actual ($000)
2008F	52.0	
2007	50.8	47.9
2006	49.9	51.2
2005	49.6	93.4[2]
2004	48.8	48.6

[2] Additional costs were required to obtain easements for Nain, Hopedale, Postville, Makkovik and Rigolet. The work was originally planned for future years.

Project Title: Legal Survey of Primary Distribution Line Right of Way **(cont'd.)**

Project Justification:

The distribution lines occupy Crown Land contrary to the Crown Lands Act. Lack of adequate title is a risk to the operation of the lines should competing requirements for the land arise. In addition, maintenance and upgrading of the lines is cumbersome and costly without appropriate legal easements.

Future Plans:

Capital funding for legal surveys for future years will be proposed in future capital budget applications.

Project Title: Upgrade Server Technology Program

Location: Hydro Place

Category: Information Systems

Definition: 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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	183.0	0.0	0.0	183.0
Labour	25.0	0.0	0.0	25.0
Consultant	18.0	0.0	0.0	18.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	24.0	0.0	0.0	24.0
Contingency	22.6	0.0	0.0	22.6
Sub-Total	272.6	0.0	0.0	272.6
Cost Recoveries	(79.1)	0.0	0.0	(79.1)
Total	**193.5**	**0.0**	**0.0**	**193.5**

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.

Project Title: Upgrade Server Technology Program **(cont'd.)**

Operating Experience: (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 this proposal:

- Major Work / Upgrades
- Maintenance History
- Outage Statistics
- Safety Performance
- Environmental Performance

Age of Equipment or System

The age of the equipment being replaced ranges from five to eight years. The average age is six years.

Anticipated Useful life

Industry standards indicate that server hardware has a useful life of five years. Beyond this timeframe reliability and support become problematic.

Industry Experience

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.

Maintenance or Support Arrangements

At this time, the Vendor support 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 fixed on a time and material basis.

Vendor Recommendations

The Vendor recommends that servers be replaced in a five year lifecycle.

Project Title: Upgrade Server Technology Program **(cont'd.)**

Operating Experience: (cont'd.)

Availability of Replacement Parts

At this time the vendor inventory of spare parts is discontinued. Parts availability is not guaranteed after five years.

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;
Supporting current versions of applications; and
Exploiting technological advances.

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 the 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.

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:

Project Title: Upgrade Server Technology Program **(cont'd.)**

Project Justification: (cont'd.)

- Levelized Cost of Energy
- Legislative or Regulatory Requirements
- Forecast Customer Growth
- Energy Efficiency Benefits
- 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 1 shows the historical costs of the Server and Operating System Evergreen Program.

Table 1. Budget History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Unit Cost ($000)(1)
2008F	249.2	0	0	0
2007	81.8	81.8	5	16.3
2006	0(2)	0	0	0
2005	212	179	12	14.9
2004	639	609(3)	28	21.8

(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.

(3 This includes purchase of servers ($182,000) plus migration to a new operating system and supporting office productivity tools.

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 (IT) infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned computer 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 2009 and be completed by the end of November 2009.

Future Plans:

This is an ongoing refresh program to maintain server performance.

Project Title: Replace Radio Tower

Location: Ebbegunbaeg

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing radio tower at Ebbegunbaeg.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	30.0	0.0	0.0	30.0
Labour	56.5	0.0	0.0	56.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	30.0	0.0	0.0	30.0
Other Direct Costs	29.3	0.0	0.0	29.3
O/H, AFUDC & Escln.	18.6	0.0	0.0	18.6
Contingency	14.6	0.0	0.0	14.6
TOTAL	179.0	0.0	0.0	179.0

Operating Experience:

Figure 1. Ebbegunbaeg Tower

Hydro's Hydroelectric Generating Station at Bay d'Espoir (Bay d'Espoir) consists of six reservoirs. Two of these reservoirs are the Meelpaeg Lake Reservoir and the Long Pond Reservoir. A control structure at Ebbegunbaeg is required to control the flow of water from Meelpaeg Lake to Long Pond. This project is required to replace the existing radio tower located at the Ebbegunbaeg Control Structure, shown in Figure 1. The radio tower is used to support the antenna required for a point to point Very High Frequency (VHF) radio link that provides voice and data communications to Ebbegunbaeg. The total five year maintenance costs for the existing tower is approximately $2,000 in total. Costs are not readily available by year. The tower was inspected by a structural engineer in 2007 and determined to be unsafe. The leg members are overstressed by more than 300 percent and the tower foundations have deteriorated showing evidence of crumbling and

Project Title: Replace Radio Tower **(cont'd.)**

Operating Experience: (cont'd.)

cracking. The tower does not meet the requirements of CAN-CSA S37-01[3], which is the industry standard to which telecommunications towers in Canada are constructed.

Project Justification:

The existing tower and foundations, which were installed in 1990, and are reaching the end of their useful lives of 20 years and are showing signs of deterioration. Failure to replace the tower could result in catastrophic failure and associated damage to equipment, property and possibly injury or loss of life. As well, the tower analysis performed in 2007 by a structural engineer, recommended that the tower not be climbed in windy or icy conditions because of the possible hazard to life involved.

Three alternatives were considered: upgrading of the tower to meet the requirements of CAN-CSA S37-01 or replacing the tower with either a steel tower or a wooden pole structure. The wooden structure replacement is the preferred option since it is less expensive and requires less maintenance.

Upgrading is not recommended by Hydro’s structural engineer and was immediately rejected as an option. The tower is constructed of thin rolled steel, and welding the necessary components that would be required for upgrading is not recommended because of the thinness and rusting condition of the tower material.

Based on costs previously incurred for the erection of similar microwave radio towers, an estimate was prepared for a steel structure. The capital cost was conservatively estimated to be $350,000. In addition to this, steel towers require maintenance inspections, with additional ongoing operating costs. Based on the past five years, this was estimated to be in the order of $300 annually.

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[3] CAN-CSA Standard S37-01, *Antennas, Towers and Antenna-Supporting Structures*, January 2006, Appendix D, Clause D1.(a).

Project Title: Replace Radio Tower **(cont'd.)**

Project Justification: (cont'd.)

In comparison, in-house expertise exists to design and install a wooden antenna supporting structure. In this case, the capital estimate is $179,000. As well, no ongoing inspection is required. Both the steel and wooden structures are estimated to have useful lives of 20 years.

Future Plans:
None.

Project Title: Replace Peripheral Infrastructure
Location: Hydro Place
Category: General Properties - Information Systems
Definition: 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 2009, this project will consist of the replacement of seven Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning as well as 27 black/white laser printers. Of the MFDs to be replaced, one is located in Whitbourne, one in Springdale, three in Holyrood, and two in Hydro Place in St. John's. The location of the black/white laser printers to be replaced are as follows: fifteen in Hydro Place; three in Bay d'Espoir; four in Bishop Falls; four in Holyrood; and one in St. Anthony. The project also includes funds for two new video conferencing units in Hydro Place.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	131.0	0.0	0.0	131.0
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.	6.0	0.0	0.0	6.0
Contingency	14.1	0.0	0.0	14.1
TOTAL	**161.1**	**0.0**	**0.0**	**161.1**

Operating Experience:

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 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.)**

Project 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 2009 have all been in service for over five years and maintenance contracts and warranties have expired. The manufacturer will only guarantee the operation of these MFDs for a period of five years.

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.

Table 1 contains a five year history of the Peripheral Infrastructure Replacement Project.

Table 1. Budget History

Year	Budget ($000)	Actual ($000)	Units	Unit Costs ($000) [1]
2008F	159	0	0	0
2007	139	139	10	13.9
2006	199	196	8	24.5
2005	117	121	56	2.2
2004	101	104	7	14.9

(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.

Future Plans:

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.

Project Title: Replace Network Communications Equipment

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

The scope of the 2009 Network Communications Equipment project is to install new administrative network communications equipment at the Stony Brook and Sunnyside Terminal Stations, and McCallum Diesel Plant. As well, an allowance is included for unforeseen changes and additions to the network at other locations.

The equipment to be installed under this program varies, but typically 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.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	35.0	0.0	0.0	35.0
Labour	52.9	0.0	0.0	52.9
Consultant	11.0	0.0	0.0	11.0
Contract Work	2.0	0.0	0.0	2.0
Other Direct Costs	11.8	0.0	0.0	11.8
O/H, AFUDC & Escln.	17.0	0.0	0.0	17.0
Contingency	11.3	0.0	0.0	11.3
TOTAL	141.0	0.0	0.0	141.0

Operating Experience:

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 Hydro's Energy Management System

Project Title: Replace Network Communications Equipment **(cont'd.)**

Operating Experience: (cont'd.)

(EMS), video camera access at remote locations, equipment monitoring, and hydrological information; and general information on Corporate policies, procedures, and initiatives.

Table 1 shows the history of expenditures in this project for the past five years.

Table 1. Budget History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Unit Cost ($000)	Comments
2008F	130.6				
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	
2003	46.5	47.0	5	9.4	

Project Justification:

The network devices addressed herein are required to support growth which occurs at offices, terminal stations, power plants and microwave repeater sites. The demand for new services includes office automation traffic such as e-mail and work requests, and access to substation automation functions such as remote high speed access to meters and Intelligent Electronic Devices (IEDs).

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Replace Drafting Scanner/Plotter

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Pooled

Classification: Normal

Project Description:

The Drafting Scanner/Plotter Replacement Project is required to replace the plotter and scanner used at Hydro Place in St. John's, as well as the scanner in Bishop's Falls. This equipment is utilized by the drafting staff on a daily basis to producing drawings for the corporation.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	120.0	0.0	0.0	120.0
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.	4.4	0.0	0.0	4.4
Contingency	12.2	0.0	0.0	12.2
TOTAL	138.6	0.0	0.0	138.6

Operating Experience:

The equipment scheduled for replacement has been in service between five and nine years and is no longer supported by manufacturer.

Project Justification:

Hydro must keep its plotting/scanning infrastructure current in order to adequately support the needs of its business. The infrastructure to be replaced is currently five to nine years of age and has reached the end of its useful life. This wide format equipment is essential to the operation of the Engineering Services and Drafting departments at Hydro. This equipment is used to scan in (digitize) paper drawings and to plot or copy existing drawings.

Project Title: Replace Drafting Scanner/Plotter **(cont'd.)**

Project Justification: (cont'd.)

If the scanner and plotter infrastructure is not kept current the following scenarios could potentially occur:

- New applications may not print on the old hardware platform.
- Speed will be decreased, resulting in lost production.
- Failure rates may be increased.
- Maintenance agreements may not be available.

Future Plans:

None.

Project Title: Replace Radomes

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Pooled

Classification: Normal

Project Description:

The Radome Replacement program is an ongoing program to replace aging and deteriorated radomes which are the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system. This project will replace the radomes on eight microwave radio antennas.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	35.0	0.0	0.0	35.0
Labour	24.0	0.0	0.0	24.0
Consultant	15.0	0.0	0.0	15.0
Contract Work	24.0	0.0	0.0	24.0
Other Direct Costs	6.6	0.0	0.0	6.6
O/H, AFUDC & Escln.	14.6	0.0	0.0	14.6
Contingency	10.5	0.0	0.0	10.5
TOTAL	**129.7**	**0.0**	**0.0**	**129.7**

Operating Experience:

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 m and range in diameter from 2 m to 5 m. 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 prevent the accumulation of ice and snow which could bend or break these elements.

Project Justification:

Radomes deteriorate over time because of exposure to wind, sun, ice and snow. Radomes must be replaced as they deteriorate. The cost of a microwave failure would be far more significant 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.

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

Attachments:

See report entitled "Microwave Antenna Radome Replacement Program" in Volume II, tab 22, for further project details.

Future Plans:

Future replacements will be proposed in future capital budget applications.

Project Title: Application Enhancements – Performance Management Software Budgeting Tool
Location: Hydro Place
Category: Information Systems
Definition: Other
Classification: Normal

Project Description:
This project is required to procure a Corporate Performance Management application that will be primarily used to enter budgets and forecasts, and view actual historic information for the purposes of budget and forecast development, variance analysis, trend analysis and cost control. It is a web-based application that will be deployed throughout the regulated company in 2009.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	112.4	0.0	0.0	112.4
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 & Escalation	3.5	0.0	0.0	3.5
Contingency	11.2	0.0	0.0	11.2
Total	127.1	0.0	0.0	127.1

Operating Experience:
A review of the budgeting and reforecasting process for operating, maintenance and administrative costs was performed within Hydro in 2008. The purpose of this review was to determine what the needs of managers are in terms of decision support tools and controls to assist them in developing and controlling their budgets.

A key finding of this review is that budget managers within Hydro cannot easily access financial data required to prepare budgets, control expenditures and conduct analysis of performance because the current Enterprise Resource Planning (ERP) System (JD Edwards) is not intuitive or particularly user-friendly. The ERP is a tool for transactional data, and is not optimal for financial reporting, budgeting and value-added analysis. In attempting to leverage the ERP for this additional functionality, Hydro is placing an undue burden upon budget managers. This results in excessive time spent trying to obtain and evaluate data. The process of extracting information from the ERP into multiple, user-specific spreadsheets is also time-consuming and problematic from a

Project Title: Application Enhancements – Performance Management Software Budgeting Tool **(cont'd.)**

Operating Experience: (cont'd.)
data-integrity perspective. Frequent reconciliations are required to ensure various personnel are working with the same data. Finally, it is difficult for managers and finance personnel to obtain a consolidated view of budgets without time-consuming integration of multiple spreadsheets in differing formats.

To save time in data retrieval, reconciliation and spreadsheet consolidation, it is recommended that Hydro procure a performance management application that provides easy access (point and click) to budgets and historic actual information. The application would allow for budgeting and reporting both financial results and non-financial performance indicators, and would be expected to improve the availability of data and enhance control.

This application will allow managers and finance personnel to easily access historic actual financial and operational data from a single source which will improve cost control and permit enhanced variance and cost trend analysis. It will also be a catalyst for suggested operational process improvements including development of budgets based on cost drivers, improved project control and reporting, a shortened budget cycle and reduction of information bottlenecks within finance.

Project Justification:
A Corporate Performance Management application will allow budget managers to easily access financial information, providing a basis for analysis and development of more accurate budgets based on historic cost drivers. It will save time through enhancements in:

- The ability of managers and executives to see an integrated view of the budgets, actual costs and variances under their responsibility; and
- The ability of the Finance Department to see budget, reforecast, and actual expenditure detail from business units.

Future Plans:
None.

Project Title: Corporate Application Environment - Upgrade Showcase Strategy Suite

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This system, Showcase Suite, provides the corporate wide reporting capability. Its primary use is to report against the business, work order and customer systems maintained with the JD Edwards suite of applications. Showcase Suite provides for both scheduled and on demand reporting needs. This project is to upgrade the Showcase Suite to the latest supported version.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	2.7	0.0	0.0	2.7
Labour	94.0	0.0	0.0	94.0
Consultant	38.2	0.0	0.0	38.2
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.8	0.0	0.0	2.8
O/H, AFUDC & Escalation	6.8	0.0	0.0	6.8
Contingency	13.8	0.0	0.0	13.8
Sub-Total	**158.3**	**0.0**	**0.0**	**158.3**
Cost Recoveries	**(45.9)**	**0.0**	**0.0**	**(45.9)**
Total	**112.4**	**0.0**	**0.0**	**112.4**

Operating Experience:

The project is triggered by the withdrawal of support for our current version by the product's vendor. The vendor has announced support termination in April 2009.

The following upgrades have occurred since installation:

Year	**Major Work/Upgrade**
2006	Showcase 7.0 Upgrade + Enterprise Reporting Enhancement
2004	Showcase 6.5 Upgrade
2002	Showcase 4.5 Upgrade

Project Title: Corporate Application Environment - Upgrade Showcase Strategy Suite **(cont'd.)**

Project Justification:

This project is justified based on the pending withdrawal of support for our current version of Showcase Suite. To continue to be supported, we must upgrade to the next release.

Table 1 shows the upgrades have occurred from 2004-2006.

Table 1. Budget History

Year	Budget ($000)	Actual ($000)	Comments
2006	105.2	157.8	Showcase 7 Upgrade
2006	136.7	162.9	Addition of Enterprise Reporting Module Showcase 7 Upgrade
2004	129.2	81.0	Showcase 6.5 Upgrade

Future Plans:

Application enhancements and upgrades occur on an ongoing lifecycle based on business demands and vendor support levels.

Project Title: Replace Fire Protection Panels

Location: Hydro Place

Category: General Properties - Administration

Definition: Pooled

Classification: Normal

Project Description:

This project consists of the complete replacement of the main fire protection panel for Hydro Place and the special purpose fire protection panel for the central information systems computer room in Hydro Place. The replacement panels will be supplied and installed by a certified fire protection systems contractor.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	30.0	0.0	0.0	30.0
Labour	30.6	0.0	0.0	30.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	10.0	0.0	0.0	10.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	11.3	0.0	0.0	11.3
Contingency	7.1	0.0	0.0	7.1
TOTAL	**89.0**	**0.0**	**0.0**	**89.0**

Operating Experience:

The fire protection panels are used to provide immediate alarms in cases of smoke or fire, initiate mitigating measures, such as sprinkler systems or gas suppression systems, and notify authorities and fire departments of the indication or presence of fire. The panels are not operating properly because some component parts in the panels have failed and replacement parts are unavailable. The panels and the component parts are no longer provided by the manufacturer.

Project Justification:

The fire protection panels are required for the protection of the Hydro Place building facilities, the operational equipment in the facility, as well as the people who use the facility.

Future Plans:

None.

Project Title: Security Smart Card and Disk Encryption for Laptops
Location: Hydro Place
Category: Information Systems
Type: Pooled
Classification: Normal

Project Description:

The Security Smart Card and Disk Encryption for Laptops Project will deploy Smart Card technology to all laptop users. 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 administration; and (4) combine both building and computer access on one card.

When an employee wants to sign in, 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 login credentials that are securely stored on the card. It also restricts unauthorized access, since an unauthorized user would need to have both the actual card and the password to unlock a laptop or application.

Project Cost: *($ x1,000)*	**2009**	**2010**	**Beyond**	**Total**
Material Supply	82.3	0.0	0.0	82.3
Labour	17.3	0.0	0.0	17.3
Consultant	10.0	0.0	0.0	10.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escalation	4.6	0.0	0.0	4.6
Contingency	11.0	0.0	0.0	11.0
Sub-Total	125.1	0.0	0.0	125.1
Cost Recoveries	(36.3)	0.0	0.0	(36.3)
Total	**88.8**	**0.0**	**0.0**	**88.8**

Operating Experience:

Currently Hydro does not have a centralized disk encryption management system. If a laptop is lost or stolen there is a high risk that any sensitive or confidential information stored on the laptop could be exposed. While passwords are an effective tool to prevent access to data, passwords combined with disk encryption will provide an extra level of security to protect sensitive information if the laptop is lost or stolen.

Project Title: Security Smart Card and Disk Encryption for Laptops **(cont'd.)**

Operating Experience: (cont'd.)

A Directive from the Government of Newfoundland and Labrador, in January 2008 (as shown on pages D-104 and D-105) indicated that storing personal or confidential government information on unencrypted portable storage devices was not permissible. As Hydro is a Crown Corporation, the same guidelines apply.

Project Justification:

This project is justified on Hydro's responsibility to protect its confidential and sensitive corporate information from accidental or targeted security exposures. Recent security breaches within the Provincial Government Departments and Agencies highlighted the need to have increased security on unencrypted mobile data that is of a personal or confidential nature to the company.

Smart Cards provide major improvements for computer access. The 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). Computer access can now be consolidated on one card that is centrally managed.

Future Plans:

Future upgrades will be proposed in future capital budget applications.

Project Title: Security Smart Card and Disk Encryption for Laptops **(cont'd.)**

Government Directive

JAN-31-2008 17:07 DEPT OF NATURAL RESOURCES

F-11 EJM

Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Natural Resources
Office of the Minister

January 31, 2008

Mr. John Ottenheimer
Chair
Newfoundland and Labrador Hydro
P.O. Box 26041
St. John's, NL
A1E 0A5

Dear Mr. ~~Ottenheimer~~: John.

Subject: **Requirements for the Protection of Personal and Other Confidential Information**

In November 2007, a privacy breach occurred involving personal information held by Government. The breach resulted from files on a computer being used by a contracted employee being made available over the Internet through a popular file sharing program (LimeWire). On January 22, 2008 the Provincial Government was apprised of a similar incident when files containing sensitive personal information on a computer owned by a company providing services to the Provincial Government and one of its agencies were made accessible over the Internet via the same file sharing program. LimeWire is one of many file sharing programs used to share and download music from the Internet.

Following the November breach, the Office of the Chief Information Officer (OCIO) immediately took steps to further enhance the security of Provincial Government computers and networks. File-sharing programs (e.g. LimeWire, Bearshare, WinMX) and "chat" programs (e.g. MSN Messenger, ICQ and Skype) can create vulnerabilities that could result in information being made available to unauthorized persons, often without the knowledge of the individual with custody of the information. Consequently, "lock-down" security mechanisms have now been implemented so that these programs can no longer be executed on Provincial Government computers under OCIO control.

Additionally, the OCIO modified the conditions of contracts with its Information Technology contractors/consultants requiring them to enter into confidentiality agreements and/or sign Oaths of Secrecy in order to continue to work on government systems.

P.O. Box 8700, St. John's, NL, Canada A1B 4J6 t 709.729.2920 f 709.729.0059

Project Title: Security Smart Card and Disk Encryption for Laptops **(cont'd.)**

Government Directive

JAN-31-2008 17:07 DEPT OF NATURAL RESOURCES [illegible]

- 2 -

As a result of the most recent breach, although Government's internal systems were not compromised, the incident highlighted that additional measures must be undertaken to ensure that personal and other confidential government information is protected to the greatest degree possible. Effective immediately it is not permissible to copy personal and/or confidential government information to portable storage devices (e.g. unencrypted flash drives, memory sticks, cds) or to work on files containing personal or other confidential government information on computers not owned by the Provincial Government. Should circumstances arise where deviation from these policies is required, authorization must be requested and received in writing from the permanent head of the organization.

The Department of Justice is also developing standard contract language for contracts let for the conduct of work utilizing personal or other confidential Provincial Government information that will require such contractors to provide the same confidentiality and privacy protection mechanisms as those practiced by Provincial Government departments.

As Minister of Natural Resources to which Newfoundland and Labrador Hydro reports, I am directing that the Board ensure that similar provisions taken by Government be implemented immediately by the Board, if not already in place. I am further directing that the Board report in writing to me of the status of measures implemented and/or planned by February 8, 2008.

Thank you for your cooperation with this matter. Should you have any questions or require clarification on any item, please contact the Office of the Clerk of the Executive Council at 729-2853.

Sincerely yours,

Kathy

KATHY DUNDERDALE, MHA
Minister

c.c. Premier
Gary Norris, Clerk of the Executive Council and Secretary to Cabinet
Ed Martin, CEO, Newfoundland and Labrador Hydro

Project Title: Application Enhancements – Perform Minor Application Enhancements

Location: Hydro Place

Category: Information Systems

Definition: Pooled

Classification: Normal

Project Description:

Hydro has many computer applications that are used by Hydro employees to run the business on a day to day basis. 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 requirements.

Project Cost: *($ x1,000)*	**2009**	**2010**	**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 & Escalation	4.3	0.0	0.0	4.3
Contingency	10.5	0.0	0.0	10.5
Sub-Total	120.2	0.0	0.0	120.2
Cost Recoveries	(34.9)	0.0	0.0	(34.9)
Total	**85.3**	**0.0**	**0.0**	**85.3**

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 2007, the most recent year for which actuals are available, the following application enhancements were made: Safety Management System, Leave Requests, Record Management Deployment, Diesel Plant Data Automation Software, and Lightning Tracking System.

Project Title: Application Enhancements – Perform Minor Application Enhancements **(cont'd.)**

Project Justification:

This project is part of normal Information Systems department work. This project 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 1 shows upgrades that have occurred from 2003-2008F.

Table 1. Application Enhancements

Year	Budget ($000)	Actual ($000)	Comments(1)
2008F	372.5(2)		Upgrade
2007	148.5(2)	148.5	Upgrade
2006	780.0(3)	390.0	Upgrade
2005	398.0	334.0	Upgrade
2004	463.0	464.0	Upgrade

(1) Upgrade refers to adding or extending functionality of applications
(2) Previous Budgets included the Internet Refresh Proposal.
(3) The "Enhancements to the Capital and Operating Process Applications" component of this budget was cancelled. Budgeted amount for this component: $390,000

Future Plans:

Future enhancements will be proposed in future capital budget applications.

Project Title: Citrix Enhancement

Location: Hydro Place

Category: Information Systems

Definition: Other

Classification: Normal

Project Description:

The Citrix software enhancement project is required to upgrade the licensing of the Citrix software suite to allow enhanced capability.

Enhancements will provide additional functionality in the following areas:

Remote Access / Performance - The remote access allows for single point of entry for users to access corporate information remotely. The enhancement of this upgrade will allow for easier administration and better performance for remote access users.

Single Sign-On - Users need only a single logon/password combination to securely launch multiple password-protected applications delivered by Citrix. This feature provides automated application logons, password policy control and self-service password reset to encourage and enforce security disciplines without burdening system administrators or users.

SmartAuditor - Provides a powerful application session recording for improved logging of user access from remote access and accelerated problem analysis. The new monitoring capabilities in Citrix allow Information Systems to quickly pinpoint and troubleshoot server, network and application programming issues that impact the user experience.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	81.5	0.0	0.0	81.5
Labour	22.0	0.0	0.0	22.0
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 & Escalation	4.3	0.0	0.0	4.3
Contingency	10.4	0.0	0.0	10.4
Sub-Total	118.2	0.0	0.0	118.2
Cost Recoveries	(34.3)	0.0	0.0	(34.3)
Total	**83.9**	**0.0**	**0.0**	**83.9**

Project Title: Citrix Enhancement **(cont'd.)**

Operating Experience:

The Citrix software has been used at Hydro since 2003 to deliver applications to all users across the corporation. The use of this software allows the corporation to centralize the storage of information and streamline application delivery by use of this software. The software is used on a day to day basis by employees to deploy desktop applications such as word processing, email and spreadsheets.

Project Justification:

This software is used on a day to day basis by users to access computer applications. Enhanced monitoring will allow for better troubleshooting of problems and allow for better levels of productivity by eliminating performance problems.

Single sign on will allow for easier administration of passwords.

The remote access functionality of this software is used 3,000 times a month by staff to access computer systems either after hours or when they are away from the office.

Future Plans:

Application upgrades occur on an ongoing life cycle based on business demands and vendor support levels.

Project Title: Replace Humidifiers in Air Handling Units

Location: Hydro Place

Category: General Properties - Administrative

Definition: Other

Classification: Normal

Project Description:

This project is the second year of a five year project that started in 2008. The purpose of this project is to replace all humidifiers in air handling systems at Hydro Place. Each humidifier has reached the end of its useful life and will be replaced. In 2009, two humidifiers will be replaced.

Project Cost: *($ x1,000)*	**2009**	**2010**	**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.	7.1	0.0	0.0	7.1
Contingency	6.1	0.0	0.0	6.1
TOTAL	74.3	0.0	0.0	74.3

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.

The replacement of two humidifiers was approved in Board Order No. P.U. 30 (2007) in the amount of $584,000 for 2008.

Project Justification:

A total of 10 humidifiers located in Hydro Place have reached the end of their useful lives. Spare parts are no longer available for the humidifiers' control systems. One humidifier is currently out of

Project Title: Replace Humidifiers in Air Handling Units **(cont'd.)**

Project Justification: (cont'd.)

service because its control system has failed and cannot be repaired. This causes a reduction in air quality in the area served by this humidifier. The supplier, Johnson Controls recommends that these humidifiers be replaced with ones that have cleanable stainless steel bottles.

Humidifiers that store water in plastic water bottles are more costly to maintain than those with stainless steel bottles because the plastic bottles are disposable. At Hydro Place, plastic bottles are replaced annually or sooner if required, at a cost of $400 to $600 each. Stainless steel bottles do not require replacement but require annual cleaning that, according to Johnson Controls, takes 15 minutes to perform. Due to better insulation properties, water stored in stainless steel bottles does not lose as much heat over time as water stored in plastic bottles. This results in energy savings.

This project will improve reliability of humidification systems, and save approximately $500 per humidifier per year in comparison to plastic bottle replacement.

Future Plans:

From 2008 until 2012, two humidifiers will be replaced each year at Hydro Place.

Project Title: Purchase Test Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Tools and Equipment

Definition: Pooled

Classification: Normal

Project Description:

This project is required to purchase test equipment for telecommunications and network equipment used by Hydro to provide operational and administrative communications. The 2009 Network Test Equipment Project is required to purchase new equipment for the support of the ongoing testing, monitoring, and maintenance activities associated with existing and newer communication technologies within Hydro's infrastructure.

Included in the scope of this project is the purchase of:

- One oscilloscope,
- One optical time domain reflectometer (OTDR), and
- One level generator.

The oscilloscope allows technologists and engineers to examine the electrical signals being created by a wide variety of equipment. The OTDR tests and troubleshoots fiber optic cables. The level generator is a signal source for testing microwave radio connections.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	54.0	0.0	0.0	54.0
Labour	4.5	0.0	0.0	4.5
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.	9.5	0.0	0.0	9.5
Contingency	5.9	0.0	0.0	5.9
TOTAL	73.9	0.0	0.0	73.9

Operating Experience:

The oscilloscope being replaced was purchased in 1981; the OTDR was purchased in 1999. The level generator is a new purchase. For depreciation purposes test equipment is assumed to have

Project Title: Purchase Test Equipment **(cont'd.)**

Operating Experience: (cont'd.)

a life of five years. The test equipment proposed has an estimated service life of 10 years. There has been no maintenance on the oscilloscope. The OTDR was recalibrated in May 2006 at a cost of $1,492 and again in December 2007 at a cost of $2,793. The level generator is a new purchase.

Project Justification:

Test equipment is a necessary component of the technologist's tools used to troubleshoot, test and repair equipment and services. The requirement for new and replacement test equipment is ongoing, as existing equipment ages and new equipment with new testing capabilities is purchased. This project will help ensure that Hydro's telecommunications maintenance staff is equipped to ensure the reliable delivery of the services required to support the power grid.

Future Plans:

Future purchases will be proposed in future capital budget applications.

Project Title: Purchase Protective Relay Event Report Software

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase, install and configure software that will automatically collect and store transmission system fault event data from digital protective relays as events occur. This software will have fault analysis capabilities. The protective relays will be configured to automatically communicate fault data to the computer. The software will reside on a single computer, which will be secured to prevent unauthorized access to protective relays. Modifications will be made to the protective relay infrastructure to facilitate communications of information by phone or network.

Project Cost: *($ x1,000)*	**2009**	**2010**	**BEYOND**	**TOTAL**
Material Supply	13.0	0.0	0.0	13.0
Labour	32.0	0.0	0.0	32.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	2.2	0.0	0.0	2.2
Contingency	4.7	0.0	0.0	4.7
TOTAL	53.9	0.0	0.0	53.9

Operating Experience:

When electrical faults occur on the transmission system, Engineering and System Operations staff obtain detailed data from the protective relays for analysis by accessing either individual relays by phone or remote data collection devices by network or phone communications. The existing process by which the data is obtained and readied for analysis is cumbersome. The process consists of manually connecting to each remote data collection device via the network or phone line using communications software, accessing the data, saving a segment of the data to a usable text file, and importing that file into the diagnostics software for troubleshooting. This is a time-consuming process and prone to errors in that should any information be missing or not saved in the proper format, the file would be rendered unusable by the analysis software. The user would then have to repeat the process. There is currently no specific centralized location for fault data.

Project Title: Purchase Protective Relay Event Report Software **(cont'd.)**

Operating Experience: (cont'd.)

This software will be a central repository for all fault data. The Energy Control Centre (ECC) operator presently has limited information on transmission line fault events. The intended system is anticipated to resolve these deficiencies and aid in expediting electrical service restoration.

Project Justification:

This project will eliminate the need for Engineering or System Operations staff to manually obtain, via the network or phone line, transmission system fault data and to manipulate the file so that it can be used by disturbance analysis software. The proposed system will consolidate fault event data to a central location thereby providing for ease of access. In addition, it is anticipated that the immediate reporting of such information to ECC operators would help line crews to reduce travel when dispatched for outages to the transmission system and time spent in locating transmission line faults.

Future Plans:

Software upgrades are to be made as new releases become available from the manufacturer. As more digital relays are added to the terminal stations across the island, they will be added to this automated data collection software service.

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Type
			($000)		
MANDATORY PROJECTS					
Public Address System - Holyrood	96	1,182		1,279	Pooled
Perform Grounding Upgrades - Various Sites		252	291	543	Pooled
TOTAL MANDATORY PROJECTS	96	1,434	291	1,822	
NORMAL PROJECTS					
New 25 kV Terminal Station - Labrador City		283	9,707	9,991	Other
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	358	2,960		3,318	Other
Refurbish Fuel Storage Facility - Holyrood		2,867		2,867	Other
Purchase Spare Stator Winding for Units 1 to 4 - Bay d'Espoir		37	2,806	2,843	Other
Upgrade Distribution Systems - All Service Areas		2,526		2,526	Pooled
Provide Service Extensions - All Service Areas		2,439		2,439	Pooled
Perform Wood Pole Line Management Program - Various Sites		2,256		2,256	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
Replace Diesel Units - Norman Bay, Postville and Paradise River		170	1,700	1,870	Pooled
Replace Insulators on 230kV Line - Stony Brook, Buchans	848	970		1,818	Pooled
Upgrade Corner Brook Frequency Converter - Corner Brook	495	1,152		1,647	Pooled
Upgrade System Security - Various Sites		767	702	1,469	Pooled
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	335	938		1,273	Pooled
Replace Accomodations, Septic System and Uprgade Plant Communications System - Cat Arm		1,254		1,254	Clustered
Replace Governor Controls Unit 2 - Cat Arm	975	74		1,049	Pooled
Customer Service Application - Hydro Place	768	182		950	Other
Replace Unit 2 High Pressure Heater - Holyrood	20	919		939	Other
Diesel Plant Automation - Makkovik and Rigolet	516	379		895	Other
Replace Insulators - Jackson's Arm, Hampden and Little Bay		874		874	Pooled
Increase Generation - L'Anse au Loup		23	821	844	Other
Replace Off-Road Tracked Vehicles - Whitbourne and Bishop's Falls		758		758	Pooled
Replace Batteries and Chargers - Various Sites		729		729	Other
Replace Poles - Jackson's Arm and Hampden		697		697	Pooled
Install Fibre Optic Cable - Hinds Lake		209	483	692	Other
Upgrade L7 Distribution System - St. Anthony		689		689	Other
Upgrade Power Transformers - Various Sites		654		654	Pooled
Increase Generation Capacity - Charlottetown	18	577		595	Other
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites		561		561	Other
Replace Switchgear - Cartwright	383	169		552	Other
TOTAL NORMAL PROJECTS	4,716	29,237	17,183	51,135	
JUSTIFIABLE PROJECTS					
Energy Conservation Upgrades - Hydro Place		833		833	Pooled
TOTAL JUSTIFIABLE PROJECTS	0	833	0	833	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years ($000)	Total	Type
MANDATORY PROJECTS					
Install Fall Arrest Equipment - Various Sites		322		322	Pooled
Replace Explosives Storage Magazines - Variouse Sites		293		293	Pooled
TOTAL MANDATORY PROJECTS	0	614	0	614	
NORMAL PROJECTS					
Replace Line L36 - Wabush		498		498	Other
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		498		498	Other
End User Evergreening Program - Various Sites		491		491	Pooled
Replace Unit 3 Steam Seal Regulator - Holyrood		475		475	Other
Replace Power Line Carrier on TL-250 - Bottom Brook to Grandy Brook		473		473	Other
Install Digital Fault Recorders - Massey Drive, Oxen Pond and St. Anthony		462		462	Other
Upgrade Gas Turbine Plant Life Extension - Hardwoods		450		450	Other
Purchase Spare Transformer - Hydro Place	86	353		439	Other
Build New Maintenance Shop - St. Anthony		429		429	Other
Upgrade Circuit Breakers - Various Terminal Stations		422		422	Pooled
Replace Insulators - Various Terminal Stations		391		391	Pooled
Replace 50kW Diesel Generator - Bay d'Espoir		36	289	325	Other
Replace Conductor on Line 2 - Rocky Harbour		325		325	Other
Replace Unit 2 Air Preheater Cold End - Holyrood		320		320	Other
Replace Cooling Water System on Units 3 and 4 - Bay d'Espoir		287		287	Other
Replace Remote Terminal Units - Various Sites		278		278	Other
Upgrade Intake Gate Controls - Hinds Lake		263		263	Other
Replace Automatic Voltage Regulator on Gas Turbine - Stephenville		262		262	Other
Replace 40 kW Diesel Generator at Spillway - Bay d'Espoir	157	103		260	Pooled
Install Meteorological Stations - Various Sites		253		253	Pooled
Replace Unit 1 Hydrogen Emergency Vent Valves - Holyrood		214		214	Other
TOTAL NORMAL PROJECTS	243	7,283	289	7,815	
JUSTIFIABLE PROJECTS					
Install Automatic Meter Reading - Change Islands and Fogo Island		491		491	Other
TOTAL JUSTIFIABLE PROJECTS	0	491	0	491	

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years ($000)	Total	Type
MANDATORY PROJECTS					
Environmental Effects Monitoring Study of Waste Water - Holyrood	73	87		160	Other
Install Waste Oil Storage Tanks - Mary's Harbour		84		84	Other
Install Meter Station for Fuel Reconciliation - Hawke's Bay		64		64	Other
TOTAL MANDATORY PROJECTS	73	235	0	308	
NORMAL PROJECTS					
Replace 69 kV Breaker L51T2 - Howley		199		199	Other
Upgrade Server Technology Program - Hydro Place		194		194	Other
Upgrade Great Northern Peninsula Protection - Various Sites		101	91	192	Other
Install Unit 1 Cold Reheat Condensate Drains and HP Heater Trip Level - Holyrood		192		192	Other
Upgrade Voltage Conversion Phase 1- Labrador City		189		189	Other
Upgrade Ventilation System - Little Bay Islands Diesel Plant		186		186	Other
Replace Radio Tower - Ebbegunbaeg		179		179	Other
Install Motorized Stack Winches - Holyrood		174		174	Other
Replace Peripheral Infrastructure - Hydro Place		161		161	Pooled
Pave Parking Lots and Roadways - Bishop's Falls		150		150	Other
Replace Service Water Piping - Unit 7 - Bay d'Espoir		144		144	Other
Replace Network Communications Equipment - Various Sites		141		141	Other
Upgrade Fuel Storage - Cartwright		139		139	Other
Replace Drafting Scanner/Plotter - Hydro Place		139		139	Pooled
Replace Recloser Control Panels - Various Sites		132		132	Pooled
Replace Radomes - Various Sites		130		130	Pooled
Application Enhancements - Performance Management Software Budgeting Tool - Hydro Place		127		127	Other
Replace Speed Increaser - Roddickton		125		125	Other
Purchase and Install a Voltage Regulator Bank - English Harbour West		123		123	Other
Install Transformer Storage Ramps - Labrador		121		121	Other
Corp. Application Environment - Upgrade Showcase Strategy Suite - Hydro Place		112		112	Other
Replace Instrument Transformers - Various Sites		107		107	Other
Replace 230 kV Breaker Controls - Oxen Pond and Bay d'Espoir		100		100	Other
Purchase and Install Electronic Recloser - Cartwright		96		96	Other
Replace Submarine Cable Terminator Kit - Change Islands and Fogo Island		96		96	Other
Replace Air Compressors - Sunnyside		96		96	Other
Install Marine Terminal Capstan Lifting Frame - Holyrood		93		93	Other
Replace Fire Protection Panels - Hydro Place		89		89	Pooled
Security Smartcard and Disk Encryption for Laptops - Hydro Place		89		89	Pooled
Purchase High Definition Infrared Camera - Central		87		87	Other
Construct ATV/Snowmobile Storage Building - Whitbourne		86		86	Other
Application Enhancements - Perform Minor Application Enhancements - Hydro Place		85		85	Pooled
Replace Drainage System - Western Avalon		84		84	Other
Citrix Enhancement - Hydro Place		84		84	Other

PROJECT DESCRIPTION	Expended to 2008	2009	Future Years	Total	Type
			($000)		
NORMAL PROJECTS (Continued)					
Purchase Boom Style Hydraulic Lift - Holyrood		82		82	Other
Replace Surge Arrestors - Various Sites		81		81	Other
Install Pole Storage Ramps - Various Sites		77		77	Other
Install Water and Sewer System - Paradise River		77		77	Other
Construct Transmission Storage Ramps - Bay d'Espoir		75		75	Other
Replace Humidifiers in Air Handling Units - Hydro Place		74		74	Other
Purchase Test Equipment - Various Sites		74		74	Pooled
Install 138 kV Capacitive Voltage Transformer - St. Anthony Airport		71		71	Other
Replace Generator Oil Level System on Units 1 and 2 - Cat Arm		68		68	Other
Install 69 kV Capacitive Voltage Transformer - St. Anthony Diesel Plant		67		67	Other
Install Remote Ice Growth Detector Beams - Various Sites		65		65	Pooled
Install Furnace Fuel Storage Tank - William's Harbour		59		59	Other
Legal Survey of Primary Distribution Line Right of Way - Various Locations		56		56	Other
Purchase Protective Relay Event Report Software - Hydro Place		54		54	Other
TOTAL NORMAL PROJECTS	0	5,328	91	5,420	

Type	Number	($000)
Clustered	1	1,254
Pooled	32	25,379
Other	75	42,804
Total	**108**	**68,437**

* *Includes multi-year projects but excludes contingency fund*

2009 LEASING COSTS

Lease of Land for Ambient Air Monitoring Site – Lawrence Pond, C.B.S.

Hydro has leased a parcel of land in the vicinity of Lawrence Pond, Conception Bay South, since 1994 for the purpose of an ambient air monitoring station that it operates to collect emissions data for its Holyrood Thermal Generating Station. To ensure that Hydro's emissions data is consistent, replicable and meaningful, it is essential that data be collected from the same point continuously. The Board last approved the lease for this site under P.U. Order No.7 (2004).

The value of renewing this lease for a further five years is $6,720 per year.

	ACTUALS				BUDGET					
	2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
GENERATION	4,443	9,352	7,557	9,636	13,586	7,886	12,800	13,632	23,431	20,799
TRANSMISSION AND RURAL OPERATIONS	14,678	16,691	19,249	19,150	28,173	29,725	25,429	28,063	19,715	29,250
GENERAL PROPERTIES	8,863	7,909	14,411	6,883	11,077	10,245	12,693	12,882	14,498	8,765
TOTAL CAPITAL EXPENDITURES	27,984	33,952	41,217	35,669	52,836	47,856	50,922	54,577	57,644	58,814

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures
GENERATION	868	8,965	1,169	10,120	1,155
TRANSMISSION AND RURAL OPERATIONS	928	27,617	5,465	26,951	(666)
GENERAL PROPERTIES	137	10,698	1,362	10,698	0
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	67	1,000	0
PROJECTS APPROVED BY PU BOARD	0	4,542	0	4,542	0
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	0	14	13	14	0
TOTAL CAPITAL BUDGET	1,933	52,836	8,076	53,325	489

Approved Board Order No. P.U. 30 (2007) 2008 Capital Budget	42,398
Carryover Projects 2007 to 2008	5,882
New Projects Approved by Board Order No. P.U. 17 (2008)	4,542
2008 New Projects under $50,000 Approved by Hydro	14
TOTAL APPROVED CAPITAL BUDGET	52,836

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures
GENERATION					
HYDRAULIC PLANTS	95	4,052	362	5,148	1,096
THERMAL PLANT	610	4,065	686	4,117	52
GAS TURBINES	163	143	55	150	7
TOOLS AND EQUIPMENT	0	705	66	705	0
TOTAL GENERATION	868	8,965	1,169	10,120	1,155
TRANSMISSION AND RURAL OPERATIONS					
TERMINAL STATIONS	235	4,065	263	4,065	0
TRANSMISSION	195	5,977	1,068	5,977	0
DISTRIBUTION	195	9,265	2,958	9,465	200
GENERATION	0	1,956	92	1,956	0
PROPERTIES	102	2,409	66	1,543	(866)
METERING	201	1,593	858	1,593	0
TOOLS AND EQUIPMENT	0	2,352	160	2,352	0
TOTAL TRANSMISSION AND RURAL OPERATIONS	928	27,617	5,465	26,951	(666)
GENERAL PROPERTIES					
INFORMATION SYSTEMS	0	3,444	1,046	3,444	0
TELECONTROL	0	2,817	126	2,817	0
TRANSPORTATION	0	2,294	138	2,294	0
ADMINISTRATIVE	137	2,143	52	2,143	0
TOTAL GENERAL PROPERTIES	137	10,698	1,362	10,698	0
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	67	1,000	0
PROJECTS APPROVED BY PU BOARD	0	4,542	0	4,542	0
PROJECTS APPROVED FOR LESS THAN $50,000	0	14	13	14	0
TOTAL CAPITAL BUDGET	1,933	52,836	8,076	53,325	489

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
HYDRAULIC PLANTS						
Replace Station Service Control - Bay d'Espoir	66	58	34	58	0	
Stator Windings Design Review - Bay d'Espoir	29	20	2	20	0	
Upgrade Spherical Valve Maintenance Seals - Cat Arm	0	1,060	133	1,826	766	1
Replace Governor Controls Unit 2 - Cat Arm	0	975	19	1,238	263	2
Arc Flash Analysis - Various Sites	0	342	3	342	0	
Replace Cooling Water Systems Units 1 and 2 - Bay d'Espoir	0	264	98	264	0	
Replace 40 kW Diesel Generator - Burnt Dam	0	157	8	157	0	
Install Meteorological Stations - Various Sites	0	222	6	222	0	
Hydraulic Structure Life Study - Bay d'Espoir	0	196	3	196	0	
Replace Cooling Water Piping System - Hinds Lake	0	193	5	193	0	
Salmon Spillway Stoplog Handling System	0	141	1	180	39	
Upgrade Intake #4 Gate Controls - Bay d'Espoir	0	116	39	144	28	
Replace Back-Up Air Dryer - Bay d'Espoir	0	73	0	73	0	
Replace Communications Room Air Conditioner - Bay d'Espoir	0	64	0	64	0	
Upgrade Access Trail - Venam's Bight	0	64	2	64	0	
Replace Fire Alarm System - Cat Arm	0	54	9	54	0	
Replace Auxiliary Service Water Pump - Cat Arm	0	53	0	53	0	
TOTAL HYDRAULIC PLANTS	95	4,052	362	5,148	1,096	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
THERMAL PLANT						
Fire Protection Upgrades - Holyrood	605	1,219	260	1,219	0	
UPS Battery Monitoring Program - Holyrood	5	74	71	74	0	
Tank Farm Upgrade	0	500	0	500	0	
Replace Unit 2 High Pressure Heater	0	20	1	20	0	
Replace Unit 1 and 2 Condenser Valve Actuators	0	313	13	313	0	
Replace Unit 2 Electromechanical Trip Device	0	305	82	305	0	
Precipitator and Scrubber Installation Study	0	272	9	272	0	
Replace 4160 Volt Motor Relays	0	172	37	172	0	
Replace Unit 2 Main Steam Stop Valve	0	171	49	171	0	
Environmental Effects Monitoring Study of Waste Water	0	73	5	73	0	
Upgrade Ambient Monitoring Station	0	128	78	128	0	
Soot Blowing Controls Study	0	123	3	123	0	
Stack Breeching Study	0	115	4	115	0	
Install Safety Egress Lighting	0	97	1	112	15	
Auto Synchronizing Units 1 and 2	0	93	2	93	0	
Install Stator Ground Fault Protection	0	85	29	100	15	
Upgrade Meteorological Station	0	75	7	75	0	
Construct Beta Attenuation Meter (BAM) Unit Enclosure	0	60	0	60	0	
Programmable Logic Controller Replacement Study	0	58	32	58	0	
Motor Control Centres Assessment	0	43	3	65	22	
Install UV Domestic Water Treatment	0	36	0	36	0	
Jetty Building Ventilation	0	33	0	33	0	
TOTAL THERMAL PLANTS	610	4,065	686	4,117	52	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
GAS TURBINES						
Replace Fuel Piping -Stephenville	145	97	50	97	0	
Vibration Monitoring System Upgrade - Hardwoods, Stephenville	18	15	1	15	0	
Gas Turbine Electrical Assessment - Holyrood	0	31	4	38	7	
TOTAL GAS TURBINE PLANTS	163	143	55	150	7	
TOOLS AND EQUIPMENT						
Replace Champion Grader V-9797 - Bay d'Espoir	0	404	0	404	0	
Purchase Grounding Trucks	0	61	0	61	0	
Purchase Tools and Equipment Less than $ 50,000	0	240	66	240	0	
TOTAL TOOLS AND EQUIPMENT	0	705	66	705	0	
TOTAL GENERATION	868	8,965	1,169	10,120	1,155	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TERMINAL STATIONS						
Upgrade Breaker Controls - Oxen Pond and Sunnyside Terminal Statio	12	28	5	28	0	
Safety and Reliability Upgrade - Hawkes Bay Terminal Station	204	145	80	145	0	
Purchase Spare Transformer - Upper Salmon	19	2,198	27	2,198	0	
Replace Battery Banks and Chargers - Various Stations	0	430	11	430	0	
Replace Disconnect Switches - Cow Head and Daniel's Harbour	0	368	13	368	0	
Upgrade Circuit Breakers - Various Stations	0	315	1	315	0	
Replace Digital Fault Recorder - Buchans	0	130	9	130	0	
Replace Compressors - Buchans	0	94	9	94	0	
Replace Instrument Transformers - Various Stations	0	74	71	74	0	
Replace Surge Arrestors - Various Stations	0	67	36	67	0	
Upgrade Station Services - Hardwoods	0	59	0	59	0	
On-Line Dewpoint Monitoring - Bay d'Espoir	0	38	0	38	0	
Replace Control Building Roof - Doyles	0	34	0	34	0	
Secondary Air Line for Switchgear - Cat Arm	0	33	0	33	0	
Replace Breaker Control Panels - Western Avalon	0	32	0	32	0	
Replace Equipment Concrete Foundation - Stoney Brook	0	20	1	20	0	
TOTAL TERMINALS	235	4,065	263	4,065	0	
TRANSMISSION						
Upgrade Corner Brook Frequency Converter - 2007	26	1,294	183	1,294	0	
Upgrade 138kV Protection - Springdale, Howley and Indian River	169	46	55	46	0	
Wood Pole Line Management Program	0	2,188	406	2,188	0	
Replace Insulators TL-232 and TL-253	0	848	107	848	0	
Upgrade Corner Brook Frequency Converter - 2008	0	495	36	495	0	
Upgrade Line TL-212 - (Sunnyside to Linton Lake)	0	464	192	464	0	
Construct Transmission Line Equipment Off-Loading Areas	0	302	10	302	0	
Replace Insulators - Various Stations	0	294	69	294	0	
Install Remote Ice Growth Detection Beam - Various Stations	0	46	10	46	0	
TOTAL TRANSMISSION	195	5,977	1,068	5,977	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
DISTRIBUTION						
Replace Diesel Unit # 290 - Williams Harbour	92	278	17	278	0	
Upgrade Distribution Systems - Various Systems	0	2,727	459	2,727	0	
Provide Service Extensions - All Service Areas	103	2,158	1,149	2,358	200	3
Upgrade Distribution Systems - All Service Areas	0	2,293	762	2,293	0	
Replace poles - South Brook and Bay d'Espoir	0	701	46	701	0	
Replace Insulators - Various Systems	0	623	391	623	0	
Replace Recloser Control Panels - Various Systems	0	223	80	223	0	
Reconfigure Feeders - Happy Valley	0	151	40	151	0	
Replace Submarine Cable Terminator - Gaultois	0	64	14	64	0	
Recloser Assessment - Happy Valley	0	47	0	47	0	
TOTAL DISTRIBUTION	195	9,265	2,958	9,465	200	
GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	0	335	0	335	0	
Diesel Plant Automation - Makkovik and Rigolet	0	516	21	516	0	
Increase Generation Capacity - Charlottetown	0	18	0	18	0	
Replace Switchgear - Cartwright	0	383	7	383	0	
Replace Mufflers - L'Anse au Loup and St. Anthony	0	479	13	479	0	
Replace Underground Fuel Lines - Little Bay Islands and Grey River	0	89	7	89	0	
Replace Meter House Equipment - Various Sites	0	75	0	75	0	
Install Day Tank and Meter - Hopedale	0	61	44	61	0	
TOTAL GENERATION	0	1,956	92	1,956	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
PROPERTIES						
Installation of Card Access System - Bishop Falls and Whitbourne	102	29	29	29	0	
Construct New Office,Warehouse,Line Depot Facilities - Happy Valley	0	1,248	0	358	(890)	4
Upgrade Ventilation System - Makkovik	0	217	0	217	0	
Construct Diesel Plant Extension - William's Harbour	0	177	0	177	0	
Replace Fire Alarm System - Hopedale and Paradise River	0	168	15	168	0	
Install Storage Ramp - Holyrood and Port Saunders	0	136	0	136	0	
Install Chain Link Fencing - Port Hope Simpson	0	84	3	84	0	
Upgrade Parking Lot - Whitbourne	0	67	5	67	0	
Install Waste Lube Oil Storage Tank - Cartwright	0	53	4	67	14	
Survey of Hydro's Primary Right of Ways - Various Sites	0	52	5	52	0	
Install Waste Lube Oil Storage Tank - Charlottown	0	46	5	56	10	
Construct Lube Oil Storage Ramps - Various Sites	0	44	0	44	0	
Install Pole Storage Ramp - Burgeo	0	43	0	43	0	
Construct Storage Shed - Paradise River	0	30	0	30	0	
Install Transformer Storage Ramp - St. Lewis	0	15	0	15	0	
TOTAL PROPERTIES	102	2,409	66	1,543	(866)	
METERING						
Install Automatic Meter Reading - 2007 - Various Systems	201	934	631	934	0	
Install Automatic Meter Reading - 2008 - Various Systems	0	567	207	567	0	
Purchase Meters and Equipment	0	67	11	67	0	
Purchase Metering Spares	0	25	9	25	0	
TOTAL METERING	201	1,593	858	1,593	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TOOLS AND EQUIPMENT						
Replace Off Road Track Vehicles - Bishop's Falls and Whitbourne		746	0	746	0	
Replace Light Duty Mobile Equipment Less than $ 50,000		588	29	588	0	
Installation of Fall Arrest Equipment - Various Sites		404	50	404	0	
Replace Boom 6069 on Track Vehicle - Stephenville		236	0	236	0	
Purchase Hydraulic Cutters and Presses - Various Sites		66	43	66	0	
Purchase Forklift for Salvage Stores - Bishop's Falls		49	0	49	0	
Purchase and Replace Tools and Equipment Less than $ 50,000	0	263	38	263	0	
TOTAL TOOLS AND EQUIPMENT	0	2,352	160	2,352	0	
TOTAL TRANSMISSION AND RURAL OPERTIONS	928	27,617	5,465	26,951	(666)	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
Infrastructure Replacement						
New Infrastructure						
Application Enhancements - Work Protection Code		678	442	678	0	
Application Enhancements - Energy Systems Water Management		651	116	651	0	
Application Enhancements - Corporate Systems		373	50	373	0	
Cost Recovery CF(L)Co		(75)	(25)	(75)	0	
Application Enhancements - Energy Systems Optimum Powerflow		216	0	216	0	
Upgrade of Technology						
Corporate Application Environment		331	85	331	0	
Cost Recovery CF(L)Co		(41)	(16)	(41)	0	
TOTAL SOFTWARE APPLICATIONS	0	2,133	652	2,133	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
COMPUTER OPERATIONS						
Infrastructure Replacement						
End User Evergreening Program		451	101	451	0	
Upgrade Enterprise Storage Capacity		327	0	327	0	
Cost Recovery CF(L)Co		(65)	0	(65)	0	
New Infrastructure						
Replace Peripheral Infrastructure		159	120	159	0	
Video Conferencing		140	0	140	0	
Security Configuration Auditing		72	0	72	0	
Cost Recovery CF(L)Co		(14)	0	(14)	0	
Upgrade of Technology						
Server Technology Program		241	173	241	0	
TOTAL COMPUTER OPERATIONS	0	1,311	394	1,311	0	
TOTAL INFORMATION SYSTEMS	0	3,444	1,046	3,444	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TELECONTROL						
NETWORK SERVICES						
Infrastructure Replacement						
Customer Service Application - Hydro Place		768	2	768	0	
Replace Power Line Carrier TL-212 - Sunnyside to Paradise River		466	13	466	0	
Replace Remote Terminal Units - Various Sites		319	62	319	0	
Refurbish Microwave Site - Gull Pond Hill		202	1	202	0	
Replace Dial Backup System - Various Sites		201	4	201	0	
Install Recloser Remote Control - Change Islands		194	11	194	0	
Replace Radomes - Various Sites		124	0	124	0	
Network Infrastructure						
Replace Network Communications Equipment - Various Sites		131	15	131	0	
Test Equipment - Hydro Place and Deer Lake		49	5	49	0	
Wireless Networking - Various Sites		46	0	46	0	
Upgrade of Technology						
Voice Communications Strategy Study - Hydro Place		190	13	190	0	
Replace Network Management Tools - Hydro Place		81	0	81	0	
Upgrade Site Facilities - Various Sites		46	0	46	0	
TOTAL NETWORK SERVICES	0	2,817	126	2,817	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
TRANSPORATION						
Replace Vehicles and Aerial Devices - Various Sites - 2007	0	468	37	468	0	
Replace Vehicles and Aerial Devices - Various Sites - 2008	0	1,826	101	1,826	0	
TOTAL TRANSPORATION	0	2,294	138	2,294	0	
ADMINISTRATION						
Security Assessment of System Operations	137	531	23	531	0	
Upgrade System Security - Various Sites		906	0	906	0	
Purchase Spare Transformer - Hydro Place		87	0	87	0	
Install Computer Room Inergen Fire Protection System - Hydro Place		116	0	116	0	
Safety Hazards Removal - Various Sites		252	0	252	0	
Purchase Office Equipment less than $50,000 - Hydro Place		137	29	137	0	
Replace Humidifiers in Air Handling Units - Hydro Place		58	0	58	0	
Replace Air Conditioning Units - Hydro Place		56	0	56	0	
TOTAL ADMINISTRATIVE	137	2,143	52	2,143	0	
TOTAL GENERAL PROPERTIES	137	10,698	1,362	10,698	0	

	Expenditures Prior To 2008	PUB Approved Budget 2008	2008 Expenditures To June 30	Expected Total Expenditures 2008	Var. from Approved to Expected Expenditures	Variance Explanation Reference
ALLOCATION FOR UNFORESEEN EVENTS						
Replace Structure # 380 on TL-212		0	67	0	0	
Allocation for Unforeseen Events		1,000	0	1,000	0	
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	0	1,000	67	1,000	0	
PROJECTS APPROVED BY PU BOARD						
Superheater Replace - Unit 1 - Holyrood		4,446	0	4,446	0	
Public Address System - Holyrood		96	0	96	0	
TOTAL PROJECTS APPROVED BY PU BOARD	0	4,542	0	4,542	0	
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Electronic White Board-Corporate Emergency Response Centre		14	13	14	0	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	0	14	13	14	0	

1. Upgrade Spherical Valve Maintenance Seals - Cat Arm

The original estimate was based upon a 2007 proposal by the manufacturer of the spherical valves to replace the existing maintenance seals with a new design. In early 2008, the manufacturer commenced preliminary engineering and design and concluded that the proposed design would be ineffective. The manufacturer subsequently submitted a new proposal on March 26, 2008, with a further improved design for the maintenance seal. This new design will result in an increase of $199,000 to the contract. A further budget increase of $186,000 is attributed to: the provision of additional in-house engineering to permit a more thorough review of the new design; more extensive factory acceptance testing; and the inclusion of some project costs that were inadvertently excluded from the previous budget estimate.

In addition, the cost estimate was based upon availability of camp facilities on-site. The closure of the cookhouse and bunkhouse at Cat Arm will result in additional costs associated with housing workers at the nearest available lodging in the community of Pollard's Point, as well as the additional labour to be incurred for workers travelling between Pollard's Point and Cat Arm. This will result in increased costs of $95,000. Furthermore, the scope of the project has been expanded to include the construction of a temporary cookhouse on-site to feed workers during the construction period at a cost of $159,000.

All of the above changes resulted in an increase in Overheads and Allowance for Funds Used During Construction, and Contingency of $126,000.

2. Replace Governor Controls Unit 2 - Cat Arm

The on-site accommodations at Cat Arm have been closed. Personnel from Hydro and General Electric, the control system supplier, will have to stay at a motel during the installation and commissioning of the governor controls and its associated equipment. This will add additional labour costs due to travel time plus the cost of accommodations. These changes have resulted in increased costs of $263,000, plus the cost of the accommodations. The scheduled time to complete the work will be extended as more time has to be used for travel.

3. **Provide Service Extensions - All Service Areas**

The increase in service extensions is due to growth in the Labrador Interconnected System with three new subdivisions planned for Happy Valley, additional housing expansion in Labrador City and new business construction in the Wabush Industrial Park.

4. **Construct New Office, Warehouse and Line Depot Facilities - Happy Valley**

This project was approved for $1,632,200 by Board Order P.U. # 30 (2007) of which $1,247,900 was to be spent in 2008 and the remainder, $384,300, to be spent in 2009. This project is now budgeted at $3,317,500 with $357,700 to be spent in 2008 and the remainder, $2,959,800, to be spent in 2009. The new schedule has the land purchase and project design occurring in the fall of 2008, contract tendering during the winter of 2009, commencement of construction in May 2009 and an in-service date of November 30, 2009. For further details please see page B - 41 Multi-Year Projects.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

Plan of Projected Operating

Maintenance Expenditures

2009 - 2018

For Holyrood Generating Station

NEWFOUNDLAND AND LABRADOR HYDRO

AUGUST 2008

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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 2009 to 2018 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 35 years old. Unit 3 is in excess of 25 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 (10) 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 (10) 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 Thermal plant. 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 Thermal Plant, noted at p. 64 that **"The Board will require NLH's10 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) **Preventive Maintenance**

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 replacement 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 9 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. This change is reflected in the increase Preventive Maintenance costs shown in the Appendices.

2) <u>Corrective Maintenance</u>

In addition to the preventive maintenance tactics outlined in Section 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. E.g. 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 their analysis indicated a common tube failure problem had developed. An approved Capital Budget proposal saw the replacement of Unit 2 Boiler Superheater tubes in September 2007. Unit 1 Boiler Superheater tubes are being 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) Projects

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, 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 will mean 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 Unit 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 who identified one of the major contributions to this failure as insufficient boiler chemical cleaning frequency (current industry practice is eight to 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 individual cost of approximately $380,000.

In 2007 a major failure of Unit 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	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
No. 1	Minor			Major			Minor			Minor
No. 2			Minor			Major			Minor	
No. 3		Minor			Minor			Major		
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 Thermal plant 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 Thermal plant, 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 2009 to 2018. 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 2009 preventive, corrective and overhaul data and the current 2009 to 2013 operating project lists from Hydro's five-year plan for the Holyrood Thermal Plant 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 2007 Hydro forecast. A single escalation rate was used in this exercise and assumed a 50% weighting of Labour escalation and 50% of Material escalation, and is as follows:-

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
%	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 2009 to 2018 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 per Unit basis.
Turbine – Minor	Major valve overhauls currently carried out every three (3) years, between major overhauls per unit basis.
Boiler – Annual	Boiler overhauls carried out annually
Boiler - Amortized Cost	Five year amortized cost of repairs completed only on Unit 2 boiler in 2006
Operating Projects	Non-capitalized projects, justified on the basis of Safety, Environment, Reliability or Cost Benefit Analyses.

Appendices 2, 3 and 4 (for Unit No's. 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 1200 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 2013. For the period 2014 to 2018, Hydro used an average per unit of the project budgets for the three units over the years 2009 to 2013 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 2014 to 2018.

SUMMARY

This Plan presents the best available information at this time for a ten-year forecast of the maintenance projects for the Holyrood Plant and is based on the 2009 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 9-year Turbine Overhauls and 3- 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 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UNIT #1 Total SEM	$2,102	$1,806	$1,746	$3,871	$1,835	$1,920	$2,493	$2,136	$2,458	$2,120
UNIT #2 Total SEM	$2,113	$2,154	$2,673	$1,892	$1,829	$4,051	$1,966	$2,396	$2,611	$2,235
UNIT #3 Total SEM	$1,721	$2,059	$1,740	$1,783	$2,217	$2,001	$2,050	$4,279	$2,582	$2,482
Common Equipment Total SEM	$4,163	$4,078	$3,338	$2,650	$2,097	$2,150	$2,203	$2,259	$2,315	$2,373
Buildings and Grounds Total SEM	$630	$642	$674	$547	$560	$543	$557	$571	$585	$599
WT Plant Total SEM	$205	$258	$189	$194	$274	$204	$238	$299	$219	$225
WWT Plant Total SEM	$121	$133	$127	$140	$133	$147	$140	$154	$147	$163
Environmental Monitoring Total SEM	$402	$340	$422	$323	$478	$339	$466	$394	$490	$375
Total Holyrood SEM	$11,458	$11,470	$10,910	$11,400	$9,423	$11,354	$10,113	$12,487	$11,407	$10,572
Total Operating Projects	$3,244	$3,049	$2,290	$1,331	$846	$829	$1,101	$1,372	$1,509	$1,308
Total Operating Projects Less Asbestos Abatement	$981	$919	$948	$727	$846	$829	$1,101	$1,372	$1,509	$1,308
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$327	$335	$344	$352	$361	$370	$379	$389	$398	$408	
Corrective – Yearly	$402	$412	$422	$433	$444	$455	$466	$478	$490	$502	
Turbine Major Overhaul				$2,081							
Turbine Valve Overhaul	$340						$409				
Boiler Annual Overhaul	$933	$956	$980	$1,005	$1,030	$1,056	$1,082	$1,109	$1,137	$1,165	
Operating Projects											
Unit #1 Boiler Chemical Clean									$390		
Overhaul Boiler Feed Pump East	$100						$116				
Overhaul Boiler Feed Pump West		$102						$118			
Projects – Lump Sum for Future Years						$40	$41	$42	$43	$44	
Total – Unit No. 1	$2,102	$1,806	$1,746	$3,871	$1,835	$1,920	$2,493	$2,136	$2,458	$2,120	
Total Operating Projects Unit 1	$100	$102	$0	$0	$0	$40	$157	$160	$433	$44	
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$322	$330	$338	$347	$355	$364	$373	$383	$392	$402	
Corrective - Yearly	$402	$412	$422	$433	$444	$455	$466	$478	$490	$502	
Turbine Major Overhaul						$2,133					
Turbine Valve Overhaul			$370						$430		
Boiler Annual Overhaul	$933	$956	$980	$1,005	$1,030	$1,056	$1,082	$1,109	$1,137	$1,165	
Boiler #2 Amortized Repair Cost	$456	$456	$456								
Operating Projects											
Unit #2 Boiler Chemical Clean								381			
Overhaul Boiler Feed Pump East			106						116		
Overhaul Boiler Feed Pump West				108						118	
Projects - Lump Sum for Future Years						$43	$44	$45	$46	$47	
Total - Unit No. 2	$2,113	$2,154	$2,673	$1,892	$1,829	$4,051	$1,966	$2,396	$2,611	$2,235	
Total Operating Projects Unit 2	$0	$0	$106	$108	$0	$43	$44	$426	$162	$165	
Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

APPENDIX 4

	($000)										
Unit No. 3	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$322	$330	$338	$347	$355	$364	$373	$383	$392	$402	
Corrective – Yearly	$402	$412	$422	$433	$444	$455	$466	$478	$490	$502	
Turbine Major Overhaul								$2,297			
Turbine Valve Overhaul		$362			$389				$430		
Boiler Annual Overhaul	$932	$955	$979	$1,004	$1,029	$1,054	$1,081	$1,108	$1,136	$1,164	
Auxiliary Equipment Annual Overhaul											
Operating Projects											
Unit #3 Boiler Chemical Clean										400	
Overhaul Cooling Water Pump East	65										
Overhaul Boiler Feed Pump East						114			120		
Overhaul Boiler Feed Pump West							116				
Projects – Lump Sums for Future Years						$13	$13	$14	$14	$14	
Total - Unit No. 3	$1,721	$2,059	$1,740	$1,783	$2,217	$2,001	$2,050	$4,279	$2,582	$2,482	
Total Operating Projects Unit 3	$65	$0	$0	$0	$0	$127	$129	$14	$134	$414	
Total SEM for all Three Units	$5,936	$6,019	$6,159	$7,547	$5,880	$7,972	$6,509	$8,811	$7,651	$6,837	
Total Project Work for Three Units	$165	$102	$106	$108	$0	$210	$330	$600	$729	$624	
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$272	$279	$286	$293	$300	$308	$315	$323	$331	$340	
Corrective – Yearly	$1,563	$1,602	$1,642	$1,683	$1,725	$1,769	$1,813	$1,858	$1,905	$1,952	
Operating Projects											
Asbestos Abatement	$2,263	$2,130	$1,342	$604							
Pipe Surveillance	$50	$51	$53	$54	$55	$57	$58	$59	$61	$62	
Plant Color Coding	$15	$15	$16	$16	$17	$17	$17	$18	$18	$19	
Total Common Equipment	$4,163	$4,078	$3,338	$2,650	$2,097	$2,150	$2,203	$2,259	$2,315	$2,373	
Total Operating Projects Common Equipment	$2,328	$2,197	$1,410	$674	$72	$74	$75	$77	$79	$81	
Total Operating Projects less Asbestos Abatement	$65	$67	$68	$70	$72	$74	$75	$77	$79	$81	
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$170	$174	$179	$183	$188	$192	$197	$202	$207	$212	
Corrective	$120	$123	$126	$129	$132	$136	$139	$143	$146	$150	
Operating Projects											
Coat Interior Liner Panels	$100	$103	$105	$108	$110	$113	$116	$119	$122	$125	
Repair & Repaint Structural Steel	$90	$92	$95	$97	$99	$102	$104	$107	$110	$112	
Exhaust Stack Maintenance	$150	$150	$170	$30	$30						
Total – Buildings and Grounds	$630	$642	$674	$547	$560	$543	$557	$571	$585	$599	
Total Operating Projects Buildings and Grounds	$340	$345	$370	$235	$240	$215	$220	$226	$231	$237	
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$53	$54	$56	$57	$59	$60	$61	$63	$65	$66	
Corrective	$80	$82	$84	$86	$88	$91	$93	$95	$97	$100	
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						
Resin Replacement (Mixed Bed B)						53					
Resin Replacement (U1 Polisher)	72						83				
Resin Replacement (U2 Polisher)					75						
Resin Replacement (U3 Polisher)		74						85			
Total WT Plant and Environmental	$205	$258	$189	$194	$274	$204	$238	$299	$219	$225	
Total Operating Projects WT Plant	$72	$122	$49	$51	$127	$53	$83	$141	$57	$59	
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$70	$72	$74	$75	$77	$79	$81	$83	$85	$87	
Corrective	$30	$31	$32	$32	$33	$34	$35	$36	$37	$37	
Operating Projects											
WWTP Periodic Basin Cleaning & Inspection	$21		$22		$23		$24		$26		
WWTP Continuous Basin Clean-Out		$22		$23		$24		$25		27	
Filter Fabric Replacement-Plate Press		$9		$10		$10		$11		11	
Total WWT Plant	$121	$133	$127	$140	$133	$147	$140	$154	$147	$163	
Total Operating Projects WWT Plant	$21	$31	$22	$32	$23	$34	$24	$35	$26	$38	
Escalation Rate (%)	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	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
Preventive – Yearly	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	
Corrective	$60	$62	$63	$65	$66	$68	$70	$71	$73	$75	
Operating Projects											
Emissions Monitoring	$150	$154	$158	$162	$166	$170	$174	$178	$183	$187	
Stack Emissions Testing	$102		$107		$113		$118		$124		
CEMS RATA Testing	$60	$62	$63	$65	$66	$68	$70	$71	$73	$75	
OPEP Exercise	$5	$5	$5	$5	$6	$6	$6	$6	$6	$6	
Tube Bundle Replacement – All Units		$32			$35			$37			
Total Environmental Monitoring	$402	$340	$422	$323	$478	$339	$466	$394	$490	$375	
Total Operating Projects Environmental Monitoring	$317	$253	$333	$232	$385	$243	$368	$293	$386	$269	
Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

	2007 ($000)	2006 ($000)
Capital Assets	2,016,315	1,976,170
Less:		
Accumulated Depreciation	570,225	536,691
Contributions in Aid of Construction	96,396	93,713
	666,621	630,404
Net Capital Assets	1,349,694	1,345,766
Balance Previous Year	1,345,766	1,345,959
Average Capital Assets	1,347,730	1,345,863
Working Capital	3,496	3,207
Fuel	25,874	24,886
Supplies Inventory	21,699	20,996
Average Deferred Charges	85,746	83,699
Average Rate Base	1,484,545	1,478,651