newfoundland labrador hydro
a nalcor energy company

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August 2, 2010

BY HAND

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

Attention: Cheryl Blundon – Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2011 Capital Budget Application

Please find enclosed ten copies of Hydro's 2011 Capital Budget Application, in two volumes, filed in accordance with the Provisional Capital Budget Application Guidelines issued by the board in October of 2007and in accordance with the guidelines and conditions for capital budget proposals as outlined by the Board in Order No. P.U. 7 (2002-2003).

Under this Application, Hydro is seeking approval of $65.1 million in capital expenditures. Also, Hydro is seeking approval of its 2009 rate base in the amount of $1,473,477.

Volume I of the filing contains an Overview of Hydro's proposed 2011 Capital Budget and its 2011 Capital Plan. The Capital Plan contains a five-year plan filed in compliance with Order No. P.U. 7 (2007) and as well contains a 20-year plan that contains other information required by the Board such as information as to the Holyrood Thermal Generating Station and as to the province's Energy Plan.

The Application is generally consistent and comparable with past applications to allow ease of comparison.

Section A sets out the high level summary of the 2011 budget by the following categories: Generation, Transmission and Rural Operations and General Properties.

Section B contains the detailed project justifications for each period over $500,000 and contains an Overview section as well as detailed explanations. Also contained in Section B are the Multi-Year Projects. Section C sets out the projects over $200,000 but less than $500,000; Section D contains the projects over $50,000 and less than $200,000.

Section E contains the classification of the capital project proposals. Section F is the section for any leases, to which there are none for this year, while Section G sets out the Schedule of Capital Expenditures for the period 2006 to 2015. Section H to the Application contains the status report for the 2010 capital program to June 30.

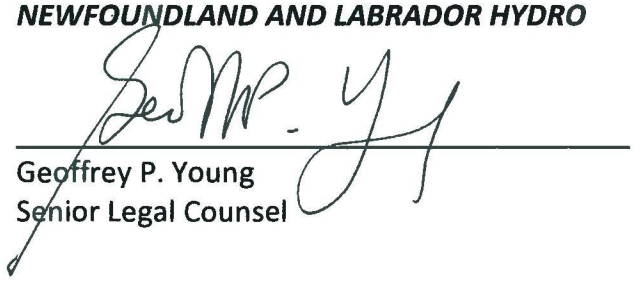
Section I to this Application is a report on the ten-year plan of maintenance expenditures for the Holyrood Generating Station required to be filed by Order No. P.U. 14 (2004). Section J sets out the 2010 rate base for Hydro. Reports one to ten that are associated with the capital project proposals over $500,000, begin in the back of Volume I.

Volumes II of the Application contains the remaining reports 28 reports associated with the capital project proposals over $500,000. This volume also includes Hydro's report, Generation Planning Issues, 2010 Mid Year Update. This report provides the information the Board requested under its letter dated August 5, 2008 pertaining to the Integrated Resource Planning.

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

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



Geoffrey P. Young
Senior Legal Counsel

Encl.

Cc: Mr. Peter Alteen,
Newfoundland Power

Mr. Tom Johnson, Consumer Advocate
O'Dea, Earle

Mr. Joseph Hutchings, Q .C.
Poole Althouse

Mr. Paul Coxworthy
Stewart McKelvey Stirling Scales

An Application to the
Board of Commissioners of Public Utilities

2011 CAPITAL BUDGET

APPLICATION

VOLUME I

August 2010

newfoundland labrador hydro
a nalcor energy company

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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 2011 capital budget pursuant to s.41(1) of the Act; (2) its 2011 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 2011 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 2009.

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

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

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

2. Section A to this Application is Hydro's proposed 2011 Capital Budget in the amount of approximately $65.1 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 2011 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 2011 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 2011 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 2011 capital projects by definitions, by classification and by materiality as required by the Capital Budget Application Guidelines.

7. Section F contains no new leases proposed for 2011 in excess of $5,000 per year.

8. Section G to this Application is a Schedule of Hydro's Capital Expenditures for the period 2006 to 2015.

9. Section H to this Application is a report on the status of the 2010 capital expenditures including those approved by Orders No. P.U. 1 (2010), projects under $50,000 not included in these Orders, and the 2009 capital expenditures carried forward to 2010.

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 2009 of $1,473,477,000.

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

13. The proposed capital expenditures for 2011 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 2011 to be approximately $400,000. The information contained in the 2011 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 2011 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

(2) Approving 2011 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 2011 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 2009 in the amount of $1,473,477,000 pursuant to section 78 of the Act.

DATED at St. John's, Newfoundland, this 24 day of August, 2009.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

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

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for an Order approving: (1) its 2011 capital budget pursuant to s.41(1) of the Act; (2) its 2011 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 2011 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 2009.

AFFIDAVIT

I, Rick O. Green, Certified General Accountant, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Controller Electric Utilities on behalf of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.

2. I have read and understand the foregoing Application.

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

SWORN at St. John's in the Province of Newfoundland and Labrador this 2nd day of August 2010, before me:

Barrister – Newfoundland and Labrador

Rick O. Green

INTRODUCTION

Hydro is required to provide reliable service to its customers, through the provisions of the Hydro Corporation Act, the Electrical Power Control Act, 1994, and the Public Utilities Act. The provision of a safe, reliable, least cost supply of electricity requires that Hydro continuously renew, expand and modify its generation, transmission and distribution assets, and the assets that support those systems. Hydro must also address changing environmental and other regulatory requirements, challenges which often require the acquisition of new assets or improvement to existing assets. Hydro's long term planning initiatives are complicated by the expected approval of the Lower Churchill Project. The closure of a paper mill, the expected startup of a nickel processing facility and the availability of additional hydroelectric energy have been considered and are reflected in the Generating Planning Issues update contained elsewhere in this submission. This Overview will discuss the projects proposed for 2011. Discussion of the 5 and 20 year plans are contained in the section entitled "2011 Capital Plan".

2011 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 a 20-Year Capital Plan which identifies the major capital expenditures which will be required to maintain the existing assets in safe, reliable operating condition to serve our customers. This 2007 initiative marked the first time Hydro consciously considered the long term requirements of its existing assets. Prior to this Hydro has had the luxury of operating assets which were relatively new, but now that many assets have reached, or are about to reach, maturity it has required us to look much further into the future to plan the long term effective management of these assets to their impending retirement or refurbishment dates. The plan contains a significant peak in 2012, resulting from several large projects, namely the Labrador City upgrade, Hardwoods gas turbine upgrade, Holyrood marine terminal and Holyrood stack breeching. The last two named projects were not included in the five year plan submitted to the Board in 2009 and this is indicative of how quickly the plan can change as the result of new information becoming available and changing conditions. Hydro has adjusted the plan to the greatest extent possible, to accommodate these and other new projects but it is inevitable that peaks will occur from time to time. The plan continues to be a living document which will be reviewed and revised annually as new information about the condition of our assets and the operating demands placed on them becomes available. General revisions will be made annually and major revisions will be made periodically.

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
- Changing operating conditions
- Asset Maintenance Strategy
- Discussions between Regulated Operations and Engineering Services
- Familiarity with equipment
- Operating and Maintenance cost, and
- Professional judgment.

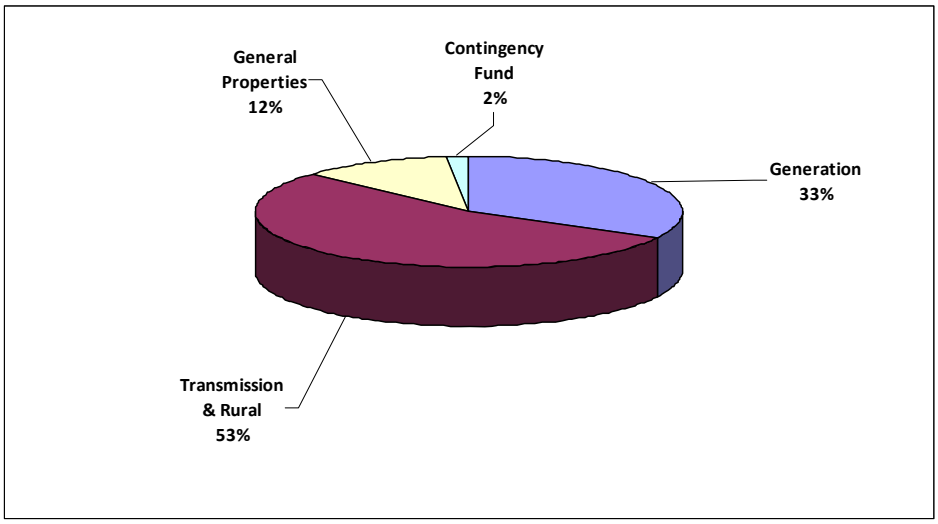
There are three broad categories of replacement criteria:

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

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

Chart 1 shows the breakdown of the 2011 Capital Budget by major classification. The classifications, other than the contingency fund, which represents only 2 percent of the 2011 budget, are then discussed further.

Chart 1. 2011 Capital Budget - Summary

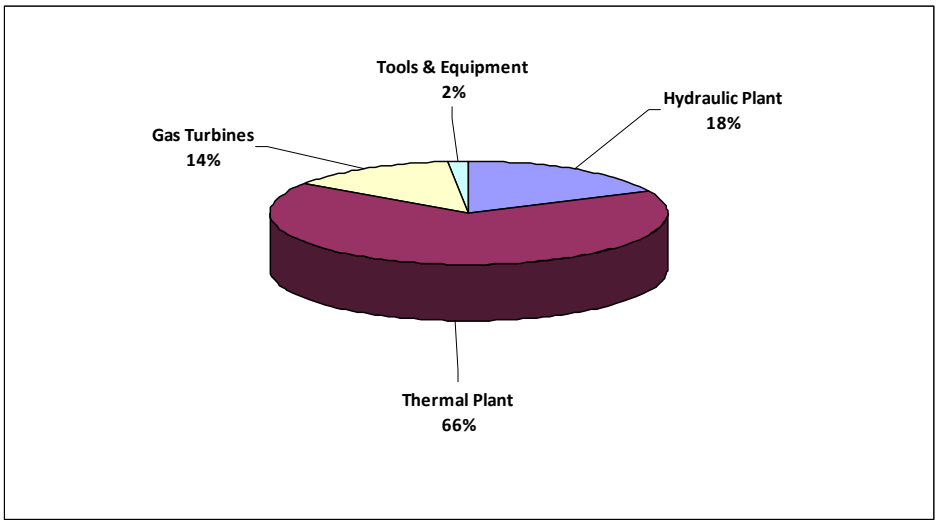


GENERATION ASSETS

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 2009, 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.

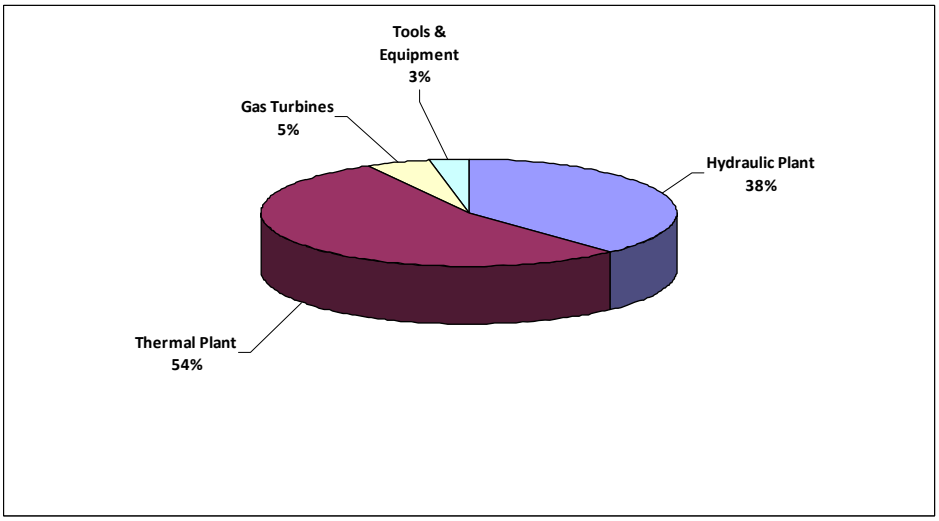
The division of the 2011 Capital Budget for Island Interconnected generation among Hydraulic Plant, Thermal Plant, Gas Turbines and Tools and Equipment expenditures is shown in Chart 2.

Chart 2: 2011 Capital Budget – Generation



The five-year (2005 to 2009) average is shown in Chart 3. For 2011, thermal plant represents 66 percent of the Island Interconnected generation budget, compared with 54 percent over the past five years. Thermal plants continue to require major capital expenditures as the majority of the plants have reached the age of maturity and significant expenditures are required to ensure that these important generating assets can continue to operate reliably.

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



Hydraulic Plant

Hydro's hydraulic generating plants range from less than 10 years to more than 40 years of age. Capital expenditures are required to ensure reliability and to maximize the potential useful operating lives of these assets, of which many components have reached or are coming to the end of their expected service lives. This application includes a proposal for the static excitation systems at Hinds Lake and Upper Salmon and the replacement of chart recorders at four plants. This equipment has become obsolete and must be replaced to ensure reliable operation of the hydro facilities, which form the backbone of our generating fleet.

Thermal Plant

The three units of the Holyrood Thermal Generating Station have now reached or exceeded their generally expected service life of 30 years. Condition assessment and selective life extension will permit them to operate reliably until 2020. Holyrood remains critical to the reliable supply of power to the Island Interconnected System, as it serves the base load of the system and will be required to do so in the short to medium term. The long term operational plan for this facility has been uncertain, as Hydro has investigated the feasibility of developing the Lower Churchill River and importing electricity from Labrador to the Island, which would eliminate the need for energy production from Holyrood. Should that project proceed, Holyrood will remain a critically important facility prior to completion of the Lower Churchill Project. Following completion of the Lower Churchill project, the Holyrood plant will continue to be an essential component of the Provincial electrical grid as a synchronous condensing facility. Additionally, the plant will function as a standby facility during the early years of operation of the Lower Churchill generating plant and direct current link between Labrador and Newfoundland, until 2020, when it will be converted for use in synchronous condensing. The implications of the Lower Churchill project are discussed in detail in the report entitled "Generation Planning Issues 2010 Mid Year Update", located in Volume II of this submission.

The challenges faced by Hydro are complex because circumstances require that Holyrood must operate in a manner quite different than the norm for thermal plants. Conventional practice is that a thermal plant is base loaded throughout its career until it reaches maturity and then the plant is operated as a peaking or standby facility in its final years, thus operating at a very low capacity factor, often less than 10 percent. This thermal plant has passed the age at which other utilities have performed condition assessment and life extension studies and have either retired the facilities or have initiated life extension projects. However,

until the Lower Churchill Project is completed and power is brought to the Island Interconnected System via a HVDC link, the Holyrood plant must continue to operate at, or near, its historical average capacity factor of 40 percent to 50 percent annually and much higher through the critical winter period. The closure of the paper mill at Grand Falls has reduced demand on Holyrood in the short term, however, when the nickel processing plant being constructed at Long Harbour begins commissioning and operation in 2011 demand on Holyrood will increase. The capital projects contained in this application are necessary to replace assets which are at the end of their useful lives, and which must be replaced to maintain reliability through to the completion of the HVDC link to the Lower Churchill development. The Holyrood Projects for 2011 are listed below:

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

- Replace programmable logic controllers
- Refurbish fuel storage facility
- Replace pumphouse motor control centers
- Replace diesel fire pump
- Replace steam seal regulator

Upgrade projects:

- Upgrade electrical equipment
- Upgrade hydrogen system
- Replace boiler blowdown tanks
- Modify Unit 3 synchronous condenser.

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 turbines at the Stephenville and Hardwoods plants, 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 generators (jet engines) at

the Stephenville and hardwoods plants, another key component, has declared them obsolete and the supply of spare parts, technical support and repair facilities continues to diminish.

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

TRANSMISSION AND RURAL OPERATIONS ASSETS

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

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

The division of the 2011 Capital Budget for Transmission and Rural Operations is shown in Chart 4. These breakdowns are generally consistent with the five-year (2005-2009) average as shown in Chart 5 below. The Labrador City voltage conversion project is a very large multi year project involving the construction of new terminal stations and the reconfiguration of the operating voltages of the entire Labrador City system, which has a significant effect on the pattern of expenditures during its implementation.

Chart 4: 2011 Capital Budget - Transmission and Rural Operations

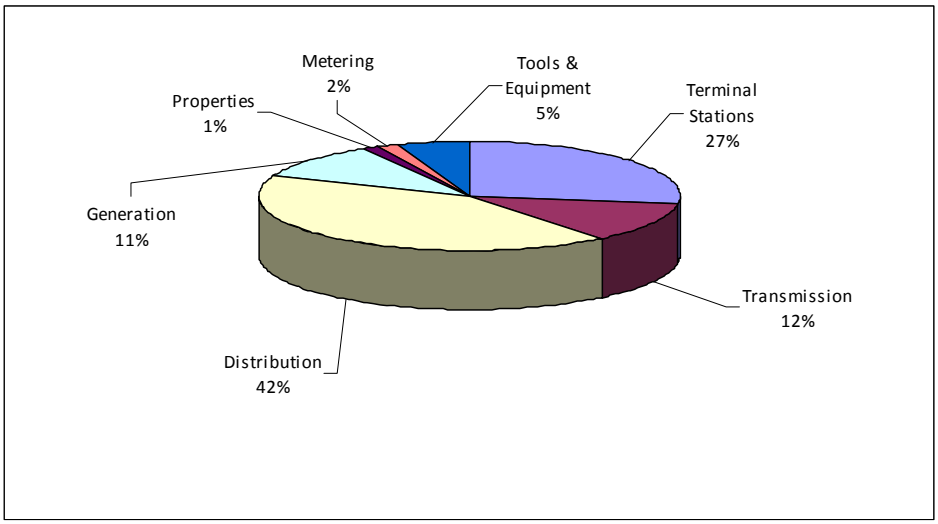
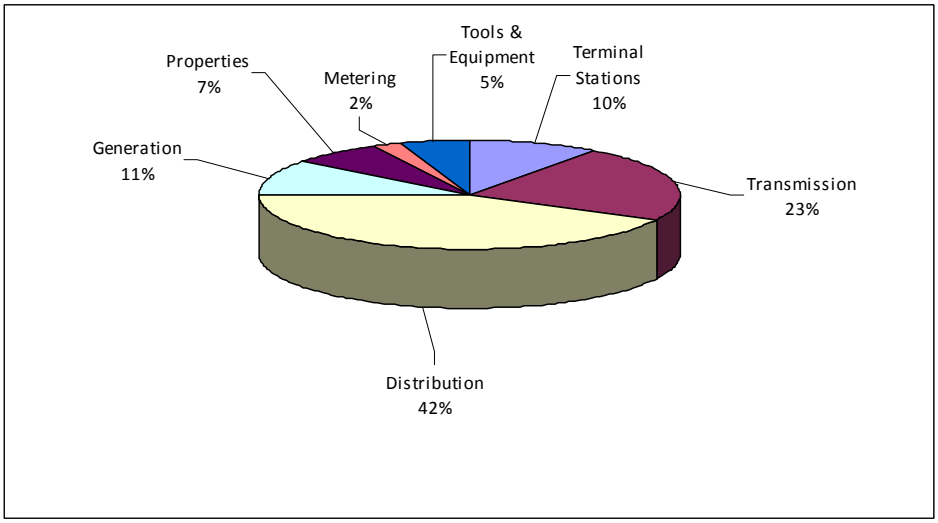


Chart 5: Five-year average Capital Budget – Transmission and Rural Operations (2005 - 2009)



Terminal Stations and Transmission

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

The terminal station and transmission proposals for 2011 are:

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

Distribution and Diesel Generation

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

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

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

The number of outages in the Labrador West area of the Labrador Interconnected System created concern about the suitability of this distribution system to serve the needs of the customers. This application contains a proposal to continue to rebuild the distribution system at a higher voltage to restore reliability and to permit growth in the area, which is a continuation of a project approved in 2009.

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 system replacements which are all necessary for the provision of reliable and cost effective service to customers.

Chart 6 and 7 show the breakdown of the General Properties Capital Budget for 2011 and the previous 5 year average, respectively.

Chart 6: 2011 Capital Budget - General Properties

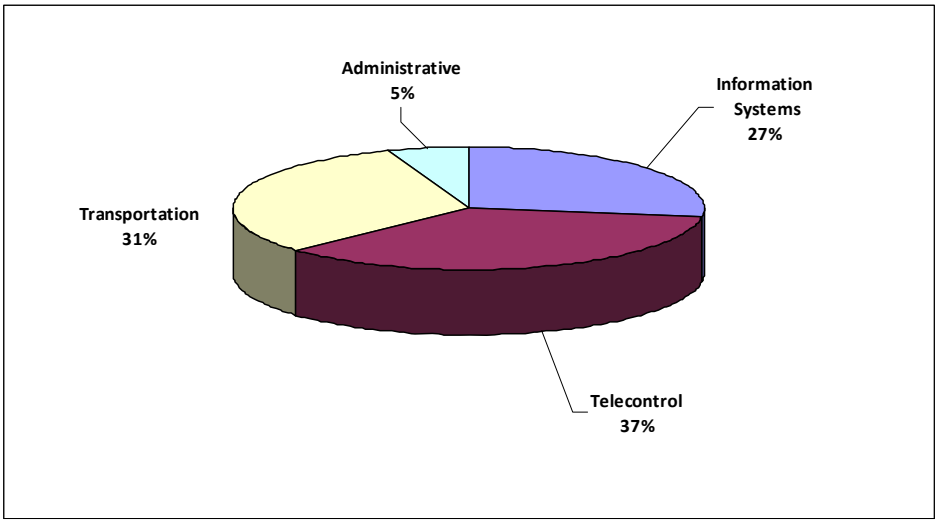
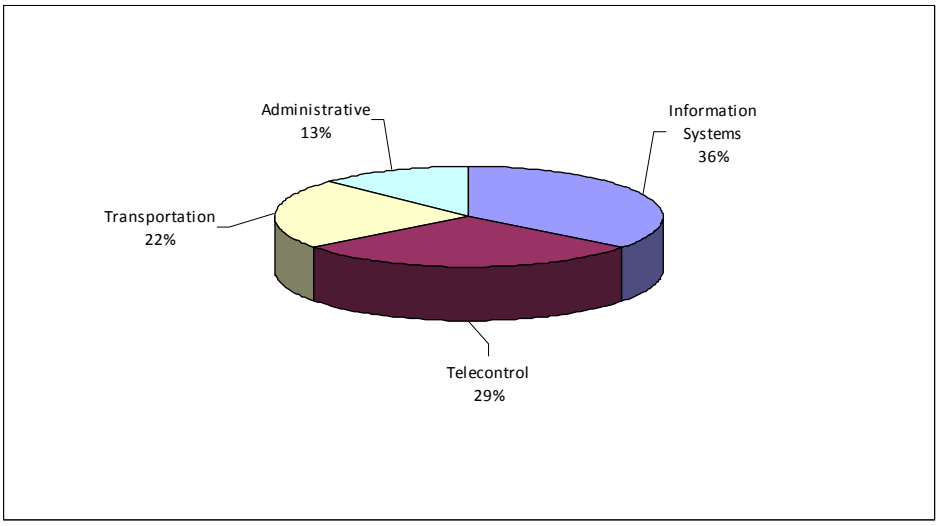


Chart 7: Five-Year Capital Budget - General Properties (2005 – 2009)



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 2011 capital budget proposals in this category include infrastructure replacements and, in some cases, ongoing replacement or refurbishment programs, for such items as:

- Radome replacements
- Replacing battery banks and battery chargers; and
- Refurbishment of the Deer Lake microwave site.

In summary, Hydro's Capital Budget Application for 2011 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

2011 Capital Plan

2010-07-09

newfoundland labrador hydro
a nalcor energy company

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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 scenarios. Hydro developed and filed a five and twenty-year plan with the 2009 Capital Budget Application. This report updates the 2010 Capital Plan.

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

The 1960's saw a vast expansion in assets to fulfill the mandate of the Newfoundland and Labrador Power Commission, Hydro's predecessor, which was to electrify the province. This rapid expansion means that many of the assets constructed have reached their expected service lives and many others are approaching that juncture. Other major assets have not reached their expected service lives but some of their components, auxiliary equipment and systems have, or are about to do so. This includes components of major facilities such as the Bay d'Espoir Generating Station, the Holyrood Thermal Generating Station, the Hardwoods and Stephenville gas Turbines, the Holyrood gas Turbine 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 Labradoreans to live in a modern society, dependent on a reliable supply of electricity for home and business use.

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

Twenty-Year Plan

Hydro's planning horizon for asset additions extends to twenty years in the future, depending on the asset, and these additions are planned for construction on a just-in-time basis. The generation plan is discussed in a report entitled "Generation Planning Issues 2010 Mid Year", located in Volume II of this submission. This 20-Year Capital Plan does not include additional generation capacity to address future energy requirements of the interconnected electrical systems, nor does it include proposals for Fuel Conservation and Demand Management (CDM). The plan does contain some additional generation capacity for isolated diesel generation systems. CDM may include other capital plans intended to reduce demand and energy needs that, aside from reducing fuel requirements, may impact generation additions. Asset replacements are planned based on condition assessments, maintenance and operating cost reviews, changing technology, expected lives of equipment and knowledge of individual assets. Table 1 summarizes Hydro's service lives for major asset classes.

Table 1 - Asset Service Lives

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 years
Diesel Plant	20 years
Transmission Line	40 and 50 years
Terminal Station	40 years
Transformer	40 years
Distribution System	30 years

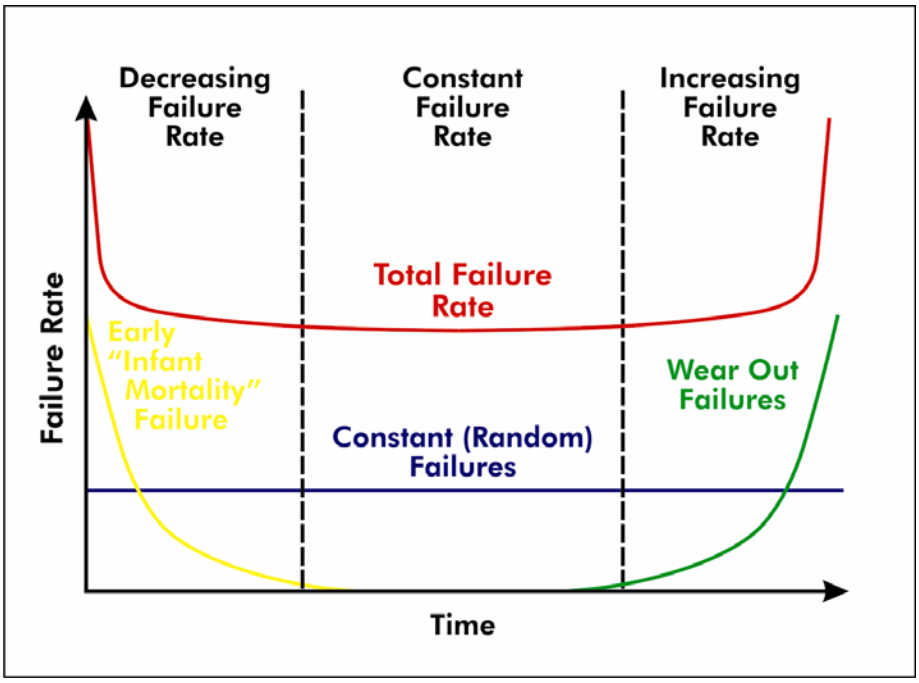
Table 2 indicates when some of Hydro's major assets were placed in service.

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	1971
Holyrood Generating Station Stage 2	1979
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

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

Chart 1 – Equipment Lifespan



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

1.Random failures, which are failures caused by a variety of reasons with unpredictable frequency.

2.Infant mortality failures, which occur during the first years of operation and are generally attributed to design, application, material or manufacturing defects or improper operation. These are "break in" failures.

3.Wear out failures, which, as the term implies, occur as the asset, or some of its components, reach the end of their service lives and break down.

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

The 20-year plan is a living document and will be revised frequently as new information about the condition of Hydro's assets becomes available, as asset management strategies evolve, and as demands and priorities change within asset classes. During the past year Hydro developed a Project Prioritization methodology to facilitate the selection of projects which best meet the criteria of providing reliable service at least cost. The methodology considers project benefits, environmental and safety aspects, customer impacts, equipment failure risk and other factors to screen and prioritize all projects being considered. It enables Hydro to quickly rank projects and is especially useful in assessing the effect new information on specific projects has on the overall ranking of all projects. Numerous changes occur each year in the project inventory as new operational data becomes available due to the following: the review of performance statistics, failures or maintenance incidents, changes in the manufacturing and delivery cycles for replacement equipment due to changing world markets, changes to system requirements and for other reasons. As a project approaches the threshold for implementation, its justification, benefits, cost and schedule are assessed more accurately and that information is used in the project prioritization process to compare its overall importance against competing potential projects. 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 2010 Mid Year" report, located in Volume II, Tab 38 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 2011 – 2015 capital expenditures to maintain the existing systems will rise to an average of $65 million over the next five-years and to an average of $56 million, expressed in 2010 dollars, over the next 20-years. Expenditures for new generation and transmission assets are not

included in these estimates, with the exception of customer requests such as Vale Inco Long Harbour and the addition of a transformer at Oxen Pond Terminal Station.

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

Strategic Spending Priorities

The strategic priorities are:

1. Mandatory Issues:

- Ensuring the safety of Hydro personnel, its contractors, and the general public;
- Compliance with legislative and regulatory requirements;

  →Dealing with environmental risks.

2. Meeting projected load growth and customer requests;

3. Achieving cost efficiencies;

4. Asset Maintenance Philosophy initiated in 2007

- Maintaining reliability by addressing issues identified by:

  →Operating experience

  →Maintenance history

  →Condition assessments

  →Performance assessments

  →Familiarity with equipment

  →Operating and maintenance cost

  →Professional judgment

  →Asset Maintenance Strategy

  →Discussion between Regulated Operations and Engineering Services

- Obtaining reliability improvement.

Asset Management Philosophy

Hydro's Asset Management Philosophy is a multi-pronged approach to formally documenting, reviewing and revising asset maintenance tactics in the short, medium and long term. A detailed review of Hydro's maintenance procedures is well advanced and will be completed in 2011. This review will ensure that all maintenance activities are the most appropriate for the current fleet of assets. The second, more high-level approach began in the last quarter of 2008. This second phase has resulted in an Asset Management Framework, and a reorganization of Hydro's structure to more effectively manage assets.

Five-Year Plan

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

The five-year plan indicates an increasing trend in expenditures as noted in the 2009 Capital Budget Application, required to address Hydro's maturing infrastructure and the need to replace assets, or components, to maintain reliable service. The plan contains significant peaks in 2011 and 2012, caused by two projects: the conversion of the operating voltage of the Labrador City distribution system, and the construction of a new diesel plant at Charlottetown. The former project is required to upgrade an old distribution system which has reached its capacity limit, the magnitude and cost of which was not known when the five year plan was prepared in 2008. The latter project is required to address a large increase in demand resulting from the expansion of a fish plant on the Charlottetown system, which Hydro was not made aware of until the fall of 2008. The very significant cost of these two projects resulted in a reprioritization of projects within the five and twenty year plans to maintain the total cost of the five year plan close to the value for the same period indicated in the 2009 Capital Budget Application. The total cost of the five year plan is less than 5% higher than indicated last year for 2010 to 2014, despite the inclusion of these two large projects.

The trend of increasing capital expenditures will continue as Hydro addresses aging infrastructure which will require significant annual expenditures to reliably enable electrical energy to be produced, transmitted and distributed. An additional influence on the magnitude of the plan is the rapidly fluctuating material and equipment cost and delivery times which have been changing much faster than previously. Raw materials, such as copper, iron and alloy steels required for the production of the equipment have fluctuated greatly in price, making it difficult to accurately estimate the cost of some projects. For example over the past five years copper prices have fluctuated between US$2,000 and US$9,000 per tonne, with one swing of $6,000 per tonne occurring during a six month period. Similarly, the delivery time for power transformers in recent years has changed from ten months to twenty-six months to twelve months. Given that the cycle time for projects, from preparation of the proposal through Board approval to implementation typically lasts one to two years, volatility in project cost and completion when scheduled will continue until market stability returns.

Generation

The requirement to invest sustaining capital in generation facilities began increasing several years ago as parts of Hydro's generating plants reached or surpassed their normally expected service lives. As each year passes more assets reach this point in their operating lives, requiring increased expenditures to maintain reliability and to ensure that the maximum economic life is extracted from each asset. Primary drivers for these projects are the realization of end of service lives for equipment, reductions in reliability or performance, the availability of new more efficient technology and considerations for safety.

Hydraulic

Ensuring reliability is the primary priority for Hydro's five-year capital plan. In recent years, Hydro has detected deterioration in the condition of the stator windings of Units 1 through 4 in the Bay d'Espoir Generating Station. These four units, the oldest of the six installed in that plant, were equipped with asphalt insulated windings, the standard insulation system of that time. These windings have deteriorated and began to show signs of imminent failure. To address this issue Hydro included the purchase of a spare winding in the 2009 Capital Plan and included the installation of that spare winding and the purchase of another in the 2010 Capital Plan. Replacement of the winding of Unit 2 is in progress and the unit will be returned to service by the end of August. The condition of auxiliary systems and equipment is as great of a concern as the main generating units, as their failure could also remove a unit or plant from service. To address this concern the 2010 Capital Plan includes projects to replace the exciters at Upper Salmon and Hinds Lake, to upgrade the Burnt Dam Spillway and to replace the station service water system at Cat Arm.

Holyrood Thermal Generating Station

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

Gas Turbines

Maintaining reliability of existing assets is also the priority for Hydro's gas turbines, which provide emergency and peaking power and function as synchronous condensers to help control voltage on the Island Interconnected system. These facilities accumulate few operating hours generating electricity but are crucial sources of power and energy during emergencies and system peaks and provide voltage

support, especially when operating as synchronous condensers. These plants, especially the 50 MW plants at Hardwoods and Stephenville, required relatively little capital expenditure until recent years. Despite their low operating hours, these units are beyond their normal life expectancy and are deteriorating, requiring an increase in capital expenditures to extend their reliable economic service lives to the greatest extent possible. A multiyear life extension project for the Hardwoods plant was begun in 2010 and a similar project is planned for Stephenville, beginning in 2014. The Stephenville project was originally planned to begin in 2012 but has been delayed to 2014 following a reassessment of its condition and a reprioritization of this work relative to other projects. Hydro's newest gas turbine plant located at Happy Valley was constructed in 1992. This plant has required only minor upgrades and is not expected to require any significant capital expenditures within the next five years.

Terminal Stations

Increasing load and maintaining reliability are the principal drivers for terminal station expenditures over the next five years. The largest single project continues to be the construction of two new terminal stations in Labrador City and the conversion of the distribution system from 4.16 and 12.5 kV to 25 kV. The distribution system is old and is loaded to capacity, requiring the construction of the two stations and the reconfiguration of the distribution system to maintain reliability and to ensure acceptable voltage levels in response to load growth. This work is contained in several capital projects which began in 2009 and will continue until late 2013. 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, was originally proposed in the 2010 Capital Plan to begin in 2012 and has been moved to 2014 in this 2011 Capital Plan. Review of the required in-service date continues and it is possible that when Hydro submits the 2012 Capital Plan in 2011 that this project may be returned to 2012.

Aging equipment is a major concern and is considered when reviewing short and long term plans. The five-year plan contains expenditures in the form of several programs to replace instrument transformers, surge arrestors, insulators, circuit breakers and disconnect switches among others. The plan also contains station specific projects such as replacing the compressed air piping at the Holyrood Terminal Station and replacing equipment in the Hawkes Bay Terminal Station, both in 2011. Hydro will, to the greatest extent possible, consolidate equipment replacements into multi year programs to ease the administrative effort for both the Board and Hydro.

Transmission

Reliability maintenance is the primary driver for transmission investment. The wood pole line management program forms the backbone of our asset management strategy for these facilities. This strategy has been in place for ten years and its effectiveness and value has been tested and demonstrated, enabling Hydro to realize the maximum useful life from these transmission systems. The program is based on periodic assessment of the wooden transmission poles and facilitates their replacement before failure, while extracting the maximum possible reliable life from each pole. In 2011 other transmission projects include Upgrading TL- 244 (Plum Point to Bear Cove) and the replacement of guy wires on TL-215 (Doyles to Port Aux Basques). During the next five years Hydro will replace insulators on TL-206 (Bay d'Espoir to Sunnyside), upgrade TL-241 (Plum Point to Peter's Barrens) and TL-221 (Hawkes Bay to Peter's Barren) along with other similar projects.

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

Distribution

New customer additions and reliability maintenance are the strategic areas addressed by the five-year Capital Plan for distribution assets. This equipment is subject to the same aging and wear as the generation and transmission assets and must be replaced periodically to ensure reliable service. The largest distribution project for the next five years will be the reconfiguration of the Labrador City distribution system, which is now in progress. As was mentioned in the previous section of this document on Terminal Stations, the distribution system is aging and is loaded to capacity, requiring its reconfiguration to maintain reliability, ensure acceptable voltage levels and to respond to load growth. The principal feature of the reconfiguration will be the increase of the distribution system voltage from 4.16 and 12.5 kV to 25 kV, enabling more energy to be distributed while maintaining acceptable voltage levels. The majority of other distribution system expenditures for the next five years will consist of service extensions and upgrades to distribution systems, distribution pole replacement, substation upgrading, and installing voltage regulators, all to maintain or improve system performance.

Rural Generation

Aging infrastructure replacement to ensure reliability is required for Hydro's twenty-one isolated electrical systems which are supplied with electricity by diesel generating sets. 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 or add generating sets in McCallum and Francois (2011), Nain (2012), Little Bay Islands and Port Hope Simpson (2013), Little Bay Islands and St. Lewis (2015). These replacements and additions are required to ensure that reliable service is provided to Hydro's isolated rural customers. Many of Hydro's diesel plants have deteriorated to a great extent and will require renovation or replacement. To prioritize this process, Hydro conducted a review of the condition of the older plants to assist in planning the replacement or modification in a logical sequence. A report summarizing the findings and recommendations was submitted to the Board December 18, 2009. This report will be used to develop a long-term plan replacement and renovation plan for diesel plants over the next two years. Currently, the five-year plan includes the replacement of the Charlottetown diesel plant (2013 – 2015) in response to a significant increase in demand from the fish plant expansion, which was communicated to Hydro late in 2008. In its 2010 Capital Plan Hydro had proposed to perform this plant construction in 2011 – 2013 but decided to delay such a significant project to enable all alternatives to be considered. A short term solution to the sudden large load increase was developed, by using the mobile unit purchased to address the load increase on the L'Anse aux Loup system. The mobile is required to address the L'Anse au Loup load during the winter and the Charlottetown load during the summer. This is satisfactory as a temporary solution until a long term plan is developed for Charlottetown.

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 $2.3 million per year during the next five years, including a major expenditure in 2012 to upgrade Hydro's enterprise software application.

Telecontrol

Obsolete technology and aging hardware are also the strategic reasons which most significantly contribute to the five-year plan for telecontrol assets. Hydro's communications network is vital to the operation and control of the power systems. Communications must be reliable and rapid to protect and control the generation, transmission and distribution equipment. It is expected that capital expenditures will average approximately $3 million per year for the next five years. The most significant of these projects will be the replacement of obsolete radio equipment (over $2 million during this period) and the replacement of fibre optic cable (over $2 million during this period).

Transportation

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

Administration

Safety, cost efficiencies, reliability and security are the primary drivers of the five-year administration capital plan. Hydro expects to spend $3 million on items such as office equipment, security systems and building air conditioning equipment during the next five years.

Holyrood

The Holyrood Generating Station is among the largest generating plants on the Island Interconnected system, and, as a thermal plant, is by far the most complex. Stage I (Units 1 and 2) was commissioned in 1971 and has passed the normal 30-year design life for such a facility. Stage II (Unit 3) was commissioned in 1979 and has reached the end of its normal life. Units 1 and 2 were modified in the late 1980s to increase their capacity from 150 to 170 MW each. This was achieved by availing of the overcapacity inherently contained in equipment of that vintage and by modifying the plant's auxiliary systems. Similar age plants have been retired or have been subjected to life assessment and extension

studies and have received large injections of capital to extend their useful lives. Some have been redeveloped into other configurations, such as combined cycle power plants. The lack of certainty in recent years about the future of Holyrood, caused by the combination of having surpassed its normal useful life and the uncertainty about the completion date of the Lower Churchill Project, has made it difficult for Hydro to formulate a definitive long term plan for this facility. Indeed, it has been necessary to develop two long term plans for the Island electrical system, isolated and interconnected.

The "Generation Planning Issues 2010 Mid Year Update" report included in Volume II, Tab 38, explains the long term role for Holyrood. In an HVDC infeed scenario, all three units will be required to operate as synchronous condensers after the infeed is completed; in an isolated island scenario all three units will be required to operate as essential generating assets, as they do now. Depending on which scenario unfolds, some or all of the Holyrood Generating plant will be required for decades into the future. Hydro has received approval from the Board to perform a condition assessment of the components of the Holyrood Generating Station required for synchronous condensing, and for those components required for generation prior to the completion of the HVDC infeed. The condition assessment is intended to provide Hydro with insight as to which components are likely to fail and when that will occur. The Phase 1 report describing the findings of the initial investigation will be filed with the Board by the end of the third quarter of 2010. When all phases of the study are completed, Hydro will have the necessary information to determine the capital replacements required to maintain Holyrood in an efficient and reliable condition. The study is being performed in phases to ensure that the scope and progress of the work matches the progress of the Lower Churchill project so that only necessary expenditures are made. Hydro will continue to periodically report to the Board on progress and will seek approval for the proposed scope of successive phases of the assessment as the work advances.

Five-Year Plan for Holyrood

The effect which the uncertainty of the Lower Churchill project has on the Holyrood facility was described in the previous section. To address this uncertainty Hydro has developed two separate generation expansion plans, described and discussed in the "Generation Planning Issues 2010 Mid Year Update" report located in Volume II, Tab 38. It is important to consider that whichever expansion scenario occurs, an isolated Island electrical system or interconnected to the Lower Churchill via HVDC link, Holyrood will be an integral and vital component of the Island Interconnected system for decades to come. In the isolated case, Holyrood will continue to be a generating station; in the interconnected case its three generating units will operate as synchronous condensers to provide system stability, inertia and voltage control. In developing the five-year project list for Holyrood, Hydro has selected only those projects associated with assets required to support synchronous condensing and those required to support generation to the expected in service of the HVDC infeed date. Hydro also anticipates maintaining this plant as a generating facility for several years after the completion of the HVDC link, until the reliability of that source of energy has been thoroughly established. To that end, Hydro plans to maintain the facility in such a manner that it can reliably produce electricity until 2020.

Maintaining Holyrood for winter reliability is the primary focus of the five-year plan. The closure of the paper mill at Grand Falls has reduced demands on Holyrood and those demands will not increase appreciably until initial commissioning of the nickel processing facility at Long Harbor planned for late 2011. Holyrood, however, remains a vital generation asset and must be maintained in reliable condition. Due to the environmental issues with the plant, legislative and regulatory requirements also contribute to the required expenditures. Each of the projects proposed to be implemented within the next five years is discussed below. These projects, required to ensure that the facility can continue to operate reliably until the completion of the Lower Churchill project, are associated with equipment required for generation, synchronous condensing, or are related to safety or environmental concerns. This Five Year Plan for Holyrood contains projects not previously identified. As new information becomes available about the condition of components and as new problems become apparent, new projects will be added to the list annually.

2011 Projects

Upgrade Stack Breeching Unit 1: Breeching is large insulated ductwork which conducts exhaust gases from the boilers to the stacks. It carries hot corrosive gases, operating under very hostile conditions. The Breeching on the three units has been repaired many times and now requires replacement which will be performed over several years. This project is required to ensure continued reliable operation until completion of the HVDC infeed.

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

Holyrood Condition Assessment: This is Phase 2 of a multi phase project to determine what components must be replaced or refurbished to ensure reliable operation of the facility. This project is required whether the plant operates in generation or synchronous condensing mode.

Replace Programmable Logic Controllers: the existing equipment is obsolete and parts are difficult or nearly impossible to obtain. These individual controllers will be removed and control functions will be provided by expanding the existing distributed control system. This is the continuation of a multi year plan begun in 2009 and which will be completed in 2012. This project is required whether the plant operates in generation or synchronous condensing mode.

Upgrade Forced Draft Fan Ductwork: This work is required to eliminate a severe air flow induced vibration condition which is cracking the ductwork of Unit 1. The duct will be replaced with stronger material and aerodynamic features to eliminate the vibration problem and ensure reliable operation.

Upgrade Hydrogen System: Hydrogen is used to cool the three generators, which will be required whether the plant operates in generation or synchronous condensing mode. The existing hydrogen control panels are obsolete and must be replaced. Hydrogen generating equipment will be installed to

produce the gas on site rather than having it trucked from mainland Canada, which provides the benefits of a secure supply, greater safety and reduced costs.

Replace Steam Seal Regulator Unit 1: This device provides controlled steam flow to and from the turbine shaft seal, permitting the turbine shaft to operate. The existing steam seal regulator is obsolete and replacement parts are no longer available. The device will be replaced with a modern equivalent. This project is required to ensure continued reliable operation until completion of the HVDC infeed. This is a continuation of work begun in 2010.

Replace Steam Seal Regulator Unit 2: The scope of this project is identical to the work being performed on Unit 1 in 2010.

Replace Pumphouse Motor Control Centers: These electrical panels are required to operate auxiliary equipment for pumping water crucial to the operation of the generating equipment. Their condition has deteriorated to the point where replacement is necessary. They will be required whether the plant operates as a generating or synchronous condensing facility. This is a continuation of work begun in 2010.

Modify Synchronous Condenser Unit 3: This project is required to eliminate excessive vibration levels which have developed since the unit was modified to permit synchronous condenser operation in 1985. The modifications will also permit a faster conversion time, thereby reducing costs. The project is required for operation of the facility both as a synchronous condenser and as a generator

Upgrade Relay Panels Unit 3: These panels have deteriorated and become overcrowded to the extent that reliability and safety are being compromised. Replacement is required to ensure reliable operation.

Replace Boiler Blowdown Tanks: Each boiler is equipped with a blowdown tank and all three have suffered corrosion and erosion damage and must be replaced to ensure reliable operation of the plant.

Upgrade Electrical Equipment: This project includes the complete replacement of the gas turbine motor control center, which is obsolete, and replacement of protection equipment for other motor

control centers throughout the plant. This work is required to ensure the safe and reliable operation of the plant in both generation and synchronous condensing modes.

Replace Diesel Fire Pump: The existing pump was installed during construction of Stage I started in 1968 and can no longer be serviced. Replacement is the only practical option. This project is required whether the plant operates in generation or synchronous condensing mode. This work was begun in 2010.

Install Weatherhoods for Vent Fans: This equipment is required to improve plant ventilation and reduce both humidity and temperature within the plant.

Future Projects

2012 Projects

Upgrade Marine Terminal: Construction of a new tanker docking facility with an improved fendering system, incorporating portions of the existing facility.

Upgrade Fuel Oil Heat Tracing: The existing heat tracing is 30 years old and has become unreliable. Replacement is required to ensure plant reliability.

Install Backup System for Raw Water Supply and Clarifiers: Provide a new temporary means of supplying raw water to the plant in the event of a disruption to the existing underground supply pipe that normally feeds the plant, or a failure of the clarifier, to improve the reliability of the plant.

Implement Energy Efficiency Initiatives: Install equipment and controls to improve the energy efficiency of the buildings and associated mechanical and electrical systems. This project is required whether the plant operates in generation or synchronous condensing mode.

2013 Projects

Install Unit 3 Cold Reheat Condensate Drains and High Pressure Heater Trip Level: Hydro's insurer, FM Global, identified a serious situation which could result in the ingress of water into the steam turbine, and cause considerable damage and an extensive outage. This project is required to ensure continued

reliable operation until completion of the HVDC infeed. Similar work was performed on Units 1 and 2 in 2009 and 2010.

Replace Condensate Polisher Annunciation Panels: This project is required to replace obsolete equipment on a vital auxiliary system.

Construct Gas Turbine Equipment Enclosure: This project involves constructing an enclosure around oil conditioning and pumping equipment to ensure reliability. This project is required whether the plant operates in generation or synchronous condensing mode.

2014 Projects

Upgrade Cranes and Hoists: Refurbish the cranes and hoists, which are over 40 years of age, to improve safety, reliability and extend service life. This project is required whether the plant operates in generation or synchronous condensing mode.

Purchase Critical Spare 4 kV Motors: This project consists of the purchase of one spare motor for each of the major equipment classes to ensure reliability. The delivery or repair cycle time of large motors is lengthy and the failure of such a motor could reduce plant capability for an extended period.

Install Economizer Recirculation Lines Units 1 and 2: Install recirculation pipes connecting the economizer to the boiler downcomer pipes to improve efficiency.

Install Main Fuel Oil Tank Farm Lighting: This project is required to improve the lighting to an adequate level.

Replace Gas Turbine Radiator: The existing radiator is more than thirty years old and requires replacement. This project is required whether the plant operates in generation or synchronous condensing mode.

2015 Projects

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

Replace Rectifying Transformer Unit 1: The existing unit contains pcb in the oil above the allowable limit of 2 ppm and must be replaced. This project is required whether the plant operates in generation or synchronous condensing mode.

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

Install Variable Speed Drivers: The scope of this project is to install new speed drivers to allow for variable operating speeds of boiler feed pumps. This project is required whether the plant operates in generation or synchronous condensing mode.

Install Turbine Lube Oil Conditioners: Install new higher efficiency lube oil conditioners for the removal of moisture and particulate to improve the reliability and extend the life of the turbine and generator bearings. This project is required whether the plant operates in generation or synchronous condensing mode.

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

Rewind Generators 1 and 2 (continues to 2016): The existing windings have reached the end of their expected life. Failure to replace will jeopardize reliability of generation supply and the ability to operate as a synchronous condenser. This project is required whether the plant operates in generation or synchronous condensing mode.

Holyrood Projects in a No Infeed Scenario

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

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

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

Should Hydro be required to operate the Holyrood facility as a generating plant significantly beyond the planned date for the HVDC infeed and a standby period beyond that date, considerable investigation and planning will be required to properly determine the extent and timing of work which will be required. The first step is 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 least cost energy is produced from the plant. This study was started in 2009, concentrating on the

plant components required for synchronous condensing and identifying the work which should be performed to ensure total plant reliability to the date of the HVDC infeed. As the items and estimates contained in the table were prepared without the benefit of a detailed assessment, it can be expected that the final scope and cost will differ from what is presented here. It can also be expected that some of these replacements or refurbishments will be required to be performed in an infeed scenario, should a component fail or deteriorate significantly such that plant reliability is compromised.

APPENDIX A

Five-Year Capital Plan

	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
GENERATION	3,271	21,334	27,652	22,586	12,956	7,504	95,302
TRANSMISSION AND RURAL OPERATIONS	5,076	35,236	31,877	30,626	35,613	44,204	182,632
GENERAL PROPERTIES	526	7,488	9,630	11,455	10,926	11,676	51,702
CONTINGENCY FUND	0	1,000	1,000	1,000	1,000	1,000	5,000
TOTAL CAPITAL BUDGET	8,873	65,058	70,159	65,667	60,496	64,384	334,636

	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
GENERATION							
Hydraulic Plant	0	3,856	4,372	3,742	9,862	2,636	24,467
Thermal Plant	1,705	14,134	19,735	18,607	1,359	3,442	58,982
Gas Turbines	1,566	2,986	3,367	183	1,687	1,413	11,201
Tools and Equipment	0	358	179	54	47	14	652
TOTAL GENERATION	3,271	21,334	27,652	22,586	12,956	7,504	95,302
TRANSMISSION AND RURAL OPERATIONS							
Terminal Stations	3,092	9,607	9,621	8,222	6,398	10,531	47,470
Transmission	141	4,154	3,486	5,762	8,170	9,408	31,122
Distribution	1,656	14,721	14,008	9,851	11,659	14,593	66,487
Generation	187	3,841	1,386	2,915	6,716	5,870	20,915
Properties	0	356	438	990	882	1,672	4,337
Metering	0	637	216	730	1,161	568	3,313
Tools and Equipment	0	1,919	2,723	2,157	627	1,561	8,988
TOTAL TRANSMISSION AND RURAL OPERATIONS	5,076	35,236	31,877	30,626	35,613	44,204	182,632
GENERAL PROPERTIES							
Information Systems	526	2,034	3,926	2,215	2,322	1,856	12,879
Telecontrol	0	2,697	1,693	3,490	1,672	5,315	14,867
Transportation	0	2,351	3,319	3,341	4,264	1,455	14,729
Administrative	0	407	693	2,409	2,668	3,051	9,227
TOTAL GENERAL PROPERTIES	526	7,488	9,630	11,455	10,926	11,676	51,702
CONTINGENCY FUND	0	1,000	1,000	1,000	1,000	1,000	5,000
TOTAL CAPITAL BUDGET	8,873	65,058	70,159	65,667	60,496	64,384	334,636

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
HYDRAULIC PLANT							
Replace Static Excitation System - Upper Salmon, Holyrood, and Hinds Lake		1,214	1,528	1,367			4,109
Upgrade Burnt Dam Spillway Structure- Bay d'Espoir		258	692	994	959		2,903
Upgrade Access Road - Various Sites		998	115		1,446	107	2,667
Upgrade Intake Gate Controls - Bay d'Espoir		352	468				820
Upgrade Generating Station Service Water System - Cat Arm		360	440				800
Purchase Hydrometeorological Stations - Various Sites		113	402	285			800
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		49	50	51	53	54	258
Purchase Spare Disconnect - Bay d'Espoir		176					176
Replace Automatic Transfer Switches - Bay d'Espoir and Hinds Lake		156					156
Replace Fire Alarm System - Hinds Lake		109					109
Install Compressor for Frazil Ice Removal - Upper Salmon		69					69
Upgrade Unit 2 and 4 Generator Bearing - Bay d'Espoir			156			185	341
Replace Microscada Computers - Granite Canal			187				187
Replace Cooling Water Rotary Strainer - Upper Salmon			114				114
Install Gates RR Pond - Granite Canal			84				84
Replace Cooling Water Pumps 2 and 4 in Powerhouse 1 - Bay d'Espoir			69				69
Install Unit 1 Governor Oil Filtration System - Upper Salmon			67				67
Refurbish Turbines - Snook's Arm and Venam's Bight				156	611		767
Install Automated Fuel Monitoring System - Upper Salmon				247	237		483
Replace Chart Recorders - Various Sites				273			273
Replace Jet Fuel Tank at Burnt Dam - Bay d'Espior				219			219
Upgrade Unit Relay Protection - Paradise River				151			151
Rewind Stator Units 4, 1 and 3 - Bay d'Espoir					4,609		4,609
Upgrade Victoria Structure - Bay d'Espoir					450	461	911
Upgrade Station Service Water System - Various Sites					606		606

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
HYDRAULIC PLANT (cont'd.)							
Replace Units 1 - 6 Autogreasing Systems - Bay d'Espoir					210	190	400
Install Automatic Sprinkler System - Bay d'Espoir					303		303
Automate Generator Deluge Systems Units 1 - 7 - Bay d'Espoir					265		265
Install New Fall Arrest Systems on Surge Tanks 1 - 3 - Bay d'Espoir					113		113
Install Dyn Air Gap Monitoring System on Units - Upper Salmon and Hinds Lake						679	679
Install Protective Coating on Surge Tank - Bay d'Espior						615	615
Install Trash/Safety Booms - Granite Canal and Hinds Lake						345	345
TOTAL HYDRAULIC PLANT	0	3,856	4,372	3,742	9,862	2,636	24,467
THERMAL PLANT							
Upgrade Stack Breaching Units 1, 2, and 3 - Holyrood		3,553	3,623	3,710			10,886
Refurbish Fuel Storage Facility - Holyrood		2,638	2,853				5,491
Complete Condition Assessment Phases 2, 3 and 4 - Holyrood		1,672	752	757			3,182
Replace Programmable Logic Controllers - Holyrood	1,208	747	902				2,857
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood		843	860	880			2,582
Upgrade Hydrogen System - Holyrood		1,192	800				1,992
Replace Steam Seal Regulator Units 1 and 2 - Holyrood	335	389	438				1,162
Replace Pumphouse Motor Control Centres - Holyrood	50	999					1,049
Upgrade Synchronous Condenser Unit 3 - Holyrood		484	406				889
Replace Relay Panels Unit 3 - Holyrood		277	554				831
Replace Boiler Blowdown Tanks - Holyrood		750					750
Upgrade Electrical Equipment - Holyrood		188	206	285			679

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
THERMAL PLANT (cont'd.)							
Replace Fire Pump Diesel - Holyrood	112	195					307
Install Weatherhoods for Vent Fans - Holyrood		208					208
Upgrade Marine Terminal - Holyrood			6,747	11,382			18,129
Upgrade Fuel Oil Heat Tracing - Holyrood			976	1,009			1,985
Install Backup System for Raw Water Supply and Clarifiers - Holyrood			496				496
Implement Energy Efficiency Initiatives - Holyrood			122	125			247
Install Unit 3 CR Condensate Drains and HP Heater Trip Level - Holyrood				245			245
Replace Condensate Polisher Annunicator Panels Units 1 and 2 - Holyrood				215			215
Upgrade Cranes and Hoists - Holyrood					550		550
Purchase Critical Spare 4kV Motors - Holyrood					421		421
Install Economizer Recirculation Lines Units 1 and 2 - Holyrood					220		220
Install Main Fuel Oil Tank Farm Lighting - Holyrood					168		168
Replace Waste Water Basin Building - Holyrood						981	981
Replace Rectifying Transformer - Unit 1 - Holyrood						839	839
Upgrade Facilities to Reduce Business Continuity Risk - Holyrood						651	651
Install Variable Speed Drives - Holyrood						436	436
Install Turbine Lube Oil Conditioners - Holyrood						339	339
Upgrade Powerhouse Door and Siding - Holyrood						131	131
Rewind Generators 1 and 2 - Holyrood						65	65
TOTAL THERMAL PLANT	1,705	14,134	19,735	18,607	1,359	3,442	58,982

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
GAS TURBINES							
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	1,324	3,367				5,995
Overhaul Gas Turbine - Holyrood		1,291					1,291
Upgrade Glycol System - Stephenville	261	299					560
Upgrade Gas Turbine Operator Console - Stephenville		72					72
Construct Gas Turbine Equipment Enclosure - Holyrood				183			183
Upgrade Gas Turbine Plant Life Extension - Stephenville					1,392	1,413	2,805
Replace Gas Turbine Radiator - Holyrood					295		295
TOTAL GAS TURBINE PLANTS	1,566	2,986	3,367	183	1,687	1,413	11,201
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000	0	280	92	54	47	14	487
Install Handheld Pendant to Overhead Crane - Bay d'Espoir			87				87
Purchase Laser Alignment Equipment - Holyrood		79					79
TOTAL TOOLS AND EQUIPMENT	0	358	179	54	47	14	652
TOTAL GENERATION	3,271	21,334	27,652	22,586	12,956	7,504	95,302
TERMINAL STATIONS							
Upgrade Terminal Stations to 25kV - Labrador City	2,983	3,500	3,507				9,990
Upgrade Power Transformers - Various Sites		866	880	4,596	899	1,213	8,453
Replace Disconnects - Various Sites		295	886	835	793	831	3,640
Replace Compressed Air System - Various Sites	79	781	564	614	917	524	3,478
Perform Grounding Upgrades - Various Sites		321	324	329	337	345	1,657

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
TERMINAL STATIONS (cont'd.)							
Replace Instrument Transformers - Various Sites		199	203	207	213	482	1,304
Replace Insulators - Various Sites		401	411	420			1,232
Upgrade Substation - Wabush		459	626				1,086
Upgrade Air Blast Circuit Breakers - Various Sites		334	336	341			1,011
Upgrade Station Reliability and Safety - Rocky Harbour		435	360				795
Replace 69kV SF6 Breakers - St. Anthony Airport		490	290				780
Replace Breaker, Structures and Disconnects - Hawke's Bay		687					687
Replace 230 kV Circuit Breaker - Sunnyside		41	590				631
Upgrade Trailer Mobile Substation - Bishop's Falls	30	468					498
Replace Surge Arresters - Various Sites		75	76	78	80	81	389
Install Alternate Station Services - Stony Brook and Massey Drive		86	109				195
Replace Digital Fault Recorder - Bay d'Espoir		169					169
Voisey's Bay Nickel - Long Harbour Power Supply	3,605	8,327	2,123				14,055
Cost Recovery - Vale Inco	(3,605)	(8,327)	(2,123)				(14,055)
Terminal Stations Compressor Replacement Program - Various Sites			116	119	121	124	480
Perform Site Work to Accommodate Mobile Transformer - Various Sites			187	289			476
Upgrade 230 kV Breaker Controls - Various Sites			45	46	48	49	188
Install B1C1 Annunication and Alarms - Goose Bay			58				58
Upgrade Transformer Differential Circuit - Grandy Brook			52				52
Upgrade Terminal Station and Replace Oil Filled Breaker B1L29 - Wiltondale				347	577		924
Install Additional 230kV Transformer - Oxen Pond					485	4,006	4,491
Install 20 MVAR Reactor - Bottom Brook					1,026	1,578	2,604
Install Station Alarm Breakouts - Various Sites					580	479	1,059
Replace Oil Filled Breakers L27T1 and L26L27 - Berry Hill					253	304	557
Install Transformer Fans - Conne River					70		70
Upgrade Control Building - South Brook and Doyles						516	516
TOTAL TERMINAL STATIONS	3,092	9,607	9,621	8,222	6,398	10,531	47,470

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
TRANSMISSION							
Perform Wood Pole Line Management Program - Various Sites		2,019	1,967	3,392	4,145	4,003	15,526
Upgrade Lines - Various Sites	141	1,055		640	1,739	920	4,494
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		791	661	784	456		2,691
Replace Guy Wires - TL-215		289	318	350	530		1,487
Replace Insulators - TL-206			541	597	660	972	2,769
Reroute Remote Section of Line - Various Sites					641	2,455	3,096
Upgrade Angle Structures - TL-259						662	662
Conduct LIDAR Surveys - Various Sites						254	254
Replace Dampers - TL-247						143	143
TOTAL TRANSMISSION	141	4,154	3,486	5,762	8,170	9,408	31,122
DISTRIBUTION							
Provide Service Extensions - All Service Areas		3,385	3,453	3,537	3,620	3,697	17,692
Upgrade Distribution Systems - All Service Areas		2,499	2,548	2,610	2,672	2,729	13,058
Upgrade Distribution Systems - Various Sites	218	2,086			3,549	5,446	11,299
Voltage Conversion - Labrador City	1,089	3,501	3,841	970			9,400
Upgrade Distribution Feeders - Various Sites	267	1,132	2,115	1,921	483	1,977	7,894
Replace Poles - Various Sites		956	652		976	623	3,207
Replace Recloser Control Panels - Various Sites		232	205	192	146		776
Upgrade L2 Voltage Conversion to 25kV - Gaultois	82	511					593
Replace Substation Infrastructure - Burgeo		128	368				496
Install Voltage Regulators - Conne River and L'Anse au Loup		293					293
Replace Submarine Cable - Pilley's Island to Long Island			826	621			1,446
Construct Storage Building - Springdale and Change Islands					213	121	334
TOTAL DISTRIBUTION	1,656	14,721	14,008	9,851	11,659	14,593	66,487

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
GENERATION							
Perform Arc Flash Remediation - Various Sites		430	380	391	402	413	2,016
Replace Fuel Storage Facility - Postville		2,007					2,007
Replace Generating Units - Various Sites	187	871			18	435	1,511
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson		155	160	164			478
Replace Mini Hydro Turbine - Roddicton		87	235				322
Replace Fuel Storage Tank - Francois		131					131
Upgrade Fuel Storage - Norman Bay		114					114
Upgrade Plant Overhead Crane Lifting System - Mary's Harbour		47					47
Install Automatic Oil Filling System - Various Sites			186	214			400
Install Engine Starting System - Various Sites			109	111	113		333
Install Plant Coolant Common Filling System - Various Sites			106	109	113		328
Upgrade Station Service - Grey River			154				154
Insulate Diesel Plant - St. Anthony			55				55
Construct New Diesel Plant - Charlottetown				1,524	3,590	1,607	6,722
Increase Generation - Various Sites				19	1,013	1,952	2,985
Extend Diesel Plant - Mary's Harbour and Port Hope Simpson				225	277		501
Upgrade Generation Transformer - Cartwright				23	258		282
Install Intermediate Tank - Nain				135			135
Upgrade Fuel Storage - Rigolet					750		750
Install 9000 Litre Bulk Fuel Tank for Trailer - Williams Harbour					74		74
Recore Secondary Radiator - Mary's Harbour					55		55
Install Engine Fuel Additive Injection System - Williams Harbour					54		54
Construct Fuel Storage Tank - Nain						760	760
Install Nox Monitors - Various Sites						596	596
Upgrade Fuel Storage - Little Bay Islands						106	106
TOTAL GENERATION	187	3,841	1,386	2,915	6,716	5,870	20,915

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
PROPERTIES							
Legal Survey of Primary Distribution Line Right of Way - Various Sites		79	155	160	164	88	646
Install Fall Protection Equipment - Various Sites		198	203	207			608
Install Waste Oil Storage Tank - St. Lewis		79	80				159
Install Pole Storage Ramps - Various Sites				462	473	484	1,418
Upgrade Warehouse Lighting - Bishop's Falls				113			113
Upgrade Classroom and Boardroom - Bishop's Falls				49			49
Replace Accommodations at Ebbegunbaeg - Bay d'Espoir					245		245
Replace Warehouse - Bay d'Espoir						1,100	1,100
TOTAL PROPERTIES	0	356	438	990	882	1,672	4,337
METERING							
Install Automatic Meter Reading - Various Sites		451	88	599	1,027	431	2,597
Purchase Meters, Equipment and Tanks - Various Sites		186	129	131	134	137	717
TOTAL METERING	0	637	216	730	1,161	568	3,313
TOOLS AND EQUIPMENT							
Replace Off-Road Track Vehicles - Bishop's Falls and Fogo		494	1,484	1,631		850	4,460
Replace Light Duty Mobile Equipment - Various Sites		757	852	308	315	322	2,554
Purchase Tools and Equipment Less than $50,000		256	183	147	99	86	770
Purchase Excavators - Various Sites		361	136		142		639
Purchase Portable Dissolved Gas Analysis Unit - Bishop's Falls		52					52
Purchase High Voltage Breaker Timing Sets - Various Sites			69	70	72		210
Replace Bulldozer - Unit No. 7657 - Bishop's Falls						303	303
TOTAL TOOLS AND EQUIPMENT	0	1,919	2,723	2,157	627	1,561	8,988
TOTAL TRANSMISSION AND RURAL OPERATIONS	5,076	35,236	31,877	30,626	35,613	44,204	182,632

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
INFORMATION SYSTEMS							
SOFTWARE APPLICATIONS							
New Infrastructure							
Perform Minor Application Enhancements - Hydro Place		121	122	125	128	131	627
Cost Recoveries		(39)	(39)	(40)	(41)	(42)	(200)
Upgrade Work Protection Safety Code Application - Hydro Place			332				332
Cost Recoveries			(100)				(100)
Upgrade of Technology							
Corporate Application Environment - Upgrade Microsoft Products	751	675	678				2,104
Cost Recoveries	(225)	(203)	(203)				(631)
Replace iSeries Computer and Upgrade Operating System - Hydro Place		643					643
Cost Recoveries		(206)					(206)
Upgrade JD Edwards - Hydro Place			1,451				1,451
Cost Recoveries			(464)				(464)
Upgrade Energy Management Systems - Hydro Place			285	290	355	195	1,124
Upgrade Microsoft Project - Hydro Place			313				313
Cost Recoveries			(100)				(100)
Upgrade Microsoft Office Products - Hydro Place				336	344	460	1,140
Cost Recoveries				(108)	(110)	(147)	(365)
Upgrade Business Intelligence Toolset Software - Hydro Place				170			170
Cost Recoveries				(54)			(54)
Upgrade Lotus Notes - Hydro Place					520		520
Cost Recoveries					(160)		(160)
TOTAL SOFTWARE APPLICATIONS	526	992	2,274	720	1,036	596	6,143

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
COMPUTER OPERATIONS							
Infrastructure Replacement							
Replace Personal Computers - Various Sites		404	449	526	527	493	2,397
Replace Peripheral Infrastructure - Various Sites		258	332	355	262	478	1,685
Upgrade Enterprise Storage Capacity - Hydro Place		227	261	266	241	92	1,087
Cost Recoveries		(73)	(83)	(80)	(72)	(28)	(336)
New Infrastructure							
Develop Learning Management System Courses - Hydro Place		123	137	140	143		543
Cost Recoveries		(40)	(44)	(45)	(46)		(174)
SAN Volume Control - Hydro Place			182				182
Cost Recoveries			(55)				(55)
Blue Coat Upgrade - Hydro Place			79				79
Cost Recoveries			(25)				(25)
TriGeo Upgrade - Hydro Place			31				31
Cost Recoveries			(10)				(10)
Upgrade of Technology							
Upgrade Server Technology Program - Hydro Place		209	571	490	341	317	1,929
Cost Recoveries		(67)	(171)	(157)	(109)	(92)	(596)
TOTAL COMPUTER OPERATIONS	0	1,042	1,652	1,495	1,286	1,260	6,736
TOTAL INFORMATION SYSTEMS	526	2,034	3,926	2,215	2,322	1,856	12,879

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
TELECONTROL							
NETWORK SERVICES							
Infrastructure Replacement							
Replace Radomes - Various Sites		196	166	160	164	168	854
Replace MDR 6000 Microwave Radio (West) - Various Sites		72	683				755
Purchase Tools and Equipment Less than $50,000		86	87	89	92	94	447
Refurbish Microwave Site - Deer Lake		207					207
Install Fibre Optic Cable Deer Lake to Berry Hill - TL226			210	1,905			2,115
Replace Remote Terminal Units - Various Sites			88	87	85	330	590
Replace Mobile Radio System Churchill Falls to Happy Valley				57	554		612
Replace Power Line Carrier Bottom Brook to Doyles - TL214				431			431
Upgrade Powerhouse Phone Services - Paradise River				99			99
Replace MDR 4000 Microwave Radio (East and West) - Various Sites					202	2,894	3,097
Network Infrastructure							
Replace Battery Banks and Chargers - Various Sites		978	241	282	289	296	2,086
Replace Network Communications Equipment - Various Sites		737	120	126	142	146	1,270
Install Substation Communications Management - Various Sites				204			204
Upgrade of Technology							
Install Tower Ice Protection - Various Sites		294					294
Upgrade Site Facilities - Various Sites		48	49	50	51	52	249
Replace Telephone Keyset - Wabush		80					80
Install Wireless Networking - Various Sites			49				49
Upgrade IP Scada Network - Various Sites					93	359	452
Replace PLC - Berry Hill to Peter's Barron - TL227						708	708
Build Remote Computer Link Between Cat Arm Governors and Bay d'Espoir						268	268
TOTAL TELECONTROL	0	2,697	1,693	3,490	1,672	5,315	14,867

PROJECT DESCRIPTION	Expended to 2010	2011	2012	2013	2014	2015	Total
				($000)			
TRANSPORTATION							
Replace Vehicles and Aerial Devices - Hydro System - Various Sites		2,351	3,319	3,341	4,264	1,455	14,729
TOTAL TRANSPORTATION	0	2,351	3,319	3,341	4,264	1,455	14,729
ADMINISTRATION							
Remove Safety Hazards - Various Sites		252	259	265	272		1,048
Purchase Tools and Equipment Less than $50,000		79	125	70	77	74	424
Replace Humidifiers in Air Handling Units - Hydro Place		76					76
Perform Upgrades as Determined in Building Condition Study - Hydro Place			150	166	246	159	722
Replace AC Units - Hydro Place			159				159
Upgrade Hydro Place Systems and Exterior - Hydro Place				1,908	2,073	2,818	6,799
TOTAL ADMINISTRATION	0	407	693	2,409	2,668	3,051	9,227
TOTAL GENERAL PROPERTIES	526	7,488	9,630	11,455	10,926	11,676	51,702

APPENDIX B

Twenty-Year Capital Plan

	Accuracy 10%	Accuracy 25%				Accuracy 50%				Accuracy 50% to order of magnitude										
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Generation																				
Hydro plants	3,856	4,372	3,742	9,862	2,636	1,150	2,190	695	515	760	575	810	275	425	510	1,025	150	510	0	0
Thermal Plant	14,333	19,938	18,814	1,359	3,442	4,700	4,200	2,750	5,100	5,250	3,700	6,750	5,300	2,325	2,850	3,000	4,700	3,650	3,900	0
Gas Turbines	2,986	3,367	183	1,687	1,413	1,400	250	950	2,450	3,450	3,100	3,325	3,410	3,450	3,250	3,530	2,220	1,600	1,200	0
Tools and Equipment	358	179	54	47	14	393	393	393	393	393	393	393	393	393	393	393	393	393	393	0
Transmission and Terminals																				
Terminal Stations	9,607	9,621	8,222	6,398	10,531	7,635	7,480	10,225	10,105	10,535	7,935	8,751	8,280	7,870	7,685	8,205	8,115	8,395	5,395	0
Transmission	4,233	3,641	5,922	8,334	9,496	8,202	10,407	9,428	8,123	8,591	11,574	12,476	11,370	18,594	16,250	15,201	16,072	17,556	23,434	25,786
Metering	637	216	730	1,161	568	33	33	33	33	33	33	33	33	33	33	33	33	33	33	0
Tools and Equipment	1,919	2,723	2,157	627	1,561	1,817	1,150	1,081	1,053	1,552	1,444	1,246	1,074	1,362	3,186	1,280	355	1,106	1,517	0
Rural Systems																				
Distribution	14,721	14,008	10,312	12,132	15,076	12,587	13,267	14,276	14,307	11,437	11,007	9,559	10,138	7,977	9,955	10,066	9,362	8,730	5,630	0
Diesel Plants	3,919	1,466	2,915	6,716	5,870	6,242	4,220	5,865	3,960	2,605	2,660	2,190	1,180	1,075	630	2,935	3,940	1,195	0	0
General Properties																				
Information Systems	2,034	3,926	2,215	2,322	1,856	3,368	4,303	4,682	3,488	2,848	6,700	1,880	6,652	2,203	2,746	1,752	1,752	2,235	1,818	0
Telecontrol	2,697	1,693	3,490	1,672	5,315	8,139	1,140	2,119	2,000	3,550	6,037	5,762	1,984	3,247	1,805	2,592	1,251	2,931	2,373	0
Transportation	2,351	3,319	3,341	4,264	1,455	1,668	3,253	2,446	1,544	4,433	2,883	2,705	1,564	2,309	2,638	1,577	0	5,187	1,798	0
Administrative	407	693	2,570	2,913	4,151	468	318	398	478	618	518	518	418	678	718	468	618	618	318	0
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	**65,058**	**70,159**	**65,667**	**60,496**	**64,384**	**58,802**	**53,604**	**56,341**	**54,550**	**57,055**	**59,559**	**57,399**	**53,071**	**52,941**	**53,650**	**53,058**	**49,961**	**55,139**	**48,809**	**26,786**
Total for 20 Years	1,116,488																			
Average	55,824																			
Total Holyrood without Lower Churchill	0	0	0	0	0	125,490	235,600	261,450	150,150	22,900	1,425	1,000	0	1,500	50	0	0	2,500	0	
Total for 20 Years	802,065																			
Average	40,103																			

	Expended to 2010	2011	Future Years	Total
		($000)		
GENERATION	3,495	21,334	10,760	35,588
TRANSMISSION AND RURAL OPERATIONS	5,076	35,236	19,641	59,007
GENERAL PROPERTIES	526	7,488	1,797	9,811
CONTINGENCY FUND		1,000	0	1,000
TOTAL CAPITAL BUDGET	9,097	65,058	32,198	106,352

	Expended to 2010	2011	Future Years	Total
		($000)		
GENERATION				
Hydraulic Plant	0	3,856	3,803	3,549
Thermal Plant	1,929	14,134	3,590	19,654
Gas Turbines	1,566	2,986	3,367	7,918
Tools and Equipment	0	358	0	358
TOTAL GENERATION	3,495	21,334	10,760	31,479
TRANSMISSION AND RURAL OPERATIONS				
Terminal Stations	3,092	9,607	7,382	20,081
Transmission	141	4,154	1,198	4,703
Distribution	1,656	14,721	8,542	24,919
Generation	187	3,841	1,822	5,695
Properties	0	356	0	356
Metering	0	637	88	725
Tools and Equipment	0	1,919	609	2,529
TOTAL TRANSMISSION AND RURAL OPERATIONS	5,076	35,236	19,641	59,007
GENERAL PROPERTIES				
Information Systems	526	2,034	475	3,035
Telecontrol	0	2,697	683	3,381
Transportation	0	2,351	639	2,989
Administrative	0	407	0	407
TOTAL GENERAL PROPERTIES	526	7,488	1,797	9,811
CONTINGENCY FUND		1,000		1,000
TOTAL CAPITAL BUDGET	9,097	65,058	32,198	101,297

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Page Ref
			($000)		
HYDRAULIC PLANT					
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake		1,214	2,895	0	B - 3
Upgrade Burnt Dam Access Road Phase 2 - Bay d'Espoir		998		998	B - 17
Upgrade Intake Gate Controls - Bay d'Espoir		352	468	820	B - 26
Upgrade Generating Station Service Water System - Cat Arm		360	440	800	B - 28
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir		258		258	C - 2
Purchase Spare Disconnect - Bay d'Espoir		176		176	D - 2
Replace Automatic Transfer Switches - Bay d'Espoir and Hinds Lake		156		156	D - 4
Purchase Hydrometeorological Stations - Various Sites		113		113	D - 7
Replace Fire Alarm System - Hinds Lake		109		109	D - 11
Install Compressor for Frazil Ice Removal - Upper Salmon		69		69	D - 19
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		49		49	
TOTAL HYDRAULIC PLANT	0	3,856	3,803	3,549	
THERMAL PLANT					
Upgrade Stack Breaching Unit 1 - Holyrood		3,553		3,553	B - 5
Replace Programmable Logic Controllers - Holyrood	1,432	747	902	3,081	
Refurbish Fuel Storage Facility - Holyrood		2,638		2,638	B - 8
Upgrade Hydrogen System - Holyrood		1,192	800	1,992	B - 10
Complete Condition Assessment Phase 2 - Holyrood		1,672		1,672	B - 13
Replace Pumphouse Motor Control Centres - Holyrood	50	999		1,049	
Upgrade Synchronous Condenser Unit 3 - Holyrood		484	406	889	B - 19
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood		843		843	B - 22
Replace Relay Panels Unit 3 - Holyrood		277	554	831	B - 24
Replace Boiler Blowdown Tanks - Holyrood		750		750	B - 30
Upgrade Electrical Equipment - Holyrood		188	491	679	B - 32
Replace Steam Seal Regulator Unit 2 - Holyrood		175	438	613	B - 34
Replace Steam Seal Regulator Unit 1 - Holyrood	335	214		549	
Replace Fire Pump Diesel - Holyrood	112	195		307	
Install Weatherhoods for Vent Fans - Holyrood		208		208	C - 44
TOTAL THERMAL PLANT	1,929	14,134	3,590	19,654	
GAS TURBINES					
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	1,324	3,367	5,995	
Overhaul Gas Turbine - Holyrood		1,291		1,291	B - 15
Upgrade Glycol System - Stephenville	261	299		560	
Upgrade Gas Turbine Operator Console - Stephenville		72		72	D - 16
TOTAL GAS TURBINE PLANTS	1,566	2,986	3,367	7,918	
TOOLS AND EQUIPMENT					
Purchase Tools and Equipment Less than $50,000		280	0	280	
Purchase Laser Alignment Equipment- Holyrood		79		79	D - 13
TOTAL TOOLS AND EQUIPMENT	0	358	0	358	
TOTAL GENERATION	3,495	21,334	10,760	31,479	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Page Ref
			($000)		
TERMINAL STATIONS					
Upgrade Terminal Stations to 25 kV - Labrador City	2,983	3,500	3,507	9,990	
Perform Grounding Upgrades - Various Sites		321	1,336	1,657	B - 49
Upgrade Substation - Wabush		459	626	1,086	B - 55
Upgrade Power Transformers - Various Sites		866		866	B - 59
Upgrade Station Reliability and Safety - Rocky Harbour		435	360	795	B - 61
Replace 69 kV SF6 Breakers - St. Anthony Airport		490	290	780	B - 65
Replace Breaker, Structures and Disconnects - Hawke's Bay		687		687	B - 69
Replace Compressed Air System - Bay d'Espoir		84	564	648	B - 71
Replace 230 kV Circuit Breaker - Sunnyside		41	590	631	B - 73
Upgrade Trailer Mobile Substation - Bishop's Falls	30	468		498	
Replace Compressed Air Piping and Install Dewpoint Monitoring - Holyrood	79	417		496	
Replace Insulators - Various Sites		401		401	C - 68
Upgrade Air Blast Circuit Breakers - Various Sites		334		334	C - 81
Replace Disconnects - Various Sites		295		295	C - 127
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station		280		280	C - 151
Replace Instrument Transformers - Various Sites		199		199	D - 21
Install Alternate Station Services - Stony Brook and Massey Drive		86	109	195	D - 35
Replace Digital Fault Recorder - Bay d'Espoir		169		169	D - 41
Replace Surge Arresters - Various Sites		75		75	D - 60
Voisey's Bay Nickel - Long Harbour Power Supply	3,605	8,327	2,123	14,055	
Cost Recovery - Vale Inco	(3,605)	(8,327)	(2,123)	(14,055)	
TOTAL TERMINAL STATIONS	3,092	9,607	7,382	20,081	
TRANSMISSION					
Perform Wood Pole Line Management Program - Various Sites		2,019		2,019	B - 41
Replace Guy Wires TL-215 - Doyles to Grand Bay		289	1,198	1,487	B - 51
Upgrade Line TL-244 - Plum Point to Bear Cove	141	1,055		1,196	
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		791		791	B - 63
TOTAL TRANSMISSION	141	4,154	1,198	4,703	
DISTRIBUTION					
Voltage Conversion - Labrador City	1,089	3,501	4,810	9,400	
Upgrade L2 Distribution Feeder - Glenburnie	267	578	2,711	3,556	
Provide Service Extensions - All Service Areas		3,385		3,385	B - 36
Upgrade Distribution Systems - All Service Areas		2,499		2,499	B - 38
Upgrade Distribution Lines - Roddickton and Makkovik	218	1,645		1,863	
Upgrade Distribution Systems - Francois, Rigolet and Happy Valley		1,068	652	1,720	B - 47
Replace Poles - Various Sites		882		882	
Upgrade L2 Voltage Conversion to 25 kV - Gaultois	82	511		593	B - 57
Replace Substation Infrastructure - Burgeo		128	368	496	C - 58
Install Voltage Regulators - Conne River and L'Anse au Loup		293		293	C - 136
Replace Recloser Control Panels - Various Sites		232		232	C - 162
TOTAL DISTRIBUTION	1,656	14,721	8,542	24,919	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years ($000)	Total	Page Ref
GENERATION					
Perform Arc Flash Remediation - Various Sites		430	1,586	2,016	B - 43
Replace Fuel Storage Facility - Postville		2,007		2,007	B - 45
Replace Unit 566 and 2001 - Francois	168	450		618	
Replace Unit 2018 - McCallum	19	421		440	
Replace Mini Hydro Turbine - Roddicton		87	235	322	C - 89
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson		155		0	D - 45
Replace Fuel Storage Tank - Francois		131		131	D - 49
Upgrade Fuel Storage - Norman Bay		114		114	D - 51
Upgrade Plant Overhead Crane Lifting System - Mary's Harbour		47		47	
TOTAL GENERATION	187	3,841	1,822	5,695	
PROPERTIES					
Install Fall Protection Equipment - Various Sites		198		198	D - 24
Legal Survey of Primary Distribution Line Right of Way - Various Sites		79		79	D - 54
Install Waste Oil Storage Tank - St. Lewis		79		79	D - 58
TOTAL PROPERTIES	0	356	0	356	
METERING					
Install Automated Meter Reading - Labrador City and Port au Choix		451	88	539	B - 75
Purchase Meters, Equipment and Tanks - Various Sites		186		186	D - 38
TOTAL METERING	0	637	88	725	
TOOLS AND EQUIPMENT					
Replace Off-Road Track Vehicles - Bishop's Falls and Fogo		494	609	1,104	B - 53
Replace Light Duty Mobile Equipment - Various Sites		757		757	B - 67
Purchase Excavators - Bishop's Falls		361		361	C - 75
Purchase Tools and Equipment Less than $50,000		256		256	
Purchase Portable Dissolved Gas Analysis Unit - Bishop's Falls		52		52	D - 62
TOTAL TOOLS AND EQUIPMENT	0	1,919	609	2,529	
TOTAL TRANSMISSION AND RURAL OPERATIONS	5,076	35,236	19,641	59,007	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Page Ref
			($000)		
INFORMATION SYSTEMS					
SOFTWARE APPLICATIONS					
New Infrastructure					
Perform Minor Application Enhancements - Hydro Place		121		121	D - 89
Cost Recoveries		(39)		(39)	
Upgrade of Technology					
Corporate Application Environment - Upgrade Microsoft Products	751	675	678	2,104	
Cost Recoveries	(225)	(203)	(203)	(631)	
Replace iSeries Computer and Upgrade Operating System - Hydro Place		643		643	C - 178
Cost Recoveries		(206)		(206)	
TOTAL SOFTWARE APPLICATIONS	526	992	475	1,993	
COMPUTER OPERATIONS					
Infrastructure Replacement					
Replace Personal Computers - Various Sites		404		404	C - 183
Replace Peripheral Infrastructure - Various Sites		258		258	C - 199
Upgrade Enterprise Storage Capacity - Hydro Place		227		227	D - 78
Cost Recoveries		(73)		(73)	
New Infrastructure					
Develop Learning Management System Courses - Hydro Place		123		123	D - 87
Cost Recoveries		(40)		(40)	
Upgrade of Technology					
Upgrade Server Technology Program - Hydro Place		209		209	D - 82
Cost Recoveries		(67)		(67)	
TOTAL COMPUTER OPERATIONS	0	1,042	0	1,042	
TOTAL INFORMATION SYSTEMS	526	2,034	475	3,035	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Page Ref
			($000)		
TELECONTROL					
NETWORK SERVICES					
Infrastructure Replacement					
Replace MDR 6000 Microwave Radio (West) - Various Sites		72	683	755	B - 81
Refurbish Microwave Site - Deer Lake		207		207	C - 209
Replace Radomes - Various Sites		196		196	D - 65
Purchase Tools and Equipment Less than $50,000		86		86	
Network Infrastructure					
Replace Battery Banks and Chargers - Various Sites		978		978	B - 79
Replace Network Communications Equipment - Various Sites		737		737	B - 83
Upgrade of Technology					
Upgrade Ice Protection - Chapel Hill Microwave Site		294		294	C - 188
Replace Telephone Keyset - Wabush		80		80	D - 91
Upgrade Site Facilities - Various Sites		48		48	
TOTAL TELECONTROL	0	2,697	683	3,381	
TRANSPORTATION					
Replace Vehicles and Aerial Devices - Various Sites		2,351	639	2,989	B - 77
TOTAL TRANSPORTATION	0	2,351	639	2,989	
ADMINISTRATION					
Remove Safety Hazards - Various Sites		252		252	C - 204
Purchase Tools and Equipment Less than $50,000		79		79	
Replace Humidifiers in Air Handling Units - Hydro Place		76		76	D - 93
TOTAL ADMINISTRATION	0	407	0	407	
TOTAL GENERAL PROPERTIES	526	7,488	1,797	9,811	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Page Ref
		($000)			
GENERATION					
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	1,324	3,367	5,995	
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake		1,214	2,895	4,109	B - 3
Upgrade Stack Breaching Unit 1 - Holyrood		3,553		3,553	B - 5
Replace Programmable Logic Controllers - Holyrood	1,208	747	902	2,857	
Refurbish Fuel Storage Facility - Holyrood		2,638		2,638	B - 8
Upgrade Hydrogen System - Holyrood		1,192	800	1,992	B - 10
Complete Condition Assessment Phase 2 - Holyrood		1,672		1,672	B - 13
Overhaul Gas Turbine - Holyrood		1,291		1,291	B - 15
Replace Pumphouse Motor Control Centres - Holyrood	50	999		1,049	
Upgrade Burnt Dam Access Road Phase 2 - Bay d'Espoir		998		998	B - 17
Upgrade Synchronous Condenser Unit 3 - Holyrood		484	406	889	B - 19
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood		843		843	B - 22
Replace Relay Panels Unit 3 - Holyrood		277	554	831	B - 24
Upgrade Intake Gate Controls - Bay d'Espoir		352	468	820	B - 26
Upgrade Generating Station Service Water System - Cat Arm		360	440	800	B - 28
Replace Boiler Blowdown Tanks - Holyrood		750		750	B - 30
Upgrade Electrical Equipment - Holyrood		188	491	679	B - 32
Replace Steam Seal Regulator Unit 2 - Holyrood		175	438	613	B - 34
Upgrade Glycol System - Stephenville	261	299		560	
Replace Steam Seal Regulator Unit 1 - Holyrood	335	214		549	
TOTAL GENERATION	3,159	19,570	10,760	33,489	
TRANSMISSION AND RURAL OPERATIONS					
Upgrade Terminal Stations to 25 kV - Labrador City	2,983	3,500	3,507	9,990	
Voltage Conversion - Labrador City	1,089	3,501	4,810	9,400	
Upgrade L2 Distribution Feeder - Glenburnie	267	578	2,711	3,556	
Provide Service Extensions - All Service Areas		3,385		3,385	B - 36
Upgrade Distribution Systems - All Service Areas		2,499		2,499	B - 38
Perform Wood Pole Line Management Program - Various Sites		2,019		2,019	B - 41
Perform Arc Flash Remediation - Various Sites		430	1,586	2,016	B - 43
Replace Fuel Storage Facility - Postville		2,007		2,007	B - 45
Upgrade Distribution Lines - Roddickton and Makkovik	218	1,645		1,863	
Upgrade Distribution Systems - Francois, Rigolet and Happy Valley		1,068	652	1,720	B - 47
Perform Grounding Upgrades - Various Sites		321	1,336	1,657	B - 49
Replace Guy Wires TL-215 - Doyles to Grand Bay		289	1,198	1,487	B - 51
Upgrade Line TL-244 - Plum Point to Bear Cove	141	1,055		1,196	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Page Ref
		($000)			
TRANSMISSION AND RURAL OPERATIONS (cont'd.)					
Replace Off-Road Track Vehicles - Bishop's Falls and Fogo		494	609	1,104	B - 53
Upgrade Substation - Wabush		459	626	1,086	B - 55
Replace Poles - Various Sites		882		882	B - 57
Upgrade Power Transformers - Various Sites		866		866	B - 59
Upgrade Station Reliability and Safety - Rocky Harbour		435	360	795	B - 61
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		791		791	B - 63
Replace 69 kV SF_6 Breakers - St. Anthony Airport		490	290	780	B - 65
Replace Light Duty Mobile Equipment - Various Sites		757		757	B - 67
Replace Breaker, Structures and Disconnects - Hawke's Bay		687		687	B - 69
Replace Compressed Air System - Bay d'Espoir		84	564	648	B - 71
Replace 230 kV Circuit Breaker - Sunnyside		41	590	631	B - 73
Replace Unit 566 and 2001 - Francois	168	450		618	
Upgrade L2 Voltage Conversion to 25 kV - Gaultois	82	511		593	
Install Automated Meter Reading - Labrador City and Port au Choix		451	88	539	B - 75
TOTAL TRANSMISSION AND RURAL OPERATIONS	4,948	29,696	18,928	53,572	
GENERAL PROPERTIES					
Replace Vehicles and Aerial Devices - Various Sites		2,351	639	2,989	B - 77
Corporate Application Environment - Upgrade Microsoft Products	526	473	475	1,473	
Replace Battery Banks and Chargers - Various Sites		978		978	B - 79
Replace MDR 6000 Microwave Radio (West) - Various Sites		72	683	755	B - 81
Replace Network Communications Equipment - Various Sites		737		737	B - 83
TOTAL GENERAL PROPERTIES	526	4,611	1,797	6,933	
TOTAL PROJECTS OVER $500,000	8,633	53,877	31,485	93,995	

Project Title: Replace Static Excitation System

Location: Upper Salmon, Holyrood and Hinds Lake

Category: Generation - Hydraulic

Definition: Pooled

Classification: Normal

Project Description:

This project is required to design, replace, supply and install new static excitation systems for the Upper Salmon, Holyrood Unit 3 and Hinds Lake generators in years 2011, 2012 and 2013 respectively. The power and control cabling and connections between the excitation systems and the generators will be replaced.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**2013**	**Total**
Material Supply	575.0	700.0	425.0	1,700.0
Labour	187.0	187.0	187.0	561.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	250.0	280.0	250.0	780.0
Other Direct Costs	21.0	21.0	21.0	63.0
O/H, AFUDC & Escln.	101.3	225.0	350.9	677.2
Contingency	80.0	115.0	132.9	327.9
TOTAL	**1,214.3**	**1,528.0**	**1,366.8**	**4,109.1**

Operating Experience:

The existing static excitation systems for the Holyrood Unit 3, Hinds Lake and Upper Salmon generators were manufactured by Westinghouse, and installed during construction of the generators in 1979, 1980 and 1982 respectively. These systems have provided service for 28 to 31 years but have come to the end of their service lives and will not receive further engineering support from the original manufacturer. The Westinghouse static excitation systems for the Upper Salmon, Holyrood Unit 3 and Hinds Lake generators operate whenever the generating unit is running. The systems in Upper Salmon and Hinds Lake are in near continuous operation, while the Holyrood Unit 3 system has been cyclic depending on seasonal load requirements.

Project Justification:

This project is justified on the requirement to maintain system reliability by replacing the static excitation systems for the Upper Salmon, Hinds Lake and Holyrood Unit 3 generators before failure, which would impair Hydro's ability to provide least-cost, reliable electrical service. In the case of Holyrood, if an infeed is brought on to Newfoundland from Labrador, the Holyrood plant will be utilized as a synchronous condenser to support system stability for the Island Interconnected system. Regardless of whether the plant is operating in generation mode, or in synchronous condense mode, the excitation system will be required. Therefore, when the infeed is realized, these upgrades will still be required.

Future Plans:

None.

Attachments:

See report entitled "Replace Static Excitation System for Generating Units" located in Volume I, REPORTS 1 - 10, Tab 1 for further details.

Project Title: Upgrade Stack Breeching Unit 1

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project involves the upgrading of the stack breeching serving generating Unit 1. The project will replace existing stack breeching with newly designed breeching that will be fabricated from high temperature carbon steel and insulated externally with water repellent insulation complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching to protect the external insulation from damage caused by ice falling from the stack and the plant power house.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	114.4	0.0	0.0	114.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	2,880.6	0.0	0.0	2,880.6
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	256.7	0.0	0.0	256.7
Contingency	299.7	0.0	0.0	299.7
TOTAL	**3,553.4**	**0.0**	**0.0**	**3,553.4**

Operating Experience:

Unit 1 stack breeching has a rectangular cross section that is constructed from carbon steel plate and insulated with borosilicate (glass) block. The stack breeching conveys the boiler flue gas outside the plant to the boiler exhaust stack where it is discharged into the atmosphere. The existing Unit 1 stack breeching was installed in 1990 replacing the original installed when Unit 1 was commissioned in 1971. In 1988, when Unit 1 was up-rated to produce 170 MW, the two forced draft fans were modified to increase the volumetric flow rate of combustion air to the boiler servicing Unit 1. The fans

convey ambient air to the boiler where it is mixed with fuel oil for combustion. After combustion, the flue gas exits the boiler and passes through the air pre-heaters prior to entering the stack breeching. In 1991, an internal inspection of the breeching revealed that erosion had caused damage to the borosilicate insulation. The erosion was attributed to the increased forced draft fan volumetric flow rate which delivered air at an average flu gas velocity of 50 feet per second compared to the original velocity at 43 feet per second. Erosion of the internal borosilicate insulation liner has been an ongoing issue inside the Unit 1 stack breeching since Unit 1 was up-rated.

In addition to erosion, cracks have developed in the internal insulating liner and concrete floor. As a result of erosion and cracks, flue gas contacts the steel plates underneath the insulation and concrete and condenses to form sulfuric acid which causes corrosion. Also, failure of the internal insulation blocks has caused the flue gas temperature to break down the adhesive membrane that bonds the blocks to the breeching plate.

Project Justification:

This project is required to maintain the reliability of generating Unit 1 at Holyrood. The stack breeching has deteriorated to a point where a complete replacement is necessary. Also, deterioration of the breeching plate has the potential to discharge the boiler flue gas that contains sulfur dioxide inside the plant. The internal insulation materials have been contaminated by boiler exhaust gases and are a safety concern for plant personnel during annual maintenance outage and can cause headaches, dizziness, nausea and loss of coordination. In addition, the corrosion has rendered the floor structure unsafe to support the load of maintenance personnel and equipment while working inside.

Failure of the breeching during operation can result in an unplanned unit outage of four to six weeks duration and a repair cost estimated at $1,000,000. An unscheduled unit outage during the peak winter load would result in a loss of 170 MW of generation to the Island Interconnected System.

Future Plans:

Projects to upgrade the stack breeching servicing Units 2 and 3 are planned for the years 2012 and 2013 respectively. Please see the five-year capital plan (Capital Plan 2011 tab, Appendix A).

Attachments:

See report entitled “Upgrade Unit 1 Stack Breeching” located in Volume I, REPORTS 1 - 10, Tab 2 for further project details.

Project Title: Refurbish Fuel Storage Facility

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project involves the upgrade of existing components within the Fuel Oil Storage Facility at the Holyrood Generating Facility (Holyrood) for the purpose of extending its useful life, ensuring system reliability, increasing the level of safety and reducing environmental risks within the facility. The scope of the work is to clean, inspect, replace floor plates, paint floor and install a roof platform for Tank No. 3. The project also includes the installation of a fuel oil level indication system on Tank 3 that will provide accurate fuel tank level feedback to the Holyrood control room and reduce or eliminate the need to complete manual fuel reconciliations. In addition, the project includes the installation of access steps over the fuel oil and steam piping system that runs north and south between Tanks 1 and 2 and also between Tanks 3 and 4 in order to enable plant personnel to safely access the roadway located on the west side of the tank farm.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	204.5	0.0	0.0	204.5
Consultant	158.0	0.0	0.0	158.0
Contract Work	1,866.0	0.0	0.0	1,866.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	184.3	0.0	0.0	184.3
Contingency	223.1	0.0	0.0	223.1
TOTAL	**2,637.9**	**0.0**	**0.0**	**2,637.9**

Operating Experience:

There are four above ground fuel oil storage tanks containing No. 6 fuel (Bunker C) and associated pipelines at Holyrood. Each tank has a storage capacity of 200,000 barrels and is 55 metres (180 feet) in diameter and 15 metres (48 feet) high. An inspection by SCE Acre's in 2003 identified corrosion of the

floor in Tank 3 and recommended replacement in 2010. The tank inspection was the basis for the recommendations which provide the scope of work for this capital project. Also, the SGE Acres report recommends continuous monitoring for corrosion of the roof plate. The evidence of water ponding on the roof of the tank indicates a deflection in the roof and flexibility of the rafters.

Project Justification:

This project is justified on the requirement to replace a failing and deteriorated fuel oil storage infrastructure in order for Holyrood to provide safe, environmentally responsible, least-cost, reliable electrical service. Tank 3 has deteriorated to a point where there is a significant risk for oil leakage and inoperability. Corrective action must be taken.

The installation of a fuel oil level indication system on Tank 3 will provide accurate fuel tank level feedback to the Holyrood control room and reduce or eliminate the need to complete manual fuel reconciliations. In addition, the installation of access steps between Tanks 1 and 2 and also between Tanks 3 and 4 will enable Holyrood personnel to safely access the roadway located on the west side of the tank farm as opposed to climbing over steam/fuel oil piping and the tank farm dyke to access the roadway from these locations.

Future Plans:

Upgrades to the fuel oil storage facility are planned for 2012 as shown in the five year plan. See the five year plan (2011 Capital Plan tab, Appendix A).

Attachments:

See report entitled “Refurbishment of the Fuel Storage Facility – Holyrood Thermal Generating Station” located in Volume I, REPORTS 1 - 10, Tab 3, for further details.

Project Title: Upgrade Hydrogen System

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Justifiable

Project Description:

This project consists of upgrading the hydrogen gas storage and control system at the Holyrood Thermal Generating Station. The work includes installing a new electrolyzer for on site production of hydrogen gas and a low pressure bulk storage system. Control panels, pipes and valves will be replaced and automatic vent valves installed. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	585.0	174.0	0.0	759.0
Labour	202.2	245.0	0.0	447.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	250.0	40.0	0.0	290.0
Other Direct Costs	15.5	6.0	0.0	21.5
O/H, AFUDC & Escln.	139.2	183.6	0.0	322.8
Contingency	0.0	151.8	0.0	151.8
TOTAL	**1,191.9**	**800.4**	**0.0**	**1,992.3**

Operating Experience:

The electrical generators at Holyrood use high (2,000 pounds per square inch gauge) pressure hydrogen gas for cooling. The hydrogen gas system consists of two bulk packs, each consisting of 16 individual cylinders. The supply of bulk packs has not been reliable because there is no local hydrogen production facility in the Province. Long lead times are required when ordering the gas and delays in receiving deliveries have been experienced resulting in situations where Holyrood had almost completely exhausted the hydrogen gas stored on site. If an adequate supply of hydrogen gas is unavailable a generating unit would have to be taken out of service. Also, high pressure hydrogen has inherent safety risks related to leaks. Since 2000, there have been 28 unsafe work conditions related to the hydrogen system. Eleven of those were incidents where hydrogen had leaked from the system. The others related to unsafe conditions pertaining to hydrogen system auxiliary equipment.

Project Justification:

The hydrogen system upgrade at Holyrood is required to enhance the reliable and safe operation of the plant. The use of high pressure hydrogen cylinders requires a new pipe connection to be made to the gas supply header, located inside the cylinder storage building, each time a bulk pack is changed. The potential for a leak that could concentrate hydrogen gas and create a potentially explosive atmosphere exists. This project will eliminate the risk by replacing the high pressure bulk packs with an electrolyzer for on site production of hydrogen gas and by installing bulk low pressure storage tanks outdoors.

A contributing factor to the development of leaks at the control stations is their close proximity to the generating units thereby exposing them to vibration. The location of the valve stations make it possible for a hydrogen rich environment to form and when a leak develops, a potential explosive atmosphere is created. To stop a gas leak, operators go to the valve station thus, entering a potentially hazardous environment. This project will reduce the exposure of valve stations to vibration by relocating them farther away from the generating units.

The existing gas control panels are over 30 years of age and have reached the end of their useful life. The analyzers of hydrogen purity inside the control panels are no longer accurate. This inaccuracy leads to excessive hydrogen consumption and inefficient operation of the generators. By replacing the gas control panels, hydrogen purity and pressure will automatically be maintained at the required levels.

In the event of a plant emergency, it may become necessary to shut down the generating units at Holyrood as quickly as possible and vent the hydrogen gas to the outdoors. Hydrogen venting is performed by operators going to the valve stations to manually release the gas. FM Global, Hydro's insurer, identifies this as a major risk and recommends installing remote control hydrogen vents.

Future Plans:

None.

Attachments:

See report entitled “Upgrade Hydrogen System – Holyrood Thermal Generating Station” located in Volume I, REPORTS 1 - 10, Tab 4, for further project details.

Project Title: Complete Condition Assessment Phase 2

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is the second phase of a condition assessment and life extension program which began in 2009. It will provide a detailed investigation of the generators and associated equipment required for long term operation of Holyrood as a synchronous condensing facility and make recommendations for work required to extend its useful life. The project will include a Level II study as per the guidelines of the Electrical Power Research Institute (EPRI). During the 1970's and 1980's, EPRI developed a three-level methodology for performing condition assessment and life extension studies within the utility industry. The level of sophistication and detail increases progressively through Levels I, II, and III studies. During a Level II assessment, the condition of equipment is assessed by performing detailed inspections, utilizing non-destructive testing techniques, and performing metallurgical analysis on material samples. Phase 2 of the condition assessment and life extension program will be completed by an engineering firm, with experience in performing condition assessment and life extension studies.

The Level II study will include recommendations with cost estimates to complete asset refurbishment tasks to maintain reliable operation of the plant. It is anticipated that the proposed 2011 project will have a 12 month duration commencing in January and ending in December.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	152.3	0.0	0.0	152.3
Consultant	1,282.0	0.0	0.0	1,282.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.0	0.0	0.0	12.0
O/H, AFUDC & Escln.	81.1	0.0	0.0	81.1
Contingency	144.6	0.0	0.0	144.6
TOTAL	**1,672.0**	**0.0**	**0.0**	**1,672.0**

Operating Experience:

Holyrood has approximately 40 years of service and, as it operates between 4,000 to 5,000 hours per year, it is at the end of its anticipated useful life of 30 years. It is typical for thermal plants to experience frequent equipment failures at the end of their useful life and such failures have been experienced at Holyrood in recent years. Normally it is financially viable to extend the life of a thermal plant rather than decommission it and build a new one. Considering the age of the plant and the increasing number of unexpected equipment failures, Phase 2 of the condition assessment and life extension program is necessary. The results of this study will assist Hydro in determining what measures need to be taken to ensure Holyrood continues to operate.

Project Justification:

This project is required to enable Hydro to operate an aging generating plant as a synchronous condensing facility past its normal expected life, thereby providing least-cost and reliable electrical power. The project will include the preparation of recommendations with cost estimates to complete asset refurbishment tasks in order to maintain reliable operation of the plant as a synchronous condensing facility into the future.

Future Plans:

Phase 3 of the program will be considered in 2012 and 2013. See the five-year plan (2011 Capital Plan tab, Appendix A).

Attachments:

See report entitled “Condition Assessment and Life Extension Study – Holyrood Thermal Generating Station” located in Volume I, REPORTS 1 - 10, Tab 5, for further project details.

Project Title: Overhaul Gas Turbine

Location: Holyrood

Category: Generation - Gas Turbines

Definition: Other

Classification: Normal

Project Description:

This project is required to overhaul the gas turbine engine at the Holyrood gas turbine plant. The scope of the work is based on an inspection by Alba Power performed on the engine in 2008. Part of the overhaul involves a detailed inspection of the internal components to finalize the scope of the work. The engine is a Rolls-Royce Avon 1533-70L.

A vendor specializing in gas turbine repairs will perform the engine overhaul. The engine will be removed from its berth at Holyrood and shipped to the vendor's repair facility for detailed inspection and subsequent repairs. Removal and reinstallation of the engine will be performed by the vendor, with assistance as required from Holyrood personnel.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
Labour	157.6	0.0	0.0	157.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	811.4	0.0	0.0	811.4
Other Direct Costs	25.0	0.0	0.0	25.0
O/H, AFUDC & Escln.	142.9	0.0	0.0	142.9
Contingency	104.4	0.0	0.0	104.4
TOTAL	**1,291.4**	**0.0**	**0.0**	**1,291.4**

Operating Experience:

The engine was purchased by Hydro in 1966 and has an anticipated useful life of 25 years. It was last overhauled in 1991. The latest internal inspection of the inside of the engine was completed in June 2008. The report from Alba Power cited the presence of corrosion and coating loss on internal

components. In October 2009, three broken discharge nozzle brackets were noted during repair work on the unit.

Project Justification:

The Holyrood gas turbine plant is critical to the successful operation of the Island Interconnected System. Its main function is to supply power to Holyrood during a black start. A black start of Holyrood is required when the plant is unable to attain power from the Island Interconnected grid due to an emergency outage caused by other generation sources. If the gas turbine failed to supply power to Holyrood during a black start, Holyrood would not be able to start until power was restored to the grid by alternate generation sources. This would cause an unnecessary delay in restoring full power to the grid. For this reason, the gas turbine plant needs to be reliable.

Future Plans:

None.

Attachments:

See report entitled "Overhaul Gas Turbine – Holyrood Thermal Generation Station" located in Volume I, REPORTS 1 - 10, Tab 6, for further project details.

Project Title: Upgrade Burnt Dam Access Road Phase 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This is Phase 2 of a project that started in 2007 to upgrade the Burnt Dam access road. This project will complete the upgrading of the existing access road to Burnt Dam. The project consists of excavating the ditches along the sides of the road, supplying and installing 35 new road culverts and supplying, spreading and compacting 50,000 tons of road topping over the entire length of the road surface. The work will be performed under contract with site supervision by Hydro personnel.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	21.0	0.0	0.0	21.0
Labour	43.0	0.0	0.0	43.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	752.0	0.0	0.0	752.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escln.	81.0	0.0	0.0	81.1
Contingency	83.4	0.0	0.0	83.4
TOTAL	**998.4**	**0.0**	**0.0**	**998.4**

Operating Experience:

The existing Burnt Dam access road was constructed in the late 1960s as part of the original Bay d'Espoir Development. This road is maintained by Hydro personnel at Bay d'Espoir using standard road grading and maintenance techniques. Over the past forty years the road topping has deteriorated to the point where the original subgrade material is exposed.

Hydro received approval under Board Order No. P.U. 35 (2006) to upgrade the Burnt Dam access road in 2007. The project involved clearing brush along the road, excavating ditches, replacing culverts to

improve drainage, and supplying and placing granular backfill. This was performed as Phase 1 of the upgrading of the Burnt Dam access road.

Project Justification:

This project is justified on the need to upgrade deteriorated infrastructure. Most of the drainage work was completed in 2007. Phase 2 will complete the drainage improvements and improve the road surface which will reduce the travel time between Burnt Dam and Granite Canal sites. Burnt Dam personnel have to travel the road to perform operational and environmental duties. Since the Granite Canal Development was commissioned in 2003, there has been an increased need for personnel stationed at the Burnt Dam site to travel to Granite Canal for water management activities. Prior to Granite Canal coming on line, personnel would only be required to travel the road four to six times per year. However, as personnel at the Burnt Dam site are responsible to respond to any alarms at Granite Canal, the road is required for increased usage. There have been incidences where Burnt Dam personnel have had to travel to Granite five times in a six day period. It takes approximately two and a half hours for a one-way trip.

Future Plans:

None.

Attachments:

See report entitled “Upgrade Burnt Dam Access Road – Phase 2” located in Volume I, REPORTS 1 - 10, Tab 7, for further project details.

Project Title: Upgrade Synchronous Condenser Unit 3

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Justifiable

Project Description:

This project is required to perform modifications to the Holyrood generating Unit 3 to reduce vibration levels during synchronous condenser operation. The existing extension shaft will be replaced with a new extension shaft complete with a journal bearing, thrust bearing and coupling assemblies. The journal bearing will control the radial vibrations of the extension shaft and generator rotor. The thrust bearing will control the axial thrust vibrations from the generator rotor. A modification to the existing Unit 3 jacking oil system will also be necessary to provide lifting oil to both the thrust and journal bearings to minimize the additional torsional resistance during synchronous condenser start-up. The project will also reduce the time required to convert Unit 3 from generation to synchronous condenser mode from approximately 16 days to approximately three to five days.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	298.4	0.0	0.0	298.4
Labour	50.0	128.0	0.0	178.0
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	131.4	0.0	131.4
Other Direct Costs	1.5	1.5	0.0	3.0
O/H, AFUDC & Escln.	33.6	73.5	0.0	107.1
Contingency	0.0	71.1	0.0	71.1
TOTAL	**483.6**	**405.5**	**0.0**	**889.0**

Operating Experience:

During synchronous condenser operation, the generator rotor moves axially and vibrates excessively, damaging the SSS clutch. Also, radial vibrations of the generator rotor at the outboard bearing are much higher than desired. The existing extension shaft extends approximately five feet beyond the

axial center of the generator outboard bearing. This unsupported length is too long and causes excessive radial vibrations at the SSS clutch.

Excessive vibration levels on Unit 3 operating in a synchronous condenser mode have been an ongoing issue since the original installation in 1985. According to Hitachi, the original equipment manufacturer (OEM), the maximum generator bearing vibration should not exceed 1.2 mil (30.5 micron) during normal operation and the generator should be immediately shut down if the vibration levels exceed 2.0 mil (50.8 micron). Occasionally, excessive vibration levels have necessitated taking the synchronous condenser off line so that corrections could be made.

Project Justification:

Unit 3 at Holyrood operates as a synchronous condenser during the off-peak period, typically between April and November each year in order to provide voltage support for the eastern portion of the Island Interconnected System. The current design of the extension shaft assembly between the generator rotor output shaft and SSS clutch does not have the capability of supporting the axial and radial vibrations experienced by the rotor during synchronous condenser operations. This project will improve the reliability of Unit 3 as a synchronous condenser by reducing the vibration levels during operation.

The proposed modifications will reduce changeover time to convert Unit 3 from generation to synchronous condenser mode. The reduced changeover time will increase the overall thermal efficiency at Holyrood. The efficiency gain is associated with not having to operate a generating unit at a relatively inefficient low load (approximately 70 MW) during the 11 day reduction in the normal changeover period. A cost benefit analysis indicates that modifying Unit 3 for synchronous condenser operation is cost effective.

Future Plans:

Assuming an infeed from Lower Churchill, it is anticipated that Holyrood will operate as a synchronous condenser plant, providing voltage support for the Island Interconnected System.

Attachments:

See report entitled “Holyrood Unit 3 Synchronous Condenser Upgrade” located in Volume I, REPORTS 1 - 10, Tab 8, for further project details.

Project Title: Upgrade Forced Draft Fan Ductwork Unit 1

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Justifiable

Project Description:

This project is required to perform modifications to the ductwork on the forced draft (FD) fans servicing generating Unit 1 in order to reduce fan vibration levels and eliminate ductwork cracking. A Computational Fluid Dynamics (CFD) analysis will be completed on the fans while they are in operation in order to model the air flow characteristics inside the intake and discharge ductwork. CFD analysis is a computer modeling technique commonly used in industry to model fluid flows and analyze problems in mechanical systems by simulating the interaction of fluid flows with equipment surfaces. Based on the results of the CFD analysis, custom fabricated equipment will be installed inside the FD fan intake and discharge ductwork.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	68.3	0.0	0.0	68.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	619.1	0.0	0.0	619.1
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	62.8	0.0	0.0	62.8
Contingency	70.9	0.0	0.0	70.9
TOTAL	**843.0**	**0.0**	**0.0**	**843 .0**

Operating Experience:

The east and west FD fan systems servicing the Unit 1 boiler are identical. During operation, the geometry of the existing FD fan ductwork causes air flow turbulence which creates vibrations on both the intake and discharge ductwork. The vibrations result in ductwork cracks which are normally repaired by Alstom Power during the annual Unit 1 planned outage. However, extensive ductwork cracking has the potential to cause an unscheduled outage in order to make repairs. An unscheduled

unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System. This represents approximately 11 percent of Hydro's Island Interconnected System's capacity.

Project Justification:

This project is required to maintain the reliability of generating Unit 1 at Holyrood. The FD fans servicing Unit 1 at Holyrood have an ongoing problem with flow induced vibration on the fan intake and discharge ductwork systems which cause cracks to develop in the ductwork. The development of cracks on an on-going basis threatens the integrity of the ductwork infrastructure and reduces the reliability of Unit 1.

In December of 2008, there was a forced outage on Unit 1 due to a failure of the intake guide vanes on the East FD fan. Failure of the intake guide vanes was due to high vibration levels caused by air flow turbulence on both the intake and discharge ductwork. In addition, high vibration levels resulted in a de-rating of Unit 1 during the 2009 operating season. Turning vanes were installed inside the fan ductwork during the 2009 annual Unit 1 outage as a temporary measure to reduce air flow turbulence and vibration levels.

Failure of the FD fan ductwork can result in an unplanned Unit 1 outage of three to four weeks duration. An unscheduled unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System. A cost benefit analysis indicates that it is cost effective to proceed with upgrading Unit 1 forced draft fan ductwork.

Future Plans:

Projects to upgrade the FD fan ductwork servicing Units 2 and 3 are planned for the years 2012 and 2013 respectively. Please see the five-year capital plan (Capital Plan 2011 Tab, Appendix A).

Attachments:

See report entitled "Upgrade Generating Unit 1 Forced Draft Fan Ductwork" located in Volume I, REPORTS 1 - 10, Tab 9, for further project details.

Project Title: Replace Relay Panels Unit 3

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing hardwired relay logic infrastructure contained in the three relay panels on Unit 3 with a distributed control system (DCS). The new system will eliminate safety concerns with the existing overcrowded panels and will allow more dependability and will offer better operator control functionality. The installation will be completed by removing the existing field wiring that terminates inside the existing relay panels. A new junction box will be installed to house the cabling required for the existing DCS control to remain functional. A new electrical enclosure containing all the required DCS hardware will be installed at the existing location and the field wiring will be re-terminated inside the new DCS control panels. The existing hardwired relay logic will be converted to a software based operating system. This new DCS hardware will be an expansion to the existing Foxboro DCS control.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	23.0	10.0	0.0	33.0
Labour	107.2	157.5	0.0	264.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	112.5	210.4	0.0	322.9
Other Direct Costs	0.6	13.5	0.0	14.1
O/H, AFUDC & Escln.	33.8	98.7	0.0	132.5
Contingency	0.0	63.5	0.0	63.5
TOTAL	**277.1**	**553.6**	**0.0**	**830.7**

Operating Experience:

The existing Unit 3 Relay Panels consist of a three section electrical enclosure that is located inside the Holyrood plant. This panel makes up the control logic section of the plant interlock system and controls the operation of motors, valves and drives associated with generating Unit 3. The purpose of

this panel is to house the relays, pneumatic timers, current transducers and terminal blocks that interface with the Holyrood Central Control Room to monitor and control the generating unit. It also houses various relays that provide the existing automated systems with remote feedback information.

The Unit 3 Relay Panels have become a safety and operational concern as these panels are overloaded and overcrowded. The controls in the Unit 3 Relay Panels are vital to the operation of the generating unit whether it is in generation or synchronous condense mode. In addition, there are relays and wiring contained in relay panels that monitor and control auxiliary functions of the turbine even when the generating unit is not in service.

Project Justification:

This project is justified on the need to replace sub-standard equipment and eliminate safety hazards. Unit 3 Relay Panels are overcrowded with wiring which prevents the doors from being able to close. There is a risk of an electrical fire occurring inside the panels. The condition of the panels violates the Canadian Electrical Code and presents safety hazards to workers.

As a result of aging and the amount of wiring, the terminal blocks inside the panel have become brittle. There is cracking in the blocks and on the bases that hold the block to the mounting rail inside the panel. As a result, energized terminal blocks are often found hanging inside the panel.

Also, integrating the relay controls into the existing DCS system will allow for improved system troubleshooting after a failure and offers the advantage of being able to make future changes in software as opposed to having to make physical wiring changes.

Future Plans:

None

Attachments:

See report entitled “Upgrade Unit 3 Relay Panels” located in Volume I, REPORTS 1 - 10, Tab 10, for further project details.

Project Title: Upgrade Intake Gate Controls

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to upgrade the electrical controls at the Bay d'Espoir Intake Gates 1, 2 and 3. This is a two year project that will also include the replacement of the powerhouse programmable logic controller (PLC) and the upgrading of the existing serial communication link between the powerhouse and intakes to an ethernet based technology. During the first year, the controls at Intake 2 and the communications link between all four intakes and the powerhouse will be upgraded. The intake gate controls at the Intakes 1 and 3 will be upgraded during the second year of the project.

The new gate control systems for each intake gate will use a PLC with a gate positioning sensor to precisely control the position of the intake gate throughout its entire operating range. The system will also monitor the fill up rate of the penstock. Other auxiliary electrical equipment such as 600 Volt starters, auxiliary limit switches and over hoist protection limit switches, used in each intake gate control system will also be replaced.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	110.0	120.0	0.0	230.0
Labour	185.4	185.6	0.0	371.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	24.4	24.4	0.0	48.8
O/H, AFUDC & Escln.	32.5	73.0	0.0	105.5
Contingency	0.0	65.0	0.0	65.0
TOTAL	**352.3**	**468.0**	**0.0**	**820.3**

Operating Experience:

Hydro has experienced two major incidents that resulted in the complete destruction of two intake gate vent houses. The incidents occurred at the Bay d'Espoir Intake Gate 4 in early 1984 and at Intake Gate 2 in July 2000 when the penstock was being refilled after a complete dewatering. During both of these incidents, Hydro personnel were working in the area and narrowly escaped without serious injury. In addition to these incidents, in July 2005, the Bay d'Espoir Intake Gate 4 was again opened beyond the prime position causing the penstock to start filling too quickly. As a result, operators forced an emergency stop to the water entering the penstock and therefore averted damage.

Project Justification:

This project is required to enhance safety at the intake gate controls at Bay d'Espoir. The existing intake gate controls installed on Intakes 1, 2 and 3 work inaccurately in that they do not offer the required precision needed during a penstock water-up procedure. After the penstock has been partially or fully dewatered, the intake gate must be brought to precisely 6.4 cm above the bottom sill plate of the gate (prime position) to allow the penstock to fill slowly. To stop the gate at the prime position, the intake gate is equipped with a rotary cam limit switch that is coupled to the hoist drum through a mechanical gearing assembly. The slackness in this gearing assembly introduces errors as large as plus or minus 18 centimeters to the final gate position, resulting in poor overall gate control.

The Powerhouse and Intake 2 PLCs are obsolete and no longer supported by the manufacturer. An upgrade to an ethernet based communication network is the industry standard for PLC communication networks.

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

Future Plans:

None.

Attachments:

See report entitled "Upgrade Intake Gate Controls" located in Volume II, Tab 11, for further project details.

Project Title: Upgrade Generating Station Service Water System

Location: Cat Arm

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace components of the generating station service water system. The scope of the project involves:

- Replacing the current carbon steel piping with stainless steel for
    - the branch pipe lines from the take-off points on the cooling water supply header to the unit housing for both generating units,
    - all four-inch and smaller diameter piping,
    - the piping on the generator bearing water supply line for Unit 1,
- Replacing the differential pressure flowmeters with electromagnetic flow measuring devices,
- Replacing the surface air cooler temperature control valve on each generating unit,
- Replacing both penstock emergency supply pressure reducing valves,
- Replacing both main cooling water pumps,
- Inspecting the common header and pressure piping within the plant,
- Removing any asbestos material from the above mentioned equipment,
- Re-insulating piping and components mentioned above.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	76.4	109.1	0.0	185.5
Labour	186.1	160.5	0.0	346.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	53.0	23.6	0.0	76.6
Other Direct Costs	16.7	16.7	0.0	33.4
O/H, AFUDC & Escln.	28.2	65.9	0.0	94.1
Contingency	0.0	64.2	0.0	64.2
TOTAL	**360.4**	**440.0**	**0.0**	**800.4**

Operating Experience:

The service water system in Cat Arm has experienced fouling problems since the plant was brought into service in 1985. At first the fouling was thought to have been caused by unsettled organic materials within the water reservoir and that over time these organics would settle or flush through the system. However this was not the case and the fouling problem has continued. In 2005, some sections of the fouled piping located inside the generator housing were replaced. This project will replace the remaining piping, except the large headers and emergency supply line, to ensure sufficient water is able to reach the necessary coolers.

Project Justification:

This project is justified on the requirement to replace deteriorating equipment in order for Hydro to provide safe, least cost, reliable electrical service. An internal study, entitled The Cat Arm Generating Station Service Water System, was completed in 2002. The study concluded that all mild steel piping should be replaced with stainless steel pipe to offer an increased resistance to fouling and corrosion, thereby improving unit reliability and reducing maintenance costs.

The main cooling water pumps are original and have reached the end of their useful lives of 25 years. The emergency cooling water supply lines are taken directly off the penstock and operate at a pressure of 550 pounds per square inch. The pressure reducing valves have corroded and need replacement. Also, asbestos in the insulation on the fittings and valves presents a health hazard and needs to be removed.

Future Plans:

Depending on the results of the proposed inspection plan a further capital program may be required to replace the high pressure piping of the emergency cooling water for the service water system.

Attachments:

See report entitled “Upgrade Service Water System” located in Volume II, Tab 12, for further project details.

Project Title: Replace Boiler Blowdown Tanks

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to replace three boiler blowdown tanks at the Holyrood Thermal Generating Station. The drain piping in the boiler blowdown pits on Units 2 and 3 will also be replaced. All piping connections on tanks will be flanged so that a specially designed metal plate can be installed to isolate the tank while work is performed in the tank. Modifications to the piping that is currently connected to each tank will be required to suit the new flanged connections. The replacement tanks will be designed and fabricated according to all requirements of the Boiler, Pressure Vessel and Compressed Gas Regulations under the Province's Public Safety Act.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	240.0	0.0	0.0	240.0
Labour	66.8	0.0	0.0	66.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	296.4	0.0	0.0	296.4
Other Direct Costs	1.5	0.0	0.0	1.5
O/H, AFUDC & Escln.	84.4	0.0	0.0	84.4
Contingency	60.5	0.0	0.0	60.5
TOTAL	**749.6**	**0.0**	**0.0**	**749.6**

Operating Experience:

The boiler blowdown tanks are mainly used in controlling the purity of the boiler feed water. They are also used to receive condensate from plant processes. The tanks are deteriorated and require replacement. A safety concern exists in that it is very difficult to gain access to the inside of the tanks for inspection and repair work because the access manways on all three tanks are only 12" x 16". Clearances between the tanks and the boilers, especially on Unit 3, are a concern for normal egress only and also for emergency rescue.

These tanks are inspected annually by Hydro's boiler service contractor, Alstom Power who has reported safety concerns with the tanks.

Project Justification:

This project is justified on the need to replace deteriorated infrastructure. An inspection performed by Alstom Power has reported that the tanks are in disrepair. The wear plates, shell walls, and an internal cone require replacement. They also report safety concerns regarding the manway size, clearances for egress, and working within the tight spaces inside these tanks. Due to the age of the tanks and their current deterioration, along with related safety concerns, Alstom Power recommends the replacement of the tanks.

Future Plans:

None.

Attachments:

See report entitled "Replace Boiler Blowdown Tanks" located in Volume II, Tab 13, for further project details.

Project Title: Upgrade Electrical Equipment

Location: Holyrood

Category: Generation - Thermal

Definition: Pooled

Classification: Normal

Project Description:

This is a three-year project to replace the circuit protection equipment in the seven motor control centers in the Holyrood plant and replace items of the electrical switchgear in the Gas Turbine unit. For the motor control centers at Holyrood, the project consists of a complete replacement of the protection equipment in each motor starter. The new protection will be in the form of thermal magnetic circuit breakers to replace the existing fuses. The new breakers will enable better coordination with the protective equipment to interrupt the electrical faults that could cause damage to the equipment or present safety hazards to workers. For the Gas Turbine unit the work involves the replacement of the motor control center, the gas turbine start rectifier, the automatic voltage regulator, exciter, automatic transfer switch and the 13.8 kV fusible disconnect switch.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**2013**	**Total**
Material Supply	63.1	63.2	63.2	189.5
Labour	29.6	29.6	29.5	88.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	82.5	82.4	82.4	247.3
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	12.8	31.1	56.8	100.7
Contingency	0.0	0.0	52.6	52.6
TOTAL	**188.0**	**206.3**	**284.5**	**678.8**

Operating Experience:

The motor control centers for generating Units 1 and 2 were commissioned in 1971 when the units were brought in service and are now 39 years old. The motor control center for generating Unit 3 was commissioned in 1979 when the unit was brought in service and is now 31 years old. The Holyrood

Gas Turbine was commissioned in 1971. The motor control center and all related electrical equipment is 39 years old. They are at the end of their useful life of 30 years.

Project Justification:

The justification for this project is based on safety and reliability. The motor control centers in the plant and the gas turbine equipment do not comply with current safety codes and standards as stipulated in the Canadian Electrical Code. The primary safety concern is that the protective devices in the motor control centers cannot interrupt the fault currents that they are subjected to. This creates a safety hazard for the employees in that the equipment may explode if unable to interrupt the fault current. Such explosions would expose employees to flying debris and arc flash energy. Also, an electrical fault can cause equipment damage and outages to the generating units.

The equipment in the Gas Turbine does not meet current safety codes and standards. The Canadian Electrical Code requires, for emergency egress purposes, a spacing of one meter between energized electrical equipment and the nearest point a person can stand in front of the equipment. The Gas Turbine equipment does not meet this requirement. In an emergency situation the escape route would be partially blocked by the equipment being worked on making it difficult for a quick escape.

The Gas Turbine equipment is obsolete and replacement parts are unavailable. A failure would render the Gas Turbine out of service until replacement equipment could be installed. Without the Gas Turbine, there is no 'black start' capability for the Holyrood plant and this directly affects the reliability of the Island Interconnected System.

Future Plans:

None.

Attachments:

See report entitled "Upgrade Electrical Equipment" located in Volume II, Tab 14, for further project details.

Project Title: Replace Steam Seal Regulator Unit 2

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

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

This project is required to replace the existing hydraulic steam seal regulator on Unit 2 with two pneumatically operated steam pressure control valves. One of these pneumatically controlled pressure regulating valves will be used to supply steam to the steam seal header and one will be used to relieve pressure from the steam seal header. The new system will be controlled using a pressure transducer and the existing Foxboro Distributed Control System (DCS). In addition, the steam seal header piping will be modified to allow the new pressure control valves to be installed at a location for easier operator access.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	110.0	165.5	0.0	275.5
Labour	18.0	71.4	0.0	89.4
Consultant	33.6	0.0	0.0	33.6
Contract Work	0.0	95.8	0.0	95.8
Other Direct Costs	2.0	2.0	0.0	4.0
O/H, AFUDC & Escln.	11.4	53.9	0.0	65.3
Contingency	0.0	49.8	0.0	49.8
TOTAL	**175.0**	**438.4**	**0.0**	**613.4**

Operating Experience:

The existing Unit 2 steam seal regulator is an automated hydraulic system with many moving parts and wear points. A daily problem with binding and sticking of the moving parts requires an operator attendant to manually free them. Improper operation of the regulator, due to binding and sticking, allows steam to travel along the turbine rotor shaft and mix with the bearing lubrication oil where it condenses to water and accelerates deterioration of the bearings.

Project Justification:

The steam seal regulator servicing Unit 2 at Holyrood is 40 years old and Hydro has been unable to secure reliable support service from the original manufacturer, General Electric (GE). In recent years, this has necessitated replacement parts being made by local machine shops by copying the original components. The industry trend is to install the proposed control valve system.

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

This project is required to maintain the reliability of generating Unit 2 at Holyrood.

Future Plans:

None

Attachments:

See report entitled “Replace Unit 2 Steam Seal Regulator” located in Volume II, Tab 15, for further project details.

Project Title: Provide Service Extensions

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	1,634.0	0.0	0.0	1,634.0
Labour	1,241.0	0.0	0.0	1,241.0
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.	191.0	0.0	0.0	191.0
Contingency	319.0	0.0	0.0	319.0
TOTAL	**3,385.0**	**0.0**	**0.0**	**3,385.0**

Operating Experience:

An analysis of average historical expenditures (2005 - 2009) on new customer connections by region is shown in the Table 2. All historical dollars were converted to 2009 dollars using the Statistics Canada Utility Distribution Line Construction index and a five year average was calculated.

Table 2: Average Annual Expenditures

Region	**Avg. Annual Expenditures (2005 - 2009) (2009 $000)**
Central	1,036
Northern	1,082
Labrador	1,237
Total	3,355

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

Table 3: Five Year Expenditures

Expenditures ($000)											
	2005		2006		2007		2008		2009		2010
Region	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**
Central	619	840	761	824	844	967	910	1,056	1,028	1,133	1,001
Northern	504	611	580	614	618	960	637	734	758	1,432	768
Labrador	605	556	643	535	622	873	612	1,340	653	1,446	659
Total	1,728	2,007	1,984	1,973	2,084	2,800	2,159	3,130	2,439	4,011 [1]	2,428

Project Justification:

Based on the three-year average of service extension expenditures for the period 2005 - 2009 the budget shown in Table 4 was developed for Northern and Labrador region, assuming distribution line cost escalation in 2011 of approximately one percent. The same assumptions are valid for the Central region as well except that it was based on a five-year average.

Table 4: Budget

Region	**2011 Budget[1] ($000)**
Central	1,045
Northern	1,092
Labrador	1,248
Total	3,385

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. Please see the five-year capital plan (2011 Capital Plan tab, Appendix A).

[2]In recent years increased numbers of housing starts in Labrador has pushed the annual cost of service extensions in Labrador above the historical five year average. With the planned expansion at the Iron Ore Company of Canada's operations in Labrador city and an influx of funds in Innu and Inuit communities, the number of housing starts is expected to continue into 2010 and 2011. Because of this, a three-year historical average was used to determine the service extension budget for 2011 for the Labrador region and the Northern region which serves the south cost of Labrador. A five-year average was used for the Central region.

Project Title: Upgrade Distribution Systems

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	1,531.0	0.0	0.0	1,531.0
Labour	591.0	0.0	0.0	591.0
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.	141.0	0.0	0.0	141.0
Contingency	236.0	0.0	0.0	236.0
TOTAL	**2,499.0**	**0.0**	**0.0**	**2,499.0**

Operating Experience:

An analysis of historical expenditures (2005 - 2009) on distribution upgrades by region is shown in Table 2. All historical dollars were converted to 2009 dollars using the Statistics Canada Utility Distribution Line Construction index and a five-year average was calculated.

Table 2: Average Annual Expenditures

Region	**Avg. Annual Expenditures (2005 - 2009) (2009 $000)**
Central	989
Northern	1,041
Labrador	446
All Regions	2,476

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

Table 3: Five-year Expenditures

Expenditures ($000)											
	2005		2006		2007		2008		2009		2010
Region	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
Central	628	1,135	701	909	806	824	915	782	1,050	1,028	1,032
Northern	616	996	836	835	873	842	969	2,062	1,026	1,148	1,072
Labrador	357	364	375	404	356	558	409	859	450	484	468
Total	1,601	2,495	1,912	2,148	2,035	2,224	2,293	3,703	2,526	2,660	2,572

Other specifically approved projects for 2004 - 2010F are listed in Table 5.

Project Justification:

Based on the five-year average for distribution system upgrades for the period 2005 - 2009 the budget shown in Table 4 was developed, assuming distribution line cost escalation in 2011 of approximately one percent.

Table 4: Budget for Distribution System

Region	2011Budget ($000)
Central	998
Northern	1,051
Labrador	450
Total	2,499

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. See the five-year capital plan (2011 Capital Plan tab, Appendix A).

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

Table 5: Five-Year Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2010F	Upgrade Distribution Feeder – L4 Roddickton (Year 1 of 2)	160.6	
	Upgrade Distribution Feeder – L1 Makkovik (Year 1 of 2)	57.1	
	Upgrade Distribution Feeder – L2 Glenburnie (Year 1 of 4)	267.3	
	Upgrade Distribution Feeder – L4 Happy Valley	265.3	
2009	Upgrade Distribution System - L7 St. Anthony	689.3	503.6
	Replace Insulators - L1 and L2 Jackson's Arm, Hampden	691.5	590.6
	Replace Insulators - L2 Little Bay Islands	182.7	120.8
	Upgrade Distribution Feeder - L36 Wabush	498.0	466.1
2008	Replace Distribution Line - L1 South Brook	987.4	1,056.4
	Upgrade Distribution System - L1 Glenburnie	533.9	405.5
	Upgrade Distribution System - L3 St Anthony	480.1	445.0
	Upgrade Distribution System - Mary's Harbour	263.5	215.6
	Upgrade Distribution System - Port Hope Simpson	205.4	215.6
	Upgrade Distribution System - L4 Bear Cove	149.8	96.8
	Upgrade Distribution Line - L11 Wabush	107.2	115.3
	Replace Insulators - Upper Salmon	236.8	194.9
	Replace Insulators - L1 Hind's Lake	168.7	158.0
	Replace Insulators - Coney Arm	126.8	132.1
	Replace Insulators - L2 Westport	90.2	87.2
2007	Insulator Replacement - Barachoix L4	120.1	123.0
	Replace Distribution Line - Brighton	192.9	230.9
	Replace Distribution Line - Seal Cove to Pass Island	547.6	552.1
	Upgrade Distribution System - L2, L3 Farewell Head	385.3	282.0
	Extend Mud Lake Submarine Cable	480.9	813.6
	Upgrade Distribution System - L1, L2 St. Anthony	364.3	301.0
	Upgrade Distribution System L1, L2 Rocky Harbour	513.5	393.7
	Upgrade Distribution System - Nain	179.4	185.8
	Replace Insulators - L7, L8 Bottom Waters	120.0	126.5
2006	Replace Insulators - L4, L5 Farewell Head	260.8	270.4
	Replace Insulators - L5, L7 - South Brook	440.7	440.8
	Replace Insulators - L4, L6 - Bottom Waters	197.5	203.4
	Upgrade Distribution System - Black Tickle	281.8	270.3
	Upgrade Distribution System - L6 St. Anthony	778.3	772.2
	Upgrade Distribution System - L6 Bear Cove	577.7	622.8
	Upgrade Distribution System - L1, L3 Hawkes Bay	379.6	421.1
2005	Replace Insulators - L6 Farewell Head	246.1	132.6
	Upgrade Distribution Line - Northern L'anse au Loup	93.1	50.5
	Upgrade Distribution System - L1, L2 L'anse au Loup	635.6	280.6
	Replace Insulators - L1 Plum Point	433.3	217.7
	Replace Insulators - L3 Hawke's Bay	292.3	103.5
	Upgrade Distribution Line - Cooks Harbour	717.5	477.8

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.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	412.5	0.0	0.0	412.5
Labour	1,114.7	0.0	0.0	1,114.7
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	93.2	0.0	0.0	93.2
O/H, AFUDC & Escln.	127.0	0.0	0.0	127.0
Contingency	172.0	0.0	0.0	172.0
TOTAL	**2,019.4**	**0.0**	**0.0**	**2,019.4**

Operating Experience:

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

below minimum acceptable levels, and indicated that rot is becoming more prevalent in the 30-40 year old poles.

Project Justification:

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

Future Plans:

The program is based on two 10 year inspection cycles beginning in 2005. It provides an annual report to identify problem areas for the regional asset managers and to develop recommendations for appropriate pole replacements, as well as other components in the following years. Please see five-year capital plan (Capital Plan 2011 Tab, Appendix A).

Attachment:

See report entitled "2011 Wood Pole Line Management" located in Volume II, Tab 16, for further project details.

Project Title: Perform Arc Flash Remediation

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This project is a five-year program to upgrade facilities to reduce the arc flash levels on electrical equipment throughout the Hydro system. The upgrades will, whenever possible, reduce the arc flash levels of equipment to more acceptable levels of Arc Flash Hazard Risk Category (HRC) 2 or lower to comply with the Canadian Standards Association Z462-08 Standard. The upgrades will include:

- Changes to existing relay settings to provide faster fault clearing times which will reduce the arc flash levels;
- Installation of special arc flash relays, which are devices designed to detect the presence of an arc flash and clear the fault instantaneously;
- Installation of multiple setting relays, which have dual protection settings (one for normal operation and one to be switched on when a worker is working on live or exposed equipment);
- Installation of current limiting fuses, which clear the fault instantaneously; and
- Installation of remote operators for circuit breakers, which allow the worker to operate the breaker from outside the arc flash boundary.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Material Supply	185.1	138.6	138.6	138.6	138.6	739.5
Labour	144.0	144.0	144.0	144.0	144.0	720.0
Consultant	0.0	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	12.6	12.6	12.6	12.6	12.6	63.0
O/H, AFUDC & Escln.	53.6	55.6	66.3	77.1	88.4	341.0
Contingency	34.2	29.5	29.5	29.5	29.5	152.2
TOTAL	**429.5**	**380.3**	**391.0**	**401.8**	**413.1**	**2,015.7**

Operating Experience:

Electrical equipment in continuous service throughout the Hydro system consists of conventional switchgear, motor control centers, disconnect switches, bus distribution splitters, distribution panels, circuit breakers and isolating switches. In 2008, Hydro initiated a study to calculate arc flash levels for various types of industrial electrical equipment for sites throughout the Hydro system. The study indicated that the Arc Flash Hazard Risk Category on Hydro's equipment range from 0 to greater than 4 and the Arc Flash Protection Boundary limits range from 0 feet to as much as one hundred and four feet. The requirement for determining arc flash risk is the 2006 edition of the Canadian Electrical Code which stated that an arc flash assessment must be performed so that electrical equipment shall be field marked to warn persons of arc flash hazards.

Project Justification:

This project is justified on the requirement for Hydro to ensure the safety of workers who are exposed to arc flash hazards during the performance of their duties. Arc flash studies indicate that there are deficiencies throughout the system where electrical equipment has unacceptable high arc flash levels greater than a hazard risk of 4. An arc flash incident creates danger to workers and causes damage to equipment.

This project will minimize or eliminate the effects of an arc flash incident and reduce its impact on the production of energy should such an arc flash incident occur.

Future Plans:

There are no future plans.

Attachments:

See report entitled "Arc Flash Remediation Program" located in Volume II, Tab 17, for further project details.

Project Title: Replace Fuel Storage Facility

Location: Postville

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Mandatory

Project Description:

This project is required to replace eight existing horizontal fuel storage tanks and the existing earthen dyke, relocate one existing self-dyking tank, and construct a new lined earthen dyke and two new 300,000 litres vertical fuel storage tanks. The existing earthen dyke material will be tested for any contamination, and will be reused, if possible. The existing liner in the dyke will be removed and disposed of properly in accordance with Hydro's environment management standards. The new tanks will be constructed on site in accordance with the American Petroleum Institute (API) Standard 650 "Welded Steel Tanks for Oil Storage".

Table 1 provides the budget estimate for this project.

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	2.0	0.0	0.0	2.0
Labour	82.2	0.0	0.0	82.2
Consultant	91.0	0.0	0.0	91.0
Contract Work	1,416.0	0.0	0.0	1,416.0
Other Direct Costs	37.8	0.0	0.0	37.8
O/H, AFUDC & Escln.	215.1	0.0	0.0	215.1
Contingency	162.9	0.0	0.0	162.9
TOTAL	**2,007.0**	**0.0**	**0.0**	**2,007.0**

Operating Experience:

The existing system consists of four 45,460 litre single wall tanks built in 1976, two 68,190 litre single wall tanks built in 1982, two 22,730 litre self-dyking tanks built in 1992, and one 45,450 self-dyking tank built in 1998 for a total capacity of 409,130 litres. The single wall tanks are located in a lined earthen dyke. The existing fuel header system consists of above ground piping and valves that run the length of the dyke, and an underground section from the self-dyking tanks to the plant.

Two of the existing single wall tanks within the dyke have illegible Underwriters' Laboratories of Canada (U.L.C.) labels, and due to recent changes in U.L.C. standards, the tanks can no longer be recertified in the field. Therefore, the two tanks are not in compliance with the Storage and Handling of Gasoline and Associated Products Regulation (GAP), 2003 regulations. The remaining four single wall tanks within the dyke were constructed in 1976 and have passed their anticipated useful life of 20 years. Also, the existing self-dyked tanks are at or near the end of their anticipated useful life of 20 years and due to their design it is difficult to complete a thorough inspection on the tank exterior.

The existing earthen dyke is also in non-compliance with the GAP Regulations. Results from permeability testing performed on the earthen dyke during the summer 2007 showed the dyke had a permeability of 50 litres per square metre per day (l/m²/day). This is twice the allowable permeability rate of 25 l/m²/day permitted by GAP Regulations.

Project Justification:

This project is justified on the requirement to replace deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service, as well as the requirement to accommodate load growth and meet GAP Regulations. The existing fuel storage facility in Postville is not adequate to meet the growing load demand on the plant. In order to ensure sufficient fuel is always available, storage requirements are based on a nine month consumption rate. Hydro's latest fuel forecast, based on fall 2009 Operating Load Forecast indicates a 413,700 litre storage requirement for 2010-2011 period, with consumption increasing by approximately six percent over the period 2010 to 2015 and a 513,600 litre storage requirement by the end of the 25 year forecast. The existing earthen dyke is not in compliance with GAP Regulations and must be replaced. The existing fuel storage capacity must be increased to meet the load growth and mitigate environmental risk. Removing the existing tanks and building new vertical tanks will enable Hydro to comply with all the GAP regulations as well as provide a reliable fuel storage system for future load growth.

Future Plans:

None.

Attachments:

See report entitled "Upgrade Fuel Storage Facility – Postville Diesel Generating Site" located in Volume II, Tab 18, for further project details.

Project Title: Upgrade Distribution System

Location: Francois, Rigolet and Happy Valley

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

Newfoundland and Labrador Hydro (Hydro) provides service to residents in select rural communities within the province through the use of existing distribution lines. This report will be focused on distribution lines located in the communities of Francois, Happy Valley, and Rigolet that have been identified as requiring upgrades to the existing infrastructure.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	270.0	130.0	0.0	400.0
Labour	251.5	102.0	0.0	353.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	308.5	260.0	0.0	568.5
Other Direct Costs	63.5	31.0	0.0	94.5
O/H, AFUDC & Escln.	91.5	70.4	0.0	161.9
Contingency	82.7	59.0	0.0	141.7
TOTAL	**1,067.7**	**652.4**	**0.0**	**1,720.1**

Operating Experience:

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

Project Justification:

This project is justified on reliability. The conditions of the components could result in system failures and have a negative effect on the safety and reliability performance of the line. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

Future Plans:

Future distribution line upgrades will be approved in future capital budget applications. See five-year capital plan (Capital Plan 2011 tab, Appendix A).

Attachments:

See report entitled "Distribution upgrades Francois, Rigolet and Happy Valley" located in Volume II, Tab 19, 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:

This project will continue the program of upgrading terminal station and distribution substation grounding that began in 2007. The project involves analyzing step and touch potentials at 22 terminal stations and 32 distribution substations, upgrading grounding grids at 46 terminal stations and 17 distribution substations, and upgrading 345 substandard gradient control mats. Step and touch potential analysis is performed to determine whether or not hazardous step and/or touch potentials can occur. The ground grids modified are those at terminal stations where analysis has shown that hazardous step and/or touch potentials can occur and the upgrade eliminates the possibility of their occurrence. The gradient control mats are upgraded to meet Hydro's current Terminals Engineering Standard TS07-004-R2.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**2013**	**2014**	**2015**	**Total**
Material Supply	48.5	48.5	48.5	48.5	48.5	242.5
Labour	148.6	148.6	148.6	148.6	148.6	743.0
Consultant	0.0	0.0	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0	0.0	0.0
Other Direct Costs	73.9	73.9	73.9	73.9	73.9	369.5
O/H, AFUDC & Escln.	23.1	25.8	30.9	39.1	47.4	166.3
Contingency	27.1	27.1	27.1	27.1	27.1	135.5
TOTAL	**321.2**	**324.0**	**329.0**	**337.1**	**345.4**	**1,656.7**

Operating Experience:

At the time when Hydro's terminal stations were built, the analytical tools needed to accurately determine step and touch potentials were not available. With these tools now available, the step and

touch potentials can be determined. If an analysis shows that hazardous potentials are present then the grounding must be upgraded to eliminate them. Analysis completed to date indicates that 93 percent of Hydro's stations have touch potentials that are hazardous as defined by IEEE Standard 80-2000 which defines a hazardous potential as a potential with a "value that can cause ventricular fibrillation of the heart".

Project Justification:

This project is justified on the requirement to eliminate the possible occurrence of unsafe step and touch potentials from Hydro's terminal stations and distribution substations in order to conform to IEEE Standard 80-2000 and Hydro's Terminals Engineering Standard TS07-004-R2 entitled "Grounding". This allows Hydro to provide safe, least-cost, reliable electrical service to its customers.

Future Plans:

There are no future plans for grounding upgrades after 2015.

Attachments:

See report entitled "Terminal Station Grounding Upgrades" located in Volume II, Tab 20, for further project details.

Project Title: Replace Guy Wires TL-215

Location: Doyles to Grand Bay

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing guy wire arrangement on TL-215 with an assembly that helps reduce the fatigue problem on the existing pre-form grips. The proposed design includes a long U-Bolt that supports a two inch pipe. The pipe increases the bend radius of the pre-form around the anchor and reduces the tendency for the guy wire pre-form to fatigue. This assembly has been successfully used on other lines in the area, such as TL-214 between the Bottom Brook and Doyles Terminal Stations, where the pre-form grip in conjunction with the U-Bolt assembly has not seen any recorded incidents of failure similar to TL-215.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**2013**	**2014**	**Total**
Material Supply	114.0	114.0	114.0	114.0	456.0
Labour	25.3	25.3	25.3	25.3	101.2
Consultant	0.0	0.0	0.0	0.0	0.0
Contract Work	120.0	120.0	120.0	120.0	480.0
Other Direct Costs	3.9	3.9	3.9	3.9	15.6
O/H, AFUDC & Escln.	25.6	54.8	86.9	161.5	328.8
Contingency	0.0	0.0	0.0	105.3	105.3
TOTAL	**288.8**	**318.0**	**350.1**	**530.0**	**1,486.9**

Operating Experience:

Over the last five years, the pre-forms on 50 structures have been replaced because they were found to be prematurely worn or have failed. A failure of this guy attachment may lead to a collapse of the entire structure during high wind conditions, resulting in an outage to the Port aux Basque area.

Project Justification:

This replacement of the guy wire attachment assembly is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service.

Future Plans:

This project is a continuation of the 2010 capital project approved by the Board of Commissioners of Public Utilities under Board Order No. P.U. 1 (2010) to replace guy hardware on TL-215. The 2010 project was the first year of a five year program.

Attachment:

See report entitled "Replace Guy Wires on TL-215" located in Volume II, Tab 21, for further project details.

Project Title: Replace Off-Road Track Vehicles

Location: Bishop's Falls and Fogo

Category: General Properties - Transportation

Definition: Pooled

Classification: Normal

Project Description:

This project involves the replacement of V7809 (Fogo), a 1993 heavy-duty off-road track vehicle, and V7895 (Bishop's Falls), a 1996 heavy-duty off-road track vehicle.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	470.0	481.0	0.0	951.0
Labour	0.2	0.2	0.0	0.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.0	3.0	0.0	6.0
O/H, AFUDC & Escln.	21.1	29.5	0.0	50.6
Contingency	0.0	95.7	0.0	95.7
TOTAL	**494.3**	**609.4**	**0.0**	**1,103.7**

Operating Experience:

The heavy-duty off-road track vehicles have an average life expectancy which ranges from 12 to 15 years, dependant on location and usage. Unit V7809 will be 18 years old at replacement and Unit V7895 will be 15 years old.

Project Justification:

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

Future Plans:

Future replacements will be proposed in future capital budget applications. See five year capital plan (2011 Capital Plan Tab, Appendix A).

Attachment:

See report entitled "Replace Off-Road Track Vehicles - Fogo and Bishop's Falls", Volume II, Tab 22, for further project details.

Project Title: Upgrade Substation

Location: Wabush

Category: Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project consists of the conversion of the two Wabush townsite 4.16kV feeders to 25kV. The work includes the addition of outdoor reclosers in the substation and retirement of the obsolete Westinghouse circuit breakers. The substation grounding and fence grounding systems will be upgraded to Hydro's current Terminals Engineering Standard, TS07-0040R2 and the Institute of Electrical and Electronic Engineers (IEEE) Standard 80-2000. The work also includes general civil works upgrades to the Westinghouse enclosure to ensure it's suitability for continued use as the substation control building.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	231.0	300.0	0.0	531.0
Labour	100.0	100.0	0.0	200.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	50.0	93.4	0.0	143.4
Other Direct Costs	12.0	8.0	0.0	20.0
O/H, AFUDC & Escln.	30.3	71.6	0.0	101.9
Contingency	36.0	53.4	0.0	89.4
TOTAL	**459.3**	**626.4**	**0.0**	**1,085.7**

Operating Experience:

The substation was built in the late 1950's. The original equipment being replaced is over 50 years old. Spare parts are available for all equipment in the substation except for the obsolete Westinghouse switchgear. Westinghouse advises that parts and servicing for the switchgear assembly are no longer available.

The existing station and fence grounding systems are not up to current Canadian Electrical Code standards

and therefore is a safety hazard to employees and the general public. All operating and maintenance work is performed by Hydro personnel. The Substation is in continuous operation to serve approximately 1,200 customers in the town of Wabush.

Project Justification:

The substation and fence grounding systems do not comply with current Canadian Electrical Code – Safety standards for Electrical Installations C22.1-09 Sections 22 and 26. In their present condition they present safety hazards for operating personnel inside the substation and members of the general public outside the substation. The ineffective grounding systems will result in improper operation of the protection and control systems and create a higher probability of equipment failures and lower service reliability to customers.

The existing Westinghouse switchgear equipment is over 50 years old and does not comply with current safety codes and standards and it cannot be retrofitted to satisfy the code requirements. Therefore the equipment must be replaced. Westinghouse advises that parts and servicing are no longer available for this equipment.

Future Plans:

There are no future plans.

Attachments:

See report entitled “Safety and Reliability Upgrades – Wabush Townsite Substation” located in Volume II, Tab 23, for further project details.

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

Project Description:

Distribution lines located in the communities of Farewell Head, Grandy Brook, and Westport have been identified as requiring pole replacements. The work required to replace the specified poles will include, but is not limited to, the installation of new poles at the same locations, transfer of existing hardware and guys, structure framing, and replacement of any deteriorated or damaged line hardware.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	175.0	0.0	0.0	175.0
Labour	254.3	0.0	0.0	254.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	234.0	0.0	0.0	234.0
Other Direct Costs	69.0	0.0	0.0	69.0
O/H, AFUDC & Escln.	76.9	0.0	0.0	76.9
Contingency	73.2	0.0	0.0	73.2
TOTAL	**882.4**	**0.0**	**0.0**	**882.4**

Operating Experience:

A visual inspection of distribution feeders is performed every eight years to evaluate the condition of the line. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed. The inspection schedule is determined through a Reliability Centered Maintenance Program initiated by Hydro and is dependant on a variety of factors including geographical location, line age, and customer usage. Inspection schedules may vary between lines depending on the existing circumstances. The deteriorated poles identified on each of these lines were classified as “B” (one to five years of remaining life) condition during the last inspection in 2007 and are scheduled to be replaced in 2011.

Project Justification:

The distribution lines were originally constructed over 40 years ago. Most of the line components, still in operation, were installed at the time of original construction and have exceeded their estimated service lives of 30 years. In addition, as result of standardized inspection and testing procedure, it has become evident that line components are greatly deteriorated and may have a remaining ultimate life span of only one to five years before widespread failure occurs. The majority of the poles identified for replacement are blackjack poles, which no longer comply with Hydro standards due to safety and environmental concerns. Failure of such components will have a negative effect on the safety and reliability performance of the line as identified earlier in the report. The failure of such a line may also result in unplanned power outages to customers at a time when required repairs may be hampered by severe weather conditions.

Future Plans:

Future pole replacements will be proposed in future capital budget applications. See the five-year capital plan (2011 Capital Plan Tab Appendix A).

Attachments:

See report entitled “Pole Replacement - 2011”, located in Volume II, Tab 24, for further project details.

Project Title: Upgrade Power Transformers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project consists of upgrading power transformers which will include either refurbishment or replacement based upon condition assessment techniques. A transformer replacement is based on the degree of degradation of the cellulose insulation and the amount of dissolved gas in the transformer oil.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	430.0	0.0	0.0	430.0
Labour	258.0	0.0	0.0	258.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	33.0	0.0	0.0	33.0
O/H, AFUDC & Escln.	72.8	0.0	0.0	72.8
Contingency	72.1	0.0	0.0	72.1
TOTAL	**865.9**	**0.0**	**0.0**	**865.9**

Operating Experience:

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

Project Justification:

The power transformers are one of the most important components on the transmission system. To maintain reliable operation of the transformer fleet it is critical to use condition assessments techniques to target weak units or problem areas within a unit for upgrading. The recommended

upgrades will serve to extend the service lives of the transformers and decrease the probability of service failures.

Future Plans:

Future upgrades will be proposed in future capital budget applications. See five-year capital plan (2011 Capital Plan Tab Appendix A).

Attachment:

See report entitled "Upgrade Power Transformers" located in Volume II, Tab 25, for further project details.

Project Title: Upgrade Station Reliability and Safety

Location: Rocky Harbour

Category: Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project consists of a general upgrade to the Rocky Harbour Terminal Station. The wood pole structures will be replaced with steel structures; the reclosers and all disconnects, power fuses, bus work and hardware will be replaced; the power transformer and voltage regulators will be reused; the protection and control equipment will be replaced and housed in a new outdoor weatherproof enclosure; and the station and fence grounding systems will be upgraded to comply with Hydro's current Terminals Engineering Standard TS07-004-R2.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	263.1	0.0	0.0	263.1
Labour	100.0	51.9	0.0	151.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	148.3	0.0	148.3
Other Direct Costs	34.0	36.3	0.0	70.3
O/H, AFUDC & Escln.	37.7	60.2	0.0	97.9
Contingency	0.0	63.4	0.0	63.4
TOTAL	**434.8**	**360.1**	**0.0**	**794.9**

Operating Experience:

The Rocky Harbour Terminal Station was brought in service in the mid 1970's and is approximately 35 years old. All the equipment in the station is original except the transformer and the voltage regulators. The voltage regulators were installed in 1993 and a used transformer was installed in 2009. There have been no major upgrades on this station since its construction. All maintenance on the station is performed by Hydro operations personnel. Spare parts are available for most of the equipment except for the reclosers and the disconnects. The terminal station is in continuous operation to serve approximately 1,100 customers in Rocky Harbour and the surrounding communities.

Project Justification:

The Rocky Harbour Terminal Station grounding system does not comply with Hydro's current Terminals Engineering Standards or the Institute of Electrical and Electronic Engineers (IEEE). In its present condition there are electrical shock hazards to operating personnel inside the station and to members of the general public outside the station. As well, the ineffective grounding system causes protection and control equipment to operate improperly which leads to lower system reliability.

The wood poles and cross arms are rotted to such a degree that the structures can no longer be climbed. Maintenance work has to be performed using a bucket truck which creates hazardous working conditions in the congested terminal yard.

The overhead disconnect switches have deteriorated insulators which break during switching operations and cause porcelain and other disconnect parts to fall from overhead thereby creating a safety hazard for employees.

Parts and servicing for the reclosers and disconnect switches are no longer available.

Future Plans:

None.

Attachments:

See report entitled "Safety and Reliability Upgrades – Rocky Harbour Terminal Station" located in Volume II, Tab 26, for further details.

Retirements:

The electrical equipment being replaced in the station will be retired.

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

Project Description:

This project is required to construct equipment off-loading areas near secondary provincial highways at points where Hydro accesses its transmission lines. Issues of public and Hydro personnel safety have shown the need for designated areas to be constructed rather than using the highway for off-loading equipment.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	106.4	0.0	0.0	106.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	531.4	0.0	0.0	531.4
Other Direct Costs	24.1	0.0	0.0	24.1
O/H, AFUDC & Escln.	62.9	0.0	0.0	62.9
Contingency	66.2	0.0	0.0	66.2
TOTAL	**791.0**	**0.0**	**0.0**	**791.0**

Operating Experience:

Hydro's maintains 56 transmission lines on the Island Interconnected System which have a combined length of 3,473 kilometers. These transmission lines are constructed of wood, steel or aluminum, or some combination thereof, and range in age from four to 45 years. Approximately 1,608 kilometers of these transmission lines are 230 kV lines used to transmit electricity from the Bay d'Espoir Hydroelectric Generating Station through the Island Interconnected System. There are also 1,231 kilometers of 138 kV and 634 kilometers of 69 kV transmission lines on the island.

In order to provide reliable service to its customers, Hydro must be able to respond to maintenance issues and emergencies in a safe and efficient manner. Heavy equipment accessing transmission lines use government approved trails which originate along adjacent highways, which have narrow

shoulders and steep embankments and where crews must contend with increasing levels of both traffic and speed. Safety is further compromised in adverse weather conditions with reduced visibility.

Flag persons and signage are often required to divert traffic or shut down traffic lanes altogether while off-loading equipment operations take place in a portion of one of the traffic lanes. Crews also have difficulty negotiating steep embankments while simultaneously attempting to stay clear of adjacent highway traffic and avoid damaging existing highway shouldering.

Project Justification:

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

Future Plans:

Construction of off-loading areas are planned in future years as shown in the five-year plan (2011 Capital Plan Tab, Appendix A).

Attachments:

See report entitled “Construct Transmission Line Equipment Off – Loading Areas” located in Volume II, Tab 27, for further project details.

Project Title: Replace 69 kV SF_6 Breakers

Location: St. Anthony Airport

Category: Transmission and Rural Operations

Definition: Other

Classification: Normal

Project Description:

This project is a two- year plan to replace two 69 kV sulfur hexachloride (SF_6) circuit breakers, B1T1 and B1L57, at the St. Anthony Airport Terminal Station. These two breakers will be replaced with new 69 kV SF_6 breakers.

The scope of work for this project includes the following:

- Purchase and delivery of the new breakers.
- Removal of the old breakers and installation of the new breakers;
- Reconnection of the protection and control equipment; and
- Commissioning of new breakers.

The replacement of breaker B1T1, scheduled for 2011, requires diesel generation at St. Anthony Diesel Plant to maintain service to approximately 3,700 customers while transmission line TL-256 is out of service. The replacement of breaker B1L57, scheduled for 2012, does not require diesel generation as power from the grid can be rerouted through a breaker bypass disconnect to maintain service to approximately 1,200 customers.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	86.0	86.0	0.0	172.0
Labour	119.5	86.2	0.0	205.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	218.1	30.2	0.0	248.3
O/H, AFUDC & Escln.	34.9	56.4	0.0	91.3
Contingency	31.3	31.3	0.0	62.6
TOTAL	**489.8**	**290.1**	**0.0**	**779.9**

Operating Experience:

Breakers B1T1 and B1L57 are leaking SF_6 gas and as a result have to be topped up with gas at varying rates. Over the last five years breaker B1T1 had to be topped up a total of 37 times or an average of once every two months. Breaker B1L57 was topped up a total of 10 times over the last five years, for an average top up period once every six months. These Westinghouse breakers have had a history of problems at other locations in the Hydro system. Consultations with other utilities have confirmed that similar problems exist with gas leakage in aging SF_6 circuit breakers.

Project 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. The SF_6 gas leaks in the 69 kV breakers, B1T1 and B1L57 cause them to be unreliable and unsafe. The leaks cause a drop in the breaker's operating pressure which, if left unattended, will result in the breaker failing to operate when required. A failure could lead to other equipment damage because the protection normally afforded by the breakers is removed. This would result in a reduced level of customer service and create safety hazards for personnel.

Future Plans:

None.

Attachments:

See report entitled "Replace 69 kV SF_6 Breakers B1T1 and B1L57" located in Volume II, Tab 28, for further project details.

Project Title: Replace Light Duty Mobile Equipment

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project consists of the replacement of 59 units of light-duty mobile equipment.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	660.0	0.0	0.0	660.0
Labour	3.5	0.0	0.0	3.5
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.	27.1	0.0	0.0	27.1
Contingency	66.4	0.0	0.0	66.4
TOTAL	**757.0**	**0.0**	**0.0**	**757.0**

Operating Experience:

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

Project Justification:

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

Future Plans:

Future replacements will be proposed in future capital budget applications. Light-duty mobile equipment replacements are proposed for the next four years as shown in the five year plan (2011 Capital Plan Tab Appendix A).

Attachment:

See report entitled “Replace Light-Duty Mobile Equipment – 2011” located in Volume II, Tab 29, for further project details.

Project Title: Replace Breaker, Structures and Disconnects

Location: Hawke's Bay

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the 69 kV circuit breaker B1L21 and its auxiliary equipment at the Hawke's Bay Terminal Station. The auxiliary equipment includes three isolating disconnect switches, a high speed ground switch and a wood pole structure on which the disconnect switches are mounted. The existing 69 kV oil filled breaker will be replaced with a new sulfur hexachloride (SF_6) gas insulated breaker. Two capacitive voltage transformers that are currently mounted on the existing wood pole structure will be relocated to the new structure.

Power outages to customers will be minimized since there is sufficient space in the Hawke's Bay Terminal Station to build the new wood pole structure before dismantling the existing structure. Termination of transmission line TL-221 will be relocated to the new wood pole structure and connected to the new circuit breaker. During the relocation of TL-221, line diesel generation will be required to provide service to customers.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	139.0	0.0	0.0	139.0
Labour	151.6	0.0	0.0	151.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	10.0	0.0	0.0	10.0
Other Direct Costs	273.4	0.0	0.0	273.4
O/H, AFUDC & Escln.	56.0	0.0	0.0	56.0
Contingency	57.4	0.0	0.0	57.4
TOTAL	**687.4**	**0.0**	**0.0**	**687.4**

Operating Experience:

The circuit breaker, disconnect switches, ground switch and wood pole structure were installed in 1970 as part of the original station construction. Since then there have been no major upgrades to this equipment. Several preventive and corrective maintenance activities have been performed which include regular preventive maintenance checks, oil sampling, dissolved gas analysis, PCB testing and repair, replacement and upgrade of equipment accessories. The circuit breaker has had several minor oil leaks in recent years and the disconnect switches have experienced jamming problems which make them unable to operate. The wood pole structure has become unstable and is at risk of falling down due to its age and deterioration beyond repair.

Project Justification:

This project is justified on the requirement to replace failing or deteriorated equipment in order for Hydro to provide safe, least-cost and reliable electrical service. All of the equipment to be replaced is at the end of its useful service life. The circuit breaker has experienced minor leaks in recent years and as it ages it is at an increased risk for more oil leaks, outages or even complete failure.

The three breaker isolating disconnect switches experience constant jamming problems and are therefore inoperable. An inoperable disconnect switch causes safety concerns since malfunctioning parts break off and fall onto workers below. Reliability is also affected since an inoperable disconnect switch prevents isolation of equipment for maintenance.

The wood pole structure has deteriorated beyond repair and is at risk of failure. Failure of the wood pole structure could result in injury to workers, damage of equipment and interruption of service to customers.

Future Plans:

None.

Attachments:

See report entitled “Replace Circuit Breaker B1L21, Structures and Disconnects” located in Volume II, Tab 30, for further project details.

Project Title: Replace Compressed Air System

Location: Bay d'Espoir

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project will replace the existing copper, brazed joint air distribution system with stainless steel piping and welded joints. The supply lines from the plant will be replaced along with all compressed air lines within the terminal station yard. The current structure is in disrepair and does not provide sufficient space to construct a new piping system while keeping the existing in service, therefore, a new enclosure will be constructed in the terminal station yard to house the new header piping and instrumentation.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	11.5	0.0	0.0	11.5
Labour	28.0	105.4	0.0	133.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	33.0	318.3	0.0	351.3
Other Direct Costs	4.5	33.2	0.0	37.7
O/H, AFUDC & Escln.	6.9	53.3	0.0	60.2
Contingency	0.0	53.4	0.0	53.4
TOTAL	**83.9**	**563.6**	**0.0**	**647.5**

Operating Experience:

The compressed air required to operate the 230 kV circuit breakers at the Bay d'Espoir Terminal Station 1 is supplied from the power house through two copper air lines with brazed joints. One of these lines has been isolated due to leaks and is inoperable. Air leaks cause equipment to operate excessively in order to replace lost air. This increases maintenance costs on equipment. Also, leaks in compressed air lines allow ingress of moisture into the air supply. Excessive moisture in the air supply can result in catastrophic, explosive failure of a circuit breaker.

The joints of the yard air system have deteriorated allowing leaks to develop. In addition, frost heave has displaced trenches and tubing runs, putting stress on the tubing and joints, which increases the incidence of joint failure and additional leaks. With these mechanisms for ingress of moisture into the compressed air system, the ability to maintain acceptable dew point temperatures has been compromised.

Project Justification:

This project is justified on the requirement to replace deteriorated infrastructure in order for Hydro to provide safe and reliable electrical service.

The compressed air distribution system is approximately 42 years old. It has reached the end of its useful life of 40 years. As observed in other compressed air distribution systems of similar age and the same construction, leaks have become common in the brazed joints and compromise compressed air quality. Replacement is required to restore the integrity of the system.

The compressed air header enclosure is in disrepair. There is insufficient space inside the enclosure to replace the existing headers while maintaining compressed air service to the terminal station yard and there is also insufficient clearance between electrical equipment and piping inside the enclosure. For this reason it is necessary to assemble new headers inside a new enclosure and transfer service to the new system upon completion.

Future Plans:

None

Attachments:

See report entitled “Replace Compressed Air System” located in Volume II, Tab 31, for further project details.

Project Title: Replace 230 kV Circuit Breaker

Location: Sunnyside

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is to replace breaker L03L06 at the Sunnyside Terminal Station. The existing breaker is a 230 kV air blast breaker and it will be replaced by a new 230 kV Sulfur hexachloride (SF_6) breaker. The scope of this work includes the removal of the existing breaker, construction of a new foundation for the breaker, purchase and installation of a new breaker, modifications to the protection and control circuits, if needed, and commissioning of the new breaker.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	225.0	0.0	225.0
Labour	32.8	165.6	0.0	198.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	5.0	55.0	0.0	60.0
Other Direct Costs	0.0	30.5	0.0	30.5
O/H, AFUDC & Escln.	3.5	62.6	0.0	66.1
Contingency	0.0	51.4	0.0	51.4
TOTAL	**41.3**	**590.1**	**0.0**	**631.4**

Operating Experience:

Circuit breaker L03L06 was manufactured by Brown Boveri and was installed in 1966. It is 44 years old. A complete overhaul of this breaker was done in 2000 and complete re-lubrication was done on the breaker in 2007.

Regular maintenance inspections of this circuit breaker indicate that the compressed air tanks no longer meet current safety codes. The minimum tank wall thickness for this type of breaker under ASME Section VIII Division 1, UG-27 is 3.84 millimeters. The minimum measured thickness of the tank wall is 2.94 millimeters.

Project Justification:

This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, reliable electrical service. Because of corrosion, the tank walls for circuit breaker L03L06 are not up to industry standards. This creates the risk of a tank rupture which is a major safety and reliability concern. Also, the circuit breaker is 44 years old and beyond its anticipated useful life of 30 years. A repair of the corroded sections on the compressed air tank was considered but it was not possible because of the construction of the tanks. The only viable option is to replace the breaker.

Future Plans:

None.

Attachments:

See report entitled “Replace 230kV Circuit Breaker” located in Volume II, Tab 32, for further project details.

Project Title: Install Automated Meter Reading

Location: Labrador City and Port au Choix

Category: Transmission and Rural Operations - Metering

Definition: Other

Classification: Justifiable

Project Description:

This project is required to implement Automated Meter Reading (AMR) in Newfoundland and Labrador Hydro's (Hydro) customer service areas of Labrador City and Port au Choix.

AMR is being implemented in approximately 20 percent of the Labrador City service area (1,000 customers). The work includes (i) the replacement of existing customer meters with AMR equipped meters, (ii) the installation of data collectors in the new Quartzite Substation being constructed in Labrador City as part of the distribution system upgrade project, (iii) communications to the AMR server located in St. John's, and (iv) configuring computer systems in St. John's to handle the AMR meter readings and billing for customers in Labrador City.

AMR is also being implemented in Hydro's customer service area of Port au Choix (approximately 570 customers). The work includes (i) the replacement of existing customer meters with AMR equipped meters, and (ii) configuring the AMR server to include customers in Port au Choix.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	248.8	0.0	0.0	248.8
Labour	136.0	26.0	0.0	162.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	15.4	0.0	0.0	15.4
O/H, AFUDC & Escln.	51.0	19.1	0.0	70.1
Contingency	0.0	42.6	0.0	42.6
TOTAL	**451.2**	**87.7**	**0.0**	**538.9**

Operating Experience:

The AMR system will replace manual handheld devices used to collect meter readings at each customer's site and eliminate the requirement for personnel to read customer's meters. Previous AMR projects completed by Hydro have implemented AMR in the service areas of Bay d'Espoir, Conne River, Cow Head, Daniel's Harbour, Gaultois, Hawke's Bay, Parsons Pond, St. Anthony and St. Brendan's. The AMR system being implemented has proven to be reliable and accurate.

Project Justification:

This project is justified on the results of a cost benefit analysis which shows that the new AMR system has economic benefit over the existing system through a reduction in controllable costs.

Future Plans:

This project is the fourth deployment of AMR to Hydro's service areas and AMR system expansion to other service areas is planned in future capital budget proposals.

Attachments:

See report entitled "Automated Meter Reading" located in Volume II, Tab 33, for further project details.

Project Title: Replace Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

The scope of work is to replace 25 light-duty vehicles and 5 heavy-duty work vehicles.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	2,253.7	605.4	0.0	2,859.1
Labour	4.4	1.0	0.0	5.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	9.0	3.0	0.0	12.0
O/H, AFUDC & Escln.	83.4	29.5	0.0	112.9
Contingency	0.0	0.0	0.0	0.0
TOTAL	**2,350.5**	**638.9**	**0.0**	**2,989.4**

Operating Experience:

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

Project Justification:

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

Future Plans:

Future replacements will be proposed in future capital budget applications. Vehicle replacements are planned for the next four years as shown in the five year plan (2011 Capital Plan Tab Appendix A).

Attachment:

See report entitled “Replace Vehicles and Aerial Devices – Hydro System 2011” located in Volume II, Tab 34, for further project details.

Project Title: Replace Battery Banks and Chargers

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

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

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	337.7	0.0	0.0	337.7
Labour	297.8	0.0	0.0	297.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	92.5	0.0	0.0	92.5
Other Direct Costs	62.5	0.0	0.0	62.5
O/H, AFUDC & Escln.	109.0	0.0	0.0	109.0
Contingency	79.0	0.0	0.0	79.0
TOTAL	**978.4**	**0.0**	**0.0**	**978.4**

Operating Experience:

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

Project Justification:

When the capacity of a battery falls to 80 percent of its rated capacity it has to be replaced as recommended by IEEE standards 450 and 1188. The batteries to be replaced are near the end of their

useful lives and have deteriorated to the 80 percent capacity level. Batteries have to be replaced before total failure occurs to ensure continued reliable operation.

Future Plans:

To continue the on going program of monitoring and testing Hydro's battery banks to determine a timely replacement. Also see the five year plan (2011 Capital Plan Tab Appendix A).

Attachment:

See report entitled “Stationary Battery and Charger Replacement Program” located in Volume II, Tab 35, for further project details.

Project Title: Replace MDR 6000 Microwave Radio (West)

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project will replace the low-capacity microwave radio equipment installed in 1999 that has reached the end of its useful life of ten years. These radio links connect remote terminal and generating stations to the main high-capacity microwave radio system connecting Hydro's Energy Control Centre in St. John's to the Bay d'Espoir Hydro Generating Station. The locations serviced by these links include the Hinds Lake, Granite Canal, and Upper Salmon Hydroelectric Generating Stations, and the Deer Lake and Buchans Terminal Stations. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	15.0	0.0	15.0
Labour	36.8	83.2	0.0	119.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	23.6	399.1	0.0	422.7
Other Direct Costs	3.6	39.0	0.0	42.7
O/H, AFUDC & Escln.	8.0	87.0	0.0	95.0
Contingency	0.0	60.0	0.0	60.0
TOTAL	**72.0**	**683.3**	**0.0**	**755.3**

Operating Experience:

The existing equipment has had a series of module failures over its life. Due to the redundant design of this equipment, module failures have not affected the performance of this equipment to date. However, the number of spare parts has been depleted and modules can no longer be purchased or repaired by the manufacturer. This is a common experience in the utility industry with this type of equipment and the vendor recommends replacement.

Project Justification:

This project is justified on the requirement to replace failing infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. The microwave radio equipment being replaced has exceeded its useful life. Hydro will still have MDR-6000 radio in service at four other terminal stations and two generating stations after this project is complete. Hydro will use the equipment removed as part of this project as spare parts to extend the life of the remaining MDR-6000 microwave radio.

Future Plans:

Spare parts of the existing equipment to be removed will be used to extend the life of the remaining MDR-6000.

Attachments:

See report entitled "Replace MDR 6000 Microwave Radio (West)" located in Volume II, Tab 36, for further project details.

Retirements:

The following assets will be retired as part of this project:

Description	Asset No.	Location
Alcatel MDR-6000 Microwave Radio	46626	Bay d'Espoir Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46610	Blue Grass Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46612	Blue Grass Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46617	Buchans Terminal Station
Alcatel MDR-6000 Microwave Radio	46609	Deer Lake Terminal Station
Alcatel MDR-6000 Microwave Radio	46627	Godaleich Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46614	Mary March Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46616	Mary March Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46615	Mary March Hill Microwave Site
Alcatel MDR-6000 Microwave Radio	46618	Sandy Brook Hill Microwave Site

Project Title: Replace Network Communications Equipment

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

A number of devices on Hydro's Administrative network are now obsolete or near obsolescence. Once obsolete, vendor support and replacement parts will no longer be available. The most critical of these at this point in time is the 6513 switch, which serves all Hydro Employees. This project proposes to replace the 6513 switch. This project also proposes to upgrade the switches and switch design of the Information Systems server switches as well as the communications room switches. This is required in order to address single points of failure in these areas. The upgrade to the server switches will also increase available throughput to these servers in order to decrease network congestion by implementing full duplex operation among all access switches. Finally, this project proposes to replace the obsolete Packeteer appliance and Cisco 7206 WAN router and upgrade the CiscoWorks LAN Management Suite. Hydro's current version of CiscoWorks LAN Management Suite (version 2.6) has reached end of engineering support and must be upgraded to version 3.2. This proposal includes consideration for unforeseen network expenditures.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	447.9	0.0	0.0	447.9
Labour	105.9	0.0	0.0	105.9
Consultant	32.4	0.0	0.0	32.4
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.5	0.0	0.0	3.5
O/H, AFUDC & Escln.	88.2	0.0	0.0	88.2
Contingency	59.0	0.0	0.0	59.0
TOTAL	**737.0**	**0.0**	**0.0**	**737.0**

Operating Experience:

Hydro's Administrative network provides employees across the Province with access to enterprise software applications and tools, including Lotus Notes, File Servers, Printers, J.D. Edwards, Workplace Hazardous Materials Information System (WHMIS) information and the public Internet. The administrative network also provides remote access to telecommunications and other operational devices located throughout the Island for remote monitoring purposes.

Project Justification:

Equipment obsolescence poses multiple risks to Hydro in that vendor support and replacement parts are no longer available and software and security updates for these devices are no longer available. The replacement of obsolete devices and upgrade of critical software such as CiscoWorks is required in order to ensure the reliability and availability of the Administrative network. The upgrade of Information Systems server switches is required to improve the redundancy of IS servers and to improve the throughput available to users. The upgrade of the communications room switches is required to resolve a single point of failure in that area as well as address growth in that area. The throughput improvements for the switch stacks on all floors in Hydro Place are required to resolve congestion as well as to provide full duplex operation for all floors. This is required in order to improve access on all floors and correct the current design deficiency. All devices proposed for upgrade are critical to employee productivity. The upgrades will improve the reliability of the administrative network for all Hydro employees. The anticipated project schedule is shown in Table 2.

Table 2: Project Milestones

Activity	Milestone
Project Initiation	February 2011
Planning, Equipment Selection	March 2011
Tendering	April 2011
Evaluation and Award	April 2011
Design/Work Packages	July 2011
Hardware Delivery	July 2011
Hardware Configuration	August 2011
Installation and Commissioning	September 2011
Final Acceptance	September 2011
Project Completion and Closeout	September 2011

Future Plans:

Future replacements will be proposed in future capital budget proposals. See the five year plan (2011 Capital Plan Tab Appendix A).

Attachments:

See report entitled “Network Communications Equipment Upgrade Program” located in Volume II, Tab 37, for further project details.

The following projects are multi-year projects and have been reviewed by the Board at previous Capital Budget Applications. All of these projects, except Upgrade Terminal Stations to 25 kV for Labrador City and the Long Harbour Power Supply for Voisey's Bay Nickel were approved in Board Order No. P.U. 1 (2010) 2010 Capital Budget. Upgrade Terminal Stations to 25 kV for Labrador City was approved by Board Order No. P.U. 36 (2008) as part of the 2009 Capital Budget Application. The Long Harbour Power Supply for Voisey's Bay Nickel was approved by Board Order No. P.U. 16 (2010).

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total
		($000)		
Upgrade Terminal Stations to 25 kV - Labrador City	2,983	3,500	3,507	9,990
Voltage Conversion - Labrador City	1,089	3,501	4,810	9,400
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	1,324	3,367	5,995
Upgrade L2 Distribution Feeder - Glenburnie	267	578	2,711	3,556
Replace Programmable Logic Controllers - Holyrood	1,432	747	902	3,081
Corporate Application Environment - Upgrade Microsoft Products	751	675	678	2,104
Cost Recoveries	(225)	(203)	(203)	(631)
Upgrade Distribution Lines - Roddickton and Makkovik	218	1,645		1,863
Upgrade Line - TL-244	141	1,055		1,196
Replace Pumphouse Motor Control Centres - Holyrood	50	999		1,049
Replace Unit 566 and 2001 - Francois	168	450		618
Upgrade L2 Voltage Conversion to 25 kV - Gaultois	82	511		593
Upgrade Glycol System - Stephenville	261	299		560
Replace Steam Seal Regulator Unit 1 - Holyrood	335	214		549
Upgrade Trailer Mobile Substation - Bishop's Falls	30	468		498
Replace Compressed Air Piping and Install Dewpoint Monitoring - Holyrood	79	417		496
Replace Unit 2018 - McCallum	19	421		440
Replace Fire Pump Diesel - Holyrood	112	195		307
Voisey's Bay Nickel - Long Harbour Power Supply	3,605	8,327	2,123	14,055
Cost Recovery - Vale Inco	(3,605)	(8,327)	(2,123)	(14,055)

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years ($000)	Total	Page Ref
GENERATION					
Replace Fire Pump Diesel - Holyrood	112	195		307	
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir		258		258	C - 2
Install Weatherhoods for Vent Fans - Holyrood		208		208	C - 44
TOTAL GENERATION	112	661	0	773	
TRANSMISSION AND RURAL OPERATIONS					
Upgrade Trailer Mobile Substation - Bishop's Falls	30	468		498	
Replace Compressed Air Piping and Install Dewpoint Monitoring - Holyrood	79	417		496	
Replace Substation Infrastructure - Burgeo		128	368	496	C - 58
Replace Unit 2018 - McCallum	19	421		440	
Replace Insulators - Various Sites		401		401	C - 68
Purchase Excavators - Bishop's Falls		361		361	C - 75
Upgrade Air Blast Circuit Breakers - Various Sites		334		334	C - 81
Replace Mini Hydro Turbine - Roddicton		87	235	322	C - 89
Replace Disconnects - Various Sites		295		295	C - 126
Install Voltage Regulators - Conne River and L'Anse au Loup		293		293	C - 136
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station		280		280	C - 151
Replace Recloser Control Panels - Various Sites		232		232	C - 162
TOTAL TRANSMISSION AND RURAL OPERATIONS	128	3,716	604	4,448	
GENERAL PROPERTIES					
Replace iSeries Computer and Upgrade Operating System - Hydro Place		437		437	C - 178
Replace Personal Computers - Various Sites		404		404	C - 183
Upgrade Ice Protection - Chapel Hill Microwave Site		294		294	C - 188
Replace Peripheral Infrastructure - Various Sites		258		258	C - 199
Remove Safety Hazards - Various Sites		252		252	C - 204
Refurbish Microwave Site - Deer Lake		207		207	C - 209
TOTAL GENERAL PROPERTIES	0	1,852	0	1,852	
TOTAL PROJECTS OVER $200,000 AND UNDER $500,000	240	6,230	604	7,074	

Project Title: Upgrade Burnt Dam Spillway Structure

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is the first year of a four-year program to upgrade the Burnt Dam Spillway Structure (Burnt Spillway). Equipment at the Burnt Spillway is at or near the end of its useful life and/or is in poor condition. After this upgrade is completed, the Burnt Spillway will be in a condition to operate safely and reliably for another 15 years.

The scope of work in the first year is to replace the stop log hoist and associated motor, bus bars, housing and access platform. The scope of work in years two to four is summarized in the *Future Plans* section of this report and includes upgrade of: stop logs; stop log storage system; spillway gates, hoists and controls; emergency hydraulic drive; and diesel power generation. The budget estimate for the 2011 portion of the program is presented in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	7.0	0.0	0.0	7.0
Labour	85.4	0.0	0.0	85.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	102.0	0.0	0.0	102.0
Other Direct Costs	21.3	0.0	0.0	21.3
O/H, AFUDC & Escln.	20.6	0.0	0.0	20.6
Contingency	21.6	0.0	0.0	21.6
TOTAL	**257.9**	**0.0**	**0.0**	**257.9**

Existing System:

The Bay d'Espoir Development includes three hydroelectric generating stations, six reservoirs, and associated dykes, dams, canals and hydraulic structures. The headwaters of the Bay d'Espoir Development begin at Victoria Lake at an approximate elevation of 320 meters. The water travels through the Granite Canal Hydroelectric Generating Station (Granite Canal), Upper Salmon Hydroelectric Generating Station (Upper Salmon) and finally through the Bay d'Espoir

Hydroelectric Generating Station (Bay d'Espoir) where it discharges at sea level. Additional water is collected, stored and diverted from a number of drainage areas between Victoria Lake and Long Pond which is the forebay for Bay d'Espoir.

The generating stations were built over a period of time with Bay d'Espoir being the oldest dating from 1968 and Granite Canal being the newest, coming online in 2003. Some of the oldest hydraulic structures within the Bay d'Espoir Development were constructed in 1967. These are the four intake structures of Bay d'Espoir, the Ebbegunbaeg Control Structure, the Salmon River Spillway Structure, the Victoria Control Structure and the Burnt Spillway. In 2008 Hydro commissioned Hatch Limited (Hatch) to conduct a condition assessment of these structures. Hatch's assessment of the Burnt Spillway (see Appendix A) is the main driver for this project.



Figure 1 - Burnt Dam Spillway Structure

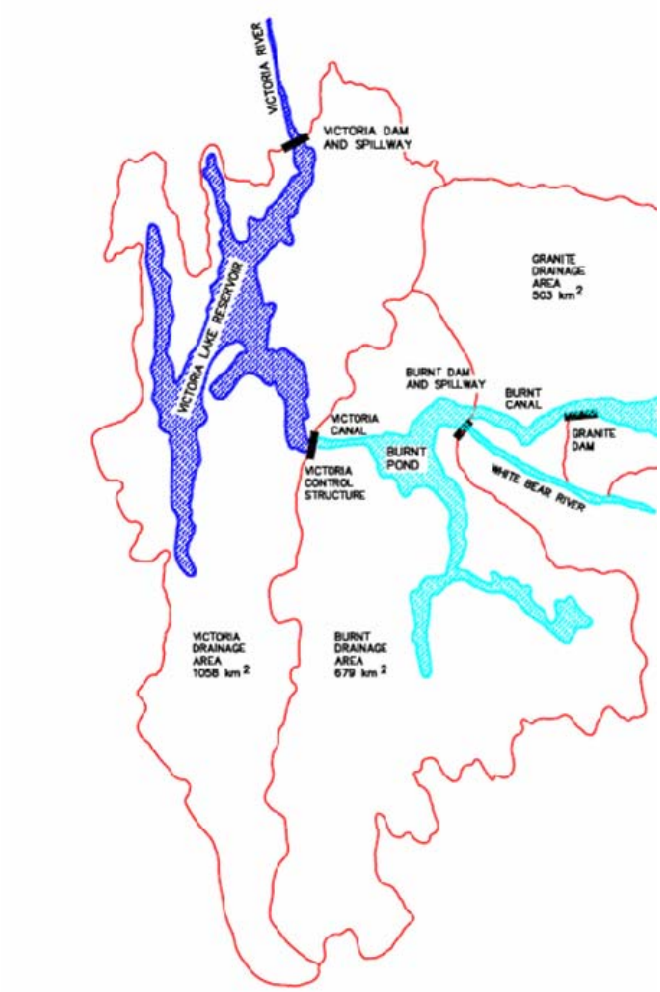


Figure 2 - Victoria Lake and Burnt Pond Reservoirs

The Burnt Spillway, shown in Figure 1 and on the map in Figure 2, is a critical hydraulic structure in the Bay d'Espoir Development. The Burnt Spillway allows water from the Burnt Pond Reservoir, a small uncontrolled reservoir south of the Victoria Lake Reservoir, to be spilled in a controlled, non-destructive manner when needed for flood control. Water discharged from the Burnt Spillway is lost from the Bay d'Espoir Reservoir System, and not available for production of electrical energy at Granite Canal, Upper Salmon and Bay d'Espoir. The spillway consists of two seven-meter wide steel gates which can release a combined 1,144 cubic meters per second of water at the maximum flood level. During the 34 year period up to 2009, one or both gates were opened and then closed for flood control 32 times.

To provide further spilling in extreme floods (1 in 10,000 years), a fuse plug has been constructed in the north end of the Burnt Canal. In the event that the Burnt Spillway is unable to handle flood flows, the fuse plug, acting like a pressure relief valve, will rupture and allow further flood waters to discharge from the reservoir. The fuse plug is designed to fail at a water elevation of 315.2 meters, whereas spilling at the Burnt Spillway normally commences at 313.9 meters. The water level in the Burnt Pond Reservoir can rise quickly in a flood situation. A delay in gate opening of 24 hours during a high run-off period could result in fuse plug failure.

Failure of the fuse plug would have significant consequences including reconstruction cost and, while waiting for reconstruction, a disruption of effective water management for the Bay d'Espoir Reservoir System. Reconstruction of the fuse plug is estimated to cost $1,000,000 and would take between six and ten months to complete, depending upon the time of year of the failure. Immediately upon failure, the Burnt Pond Reservoir would drain down to the bottom elevation of the fuse plug, resulting in a loss of dead storage from the Burnt Pond Reservoir. While awaiting reconstruction, there would be loss of the use of the Victoria Lake Reservoir, which may contain up to 550 Gigawatt-hours of stored energy. Water that would normally be released from the Victoria Lake Reservoir into the Burnt Pond Reservoir and which would subsequently flow through the Burnt Canal to the remainder of the Bay d'Espoir Reservoir System, would instead be spilled through the Burnt Spillway and/or the failed fuse plug.

In addition to flood control, the gates at the Burnt Spillway provide fisheries compensation flow into the White Bear River (shown in Figure 2) to protect fish populations. In accordance with an agreement between Hydro and the Federal Department of Fisheries, a flow of 7.08 cubic meters per second must be maintained at the mouth of the White Bear River from June 1 to September 30 each year. This is achieved by releasing up to 4.25 cubic meters per second through the Burnt Spillway during this period. This is a small flow in comparison to the flood flows that the Burnt Spillway is capable of releasing, and is achieved by cracking open one gate approximately 8.5 centimeters. During the 34 year period up to 2009, the gates were operated for fisheries compensation flow every year except for one, with an average of four gate open/close operations per year.

The Burnt Spillway is equipped with a stop log system that permits isolation of the spillway gates for maintenance activity. Each stop log is fabricated from two horizontal steel beams, end members, grip hooks and rubber seals. The stop logs can be used for either of the two spillway gates. To isolate a gate, the stop logs are inserted into slots in the concrete structure upstream of the gate, as shown in Figure 3. When the stop logs are in place, the area between the stop logs and the gate is de-watered. A monorail hoist system, as shown in Figure 4, is used to install and remove the stop logs. The hoist is controlled by an operator on the bridge, via a suspended push button station. The hoist system includes an electric hoist, a monorail structure and a master log which mates with the stop logs.



Figure 3 - Stop Logs in Place, Master Log Still Attached



Figure 4 - Monorail Hoist for Stop Logs

The study by Hatch in 2008 included: a review of engineering drawings, operation and maintenance manuals, work order history and preventative maintenance routines; site visits, component inspections and functional testing of equipment; discussions with Hydro personnel; determination of a Health Index for each site; and a risk-based failure cost analysis to determine the least-cost course of action. The results of this study are detailed in the *Hydraulic Life*

Expectancy Study Final Report, May 22, 2009. Applicable excerpts of this report are included in Appendix A.

Hatch applied their Health Indexing System to quantify the overall condition of each hydraulic structure, as described on pages 8 and 9 of their report (Appendix A). The Health Index of each site is shown in Table 2. Note that the Burnt Spillway has the lowest overall health index with a score of 66 out of a maximum possible of 100. Page 24 of the Hatch report (Appendix A) details how the Health Index was calculated for the Burnt Spillway.

Table 2: Health Indices for Hydraulic Structures

Hydraulic Structure	Health Index (0-100)
Burnt Spillway	66
Victoria Control Structure	68
Salmon River Spillway	71
Bay d'Espoir Intakes (4)	73
Ebbegunbaeg Control Structure	80

Hatch rated the condition of the stop logs and monorail hoist as "1" which indicates "poor condition, serious deterioration of at least some parts; function is inadequate". On Page 20 of the report, Hatch stated: "The power track supplying the hoist motor is out of service and a temporary power supply has been installed. This is hazardous and unreliable. The electrical junction box on the hoist is severely corroded and likely no longer watertight. The power track should be replaced by a heated power track bus system in order to prevent ice buildup along the power track during winter season." Furthermore, on Page 24, Hatch reported that: "The stop log monorail hoist is in poor condition and poses a safety hazard." Hatch noted that there are recurring problems with the bus bars and that the hoist trolley does not travel fully on the monorail beam near Gate 1. The enclosure for the hoist is corroded and the access platform is inadequate in that it does not allow safe, ergonomic work positioning for hoist inspection and maintenance.

Hatch made a number of short-term (within two years) recommendations focusing on reducing the risk of operational failure of the gates. Complete rehabilitation of gate mechanical and

electrical equipment was recommended to improve reliability. The stop log monorail hoist was identified as a safety concern and recommended to be replaced as well.

Hatch also recommended medium term (two to seven years) recommendations related to areas for further study and evaluation and long term (beyond seven years) recommendations regarding additional gate heating and video camera surveillance. Hatch's recommendations were made with the objective of increasing the service life of the Burnt Spillway to the Year 2035.

Age of Equipment or System

The Burnt Spillway was constructed in 1967. The stop log system, including the stop logs, master log, electric hoist and monorail structure, is original and has been in service since 1967.

Major Work/or Upgrades

There have been no major upgrades to the stop log system since installation.

Anticipated Useful Life

The stop logs have an anticipated service life of 50 years. The stop log monorail hoist system has an anticipated service life of 35 years.

Maintenance History

The five-year maintenance history for the stop log system is shown in Table 3.

Table 3: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	1.2	0.3	1.5
2008	1.0	0.0	1.0
2007	0.5	0.0	0.5
2006	0.6	0.0	0.6
2005	0.0	0.8	0.8

Outage Statistics

Outage statistics for the Burnt Spillway are not formally recorded. A review of work order history indicates that there have been at least four occasions when a gate could not be opened or closed due to cold temperatures, ice accumulation, or hardening of the grease for the gate hoist screw stems. An outage of a gate at the Burnt Spillway does not directly impact production at any of the three downstream generating stations.

Industry Experience

There is no relevant industry experience pertaining to the stop log system.

Maintenance or Support Arrangements

Hydro utilizes a contractor for inspections of the stop log hoist, as part of a larger crane inspection program. Routine preventive and corrective maintenance is performed by Hydro personnel, supplemented by contractors when expertise is required.

Vendor Recommendations

There are no vendor recommendations pertaining to the stop log system.

Availability of Replacement Parts

Availability of replacement parts for the stop log system is unknown.

Safety Performance

There are several safety performance issues with respect to the stop log hoist system. Hatch identified safety concerns in their condition assessment, and the crane inspector reported issues from his 2009 inspection. Safety hazards have been documented by Hydro employees, through Hydro's Safe Workplace Observation Program. Following is a list of safety performance issues:

- The power track that safely supplies electricity to the hoist motor is out of service and a temporary power supply has been installed which could become entangled or worn as the hoist travels;
- The electrical junction box on the hoist is severely corroded and no longer watertight which can lead to electrical shocks;
- Electrical arcing occurs at the 600 Volt bus bar while the hoist is operating;

- There is potential for the hand held pendant control cable to contact the bus bar and cause an electrical shock; this could be eliminated by replacing the pendant control unit with a radio control unit;
- The hoist trolley does not travel fully on the monorail beam near Gate 1. The guide rollers are not making proper contact with the beam;
- The hoist enclosure is corroded;
- The access platform is inadequate in that it does not allow safe, ergonomic work positioning for hoist inspection and maintenance;
- Labels for the monorail travel directions and capacity tonnage (metric) are not visible from ground level;
- The hand held pendant controller does not have labeled travel directions on its controls; and
- The termination of the wire rope is inadequate in that the wire rope does not protrude from the back side of the wedge socket at least 150 millimeters and there is no crosby clip on the wire rope as a back-up to the wedge socket.

Environmental Performance

The gates at the Burnt Spillway are used to provide fisheries compensation flow into the White Bear River to protect fish populations. In accordance with an agreement between Hydro and the Federal Department of Fisheries, a flow of 7.08 cubic meters per second must be maintained at the mouth of the White Bear River from June 1 to September 30 each year. This is achieved by releasing up to 4.25 cubic meters per second (m^3/s) through Burnt Spillway during this period, by cracking open one gate approximately 8.5 centimeters (cm). Hydro relies on Environment Canada flow data for White Bear River to schedule compensation flows through Burnt Spillway. During the 34 year period up to 2009, the gates were operated for fisheries compensation flow every year except for one, with an average of four gate open/close operations per year.

Hydro monitors and records compliance under this agreement. During the period 2000 to 2009, Hydro has been non-compliant on two occasions. In June 2000 Hydro was non-compliant for 15 hours and in September 2000 Hydro was non-compliant for 10 hours. Both of these events were due to the flow data being unavailable to Hydro by Environment Canada during the monitoring process. The data retrieval system has since been improved and Hydro receives data updates approximately every four hours to ensure full compliance.

Operating Regime

Hydro has two personnel at the Burnt Dam site on a continual basis. The spillway gates operate on a periodic basis of approximately five gate operations per year.

Justification:

This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, reliable flood management for the Victoria Lake and Burnt Pond Reservoirs as well as fisheries compensation flow into the White Bear River. A condition assessment conducted by Hatch in 2008 identified the Burnt Spillway as having the lowest overall Health Index when compared to seven other hydraulic structures of similar vintage within the Bay d'Espoir Development. Hydro's ability to continue to manage flood waters and meet its fisheries compensation commitments is contingent upon the successful upgrade of the Burnt Spillway. When the four-year upgrade program for the Burnt Spillway is complete, this hydraulic structure will be in a condition to operate safely and reliably for at least another 15 years.

Hatch identified the stop log hoist as having serious deterioration resulting in inadequate function and safety hazards. Hazardous conditions have been further identified by both Hydro employees and the contracted crane inspector. Upgrade of the stop log hoist in Year One of the upgrade program will ensure that all safety hazards associated with the stop log hoist are addressed. A reliable stop log hoist after Year One will also permit safe isolation of the spillway gates to facilitate further upgrade work in the remaining three years of the program, as well as the on-going preventive maintenance program.

Net Present Value

A net present value calculation was not performed since there is no viable alternative to upgrading the Burnt Spillway.

Levelized Cost of Energy

The levelized cost of energy is not applicable to this project since the project does not pertain directly to a source of electricity generation.

Cost Benefit Analysis

A cost-benefit analysis was not performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

In 1966, an agreement was made between the Newfoundland and Labrador Power Commission (now Hydro) and the Department of Fisheries of Canada (now Fisheries and Oceans Canada) titled *Release of Water to Protect Fish Populations in Grey River and White Bear River.* The agreement took effect February 1966 and was varied by letters dated September 8, 1977 and July 11, 1996. The agreement established measures to be taken by the Power Commission for the conservation of stocks of anadromous fishes to be affected by the Bay d'Espoir Development, under the provisions of the Fisheries Act, R.S.C. 1952, c.119; as amended by 1960-61, c.23. Under this agreement, Hydro is required to provide fisheries compensation flow into the White Bear River to maintain a flow of 7.08 cubic meters per second at the mouth of the White Bear River from June 1 to September 30 each year. This is achieved by releasing up to 4.25 cubic meters per second through one of the gates at the Burnt Spillway during this period. Hydro's ability to meet its fisheries compensation commitment is contingent upon the successful upgrade of the Burnt Spillway to ensure reliable gate operation.

Historical Information

There is no historical information applicable to this project.

Forecast Customer Growth

Forecast customer growth does not impact 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 losses during construction.

Status Quo

The status quo is not acceptable. It is imperative that the Burnt Spillway be upgraded to ensure safe, reliable operation of the gates allowing flood waters to be spilled in a controlled, non-destructive manner when reservoir levels reach prescribed levels, and allowing water to be released to meet Hydro's fisheries compensation requirements to protect fish populations.

A delay in gate opening of 24 hours during a high run-off period could result in fuse plug failure which will have severe consequences.

Failure to open a gate for fisheries compensation flow could result in non-compliance with Hydro's agreement with Fisheries and Oceans Canada and may result in loss of fish.

Failure to upgrade the stop log hoist in Year One of the upgrade program will result in hazardous conditions persisting and worsening and will negate Hydro's ability to safely perform additional upgrade work in the remaining years of the program as well as the ongoing preventive maintenance program.

Alternatives

There are no viable alternatives to upgrading the Burnt Spillway.

Conclusion:

It is imperative that the Burnt Spillway be upgraded to ensure safe, reliable operation of the gates, allowing flood waters to be spilled in a controlled, non-destructive manner when reservoir levels reach prescribed levels, and allowing water to be released to protect fish populations. There are no viable alternatives and the status quo is not acceptable.

Project Schedule

The project schedule is shown in Table 4 below.

Table 4: Project Schedule

Activity	Month(s)
Design and Tender	January - April
Install and Commission	July - August
Documentation	October - December

Future Plans:

Future plans include additional upgrade work at the Burnt Spillway in Years two, three and four as follows:

Year Two – 2012

Stop logs and gate hoist.

1. Upgrade stop logs.
2. Install stop log storage rack.
3. For each gate, dewater gate and inspect concrete, embedded parts (track and seal plates), sill heaters, gate rollers, connection of screw stems to gates, and limit switches.
4. For each gate, remove, clean and inspect screw stems. Replace drive nuts. Procure spare drive nuts. Modify screw column access hatch to prevent water ingress. Install stem protectors and add screw column support.
5. For each gate, remove, clean and inspect shafts. Replace or refurbish shaft couplings.
6. For each gate, refurbish or replace hoist gear boxes. Modify gear box access hatches to eliminate water ingress. Seal sight glass and install dip stick arrangement for gear box oil level. Equip with heaters to prevent icing.
7. For each gate, replace hoist motor and install manual release brake.

Year Three – 2013

Gates and gates electrical & controls.

8. For each gate, repair concrete and embedded parts (gate roller tracks & seal plates).
9. For each gate, replace gate rollers.
10. For each gate, repair gate coating.
11. For each gate, replace upper and lower cut-off limit switches, overload switches and gate positioning measurement and controls. Provide accuracy needed for fish compensation adjustments (small gate openings).
12. For each gate, reroute control cabling to remove junction box on top of structure. Replace disconnect switches in the control building with 600 Volt distribution panel and disconnects with viewing window. Right-size the starter overloads. For each gate, install stepped, thermostatic control and monitoring on gate, gain and sill heaters. Put sill heaters on two separate circuit breakers. Replace flexible cables for heaters. Modify the sill heaters to make them easier to replace.
13. Replace 120/240 Volt distribution panel.
14. Replace the 600 Volt to 120/240 Volt transformer.

Year Four – 2014

Emergency hydraulic drive and diesel generation.

15. For each gate, install permanent emergency hydraulic drive for the gate hoist, complete with enclosure, piping, sump, and clutches.
16. Replace 25 kilowatt and 75 kilowatt diesel generator sets and controls.
17. Replace DC disconnect switches in the diesel building with non-fusible disconnects with viewing window.
18. Replace cables from the diesel building to the gate control building. Raise cable penetrations above flood water line and seal penetrations.
19. Modify the existing generator exhaust stacks for improved dispersion of pollutants.
20. Raise generator radiator above snowline or move indoors with adequate ducting and air supply.

A preliminary budget for Years two, three and four of the program to upgrade the Burnt Spillway is summarized in Table 5.

Table 5: Preliminary Budget – Upgrade Burnt Spillway, Years 2-4

Year	**Budget** *($ x1,000)*
2012	692
2013	994
2014	959

In 2008, Hatch completed a life expectancy study for eight hydraulic structures on the Bay d'Espoir Reservoir System. With the lowest Health Index, the Burnt Spillway was the first site chosen for upgrading. Similar upgrade programs for the remaining seven hydraulic structures appear in Hydro's 5-year and 20-year capital plan, with the next site being the Victoria Control Structure scheduled to be upgraded starting in 2013.

Appendix A

Hydraulic Structure Life Expectancy Study – Final Report (Hatch)

(excerpts applicable to the Burnt Dam Spillway Structure)

Newfoundland and Labrador Hydro

Hydraulic Structure Life Expectancy Study

Final Report

H330777
Rev. 0
May 22, 2009

HATCH™

Newfoundland and Labrador Hydro
Hydraulic Structure Life Expectancy Study

Final Report

Prepared by: Rick Hibbs, P.Eng. — May 22, 2009 Date

Approvals

Hatch

Approved by: Gregory Saunders, P.Eng. — May 22, 2009 Date

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PEG Newfoundland and Labrador
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Executive Summary

Hatch conducted a Life Expectancy Study of five hydraulic structures in the Bay d'Espoir Development: the Bay d'Espoir Intake, Burnt Spillway, Salmon River Spillway, Ebbegunbaeg Control Structure, and Victoria Control Structure. The study included: a review of drawings, operation and maintenance manuals, work order history and preventative maintenance routines; site visits, component inspections and functional testing of equipment; discussions with Hydro personnel; determination of a Health Index for each site; and a HydroVantage analysis which uses a risk-based failure cost to determine the least-cost course of action.

The findings of the Life Expectancy Study are summarized as follows.

Bay d'Espoir Intake

- Health Index 73.
- Short term recommendations focus on upgrading electrical components of the structures and continued implementation of PLC controls to Gates 1-3 similar to Gate 4. The estimated total cost of the short term recommendations is $227,000.

Burnt Spillway

- Health Index 66.
- Short Term Recommendations focus on reducing risk of operational failure of the gates. Complete rehabilitation of gate mechanical and electrical and upgrades to communications are recommended in the short term to improve reliability. The stoplog monorail hoist is a safety concern and should be replaced. The estimated total cost of the short term recommendations is $370,000.

Ebbegunbaeg Control Structure

- Health Index 80.
- Short Term Recommendations focus on enhancing reliability by replacing gain heating systems, rehabilitating gate roller assemblies, and improving communications. The screw stem hoists can remain in service but should be rehabilitated within seven years. The estimated total cost of the short term recommendations is $245,000.

Salmon River Spillway

- Health Index 71.
- Short Term Recommendations focus on reducing risk of operational failure through complete mechanical and electrical rehabilitation to improve reliability. The estimated total cost of the short term recommendations is $245,000.

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Victoria Control Structure

- Health Index 68.
- Short Term Recommendations focus on upgrading electrical components that are at end of life, revamping the preventative maintenance routines, and performing a civil inspection. The estimated total cost of short term recommendations is $145,000.

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1. Introduction

Newfoundland and Labrador Hydro (Hydro) contracted Hatch to perform a Hydraulic Life Expectancy Study for some of the water control structures in the Bay d'Espoir Development. The study will provide Hydro with the remaining useful life of the equipment at the structures and the necessary repairs or replacements to increase life by 25 years. This report documents the investigations, observations and analyses conducted, and lists recommendations to achieve Hydro's objectives.

1.1 Background

Hydro is a utility which owns and operates facilities for the generation, transmission and distribution of electricity to utility, industrial and residential customers in the Province of Newfoundland and Labrador. On the island, Hydro has nine hydroelectric generating plants with a total installed capacity of 980 MW and five thermal generating plants with a total installed capacity of 626 MW, interconnected by an electric power grid.

The Bay d'Espoir Development includes three generating stations and a series of dykes, dams, canals, control structures, spillways and reservoirs. The headwaters of the Bay d'Espoir Development begin at Victoria Lake at an approximate elevation of 320 m. The water travels through Granite Canal Generating Station, Upper Salmon Generating Station and finally through the Bay d'Espoir Generating Station where it discharges at sea level. Additional water is collected, stored and diverted from a number of drainage areas between Victoria Lake and Long Pond, which is the forebay for the Bay d'Espoir Generating Station. The generating stations were built over a period of time with Bay d'Espoir being the oldest dating from 1968 and Granite Canal being the newest, coming online in 2003.

Some of the oldest water control structures on the Bay d'Espoir Development are the four intake structures to the Bay d'Espoir Generating Station (1968-1977), the Burnt Spillway (1967), the Ebbegunbaeg Control Structure (1967), the Salmon River Spillway (1967), and the Victoria Control Structure (1967). Hydro has selected these structures for study to determine the condition of mechanical, electrical and protective equipment.

1.2 Objectives

The objectives of the study, as identified in Request for Proposal 2008-39101, are as follows.

1. Determine the condition of the hydraulic structures.
2. Make recommendations for immediate and long-term repair, upgrade and replacement of equipment such that the useful life of the structures will be extended to year 2035. Recommendations are to be itemized by location, discipline and priority.
3. Prepare budgetary estimates of required materials, labour and engineering for all recommendations.

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In addition, other concerns were identified during the site visit meeting at the Bay d'Espoir Generating Station on October 15, 2008. Although these issues were not in the original scope of work of the Hatch Proposal dated August 11, 2008, some are addressed in this report. The list of issues is as follows.

- Inspection requirement and frequency of inspection for gate rollers.
- Requirements for interior gate heating versus up-lifters.
- Detailed PM Inspections missing from existing program for gates 40+ years.
- 100% heated gates/gains vs. a single gate.
- Continuous vs. intermittent gate/gain heating.
- Type of lubricant recommended for gate screw stems.
- Frequency required for cleaning screw stems.
- Protective covers for screw stems – Telescopic vs. Flex Material.
- Water leakage into gearboxes.
- Heating requirement for lube oil in gear boxes.
- Frequency for changing oil in gear boxes.
- Advantage of enclosing structures – benefits.
- Replacement vs. rewinds on spillway gate hoist motor.
- Spare parts recommendations.
- Condition assessment/inspection of gate stem gearboxes.
- Condition of master logs.
- Alignment checks for gates/gains.
- Condition of monorail hoist system and recommendations for improvement.
- Condition of monorail bus bars and recommendations for most durable type.
- Evaluation of gate electrical system.
- Evaluation of gate emergency lift system.
- Evaluation of gate electrical protection system.
- Adequacy of gearbox/motor size for gearbox and motor at Victoria Control.
- Comment on gate heating deficiencies at Victoria Control.
- Benefits/disadvantage of gate hoist control system on Ebbegunbaeg Gate 2.
- Benefits/disadvantage of screw stem hoist system at Ebbegunbaeg.

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- Recommended inspections for intake gates.
- Other points.

1.3 Approach

Hatch undertook the following activities in preparation of the recommendations.

- Reviewed drawings and operation and maintenance manuals.
- Reviewed preventative maintenance program and work order history.
- Conducted site visits including visual inspections, condition assessment of structures and functional tests where possible.
- Held meetings and discussions with Hydro personnel.
- Analysed observations and findings using Condition Index (CI) and Health Index (HI) methodology.
- Performed a HydroVantage Analysis of selected components.
- Co-ordinated effort to match results of condition assessment with the HydroVantage results.
- Itemized recommendations in order of priority of critical and non-critical components at each hydraulic structure.
- Prepared a budget cost estimate for labour, materials and engineering for the recommendations.

1.4 Report Organization

Section 2 of this report describes the methodology used to perform the assessments, conduct the analyses, and make the recommendations. Sections 3-7 provide detailed findings, analysis results and recommendations for each structure. More detail can be found in the appendices. Electrical site inspection checklists, mechanical site inspection checklists, HydroVantage analysis results and selected photographs of the structures are found in Appendices A, B, C and D, respectively. Section 8 of the report summarizes the recommendations and includes cost estimates.

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2. Methodology

The project was completed in primarily two phases: Data Collection and Analysis. The Data Collection Phase consisted of gathering all sources of information and processing the information such that it could be analyzed. The original scope of work at the time of award provided for analysis of life expectancy and the preventative maintenance program of selected structures. Following the site visit, Hydro extended the scope of work to include the optional HydroVantage analysis as proposed by Hatch. Work conducted in the Data Collection and Analysis phases facilitated drawing conclusions and preparing the recommendations.

2.1 Data Sources

The following sources of information were included in this study.

2.1.1 Drawings

Hydro provided several electrical, mechanical and structural drawings for the structures. The drawings were primarily used in developing a familiarity with the structures and in preparing check sheets for the site visits.

2.1.2 Operation and Maintenance Manuals

The operation and maintenance manuals for each structure were reviewed at Hydro's offices and relevant sections were copied. The manuals differ greatly because equipment came from different suppliers. The manuals were used in preparation of check sheets and maintenance reviews.

2.1.3 Interviews

Rather than conduct formal interviews, the Hatch engineers engaged Hydro staff during the site inspections and functional tests. This approach allowed Hydro staff to demonstrate and illustrate their concerns and quickly recall maintenance and repair history. Valuable information was provided by the staff and that information fed directly into the Life Expectancy Analysis.

2.1.4 Preventative Maintenance Program

Hydro provided the mechanical and electrical preventative maintenance check sheets and schedule for the structures.

2.1.5 Maintenance History

Hydro provided five years of maintenance work order history from their JD Edwards maintenance program for each of the structures. The work orders were compiled and compared to identify recurring maintenance concerns.

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2.1.6 *Site Inspections*

Site inspections were conducted October 15 to 18, 2008 by Kishen Bhan, Lewis Hann and Rick Hibbs of Hatch, and Paul Hancock, Hubert Fudge, Rodney Willcott, and Walter Organ of Hydro. In preparation for the site visits, Hatch prepared check sheets for recording the condition of various components. The site inspections were mostly visual; however, simple tests were also conducted such as determining if rollers were seized and measuring starting/normal currents drawn by the hoist motors and gate and gain heaters. Where possible, access was made to the gate leaves, the hoist structure and inside gates to permit closer inspections. Hydro maintenance staff also removed covers of gearboxes and electrical panels to permit internal inspections.

2.1.7 *Functional Tests*

Functional tests were performed on Burnt Spillway Gate 2 and Salmon River Spillway Gate 1 while the upstream stoplogs were in place. Ebbegunbaeg Gates 1 and 2 were operated under flowing conditions. The four Victoria Control gates were operated under both flowing and dry conditions. The Bay d'Espoir intake gates could not be tested due to plant loading. Functional tests involved lifting and lowering the gates under normal power supply; the emergency hydraulic hoists were started but not used.

2.2 Analysis

2.2.1 *Electrical General*

Performing a condition assessment for low voltage power equipment and its components requires a review of maintenance records, spare parts availability, and analyzing the condition against the required functionality and safety considerations. Age is only one of many factors that should be considered in assessing the condition of electrical equipment. The rate and severity of degradation depend on operational duties of the equipment and environmental factors.

Overall equipment condition assessment includes consideration of the following:

- Physical condition;
- Functional requirements and performance;
- Frequency of emergency/preventative maintenance;
- Spare parts availability; and
- Fire and safety implications.

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Outdoor components experience the following types of degradation:

- Wiring insulation deterioration;
- Mechanical (supports and mounting);
- Corrosion; and
- Moisture ingress.

Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in outdoor electrical equipment. Age alone is not a good indicator of equipment condition, as the effects of the operating environment generally have a significant impact.

Indoor components experience the following types of degradation:

- Wiring insulation deterioration;
- Poor electrical connections due to corrosion, vibration or other physical problems;
- Corrosion (unheated space).

Wiring insulation degradation can lead ultimately to failures and equipment unavailability. Assessment of the insulation integrity of low voltage equipment is performed by visual inspection and testing using a mega-ohm meter, often referred to as Megger Testing.

Moisture and high humidity in electrical equipment enclosures and electrical rooms promote corrosion and should be avoided. When ambient temperatures fall below the dew point, condensation can occur. In the event water enters equipment enclosures and electrical rooms through roof or other leaks, it can affect performance and aggravate long-term corrosion. Routine inspections and maintenance can detect and mitigate corrosion, but providing proper environmental conditions or installing equipment designed for humid environments can prevent corrosion significantly.

Generally, visual inspections offer the best form of condition assessment for low voltage distribution panels and control panels. Visual inspections are an important part of any maintenance program but need to be accompanied by routine functional checks and tests that will clearly identify problems that require mitigation.

Normally, it may not be practical to test the electrical functionality of low voltage fuses and breakers during routine inspections, but it is important that this equipment is maintained in good service condition. Alarms and supervisory systems can sometimes be utilized to identify power system and equipment failures.

Wiring insulation may degrade from fraying and brittleness. Older power distribution and control cables are insulated with rubber-based insulation that tends to deteriorate over time. In many cases,

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this deteriorated insulation falls away when touched, exposing conductors. Modern PVC insulated cables do not tend to have this problem except when exposed to severe overheating.

Replacement of low voltage electrical distribution equipment, control panels and associated wiring that is at or near the end of service life is a cost effective risk management strategy.

2.2.2 *Mechanical General*

The mechanical condition assessment of the hydraulic structures includes both structural steel components and strictly mechanical components.

The structural steel components include the gate leaf components such as skinplate, girders, stiffeners and end trucks; stoplog steel components and hoist structure. For these steel components, the main indicators of serviceability are corrosion, distortion and signs of excessive stress in connections such as weld cracks or bolt looseness. After review of the work order history and discussion with Hydro personnel at the kick-off meeting, it was concluded that there was no preliminary evidence of excessive corrosion or over-stressing and thus no Non-Destructive Examination (NDE) of the steel work was considered warranted.

The mechanical components investigated include the gate roller assemblies and gains, the gate seals and sealing surfaces, and the hoisting equipment.

The ideal method to inspect the roller assemblies is to disassemble the rollers and inspect the bushings, pins and thrust washers. It is likewise desirable to measure the straightness and plumbness of the gains. This was not possible in the limited time available for inspections. The rollers were visually observed while the gates were in motion and accessible rollers were rotated by hand, where possible. Rollers which rotated were considered effective, while those that did not were suspect. However, by this simple method, it cannot be concluded that a roller assembly has failed (seized). Similarly, side rollers which maintained contact and rotated were considered effective. Close access to the gains was not possible; visual examination from the deck for scrape marks, galling, and corrosion was used to determine condition.

In most cases, it is not possible to visually inspect the gate seals unless the gate is removed from the structure. The condition of the seals was evaluated based on their ability to retain water while in service.

Both wire rope and screw stem hoists are used in the Bay d'Espoir Development Structures. The weakest component in a wire rope hoist is typically the rope itself. This will normally require replacement before the drum, fan brake or gear box. Confirmation of wire rope strength is normally done via a pull test; however this is impractical for ropes in service which instead are inspected for corrosion, fraying, kinks and distortion. Wear and material loss is the main indicator of condition for the remaining components on wire rope hoists and the components of screw stem hoists. Gears, drums and screws should have patterns of equal wear; broken teeth and gouges are signs of localized overstressing. The effects of unequal and excessive wear can often be heard when the hoist is operating.

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2.2.3 *Life Expectancy*

Hatch pioneered the Health Indexing System to quantify the condition of the equipment relative to long term degradation factors that signify cumulative problems leading to end-of-life (EOL).

The following condition ratings provide the basis for formulating an overall Health Index for the relevant equipment/system:

3 Good condition, only minor deterioration or defects are evident.

2 Fair condition, moderate deterioration, function is adequate.

1 Poor condition, serious deterioration of at least some parts. Function is inadequate.

0 Unacceptable conditions, extensive deterioration, barely functional, may be unsafe to operate.

To calculate the Health Index for each component, weighting is given to each of the subcomponents based on its relative importance: 8 for a dominant subcomponent whose failure or end-of-life determines that for the whole component, 4 for high importance subcomponents, 2 or 3 for medium importance subcomponents and 1 for low importance subcomponents. For each individual subcomponent, the weighting is then multiplied by 3, 2, 1 or 0 corresponding to the condition rating as shown on the Condition Assessment form. The overall Health Index is then derived from the sum of these products for all subcomponents. The standard procedure is to normalise this sum to give a final result based on a scale of 0 to 100. Health Index is the actual sum of products divided by the maximum possible sum of products and then multiplied by 100. The maximum possible sum of products is obtained by setting the condition rating at 3 for all subcomponents. Thus, a component in perfect condition would have a Health Index of 100.

One Health Index has been prepared per structure, reflecting the mechanical and electrical condition of all gates and hoists. Table 2-1 ranks the Health Index score against overall condition and intervention required.

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Table 2-1: Health Index Scale for Head Gate Hoist

Health Index	Condition	Description	Requirements
85-100	Excellent	No noticeable defects or deterioration.	Normal maintenance
70-84	Very Good	Generally only minor defects or deterioration apparent; or significant deterioration in very few subcomponents but no noticeable defects or deterioration in remainder.	Normal maintenance Consider replacement or rehab for deteriorated items.
55-69	Good	Some deterioration or defects are apparent, but function is not significantly affected.	Increased inspection or testing. Consider replacement or rehab for deteriorated items.
40-54	Fair	Moderate deterioration or presence of defects. Function is still adequate.	
25-39	Poor	Serious deterioration or defects in several subcomponents. function is not adequate.	Plan a rehab or replacement in near future. Safety evaluation required.
10-24	Very Poor	Extensive serious deterioration and defects, barely functional.	
0-9	Failed	No longer functions. General failure of a major subcomponent.	Not to be operated.

2.2.4 *Maintenance Records and Preventative Maintenance Program*

The maintenance records were reviewed and grouped so that recurring maintenance issues could be identified. The findings were discussed with Hydro prior to the site visit to confirm if any special tests or examinations were warranted. Two issues recurred most frequently: replacement of up-lifters and trouble with the new wire rope hoist in Ebbegunbaeg. The first issue was not a concern to Hydro; the up-lifters are generally working quite well for Hydro and these sealed units are fairly inexpensive so spares are kept in inventory and units replaced when necessary. The new wire rope hoist in Ebbegunbaeg had some initial problems when placed into service but these were rectified and the hoist has been reliable since.

The preventative maintenance program check sheets were compared amongst the structures and reviewed for completeness.

2.2.5 *HydroVantage*

The HydroVantage Analysis uses a risk-based failure analysis to identify the least long-term cost of operation that will optimize the reliability of the structures. The analysis takes into consideration the failure curves of components, the effective age of the components, maintenance costs, rehabilitation and/or replacement costs, unplanned repair costs, and forced outage costs. HydroVantage uses this information to determine the course of action which produces the least net present value (NPV). Courses of action include interventions such as replacement and rehabilitation (and the timing of such) versus run-to-failure. The list of components is presented in Table 2-2.

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Table 2-2: HydroVantage List of Components

Structure	Component	Description
Bay d'Espoir Intake	motor starter distribution panel wire rope hoist wire rope roller assembly	 all 8 rollers
Burnt Spillway	motor TEFC type gate/gain heater screw stem hoist screw stem gearbox roller assembly	 not including gearbox same curve as hoist all 8 rollers
Salmon River Spillway	motor starter gate/gain heater screw stem hoist sluice gate assembly	 gate "as a whole"
Victoria Control Structure	motor Limitorque type distribution panel screw stem hoist screw stem hoist manual	 powered (like others) simpler than powered
Ebbegunbaeg Control Structure	motor starter gate/gain heater screw stem hoist roller assembly	 all 8 rollers

To prepare the HydroVantage model, the following was considered.

1. Rollers. It is assumed that operation of the gate will be affected when two rollers fail. It is further assumed that the first roller failure will go unnoticed.
2. Intake Gates. The intake gates are normally open and closed once a year during maintenance. It is assumed that there is a very low probability (and hence risk) of an intake gate or hoist failure causing the gate to close while a connected turbine is in operation. Failure to close during a maintenance inspection carries no outage cost. Failure to open following a planned maintenance will result in some outage cost. It is further assumed that the first week (seven days) of an unplanned intake gate outage will not result in lost generation; other units can be dispatched. However, an outage longer than one-week is expected to result in lost generation and hence consequence costs.
3. Control Gates. All the control structures reviewed have more than one gate and thus have inherent redundancy. Failure of a control gate to open on demand has little consequence unless all gates are required to be fully open. However, failure of a control gate to close can carry the

risk of releasing too much water and thus requiring spillage downstream of the structure and lost production.

4. Spillway Gates. Similar to the control structures, the spillway structures have inherent redundancy, so failure to open gates has little consequence other than if all gates are required to be fully open. Failure to close a spillway gate on demand will result in direct loss of water otherwise available for production. The spillway gates are rarely used (Burnt Spillway about once a year and Salmon River Spillway less frequently) and are opened only for maintenance or to spill excess water.

5. Energy Conversion of Water. Hydro provided the following energy conversions for the various structures in terms of barrels of No. 6 fuel oil consumed at the Holyrood Thermal Generating Station.

   - The closure of an intake gate resulting in lost production has the equivalent of 5,700 barrels/day.
   - Excess water spilled from Burnt Spillway has a value of 1,050 barrels per million cubic metres (bbls/mcm) of water. Burnt Spillway has a total spill capacity of 1,091 m^3/s.
   - Excess water spilled from Salmon River Spillway has a value of 690 bbls/mcm and the spillway is rated at 1,589 m^3/s.
   - Water over-released at Ebbegunbaeg would be spilled at North Salmon Spillway and has a value of 207 bbls/mcm. Ebbegunbaeg has a total capacity of 338 m^3/s.
   - Water over-released at Victoria would be spilled at Burnt Spillway which has a value of 1,050 bbls/mcm. Victoria Control Structure has a total flow capacity of 153 m^3/s.

6. Fuel Cost. Hydro requested that two values of fuel oil be considered. In 2007, the average purchase price for fuel oil for the Holyrood Thermal Generation Station was $52.50/bbl. The most recent forecast price used by Hydro was prepared in June 2008 and was $117.85/bbl.

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4. Burnt Dam Spillway

4.1 Site Description

The Burnt Dam Spillway consists of two 7 m (22 ft) wide fixed wheel gates that operate under a maximum head of 8 m (26 ft) and are equipped with screw-stem hoists. Both gates are equipped with provision for gain heating, but only one gate is double-sided and heated. Submersible up-lifters are used to keep ice away from the face of the gate. The spillway discharges water out of the Bay d'Espoir Hydroelectric system that would otherwise be used by three generating stations: Granite Canal, Upper Salmon, and Bay d'Espoir. The watershed can flood quickly and the spillway is used annually. The site is manned and there is a hydraulic emergency hoist if there is a power supply or motor failure.

4.2 Site Visit and Functional Testing

4.2.1 Electrical

4.2.1.1 Power Distribution

Power for Burnt Dam Spillway is supplied from an onsite diesel generator plant that runs continuously to supply the gate structure as well as the living quarters. An additional diesel is started when the gate hoists are to be operated. Assessment of the diesel power supply was not in the scope of this study.

The power center at the base of the gate structure is supplied with 600 V 3-phase power from a 40 A breaker in the diesel building. The power center 600 V distribution utilizes a 600 V splitter and disconnects to feed the gate hoist motors, gain heaters, gate heaters and blowers, monorail hoist and a single phase120/240 V step-down transformer. The splitter panel and disconnects appear to be original equipment, are corroded and weathered and are at the end of their service life. The 120/240 V distribution panel supplies the siren, lighting, motor heaters, receptacles and a baseboard heater power center. The 25 kVA, 120/240 V step-down transformer appears to be original equipment and at the end of its service life.

An electrical enclosure at the top of the gate structure originally housed the motor and heater control equipment. This enclosure now serves primarily as junction box as the electrical equipment has been relocated to the power center at the base of the structure. When the cables are replaced and re-routed, this panel will be redundant.

4.2.1.2 Motors and Controls

Each of the two gates has an 11 kW (15 hp) motorized stem screw gate hoist. Starters and controls for the gate hoist have been relocated to the power center at the base of the structure but were not updated at that time. Two new Allen-Bradley size 4 combination starters have been purchased to replace the existing units. One starter has been installed on Gate 1 and the other is being stored in the power center. These starters are significantly oversized for the hoist motors and precautions need to taken to ensure properly sized fuses and overloads are installed.

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The motor nameplate data indicates the rated voltage is 550 V. The motors are original equipment and have been exposed to high humidity and temperature variations for in excess of 40 years and should be replaced.

The monorail hoist was not accessible for a close-up inspection but serious maintenance issues exist with this piece of equipment. The power track supplying the hoist motor is out of service and a temporary cabtire power supply has been installed. This is hazardous and unreliable. The electrical junction box on the hoist is severely corroded and likely no longer watertight. The power track should be replaced by a heated power track bus system in order to prevent ice buildup along the power track during winter season.

Functional tests on Spillway Gate 2 were carried out with the stoplogs in place. Voltage drop, as measured during the raise test, was less than 1% at the motor starter. Voltage unbalance was approximately 1%. Current unbalance was in excess of 10% and the motor load approached the full load rating. Considering the test was performed under very favourable conditions, no ice and stoplogs in place, this could be indicative of other problems and may be an issue during heavier loading conditions. Increased motor loads will likely push the hoist load beyond its capacity and prevent operation of the gate. The higher than expected motor currents are likely the result of higher than design lifting loads due to mechanical binding or misalignment and should be resolved.

4.2.1.3 *Gate and Gain Heaters*

Gate 1 is the only heated gate at the Burnt Spillway structure.

Gate heating for Spillway Gate 1 consists of two gate heaters rated at three by 12 kW, 600 V, 3-phase and two blower motors rated at 0.75 kW (1 hp), 3-phase, 600 V. Both the gate heaters and blower motors are installed within the gate steel enclosure fed through power cables from the 575 V power distribution panel. The blower motors are required to maintain a constant temperature in the various areas of the gate by circulating hot air. Each of the gate heaters and blower motors has been provided with individual controls through switching panel boxes with indications displayed locally over the gain heater panels.

Gain heating for Spillway Gate 1 consists of two sets of gain heaters rated at 6 kW, 600 V, 1-phase, one each installed on the east and west side gains of the spillway gate. In addition, a sill heater rated at 12 kW, 600 V, 1-phase is provided and installed in the gate bottom sill.

The gate and gain heating equipment appears to be original; it is highly corroded with no provision for thermostatic control including high and low current operation during winter and summer months. It was also reported that the blower motor in Spillway Gate 1 fails almost every year and has to be rehabilitated or replaced. Further, there is no provision for remote alarm and indication of gate and gain heaters. Thermostatic control and multi-modes of gate and gain heater operation offer advantages in terms of increased operating efficiencies as well as reduced operation and maintenance costs. The heaters also have a longer life since their operation is mainly controlled by preset temperatures in at least two operating modes. Replacement of gate and gain heating controls including provision for local and remote indication and alarm sensing is therefore required at Gate 1.

Gate 2 has provision for installation of gain heaters in its respective gains; the gate is not insulated and does not have a downstream facing plate. Utilities have started using marine de-icers with success, but have not made the move to discontinue internal gate heating. Not only does internal heating keep ice off the face of the gate and rollers, it also prevents condensation and corrosion inside the gates.

An internally heated gate with upstream de-icers will be more reliable than a non-heated gate. However, operating history for Burnt Spillway does not justify the cost of operating a second heating system and maintaining the equipment in good working order. Overtopping of the dams has not occurred, despite having only one heated gate at each structure with unreliable heating systems. Therefore the risk has been manageable. However, it may be more economical to install, operate and maintain a second gate heating system than managing the risk: overtime, ploughing roads, helicopter travel, etc necessary when a gate does not lift on command. Determination of the cost of managing the risk was beyond the scope of this study.

Burnt Spillway is an ideal test subject for heated/unheated gate question since there are two identical gates and both can have functional gain heaters. Could an un-heated gate perform adequately with well-maintained sill and gain heaters and marine de-icers? Since Burnt Spillway gates are used regularly, this can be monitored and an empirical conclusion reached over time.

Electrical inspection and functional testing were carried out on the gate and gain heating system at Gate 1 during the site visit. The heaters and blower motors were switched on, and currents and voltages of each component were recorded. The heaters and blower motors were found to operate satisfactorily.

4.2.1.4 *Instrumentation Control and Communication*

Presently, head pond measurements are performed manually from a water level measuring device and a staff gauge installed permanently in a heated gauging pit at the upstream west side wall of the spillway gate. The water level measuring device has provision for remote water level indication and telemetry through the supervisory terminal box installed in the diesel generator building. It was however reported that head pond level was manually transmitted by the operating staff stationed 24/7 at Burnt Dam to the system control centre at St. John's.

Gate position sensing was originally performed through a combination of 5-position selector switching and a set of vane actuated switches with provision for remote indications through a set of individual relays at each set position. Any changes to the above mentioned design after installation of the new motor starter panel for Spillway Gate 1 could not be verified during the site inspection.

Lower and upper limit cut-off switches provide over-travel protection to the spillway hoist and hoist motors.

Controls and communication between Gates 1 and 2 and the system control centre at St. John's are performed with a low baud internet connection using VoiP communication protocol and a VHF radio link to Granite Canal Generating Station located 25 kms from the spillway. All spillway

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controls are performed by local operators. No telephones are provided at the spillway gate enclosure; however, telephones are available in the residential building for operators.

The following data was reported to be sent manually from the spillway gates and control dam to the remote station at Granite Canal GS and control centre in St. John's:

- Pond water level.
- Pond water temperature.
- Metrological station data.

No remote camera is installed at the spillway gate locations to provide real time security in the spillway and the dam area and surroundings.

Functional tests on Spillway Gate 2 were carried out and included verification of the upper and lower limit switches. Although the gate was lifted to 9 m (indicated on the staff height gauge), the upper limit switch did not operate.

Functional tests on gate instrumentation were performed on Spillway Gate 2; however tests such as simulation of alarms and remote control were not performed.

4.2.2 *Mechanical*

4.2.2.1 *Gates*

The downstream sides of both gates were visible during the site visit. The stoplogs were in place so that Gate 2 could be dewatered and lifted.

The gate leaves were generally in fair condition. The gates will require painting soon and the bolts holding together the skinplate sections on Gate 2 showed signs of corrosion. There was some loose insulation on Gate 1.

4.2.2.2 *Rollers*

The rollers were inspected on Gate 2 as it was lifted and lowered and they were observed to be in good overall condition. The rollers moved as the gate was lifted and a sample of rollers could be rotated by hand.

4.2.2.3 *Seals and Guides*

The side seals are brass rods and are generally in good shape. There was some small leakage on the sides. The bottom seals were not visible but it was noted that Gate 1 sealed well on the bottom.

The guides for Gate 2 appeared to be in good condition.

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As Gate 2 was lifted, the brass seal rods produced a fair amount of vibration noise and the gate rubbed against the upper guides near the top of its range of motion. The brass seal rods are a free-moving bar held in place by water pressure. Since the gate was lifted behind stoplogs, the hydrostatic head on the gate quickly dissipated and there was no load on the rods to prevent them from vibrating. The gate rubbing on the upper guides may be just excessive paint buildup, but the motor current readings during lift were high and further investigation is warranted.

4.2.2.4 *Hoists*

The screw stem hoists are original to the structure. Generally the hoists are in fair condition but are showing signs of wear. The reducing gear box has water-contaminated oil in Gate 2 and water infiltration into the screw hoists is also a concern. The screw stems appear to be in good condition but need to be cleaned of excessive grease. Although the emergency hydraulic hoist provides back-up in event of power supply failure or motor failure, it cannot move a gate if there are problems with the gearbox, screw stems or screw hoists and it does take some time to set up so operation of the gate is delayed.

Refurbishment of the hoists is required as follows.

- Gear Box: Disassemble, inspect and repair gears as necessary, replace bushings, replace heater, replace seals.
- Shafts, couplings and bushings: Disassemble, Liquid Penetrant Inspection, replace bushings
- Hoists: Disassemble and clean, inspect and repair gears as necessary, replace bushings, inspect bronze lift nut, inspect thrust bearing, replace seals, check/repair/replace grease lines. (Be equipped to replace lift nut and thrust bearing.)
- Screw Stems: Clean, inspect and local repairs to threads as necessary. (Replace if not straight or elongation observed.)
- Limit Switches: Test, repair or replace. Replace weather covers.

There was a program of greasing the screw stems which has now created the situation of excessive buildup of hardened grease in the screw hoists. Grease is used for both screw-stem protection and smooth operation of the hoist. A major hoist manufacturer, Armtec recommends Shell SRS 2000 for screw stem lubrication and inspection every six months: if lubricant is dirty or feels gritty, completely remove grease and apply new grease. The recommended methodology is to open the gate and remove grease from the stem (above the hoist) while running the gate. Apply new grease to the stem above the hoist while closing the gate, thereby cleaning the lift nut with new grease. Remove excess grease from top (clean) and bottom (dirty) of hoist.

A well-fitted telescopic stem cover may help keep the grease clean, but may also cause other problems such as condensation and corrosion. Alternatively, changing the grease as per the above procedure every two years, during the dewatering PM, may work better.

4.2.2.5 *Stoplogs and Hoist*

The stoplogs were in place for isolation of Gate 2 and could not be directly observed. Leakage between logs was evident.

Hydro staff identified that there was a safety concern with the masterlog; the stoplogs must rotate 90° from the stored to in-service position. The stoplog monorail hoist was in poor condition and poses a safety hazard. It was not operated during the site visit, but it was reported that there are recurring problems with the bus bars and it was evident that hoist trolley does not travel fully on the monorail beam near Gate 1.

4.3 Maintenance Records Review

There were four work orders issued since 2005 that dealt with a gate failing to operate. Three of these work orders originated in either November or January months, and are thus assumed to be related to spill events.

There are annual and bi-annual preventative maintenance routines for the gates. The routines are fairly thorough and include dewatering a gate every two years.

4.4 Health Index

The Heath Index score for the Burnt Spillway Gates is 66, which corresponds to a condition of Good.

Components	Weight	Condition Rating	Weighted Score
Gate	8	2	16
Roller Assemblies	4	3	12
Seals & Guides	2	3	6
Gate Hoist	4	2	8
Stoplogs and Hoist	1	1	1
Cubicles, Enclosures & Buildings	1	2	2
600V Splitter Panel	3	1	3
Branch Panel	2	2	4
Transformer	3	1	3
Cables	3	2	6
Total of Observed Components	31		61
Maximum Possible Score	31	3	93
Health Index	(61/93)*100		66

4.5 HydroVantage Analysis Results

Five components were studied with HydroVantage: the motors, the gate/gain heaters, the screw stem hoist (less gearbox), the hoist reducer gearbox, and the roller assemblies.

For analysis purposes, it is assumed that a forced outage will only produce consequence costs if the failure causes delay in closing a gate and hence release of too much water during a spill event. It is

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assumed that, since there are two gates, the likelihood of needing both gates open or being able to open neither gate is remote.

The results of the analysis using the 2007 average fuel cost are as follows:

- Replace the motors now.
- Replace the entire gate and gain heating system now.
- Rehabilitate the hoists now.
- Replace the hoist reducer gearbox now.
- Rehabilitate the roller assemblies now.

The results of the analysis cannot be more definitive; Burnt Spillway has such a high risk cost that intervention can be justified at even a very low fuel cost.

The consequence cost of a failure at the Burnt Spillway is exceptionally high at $2.6 million per day using the 2007 average fuel cost. The high consequence cost combined with the frequent use of the spillway and frequent failure (as per the work order history) results in very high risk. Thus any action to reduce risk can be easily justified. A high-level study was performed to determine if the high risk and high operating costs of the spillway structure could justify complete replacement of the spillway gates with an overflow spillway. An overflow spillway would require no electrical, no manpower and little maintenance. An overflow spillway sized to replace both gates is estimated to cost $11 million and one sized to replace one gate is estimated to be half as much. Although the risk cost of the spillway gates is very high, it can be reduced by rehabilitation of components (less than $0.5 million) and thus rehabilitation is a cheaper alternative than complete replacement. However, building an overflow spillway sized to handle most floods (say 1:10 or 1:20 year floods) could allow operation of the structure without permanent attendance and would significantly reduce operating cost and risk. This alternative should be investigated further but should not delay immediate actions to reduce risk such as gate rehabilitation.

4.6 Recommendations, Burnt Spillway

4.6.1 Short Term (0-2 Years)

18. Refurbish the electrical/mechanical components of the structure including: gate painting, inspection of embedded parts, roller assembly rehabilitation, hoist refurbishment, motor replacement, and heating system replacement including controls with provision for dual operating modes and thermostatic temperature controls.
19. Upgrade existing water level measuring instrumentation with capability to transfer water level data to remote centre.
20. Calibrate and re-test the upper and lower cut-off limit switches for proper functionality and safety.

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21. Upgrade the communication system to a broadband system by radio or satellite for automatic transfer of gate control and water level data, and other parameters for alarm, indication including video signals and reporting to remote control centre.
22. Replace all 600 V distribution equipment in the power center (splitter panel, disconnects, step-down transformer.)
23. Replace the 120/240 V distribution panel.
24. Replace and re-route all power and control cables, making the electrical panel at the top of the structure redundant and eliminating unnecessary terminations that are a source of potential problems.
25. Replace stoplog monorail hoist. Replace existing power track with a heated power track bus system.

4.6.2 *Medium Term (2-7 Years)*

26. Investigate requirement for remote operation of the two spillway gates by installing PLC based controls and data acquisition equipment for transfer of data and control.
27. Investigate replacement or upgrade of gate positioning devices at Spillway Gates 1 and 2 by digital encoders or infrared position devices.
28. Investigate full or partial replacement of gated spillway structure with overflow structure.

4.6.3 *Long Term (Beyond 7 Years)*

29. Investigate requirement of gate and gain heating for Spillway Gate 2, in view of high risk costs.
30. Install video camera fitted with defrosting visor for real time surveillance and security against illegal intrusions.

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Burnt Spillway

Short Term Recommendations (0-2 Years)			Medium Term Recommendations (2-7 Years)			Long Term Recommendations (Beyond 7 Years)		
No.	Brief Description	Budget Cost	No.	Brief Description	Budget Cost	No.	Brief Description	Budget Cost
18	Mech/Elec Refurbishment	140,000	26	Investigate Remote Operation	10,000	29	Heating Gate 2	10,000
19	Water Level Measurement	25,000	27	Investigate Gate Positioning	5,000	30	Video Camera	50,000
20	Calibrate limit switches	0	28	Investigate Overflow Spillway	50,000			
21	Broad Band Communications	100,000						
22	600V Distribution Equipment	15,000						
23	120/240V Distribution Panel	5,000						
24	Power and Control Cables	10,000						
25	Stoplog Monorail Hoist	75,000						
		370,000			65,000			60,000

Total for Burnt Spillway $495,000

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Project Title: Install Weatherhoods for Vent Fans

Location: Holyrood

Category: Generation - Thermal

Type: Other

Classification: Normal

Project Description:

This project is required to install corrosion resistant weatherhoods on 12 exhaust fan outlets located on the exterior wall of Stage 1 of the Holyrood Thermal Generating Station (Holyrood). This project will improve the efficiency of the exhaust air system in the upper elevations of Stage 1 of the Holyrood plant during windy days. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	54.6	0.0	0.0	54.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	111.3	0.0	0.0	111.3
Other Direct Costs	1.0	0.0	0.0	1.0
O/H, AFUDC & Escln.	24.6	0.0	0.0	24.6
Contingency	16.7	0.0	0.0	16.7
TOTAL	**208.2**	**0.0**	**0.0**	**208.2**

Existing System:

The Holyrood Thermal Generating Station was constructed in two stages. Stage 1 was completed in 1971 bringing on line two generating units, Units 1 and 2, each rated at 150 MW. Stage 2 was completed in 1979 bringing on line an additional unit, Unit 3, also rated at 150 MW. Units 1 and 2 were up-rated to 170 MW in 1988 and 1989 respectively.

Twelve exhaust fans are currently installed in Stage 1 to exhaust air from the upper elevations of the plant. Four fans are located on the north side of the plant and eight are located on the south side. These exhaust fans are used to control the heat and humidity inside the plant. As well, they remove dust particles from the plant.

High wind is a common weather occurrence around Holyrood. High winds push against the building's exterior and interfere with the flow of exhaust air out of the building. High wind does not interfere with exhaust air flowing from Stage 2. However, in Stage 1, much of the air that is exhausted makes its way back into the plant. To improve ventilation and heat dissipation in Stage 1 during windy periods, operators often open doors along the north and south walls. Also, some windows and roof hatches are opened to improve air quality.

Air flow testing on the Stage 1 and Stage 2 exhaust fans was performed by Hydro's engineering staff. This testing revealed that on windy days, the fans in Stage 1 do not operate as efficiently as those in Stage 2. As a result, the air quality in Stage 1 diminishes during windy days.



Figure 1: Holyrood Thermal Generating Station

Figure 1 shows a photo of Stage 1 and Stage 2 of Holyrood. The Stage 1 exhaust fan outlets on the south side of the plant are circled in Figure 1. Notice that the adjacent Stage 2 exhaust fan outlets have weatherhoods and those in Stage 1 do not. A typical Stage 2 weatherhood is shown in Figure 2.

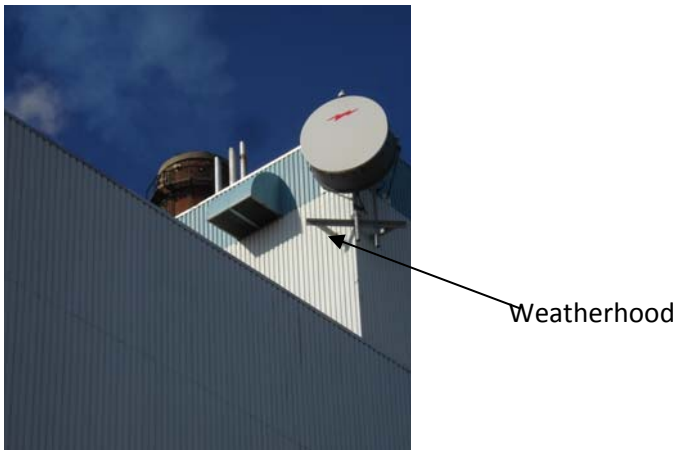

Figure 2: Typical Stage 2 Weatherhood

Age of Equipment or System

Holyrood Stage 1 was constructed in the period 1969 to 1971. The Stage 1 exhaust air system was installed in 1969 during the construction. Unlike Stage 2, weatherhoods were not installed on the 12 exhaust fan outlets in Stage 1.

Major Work/or Upgrades

Stage 1 exhaust fan outlets do not have weatherhoods installed. Therefore, this section is not applicable to this project.

Anticipated Useful Life

The weatherhoods have an estimated service life that exceeds the end of service life for Holyrood, forecasted to extend to the year 2020.

Maintenance History

Since this is a new installation, maintenance history is not applicable.

Outage Statistics

The exhaust fan outlets being modified under this project do not affect or cause plant outages.

Industry Experience

The Stage 2 exhaust fan outlets have weatherhoods. These weatherhoods have proven their

effectiveness in maintaining exhaust fan performance during windy days when the wind pressure on the exterior of the building is high. Refer to Appendix A for air flow test results taken by Hydro for both Stage 1 and Stage 2 exhaust fans. The data indicates that unlike Stage 1, Stage 2 exhaust fans do not experience backflow during windy days.

Maintenance or Support Arrangements

The weatherhoods installed under this project will be maintained by Hydro personnel at Holyrood in the same fashion as those installed on Stage 2 exhaust fan outlets.

Vendor Recommendations

There are no vendor recommendations associated with this project.

Availability of Replacement Parts

Replacement parts for the weatherhoods are available locally from suppliers of sheet metal products.

Safety Performance

Exhaust fans perform an important function at any thermal generating station. Harmful fumes, gases, and heat are extracted from Holyrood by the exhaust fans. Due to the decrease in fan performance during windy days, the Holyrood Occupational Health and Safety Committee (OHSC) regularly discuss health issues regarding exhaust fans and the status of this project within Hydro's capital budget plan. Appendix B contains OHSC committee meeting minutes for November 17 and 25, 2009, and January 13, 2010. This project is referred to as the Power House Fan Hoods project in these meeting minutes.

Environmental Performance

There are no environmental performance issues related to this project.

Operating Regime

The Stage 1 exhaust fans operate continuously when generating Units 1 and 2 are operating.

Justification:

This project is justified on the basis of improving safety and health in the workplace. During high winds, the wind pressure against the north and south exterior walls of the Holyrood Thermal Generating Station is strong enough to force previously exhausted air back into the plant through the exhaust fan outlets installed in Stage 1. Airflow measurements, taken by Hydro's Engineering Services and the Holyrood engineering staff, revealed that the backflow of air was 45 percent, with a peak of 78 percent when outdoor winds speeds reached 50 kilometers per hour. Refer to Appendix A for airflow testing data.

Weatherhoods help mitigate the effects of wind pressure by shielding the exhaust air outlets from the wind and by directing the flow of exhaust air downward. As proven by air flow testing data, the use of weatherhoods has enhanced the exhausting capabilities of exhaust fans in Stage 2 during windy days. Adding weatherhoods to the exhaust fans in Stage 1 will improve the health and safety of workers by improving air quality in this section of the plant.

Net Present Value

A net present value calculation is not required since there are no viable alternatives.

Levelized Cost of Energy

The levelized cost of energy is not applicable since no new generation source is being considered.

Cost Benefit Analysis

A cost benefit analysis has not been performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

Since this is not a recurring project, historical information is not available.

Customer Growth

This project is not required to accommodate customer load growth.

Energy Efficiency Benefits

There are no energy efficiency benefits resulting from this project.

Losses during Construction

There will be no losses during construction as a result of this project since all installation work will be done during scheduled outages.

Status Quo

The status quo is not acceptable. If this project is not completed, Stage 1 of the Holyrood plant will continue to experience a buildup of fumes, gases, and heat in the upper elevations of the plant during windy days. This is no longer acceptable.

Alternatives

The only viable alternative is to install weatherhoods on the 12 exhaust fan outlets of Stage 1 at Holyrood.

Conclusion:

Corrosion-resistant weatherhoods are needed on the 12 exhaust fan outlets located on the exterior wall of Stage 1 at Holyrood. This will improve the efficiency of the exhaust air system in the upper elevations of Stage 1 during windy days. This will result in an improvement in air quality and in turn, will improve the health and safety of workers in the plant.

Project Schedule

The proposed project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Milestone
Project Initiation	January 2011
Construction Tender	May 2011
Installation	August 2011
Project Closeout	November 2011

Appendix A

WALL EXHAUST FAN FLOW MEASUREMENT DATA

Test 1

Unit 1

Fan #	Flow (cfm)				Wind (km/h)	Weather Hood	Building Pressure (in H20)
	Out	Backflow	Backflow %	Nett Flow			
1 (South)	11692.8	6982.8	59.7	4710.0	SW 50 to 70	no	-0.5
2 (South)	11664.0	5246.3	45.0	6417.7	SW 50 to 70	no	-0.5
3 (South)	12508.8	5697.1	45.5	6811.7	SW 50 to 70	no	-0.5
4 (South)	11846.4	9308.1	78.6	2538.3	SW 50 to 70	no	-0.5
5 (North)	15321.8	NIL	NIL	15321.8	SW 50 to 70	no	-0.5
6 (North)	13078.2	NIL	NIL	13078.2	SW 50 to 70	no	-0.5

Unit 2

Fan #	Flow (cfm)				Wind (km/h)	Weather Hood	Building Pressure (in H20)
	Out	Backflow	Backflow %	Nett Flow			
7 (South)	10569.6	4489.6	42.5	6080.0	SW 50 to 70	no	-0.5
8 (South)	11875.2	4089.4	34.4	7785.8	SW 50 to 70	no	-0.5
9 (South)	11990.4	2063.1	17.2	9927.3	SW 50 to 70	no	-0.5
10 (South)	11692.8	4602.3	39.4	7090.5	SW 50 to 70	no	-0.5
11 (North)	15719.4	NIL	NIL	15719.4	SW 50 to 70	no	-0.5
12 (North)	12936.2	NIL	NIL	12936.2	SW 50 to 70	no	-0.5

Unit 3

Fan #	Flow (cfm)				Wind (km/h)	Weather Hood	Building Pressure (in H20)
	Out	Backflow	Backflow %	Nett Flow			
1 (South)	9596.5	NIL	NIL	9596.5	SW 50 to 70	yes	-0.5
2 (South)	7531.0	NIL	NIL	7531.0	SW 50 to 70	yes	-0.5
3 (South)	11075.5	NIL	NIL	11075.5	SW 50 to 70	yes	-0.5
4 (South)	12444.0	NIL	NIL	12444.0	SW 50 to 70	yes	-0.5
5 (South)	11288.0	NIL	NIL	11288.0	SW 50 to 70	yes	-0.5
6 (South)	10965.0	NIL	NIL	10965.0	SW 50 to 70	yes	-0.5

WALL EXHAUST FAN FLOW MEASURMENT DATA

Test 2

Unit 1

Fan #	Flow (cfm) Out	Backflow	Backflow %	Nett Flow	Wind (km/h)	Weather Hood	Building Pressure (in H20)
1 (South)	11899.2	3154.1	26.5	8745.1	S37 to 57	no	-0.2
2 (South)	12154.5	3312.7	27.3	8841.8	S37 to 57	no	-0.2
3 (South)	11555.1	3174.5	27.5	8380.6	S37 to 57	no	-0.2
4 (South)	11310.9	3527.8	31.2	7783.1	S37 to 57	no	-0.2
5 (North)	17608.0	NIL	NIL	17608.0	S37 to 57	no	-0.2
6 (North)	15676.8	NIL	NIL	15676.8	S37 to 57	no	-0.2

Unit 2

Fan #	Flow (cfm) Out	Backflow	Backflow %	Nett Flow	Wind (km/h)	Weather Hood	Building Pressure (in H20)
7 (South)	13098.0	2954.7	22.6	10143.3	S37 to 57	no	-0.2
8 (South)	12853.8	3422.6	27.6	9431.2	S37 to 57	no	-0.2
9 (South)	11277.6	3253.0	28.8	8024.6	S37 to 57	no	-0.2
10 (South)	11444.1	3014.4	26.3	8429.7	S37 to 57	no	-0.2
11 (North)	16756.0	NIL	NIL	16756.0	S37 to 57	no	-0.2
12 (North)	14427.2	NIL	NIL	14427.2	S37 to 57	no	-0.2

Unit 3

Fan #	Flow (cfm) Out	Backflow	Backflow %	Nett Flow	Wind (km/h)	Weather Hood	Building Pressure (in H20)
1 (South)	8602.0	NIL	NIL	8602.0	S37 to 57	yes	-0.2
2 (South)	9919.5	NIL	NIL	9919.5	S37 to 57	yes	-0.2
3 (South)	14110.0	NIL	NIL	14110.0	S37 to 57	yes	-0.2
4 (South)	15079.0	NIL	NIL	15079.0	S37 to 57	yes	-0.2
5 (South)	11798.0	NIL	NIL	11798.0	S37 to 57	yes	-0.2
6 (South)	11075.5	NIL	NIL	11075.5	S37 to 57	yes	-0.2

Appendix B

newfoundland labrador hydro
a nalcor energy company

File # 102.01.17/3

November 17, 2009

To: Terry LeDrew, Plant Manager

Fr: Holyrood OHSC

PERMANENT RETAIN IN FILE

A meeting of the OHSC was held from 1:30 to 3:00 PM on November 17, 2009 to review the following topics:

- The current state of the Warm-Air Make-Up System and Improvements required – the OHS committee requests a meeting to begin dialogue on a way forward; and,
- The Capital Budget Program 2010 – 2014 and the methodologies used to establish priorities for Capital Projects – the committee requests a meeting: to review how the current process can be improved to ensure proper weighting and timing is given to safety related projects; and, to review the possibility of changing the timing of the projects in the current 2010 – 2014 program, namely Pump House MCCs, Plant Roof Access Ladders, Unit 3 Relay Logic Panel, Carpenter Shop Relocation, Power House Fan Hoods – recognizing that some of these are relatively low cost improvements.

The committee requests a meeting to review these topics prior to end of day, Friday November 20, 2009.

Thanks for the consideration given these ongoing plant concerns.

On Behalf of Holyrood OHSC,

for JABEZ LANE

JABEZ LANE, OHSC CO-CHAIR
Union

WAYNE RICE, OHSC CO-CHAIR
Management

newfoundland labrador hydro
a nalcor energy company

File # 102.01.17/3

November 25, 2009

PERMANENT RETAIN IN FILE

To: Terry LeDrew, Plant Manager

Fr: Holyrood OHSC, Meeting November 24, 2009

In Attendance:

Mike Flynn (OHSC Member – Management)

Wade Kelloway (Safety Coordinator)

Jabez Lane (OHSC Co-Chair – Union)

Terry LeDrew (Plant Manager)

Fred Penny (OHSC Member – Union)

Wayne Rice (OHSC Co-Chair – Management)

Charlie Saunders (OHSC Member – Union)

Subject: Warm-Air Make-Up System and Capital Project Timing

Thank-you for meeting with us yesterday and advising on: the status of plans for a concerted effort to perform maintenance on the warm-air make-up system with a view to a staged return to service of the individual ventilation units; and, plans to bring our HVAC service contractor Johnston Controls to site for an initial review of the warm air make-up system with a view to initializing a larger engineering study. We ask that you update us as this unfolds and we recognize that much review is needed to establish scopes and schedules for repair.

The Committee acknowledges the positive discussion held on: the prioritization of capital projects in the 5 year plan and the need to improve how proper weighting and timing is given to safety related projects; and, the possibility of changing the timing of certain projects in the current 2010 – 2014 program, namely Pump House MCCs, Plant Roof Access Ladders, Unit 3 Relay Logic Panel, Carpenter Shop Relocation, Power House Fan Hoods. The Committee acknowledges that the 2010 capital budget program has been submitted for PUB review and that this request comes at a less than ideal time. However, we feel that the safety concerns of

the projects listed are such that they warrant another review for advancement to 2010. To support this effort, the Committee is prepared to offer assistance in support of this change by soliciting the opinion of a representative (s) of the Department of Government Services, who could, as a minimum, review the projects against recently revised OHS Regulations.

Notwithstanding, the timing of the request, we submit that this request be viewed in a positive light as a further demonstration of the Plant's ever-increasing commitment to Safety Leadership.

The Committee would appreciate a timely response – thanks for consideration given these ongoing plant concerns.

On Behalf of Holyrood OHSC,

JABEZ LANE, OHSC CO-CHAIR
Union

WAYNE RICE, OHSC CO-CHAIR
Management

c.c. Greg Burry, Gerard Molloy (OHSC Members – Union)

newfoundland labrador hydro
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File # 102.01.17/3

January 13, 2010

To: Terry LeDrew, Plant Manager

Fr: Holyrood OHSC, Meeting January 13, 2010

PERMANENT RETAIN IN FILE

In Attendance:

Greg Burry (OHSC – Union)

Jabez Lane (OHSC Co-Chair – Union)

Fred Penny (OHSC Member – Union)

Wayne Rice (OHSC Co-Chair – Management)

Charlie Saunders (OHSC Member – Union)

Absent:

Mike Flynn (OHSC Member – Management)

Wade Kelloway (Safety Coordinator)

Greg Molloy (OHSC – Union)

Subject: Warm-Air Make-Up System and Capital Project Timing

A OHSC met today to review status of issues noted in the letter from the committee dated November 25, 2009, namely:

1. *The status of plans for a concerted effort to perform maintenance on the warm-air make-up system with a view to a staged return to service of the individual ventilation units; and, plans to bring our HVAC service contractor Johnston Controls to site for an initial review of the warm air make-up system with a view to initializing a larger engineering study.*

2. *In general, the timing and prioritization of safety related projects; and, the possibility of changing the timing of certain projects in the current 2010 – 2014 program, namely Pump House MCCs, Plant Roof Access Ladders, Unit 3 Relay Logic Panel, Carpenter Shop Relocation, Power House Fan Hoods. The Committee acknowledges that the 2010*

capital budget program has been submitted for PUB review and that this request comes at a less than ideal time. However, we feel that the safety concerns of the projects listed are such that they warrant another review for advancement to 2010

With respect to item #1, following the review of the system condition spear-headed by Glen Kennedy in December 2009 and as you requested, the OHSC co-chairs have reviewed individually and also today with other committee members how best to coordinate the ongoing maintenance effort. The general consensus is that for the system to be made operational to the point that it can be covered through routine work orders, coordination with the various shops should be guided by someone with an engineering/technical background, e.g. Plant Mechanical Engineer. Further, that group could eventually act in an advisory role for consultant's coming to site. The committee also feels that the Warm Air Make-Up is a vital plant system and therefore deserves as much annual maintenance attention and capital upgrade consideration as other parts of the facility. Please advise on: the composition of the maintenance steering group; and, the plans to complete an HVAC review.

With respect to item #2, the committee acknowledges that, following the letter of November 25th, 2009, there have been positive actions taken: a meeting was set up to review the project prioritization with assets; all of the five projects under consideration namely Pump House MCCs, Plant Roof Access Ladders, Unit 3 Relay Logic Panel, Carpenter Shop Relocation, Power House Fan Hoods have been moved to 2011; you have updated the committee that the Engineering portion of the Pump house MCC project is scheduled for 2010, albeit the project is still under review; and, consideration is being given to making this a single year project for 2010.

Please provide an update on the status of the remaining projects.

The Committee would appreciate a timely response – thanks for consideration given these ongoing plant concerns.

On Behalf of Holyrood OHSC,

for JABEZ LANE

JABEZ LANE, OHSC CO-CHAIR
Union

WAYNE RICE, OHSC CO-CHAIR
Management

c.c. Gerard Molloy, Mike Flynn

Project Title: Replace Substation Infrastructure

Location: Burgeo

Category: Transmission and Rural Operations - Distribution

Type: Other

Classification: Normal

Project Description:

This project is required to replace the following infrastructure at the Burgeo Substation:

- six Blackjack Wood Poles;
- 27 Crossarms;
- 21 Suspension Insulators;
- 21 Pin-Type Insulators; and
- nine Bypass Switches.

During construction, a 25/4.16 kV mobile transformer will be required to supply power to the three distribution feeders from the Burgeo substation. The use of this mobile transformer will allow dismantling of the existing substandard substation and rebuilding the new substation in the same location, without major customer outages. Existing equipment, such as the power transformer which was installed in 1987 and reclosers, will be re-installed after the new infrastructure is replaced. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	30.0	100.0	0.0	130.0
Labour	68.0	82.0	0.0	150.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	80.0	0.0	0.0
Other Direct Costs	18.0	20.0	0.0	38.0
O/H, AFUDC & Escln.	11.5	46.5	0.0	58.0
Contingency	0.0	39.8	0.0	39.8
TOTAL	**127.5**	**368.3**	**0.0**	**495.8**

Existing System:

The community of Burgeo is located on the southwest coast of the Province. The Burgeo Substation receives power via a three-phase 25 kV distribution line (L1) that originates at the Grandy Brook Terminal Station at an approximate distance of 26 kilometers. The substation contains one 5/6.6/8.3 MVA, 25/4.16 kV transformer that serves approximately 350 customers in the community of Burgeo. Figure 1 shows a picture of the Burgeo substation.



Figure 1: Burgeo Substation

The Burgeo substation was constructed in 1967. At the time of construction blackjack wood poles were used. The poles have deteriorated and require replacement. Hydro has an ongoing capital program to remove all blackjack poles from its distribution systems. Blackjack poles are poles that were pressure treated with creosote for protection against moisture and insect damage. They were widely used for distribution construction during the 1960's and 1970's. Over

time, the protective creosote coating tends to leech into the surrounding earth causing potential for ground/water contamination. As a result of this, blackjack poles are no longer environmentally acceptable and are no longer used in the utility industry. In addition, industry experience has shown that blackjack poles pose a risk to the safety of operations workers and the structure reliability of the distribution system.

The majority of substation components was installed at the time of original construction and have far exceeded their economic lives of 30 years. The poles, crossarms, insulators, and switches in the substation are deteriorated and have an expected remaining life of one to five years before widespread failure occurs. The porcelain suspension insulators are no longer used by Hydro due to the fact that industry experience has shown that they are unsafe by today's standards or commercially unavailable. As the cement in the porcelain ages, it expands and cracks. This aging process exerts pressure on the porcelain part of the insulator such that the porcelain cracks and causes the insulator to fail. Hydro also has an ongoing capital program to replace aging porcelain insulators.

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

Also, the substation electrical grounding systems are operational but do not comply with current Hydro Distribution Standard DI-15-01 for System Grounding. This standard states that substation grounding resistivity is to be less than six ohms. Currently the condition of the grounding system in this substation does not allow for less than six ohms of ground resistance. This presents a safety hazard for Operations personnel.

The substation has deteriorated components as listed below:

- Damaged and corroded concrete equipment pads;
- Exposed electrical grounding in some areas; and
- A burned off underground 4.16 kV line has been temporarily replaced with an overhead line.

This temporary overhead line consists of one new pole structure which is located just outside of the station fence, and a new conductor which extends to the next existing pole in distribution line L2. This pole is where the previous underground line was brought up the pole and converted to be an overhead line and it has not been changed or modified except for the connection of overhead conductor from the new temporary structure, and removal of the underground conductor since the temporary overhead line has been in place.

Also, currently there is not enough room on one side of the station to physically open switches while standing inside the fence. Switching on this side of the station has to be performed from outside the fence which creates a safety hazard and does not comply with current switching standards and procedures.

Age of Equipment or System

The substation was constructed in 1967 and is currently 43 years old.

Major Work/or Upgrades

There have been no major work or upgrades performed on the substation.

Anticipated Useful Life

The anticipated useful life of this distribution substation is 30 years.

Maintenance History

Maintenance history for the substation is included in the maintenance history for the 25 kV line, L1. Hydro does not record maintenance costs separately for the substation. The five-year maintenance history for the substation and line is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	0.0	10.1	10.1
2008	1.6	8.9	10.5
2007	27.4	5.8	33.2
2006	0.0	16.3	16.3
2005	0.5	23.7	24.2

Outage Statistics

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

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

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

Table 3 lists the 2005 to 2009 SAIFI and SAIDI data, 2005 to 2009 corporate values, and the latest CEA five year average (2004 to 2008) for comparison. Hydro does not determine SAIFI and SAIDI down to a substation level so data is provided for the Grandy Brook Distribution System to which the Burgeo substation belongs.

Table 3: Outage Statistics - SAIFI SAIDI Data

Five Year Averages (2005 to 2009)				
Location	All Causes		Defective Equipment	
	SAIFI	SAIDI	SAIFI	SAIDI
Grandy Brook Distribution System	2.54	3.95	0.21	0.36
Hydro Corporate	5.65	9.27	0.42	0.93
CEA (2004 – 2008)	2.65	7.74	0.49	1.28

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

Industry Experience

Using a standardized inspection/grading system within the utility industry, this substation has been identified for replacement as it is close to the end of its useful life. Hydro performs inspections on all distribution line components classifying them using the following standardized grading system:

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

Of the six poles that form the substation, three are rotten which means they are Grade "C" and have been determined as being very close to failure, possibly within a year. The remaining three poles have been classified as Grade "B". Also, all of the crossarms have been identified as being either Grade "C" or Grade "B" and also pose a high risk of failure. The crossarms are made of the same material as the blackjack poles.

Maintenance or Support Arrangements

A visual inspection of this substation is performed approximately every six months to evaluate the condition of the substation. This inspection is completed by Hydro personnel and any corrective maintenance required is reported, scheduled and completed.

Vendor Recommendations

There are no vendor recommendations for this project.

Availability of Replacement Parts

Replacement parts are generally available however porcelain suspension insulators have been replaced with polymer suspension insulators due to higher durability and vandalism resistance.

Safety Performance

The following safety issues have been identified:

- The poles are deteriorated, rotten, and pose a risk to the safety of operations personnel who may be performing climbing activities to conduct regular inspections or maintenance work.
- This station's electrical grounding grid uses copper ground conductor. Copper conductor becomes very brittle and more susceptible to breakage over time. A conductor failure would result in outages and may result in potential injury or damage to persons and property.

Environmental Performance

No environmental issues have been identified other than the removal of blackjack poles.

Operating Regime

The Burgeo Substation is in continuous operation providing service to approximately 350 customers in the community of Burgeo.

Justification:

The Burgeo Substation was originally constructed over 40 years ago. Substation components to be replaced with this project were installed at the time of original construction and have exceeded their useful lives. Hydro's standardized inspection and testing procedures indicate that the substation components are greatly deteriorated and may have a remaining life span of only one to five years before widespread failure occurs.

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

level of difficulty in material procurement for repair.

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

Net Present Value

A net present value calculation was not performed in this instance as there is no viable alternative to replacing the deteriorated components of the substation.

Levelized Cost of Energy

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

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

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

Historical Information

There have been no substation replacements within the past five years.

Forecast Customer Growth

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

Energy Efficiency Benefits

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

Losses during Construction

There are no anticipated energy losses during construction.

Status Quo

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

- The substation has exceeded its economic life of 30 years;
- Failure to upgrade the existing substation could increase the number of outages due to deteriorated components; and
- The presence of blackjack poles poses a safety risk to Hydro operations personnel and are not environmentally acceptable.

Alternatives

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

Conclusion:

This project is required to ensure that a reliable energy supply is available for the customers serviced by this substation. Since the existing substation has achieved its 30 year lifespan, to avoid jeopardizing the integrity of the system, it is recommended to replace these substation components by 2012.

Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity	Milestone
Initiation	April 2011
Design Complete	June 2011
Equipment Ordered	August 2011
Installation Commences	June 2012
Installation Complete	September 2012
Project Closeout	October 2012

Project Title: Replace Insulators

Location: Various Sites

Category: Transmission and Rural Operations – Terminal Stations

Type: Pooled

Classification: Normal

Project Description:

This project consists of the purchase and installation of 230, 138 and 69 kV station post and suspension insulators at various high voltage terminal stations on the Island Interconnected System. This project is part of a multi- year program for replacement of insulators which started in 2003. The insulators will be purchased in bulk and delivered to Hydro's central maintenance facility at Bishop Falls. Then as outages are scheduled, the insulators will be shipped from this central location for installation in the particular stations. The 2011 budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	193.5	0.0	0.0	193.5
Labour	124.0	0.0	0.0	124.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escln.	32.2	0.0	0.0	32.2
Contingency	33.6	0.0	0.0	33.6
TOTAL	**401.3**	**0.0**	**0.0**	**401.3**

Existing System:

Insulators are an integral part of the transmission system. They support and insulate the energized portions of the system from the structures and grounded areas. Terminal Stations contain post-type insulators, cap and pin-top insulators, mulitcone design insulators, and suspension type insulators. As the cement in these insulators age, it grows and cracks. As the cement growth progresses, it exerts increased pressure on the porcelain part of the insulator such that the porcelain cracks and causes the insulator to fail.

Age of Equipment or System

The insulators in use on the Island Interconnected System range in age from one to forty two years. The insulators targeted for replacement under this project were manufactured before the mid 1970's. There are approximately 50 percent left to be replaced.

Major Work/or Upgrades

There has been no major work or upgrades on terminal station insulators since they were installed. Replacements have only been made as failures occurred or as part of this insulator replacement program.

Anticipated Useful Life

The anticipated service life of the new insulators is 40 years; however, this may vary depending on the service environment.

Maintenance History

Normal maintenance for insulators is to replace them upon failure.

Outage Statistics

Hydro tracks all system outages using industry standard indexes System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI). SAIDI and SAIFI are explained as follows:

SAIDI - Indicates the system average interruption duration for customers served per year, or the average length of time a customer is without power in the respective distribution system per year.

SAIFI - Indicates the average of sustained interruptions per customer served per year, or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 2 lists the 2005 to 2009 system average transmission (T) T-SAIFI and T-SAIDI data and the latest CEA five year averages (2003 to 2007). CEA statistics for 2004 to 2008 are not issued yet.

Table 2: SAIFI/SAIDI Average

Five Year Averages		
	T-SAIFI	**T-SAIDI**
Hydro System (2005-2009)	1.01	59.07
CEA (2003-2007)	0.85	130.71

The stats do not relate directly to insulator failures but they include insulator and other station equipment failures at the delivery point.

Industry Experience

The industry experience of cement growth and cracking with the older Canadian Ohio Brass (COB) insulators manufactured prior to the mid 1970's is the same as Hydro's.

Maintenance or Support Arrangements

Normal operation and maintenance work is performed by Hydro personnel. A visual inspection of the terminal stations is done every ninety days during which insulators are checked for cracks or chips.

Vendor Recommendations

Hydro maintains regular contact with other major utilities and equipment manufacturers on matters related to the operation and maintenance of its equipment. Current insulator manufacturers have identified and researched the cement growth problems and have developed more sophisticated cement compounds to eliminate the cement growth problem. The manufacturers recommend that the older insulators manufactured before the mid 1970's be replaced.

Availability of Replacement Parts

Replacement insulators are generally readily available within six to eight weeks of an order. However, long delivery times may occur depending on the market conditions.

Safety Performance

In general terms, the safety performance of the insulators is good. However, in situations where the insulators are under structural stress, the cement growth condition will lead to a failure of the insulator. This failure creates a safety hazard for operations personnel when broken insulator parts fall to the ground.

Environmental Performance

There are no specific environmental issues relating to insulators other than the proper disposal of the retired insulators.

Operating Regime

The insulators are in continuous use.

Justification:

This project is justified on the requirement for Hydro to provide safe and reliable power and a safe working environment for its staff. Insulators provide electrical insulation between energized equipment and ground. When insulators fail, a short circuit to ground is created and loose and falling parts can result. Both create system outages and safety hazards to personnel. In service failures have occurred while maintenance personnel were working on the equipment. To prevent such failures from occurring Hydro proposes and plans to replace deteriorated post, suspension and multi-cone type insulators.

The manufacturers have identified and researched the cement growth problems and have developed more sophisticated cement compounds to eliminate the problem in the future. For existing installations, the manufacturers recommend that the older insulators be replaced.

Net Present Value:

A net present value calculation was not performed in this instance as there is no viable alternative to replacing the insulators.

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.

Historical Information

Table 3 contains the historical information for insulator replacements for the period 2005 to 2010. Hydro expects to have its insulator replacement plan completed by 2013.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)
2010F	399.0		3,041	
2009	390.9	426.9	1,521	0.3
2008	294.3	324.0	1,963	0.2
2007	323.0	297.5	2,140	0.1
2006	306.8	256.2	1,140	0.2
2005	228.0	163.3	2,304	0.1

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.

Status Quo

The status quo is not an option. The insulators must be replaced to maintain system reliability and a safe working environment.

Alternatives

There are no alternative solutions to the problems described with the insulators other than direct replacements.

Conclusion:

When insulators fail they create a short circuit to ground and result in loose and falling parts. This creates safety hazards to personnel and results in system outages. To prevent such failures from occurring, Hydro proposes to replace all post, suspension and multi-cone type insulators manufactured by Canadian Ohio Brass.

Project Schedule

Table 4 presents the anticipated project schedule.

Table 4: Project Schedule

Activity	**Milestone**
Project Start	January 2011
Initial Planning and Equipment Ordering Tendering	February 2011
Equipment Delivery	July 2011
Equipment Installations and Commissioning	November 2011
Project In Service	November 2011
Project Completion and Close Out	December 2011

Future Plans:

Future replacements will be proposed in future capital budget applications. Insulator replacements are planned for the next two years as shown in the five year capital plan (2011 Capital Plan Tab, Appendix A).

Project Title: Purchase Excavators

Location: Bishop's Falls

Category: General Properties - Transportation

Type: Pooled

Classification: Normal

Project Description:

This project is required to purchase two 12 ton excavators with brush cutter attachments for access trail maintenance and transmission line work. The budget estimate for this project is shown in Table 1:

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	317.0	0.0	0.0	317.0
Labour	0.5	0.0	0.0	0.5
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.	11.7	0.0	0.0	11.7
Contingency	31.8	0.0	0.0	31.8
TOTAL	**361.0**	**0.0**	**0.0**	**361.0**

Existing System:

The two new excavators will replace 15 backhoe attachments for heavy duty off-road track vehicles. The attachments were retired as a result of changes in the Occupational Health and Safety Regulations, Roll Over Protection Structures, Section 261 and Section 262 that came into effect on August 7, 2009. The regulations state:

> *Section 261 (2) The minister may require a rollover protective structure to be installed on mobile equipment, other than mobile equipment referred to in subsection (1), where the design of the equipment or circumstances of use indicate the need.*
>
> *Section 262 A rollover protective structure shall meet the requirements of one of the following applicable standards or other standard acceptable to the minister:*

(a) CSA Standard B352.0-95 "Rollover Protective Structures (ROPS) for Agricultural, Construction, Earthmoving, Forestry, Industrial, and Mining Machines -- Part 1: General Requirements",

(i) CSA Standard B352.1-95 "Rollover Protective Structures (ROPS) for Agricultural, Construction, Earthmoving, Forestry, Industrial, and Mining Machines -- Part 2: Testing Requirements for ROPS on Agricultural Tractors", or

(ii) CSA Standard B352.2-95 "Rollover Protective Structures (ROPS) for Agricultural, Construction, Earthmoving, Forestry, Industrial, and Mining Machines -- Part 3: Testing Requirements for ROPS on Construction, Earthmoving, Forestry, Industrial, and Mining Machine";

These changes have made backhoe attachments for heavy duty off-road track vehicles redundant and unsafe. An engineered solution to resolve the roll over protection and pinch point protection was not viable. The cost to engineer and test the structure was prohibitive because each structure had to be designed for the specific unit and was not interchangeable because of the certification.

Age of Equipment or System

This is the first purchase of 12 ton excavators required to maintain access trails and transmission line right-of-ways. Therefore, age of equipment is not applicable. In addition, the excavators will be used for pole installation and emergency repairs to wood pole transmission lines.

Major Work/or Upgrades

There have been no major upgrades on the equipment.

Anticipated Useful Life

The anticipated useful life for excavators is 12 to 15 years based on usage.

Maintenance History

Maintenance history is not applicable since this is a new purchase and there are no 12 ton excavators in Hydro's fleet of off-road vehicles.

Outage Statistics

There are no outage statistics related to the excavators.

Industry Experience

Heavy duty off-road equipment is a standard component of any electric utility maintenance fleet used to maintain transmission or distribution lines and access trails in remote areas. The replacement criterion across the Canadian Utility Industry varies depending on location, exposure to harsh environmental conditions, and the number of service hours for the equipment. While some variances exist, it is generally the case that this type of equipment is replaced in a 12 to 15 year time frame depending on its functionality and condition. The criterion utilized by Hydro is to consider replacement for units which are 12 years old based upon an evaluation of maintenance costs and technological advances.

Maintenance or Support Arrangements

The Hydro fleet of off-road track vehicles is primarily maintained by Hydro maintenance personnel. Outside maintenance garages are utilized when the required maintenance is within their expertise.

Vendor Recommendations

There are no vendor recommendations for this project.

Availability of Replacement Parts

Replacement parts for off-road equipment are normally available for 15 to 18 years after purchase.

Safety Performance

The two excavators will replace 15 backhoe attachments on heavy duty off-road track vehicles. The attachments were retired as a result of changes in the Occupational Health and Safety

Regulations, Roll Over Protection Structures, Section 261 and 262. These changes have made backhoe attachments for heavy duty off-road track vehicles redundant and unsafe.

Environmental Performance

Replacement units are now certified Tier 3 for emission compliance. Tier 3 is a standard to regulate sulfur emissions from diesel engines. The regulations promulgated in February 2005 by Environment Canada, introduced emission standards for model year 2006 and later diesel engines used in off-road applications. The Canadian Off-Road Compression-Ignition Engine Emission Regulations align the engine certification values with those of the US EPS Tier 2 and Tier 3 values.

Operating Regime

As this project relates to the replacement of mobile equipment, there is no relevant data related to operating regime.

Justification:

Hydro maintains 3,742 kilometers of transmission lines and 3,334 kilometers of distribution lines throughout the Island Interconnected System, much of which is located in remote areas that are inaccessible to wheeled vehicles. Heavy off-road track equipment is essential to the line crews in accessing these lines for inspections and to perform planned or emergency maintenance.

Hydro operates in many diverse locations across the province. This equipment is critical to provide economical and reliable electricity and to ensure that employees are provided with safe and reliable equipment.

This proposal provides for the purchase of two excavators which will be used to maintain transmission or distribution lines and access trails in remote areas. These units will provide the operators with more efficient and ergonomically designed units. Technological improvements in the cab design have reduced the noise and heat levels in the cab. Drive trains have improved from mechanical to hydrostatic. Safety improvements include interlocks to prevent operation of the unit without the operator in the driver's seat.

Net Present Value

A net present value calculation was performed in this instance to determine whether Hydro should buy or lease off-road excavators. See "Cost Benefit Analysis" section for details.

Levelized Cost of Energy

As this project relates to the replacement of mobile equipment, there is no relevant data related to levelized cost of energy.

Cost Benefit Analysis

A Cost Benefit Analysis was performed to compare two alternatives; to purchase or to rent. In both alternatives, operating and maintenance costs were not considered because they were assumed to be the same for purchase or rental options. Table 2 shows the results of the Cost Benefit Analysis.

Table 2: Cost Benefit Analysis Results

Purchase Two Excavators **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2022**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Buy New Rent	293,519 405,403	0 111,885

As can be seen from Table 2, the Buy New option is the least cost alternative. By buying new excavators, Hydro will realize a cost savings of $111,885 over the 12-year period to 2022. This period is considered the average life of an off-road excavator.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

There is no historical information available.

Forecast Customer Growth

As this project relates to the replacement of mobile equipment, there is no relevant data related to forecast customer growth.

Energy Efficiency Benefits

As this project relates to the replacement of mobile equipment, there is no relevant data related to energy efficiency benefits.

Losses during Construction

As this project relates to the replacement of mobile equipment, there is no relevant data related to losses during construction.

Status Quo

The status quo is not an acceptable option because Hydro has to respond to changes in the Occupational Health and Safety Regulations concerning backhoe attachments on off-road vehicles.

Alternatives

Hydro considered two alternatives. Alternative 1 was to buy new excavators and Alternative 2 was to lease them. The purchase of two new excavators is the least cost alternative.

Conclusion:

This proposal provides for the purchase of two heavy duty excavators. These excavators will be strategically located within TRO and will be utilized on a regular basis to support Hydro Operations personnel in the maintenance of access trails, transmission line right-of-ways and for pole installation and emergency repairs to wood pole transmission lines.

Project Schedule

This project is scheduled to be completed in December 2011.

Project Title: Upgrade Air Blast Circuit Breakers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: Pooled

Classification: Normal

Project Description:

This project is required as part of an upgrading program to refurbish all Brown Boveri DCVF, DCF and DLF models of 138 kV and 230 kV air blast circuit breakers, at a rate of four each year. The breakers will be completely dismantled, cleaned, refitted with new parts, gaskets and seals as required and reassembled. The porcelain housings will be inspected and tested for cracks or weaknesses. Depending on the results of these tests, the porcelain housings may also be replaced as part of the upgrades. The breaker will then be tested to confirm that it is ready for return to service.

The order of the upgrades is done according to the priority and criticality of the breaker on the system. The highest priority breakers are those serving the generation units and the main power transformers. The upgrade rate of four units each year is based on system requirements, available outages to remove and re-install the breakers, and the available personnel to complete the work.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	160.0	0.0	0.0	160.0
Labour	103.0	0.0	0.0	103.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	15.5	0.0	0.0	15.5
O/H, AFUDC & Escln.	27.2	0.0	0.0	27.2
Contingency	27.8	0.0	0.0	27.8
TOTAL	**333.5**	**0.0**	**0.0**	**333.5**

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 41 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.

Age of Equipment or System

The air blast circuit breakers were installed in the 1960's and 1970's.

Major Work/or Upgrades

There have been no major upgrades to these breakers since they were originally installed. There have been some minor modifications done on some units according to the manufacturer's recommendations. Other than this, the units have seen the standard maintenance inspections and servicing over the years.

Anticipated Useful Life

The normal service life of power circuit breakers is 30 years. Beyond 30 years, it is normally expected that such equipment would either have to be upgraded or replaced. This upgrade will extend the service life by approximately 15 years.

Maintenance History

Hydro has experienced problems with air leaks or valves sticking, resulting in increased maintenance costs and breaker unavailability. Some maintenance modifications, as recommended by the manufacturer, were completed to correct these problems. In particular there have been problems with the generator breakers at Bay d'Espoir which have resulted in the generating unit being unavailable. The problems being experienced by Hydro are common in the utility industry and owners of these types of air blast breakers have addressed the problem through similar upgrading programs. Detailed maintenance costs by breaker are not readily available.

At the Sunnyside Terminal Station, broken insulator supports caused breaker interrupter heads to drop off and fall to the ground. This caused damage to adjacent equipment and resulted in system outages.

At the Massey Drive Terminal Station, there were timing and phase disagreement problems that could have caused an extended outage to the Corner Brook Pulp and Paper Mill. At Bay d'Espoir, there were timing and air quality problems with breakers serving the generation units. These problems had the potential of causing generation and system wide outages. Other nuisance trips and outages of shorter nature have also occurred at various points on the system.

Maintenance inspections performed in the earlier in-service years of these breakers provided little evidence of the anticipated wear of parts and gasket fatigue. In later years, however, inspections of gaskets and seals, plus evidence of wear and tear of other mechanical components confirmed that a 'one time' upgrade program is the best approach to extending the service lives of the breakers. This conclusion was derived through consultations with other utilities and with the original equipment manufacturer.

The five-year maintenance history for the Brown Boveri DCVF, DCF and DLF models of air blast circuit breakers is shown in Table 2:

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	15.0	46.0	61.0
2008	16.4	116.0	132.4
2007	7.7	121.0	128.7
2006	7.8	189.0	196.8
2005	10.7	157.0	167.7

Outage Statistics

Table 3 below lists the previous five-year average for the performance of 138 kV and 230 kV circuit breakers. A comparison is made between Hydro's last 5 year performance to the latest CEA five year average (2003-2007).

There have been 11 forced outages due to problems with these breakers over the last five years.

Table 3: Air Blast Breaker Performance

	Number of Forced Outages	Frequency (per a) [1]	Unavailability (percent) [2]
230 kV			
2004-2008	8.00	0.030	0.002
CEA (2003-2007)	269.00	0.100	0.074
138 kV			
2004-2008	4.00	0.020	0.001
CEA (2003-2007)	735.00	0.090	0.065

[1] Frequency (per a) is the number of failures per year.
[2] Unavailability is the percent of time per year the unit is unavailable.

Industry Experience

Hydro's experience is that the breakers are capable of providing reliable service to the system, however, there have been operational issues centered around leaking seals and gaskets, malfunctioning valves, failing capacitors and resistors, porcelain failures and minor controls issues.

Hydro consulted with other Canadian Utilities and the manufacturer of these breakers and has found that other utilities experience similar problems with the breakers. Other utilities are managing by either replacing the breakers or doing minor 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. Hydro would replace air blast breakers with Sulfur Hexafluoride (SF_6). 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 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 cause an explosion.

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.

Net Present Value

There are two solutions to the problems described with the air blast breakers. These are to upgrade the breakers, as proposed, or to replace them. The operation and maintenance costs of either alternative are generally the same. Upgrading the breakers is more cost effective than a replacement program. The average upgrade cost is approximately $80,000 as indicated in Table 4, whereas the average replacement cost of a 230 kV breaker is approximately $350,000 including engineering and commissioning. Replacements would include costs for modifications to civil, mechanical, electrical, and controls subsystems associated with each breaker. With the upgrades, these costs are eliminated.

Levelized Cost of Energy

The levelized cost of energy is not applicable as there is no new generation source considered.

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

No legislative or regulatory requirements affect this project. The existing breakers comply with all applicable codes and standards of the industry.

Historical Information

The upgrade program was started in 2007 and is forecast to continue until 2013. For the years 2007 to 2009 Table 4 shows the summary costs for each year.

Table 4: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2010F	342.2		4		
2009	339.7	364.6	4	91.2	Completed Breakers LO3L17 WAV, LO5L35 STB,B1L32 STB, B1L17 WAV, and replaced relief valves in 13 other breakers.
2008	315.2	289.7	4	72.4	Completed Breakers B1L18 OPD, B1L31 STB, L05L31 STB, B1L36 OPD
2007	257.8	146.4	2	73.2	Completed B1L28 MDR, B5B6 BDE

It should be noted that the cost per unit to upgrade a breaker will vary depending on a number of factors related to location, weather, outages, systems requirements, etc. The unit cost is the quotient of the total actual divided by the number of breakers upgraded.

Forecast Customer Growth

The forecast customer load on the system has no effect 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 alternatives to address the problems described with the air blast breakers. Alternative 1 is to upgrade the breakers, as proposed. Alternative 2 is to replace them. The operation and maintenance costs of either alternative are generally the same. The upgrade option was chosen because it is the least cost alternative.

Replacement requires the purchase of newer technology, sulfur hexafluoride(SF_6) gas breakers. These breakers have a different operating arrangement and larger size as compared to the air blast units. Replacement with SF_6 gas breakers would require major modifications to the breaker foundations, controls systems, station protection systems and general station arrangements. The cost for the replacement alternative is higher than the upgrade alternative as previously discussed.

Conclusion:

The existing air blast breakers have deteriorated. The justification for this project is based on the need to upgrade the breakers to operate properly and reliably, and to extend the reliable service lives of the breakers.

Project Schedule

Table 5 presents the anticipated project schedule.

Table 5: Project Schedule

Activity	Milestone
Project Start	January 2011
Initial Planning and Equipment Ordering Tendering	February 2011
Equipment Delivery	July 2011
Equipment installations and Commissioning	November 2011
Project In Service	November 2011
Project Completion and Close Out	December 2011

Future Plans:

Future upgrades will be proposed in future capital budget applications. Circuit breaker upgrades are planned for the next three years as shown in the five year plan (2011 Capital Plan tab, Appendix A).

Project Title: Replace Mini Hydro Turbine

Location: Roddickton

Category: Transmission and Rural Operations – Generation

Type: Other

Classification: Normal

Project Description:

This project is required to replace the hydraulic turbine at the Roddickton Mini Hydro Plant (Mini Hydro Plant). The scope of this project is to replace the hydraulic turbine which includes the two guide vanes, the horizontal cross-flow runner, the casing and the associated bearings and seals. In addition, the design of the trash rack at the intake structure will be reviewed, and a modified or new trash rack will be installed if necessary. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	65.0	91.3	0.0	156.3
Labour	13.3	58.9	0.0	72.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	12.1	0.0	12.1
Other Direct Costs	2.4	19.6	0.0	22.0
O/H, AFUDC & Escln.	6.1	27.2	0.0	33.3
Contingency	0.0	26.3	0.0	26.3
TOTAL	**86.8**	**235.4**	**0.0**	**322.2**

Existing System:

The Mini Hydro Plant was built and commissioned in 1981 as a demonstration project for the Agreement on Renewable Energy Conservation Technology, between Newfoundland and Labrador Hydro and the Government of Canada. The development consists of a single run-of-river hydro plant located on Marble Brook near Roddickton, on the east side of the Great Northern Peninsula. Figure 1 shows the location of the Mini Hydro Plant.

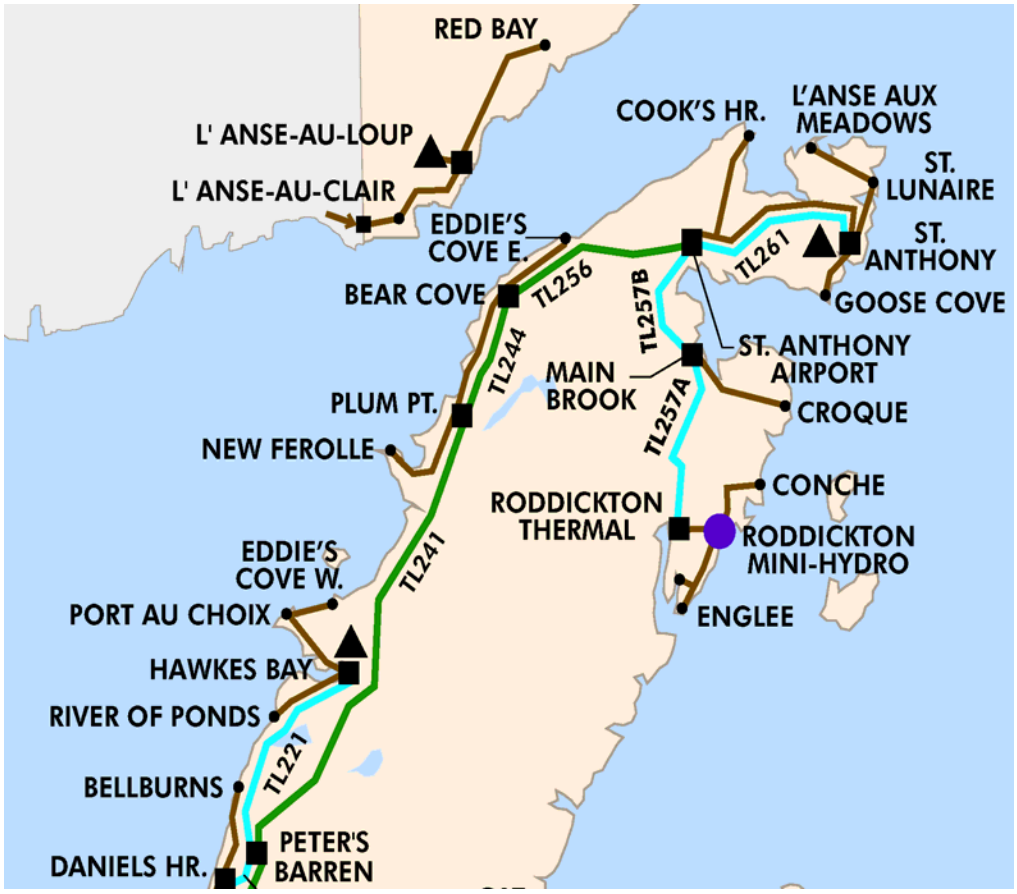

Figure 1 - Great Northern Peninsula Portion of the Island Interconnected System

The powerhouse contains a single turbine, the prime mover for the generator, which is rated at a capacity of 405 kW. The Mini Hydro Plant produces an average annual 804,000 kilowatt-hours of energy which is transmitted into the Island Interconnected System. The plant is unattended. The St. Anthony Diesel Plant Operator visits the plant once per week to observe operating conditions and to adjust the unit load based upon the water level in the reservoir.

The hydraulic turbine is a cross-flow type turbine manufactured by Ossberger GmbH + Co of Germany. Refer to Figure 1 and Figure 2 of Appendix A for diagrams of the turbine. The water flowing into the turbine is controlled by two balanced, profiled guide vanes which divide and direct the water flow, and allow it to enter the runner smoothly. The runner is equipped with 30 blades, manufactured of bright-rolled, profiled steel, which are welded to end disks. The turbine has no vibration or temperature monitoring devices or protection systems to prevent failure.

Water is supplied to the turbine through a single penstock. Water is admitted into the penstock at the intake structure. The intake structure is fitted with a trash rack to prevent large foreign objects from entering the unit.

An inspection of the turbine runner on November 12, 2009 by Hydro determined that the runner was in an advanced state of deterioration, with one blade bent out of shape and pencil sized holes worn entirely through most blades. The inspection report is included as Appendix A.

The bent runner blade is attributed to an unknown object having passed through the turbine. The holes worn through the runner blades are at the same location on each blade and are the result of a disruption of the water flow pattern. Upon a review of the 2009 runner inspection photographs, the manufacturer indicated that the disruption may be associated with damage to the associated guide vane or may be attributed to a poor alignment of the runner stiffener plates with respect to the guide vane. The manufacturer advised that newer turbine designs include runner stiffener plates that better align with the flow pattern imparted by the guide vanes. The condition of the two turbine guide vanes is unknown. It is possible that one guide vane sustained damage from the same object that damaged the runner.

The condition of the existing turbine bearings is also unknown but is expected to be deteriorated after 29 years of service. The manufacturer advised that newer turbine designs are provided with spherical rolling element bearings which are more efficient and replaceable.

The trash rack has not been inspected. Since it is known that an object passed through the trash rack and subsequently damaged the runner, the trash rack either has an inadequate mesh size or it has deteriorated or has been damaged.

Age of Equipment and System

The hydraulic turbine and the intake trash rack are original and have been in service since the Mini Hydro Plant was commissioned in 1981. The associated speed increaser, which is a gear box between the turbine and generator, was replaced in 2009. All other associated equipment, including the generator, flywheel, governor, controls, penstock, turbine shut-off valve, and intake shut-off valve are original and have been in service since 1981.

Major Work or Upgrades

There have been no major upgrades to the turbine or trash rack since installation.

Anticipated Useful Life

The hydraulic turbine and trash rack both have an estimated service life of 50 years. The manufacturer advised that the expected life of the runner for this type of turbine may be anywhere from 10 to 50 years, depending upon water quality and flow regime. Based upon the present condition of the 29 year old runner at Roddickton, there is a high probability that, within the next five years, this runner will deteriorate to the point of causing severe hydraulic imbalance, resulting in destruction of the entire turbine.

Maintenance History

There has been no preventive or corrective maintenance on the hydraulic turbine or trash rack over the past five years, except for the runner inspection completed in 2009.

Outage Statistics

Outage statistics for this hydro plant are not recorded due to the Mini Hydro Plant's relatively minor contribution to the Island Interconnected System. Anecdotal evidence indicates that there have been no outages attributed to the hydraulic turbine or trash rack over the past five years.

Industry Experience

Industry experience regarding the replacement of turbine runners is not relevant. Similar runners at other hydro plants can have very different service lives due to variations in water quality and flow regime.

Maintenance or Support Arrangements

There are no vendor or contractor maintenance or support arrangements for the hydraulic turbine or trash rack. Any corrective repairs would be performed by Hydro supplemented as required by external contractors.

Vendor Recommendations

The manufacturer, Ossberger GmbH + Co of Germany, reviewed photographs from the 2009 turbine runner inspection report and noted that the holes worn through most runner blades are at the same location on each blade, indicating a disruption of the flow pattern. The manufacturer noted that this disruption may be associated with damage to the associated guide vane or may be attributed to a poor alignment of the runner stiffener plates with respect to the guide vane. The manufacturer advised that newer turbine designs include runner stiffener plates that better align with the flow pattern imparted by the guide vanes.

The manufacturer stated that the existing white metal turbine bearings are expected to be substantially deteriorated, having been in service for 29 years. The manufacturer advised that newer turbine designs are provided with spherical rolling element bearings which are more efficient and replaceable.

Availability of Replacement Parts

A replacement turbine runner or a complete new turbine is readily available from the original turbine German manufacturer, Ossberger GmbH + Co, through its North American supplier, Hydropower Turbine Systems, Incorporated located in Hayes, Virginia.

Safety Performance

There are no safety performance issues with the hydraulic turbine or trash rack.

Environmental Performance

There are no environmental performance issues with the hydraulic turbine or trash rack.

Operating Regime

The Mini Hydro Plant is a run-of-river hydro plant. The single hydraulic turbine operates continuously when sufficient water is available in the reservoir.

Justification:

This project is justified on the requirement to replace failing, deteriorated equipment in order for Hydro to provide least-cost electrical service. A cost benefit analysis was performed to

compare alternatives, including the status quo. The least cost alternative is to complete a planned replacement of the hydraulic turbine.

Net Present Value

The net present value of the least cost alternative is $200,269 in 2010 dollars, as shown in the Cost Benefit Analysis Section of this report.

Levelized Cost of Energy

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

Cost Benefit Analysis

A cost benefit analysis was conducted for four viable alternatives to address the failing, deteriorated equipment:

- complete a planned runner replacement in 2011-2012;
- complete a planned replacement of the entire turbine in 2011-2012;
- operate the existing runner to catastrophic failure (assumed in 2015) and replace the entire turbine; or
- operate the existing runner to catastrophic failure (assumed in 2015) and decommission the Mini Hydro Plant.

Alternatives 1, 2 and 3 include an inspection, design review and, if required, modification or replacement of the trash rack at the intake. This work is necessary to ensure that the turbine is protected from any further impact damage from large foreign objects.

For Alternative 1, it was assumed that a new runner installed in the existing turbine would increase the turbine efficiency from 77 to 82 percent, resulting in a 6.5 percent increase in energy production. For Alternatives 2 and 3, it was assumed that a new turbine would increase the turbine efficiency from 77 to 85 percent, resulting in a 10.4 percent increase in energy production. The value of this additional energy was derived using the Levelized Unit Energy Cost (LUEC) of $90 per Megawatt-hour, which is representative of the (regulated) long run marginal generation cost for the Island.

The assumption of failure in 2015 for Alternatives 3 and 4 is based upon the conclusion by Hydro's Engineering Services Division that there is a high probability that, within the next five years, the runner will deteriorate to the point of causing severe hydraulic imbalance, resulting in destruction of the entire turbine.

The results of the cost benefit analysis are summarized in Table 2. The least cost alternative is Alternative 2 - to complete a planned replacement of the entire hydraulic turbine.

Table 2: Results from Cost Benefit Analysis

RWC - Replace Mini Hydro Runner or Entire Turbine **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2050**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
1. Replace Runner - Planned	308,110	107,841
2. Replace Entire Turbine - Planned	200,269	0
3. Replace Entire Turbine - Unplanned	212,810	12,541
4. Run to Failure and Shut Down Plant	720,869	520,600

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements related to the justification of this project.

Historical Information

There is no historical information.

Forecast Customer Growth

The forecast of customer load growth does not affect this project.

Energy Efficiency Benefits

For the least cost alternative, additional energy will be generated and supplied into the Island Interconnected System because of an increase in turbine efficiency. While it is not possible to accurately measure turbine efficiency at this plant, it is estimated that the deteriorated turbine is presently operating at an efficiency of 77 percent as compared to its original guaranteed

efficiency of 82 percent. For Alternative 2: Replace Entire Turbine – Planned, a new turbine with improved runner and bearing design is expected to operate at an efficiency of 85 percent, resulting in a 10.4 percent increase in energy production.

Losses during Construction

For the least cost alternative, it was assumed that 30,557 kilowatt-hours of production would be lost during a one month outage. This is based upon historical average production in August at the Mini Hydro Plant. These losses during construction were included in the cost-benefit analysis.

Status Quo

The status quo has been modeled as two scenarios: Alternative 3 – to operate the existing runner to catastrophic failure and then replace the entire turbine; and Alternative 4 – to operate the existing runner to catastrophic failure and then decommission the Mini Hydro Plant. Alternative 4 includes a cost of $200,000 in 2010 dollars to decommission the Mini Hydro Plant. Based upon the present condition of the 29-year-old runner at Roddickton, Hydro's Engineering Services Division has concluded that there is a high probability that, within the next five years, this runner will deteriorate to the point of causing severe hydraulic imbalance, resulting in destruction of the entire turbine.

Alternatives

A cost benefit analysis was conducted for four viable alternatives to address the failing, deteriorated equipment, as described in the Cost Benefit Analysis Section of this report.

Repair of the existing runner was considered but ruled out as a viable alternative due to the extent of wear and the high potential for detrimental stresses that would be introduced by any welding repairs. Replacement of the runner is a viable alternative. A new runner to fit the existing turbine is available from the original manufacturer. Replacement of the entire turbine is also a viable option and has the added benefit of improved designs of the runner and bearings.

Conclusion:

The turbine runner is in an advanced state of deterioration, with one blade bent out of shape and pencil sized holes worn entirely through most blades. Runner repair is not a viable alternative. Hydro's Engineering Services Division has concluded that there is a high probability that, within the next five years, this runner will deteriorate to the point of causing severe hydraulic imbalance, resulting in destruction of the entire turbine. Running the turbine to failure is viable, but is not the least cost alternative. The cost-benefit analysis concludes that a planned replacement of the entire turbine is the least cost alternative.

Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Project Activity	**Milestones**
Open Project; Design & Order Equipment	November 2011
Prepare Work Procedures and Safety Plan	June 2012
Install	August 2012
Commission	September 2012
Document and Close Project	November 2012

Appendix A

Runner Inspection, Roddickton Mini Hydro Plant, November 12, 2009

Runner Inspection

Roddickton Mini-hydro

Inspection Date: November 12, 2009

Report Date: December 22, 2009

REGISTERED PROFESSIONAL ENGINEER GREGORY READ Greg Read SIGNATURE 2009-12-22 DATE NEWFOUNDLAND & LABRADOR	ELEC. - n/a
	P&C - n/a
	MECH. GR
	CIVIL - n/a

Approved for Release

Jan. 5th/2010
Date

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5. ALTERNATIVES FOR CORRECTIVE ACTION 3
6. RECOMMENDATIONS 4
APPENDIX A: PHOTOGRAPHS OF RUNNER – NOVEMBER 12, 2009
APPENDIX B: PROPOSAL FOR THE SUPPLY OF A REPLACEMENT RUNNER

1. SUMMARY

The original turbine runner at Roddickton Mini-hydro, which has been in service since 1981, was inspected on November 12, 2009 and found to be in a deteriorated state, with pencil sized holes worn entirely through most blades and one blade bent out of shape. Runner repair is not recommended due to the extent of damage and the risk of detrimental stresses that would be introduced during any weld repair. Runner replacement is a viable option. A new runner could be purchased from the original manufacturer at a cost of $38,630 (USD). It is recommended to conduct a cost benefit analysis to determine if there is an economic case for runner replacement.

2. BACKGROUND

Roddickton Mini-hydro Development, operated and maintained by TRO Northern, was built and commissioned in 1981. It consists of a single run-of-river hydro plant located on Marble Brook near Roddickton, on the east side of the Great Northern Peninsula. The powerhouse contains a single Ossberger cross-flow turbine driving a Kato revolving field alternating current generator, rated at 405 kW. On average, this plant produces 804,000 kilowatt-hours of electricity per year, which is delivered into the Island Interconnected System.

The hydro turbine rotates at a speed of 450 rpm and is coupled to the generator via a speed increaser which increases speed to 1200 rpm. In November of 2009, a capital project (CBU 14100901; Project Manager – Greg Read) was undertaken to replace the speed increaser. To enable this work, the unit was shut-down and isolated, with the penstock dewatered. This provided an excellent opportunity for an inspection of the turbine runner. Access to the runner for inspection is easy - simply walk into the concrete draft tube from the tailrace and look up! No covers need to be removed. Greg Read of Engineering Services – Mechanical and Baxter Penney of TRO Northern performed an inspection on November 12, 2009.

3. TURBINE DESIGN

The Ossberger turbine, illustrated in Figures 1 & 2, is a cross-flow turbine. The admission of water is controlled by two balanced profiled guide vanes which divide the water flow, direct it,

and allow it to enter the runner smoothly, independent of the opening width. Each of the two guide vanes impart a rectangular cross-section to the water jet, which flows through the blade ring of the cylindrical runner, first from the outside inward, then after passing through the inside of the runner, from the inside outward. [1]

The manufacturer claims that, due to its very design, this turbine is not prone to cavitation; the machine can be run within the whole range of admission (0% to 100% opening) without restrictions.

The runner is equipped with 30 blades, manufactured of a bright-rolled profiled steel, which are welded to end disks. The runner would have been balanced by the manufacturer prior to final assembly of the turbine.

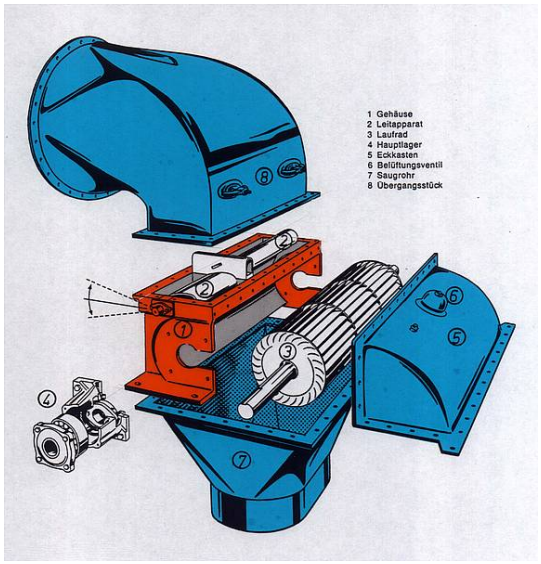


Figure 1 - Ossberger Turbine[2] (typical)

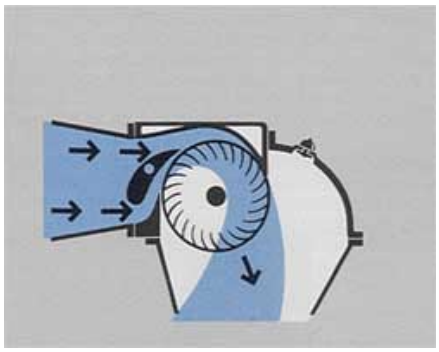


Figure 2 - Horizontal Inflow[3] (as oriented at Roddickton)

[1] http://www.ossberger.de/cms/en/hydro/the-ossberger-turbine/

[2] Ibid

[3] Ibid

4. TURBINE CONDITION

The turbine runner is original and has been in service since 1981.

On November 12, 2009, the runner was inspected and found to be in a deteriorated state, with pencil-sized holes worn entirely through most blades and one blade bent out of line. All holes are on the side of the runner which is closest to the generator, which corresponds to the smaller of the two guide vanes. Based upon the wear pattern, it is concluded that the unit is operated for a significant portion of time with only the smaller guide vane opened.

Appendix A contains photographs of all blades, as well as miscellaneous detail photographs. (Unfortunately, the quality of some photos is poor.)

The condition of the turbine guide vanes and bearings is unknown.

5. ALTERNATIVES FOR CORRECTIVE ACTION

Runner repair is not recommended due to the extent of the damage and the risk of introducing detrimental stresses during any welding repair.

Replacement of the runner with a newly fabricated runner is viable and requires only minimal disassembly of the turbine. Ossberger, the original manufacturer, through its North American supplier, Hydropower Turbine Systems, Inc., is able to supply a replacement runner within four months, at a cost of $38,630 (USD), F.O.B. St. John's NL. Their proposal is included in Appendix B. TRO Northern forces are able to perform the installation.

Mr. Alfred Patzig, President of Hydropower Turbine Systems, Inc., viewed photographs in this inspection report and commented in an email dated December 21, 2009: "Since most or all blades are affected [by the damage], a repair weld wouldn't seem practical and once you start welding, additional stresses are introduced. A replacement runner would be the appropriate choice." It is interesting to note that Mr. Patzig recalls overseeing the installation of this unit in Roddickton himself, in 1981.

Replacement of the runner is recommended, provided that a cost benefit analysis can prove that it is economically preferred to replace the runner compared to operating the existing runner in its deteriorated state until total failure.

6. RECOMMENDATIONS

A. Inspect turbine guide vanes and bearings at the next opportunity.

B. Complete a cost-benefit analysis to determine if replacement is the economically preferred alternative compared to operating the existing runner in its deteriorated state until total failure.

C. Depending upon the results of the cost-benefit analysis, initiate a capital budget proposal to replace the runner and, if necessary, replace or refurbish the guide vanes and bearings.

APPENDIX A

PHOTOGRAPHS OF RUNNER – NOVEMBER 12, 2009



Photo 1: Runner Blades 1 to 4

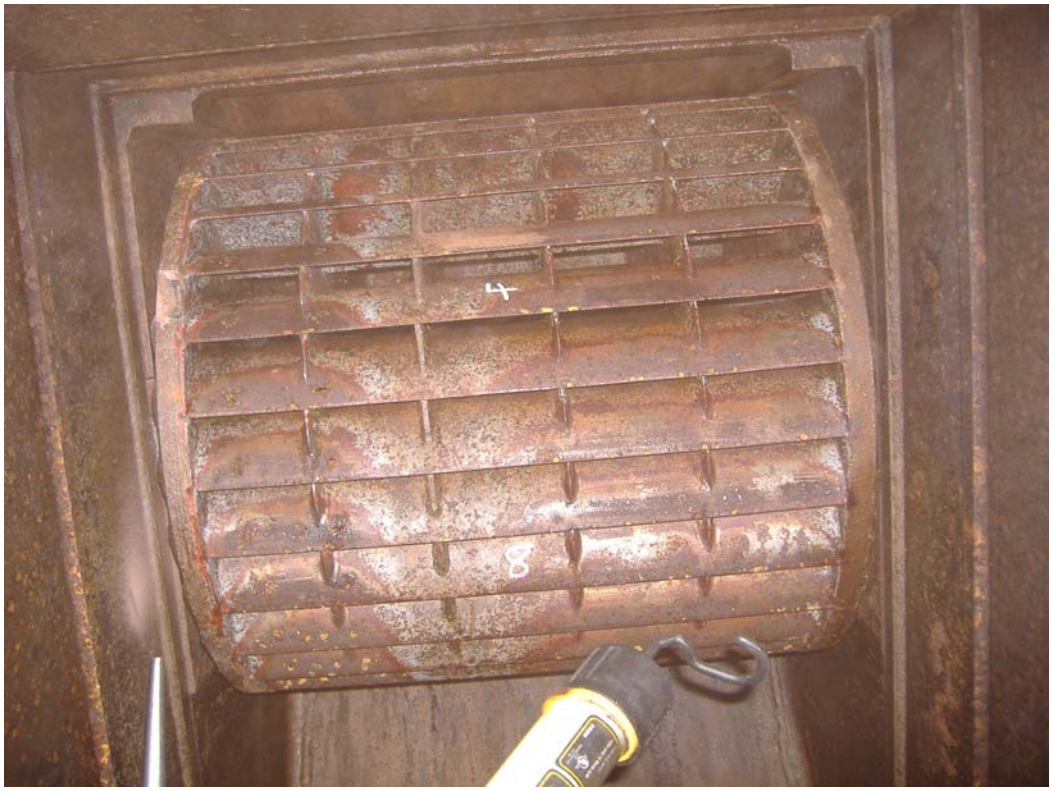


Photo 2: Runner Blades 5 to 8



Photo 3: Runner Blades 9 to 12



Photo 4: Runner Blades 13 to 16



Photo 5: Runner Blades 17 to 20 (Out of Focus)



Photo 6: Runner Blades 21 to 24 (Out of Focus)



Photo 7: Runner Blades 25 to 28 (Out of Focus)



Photo 8: Runner Blades 29 and 30 (Out of Focus)

Miscellaneous Photos





















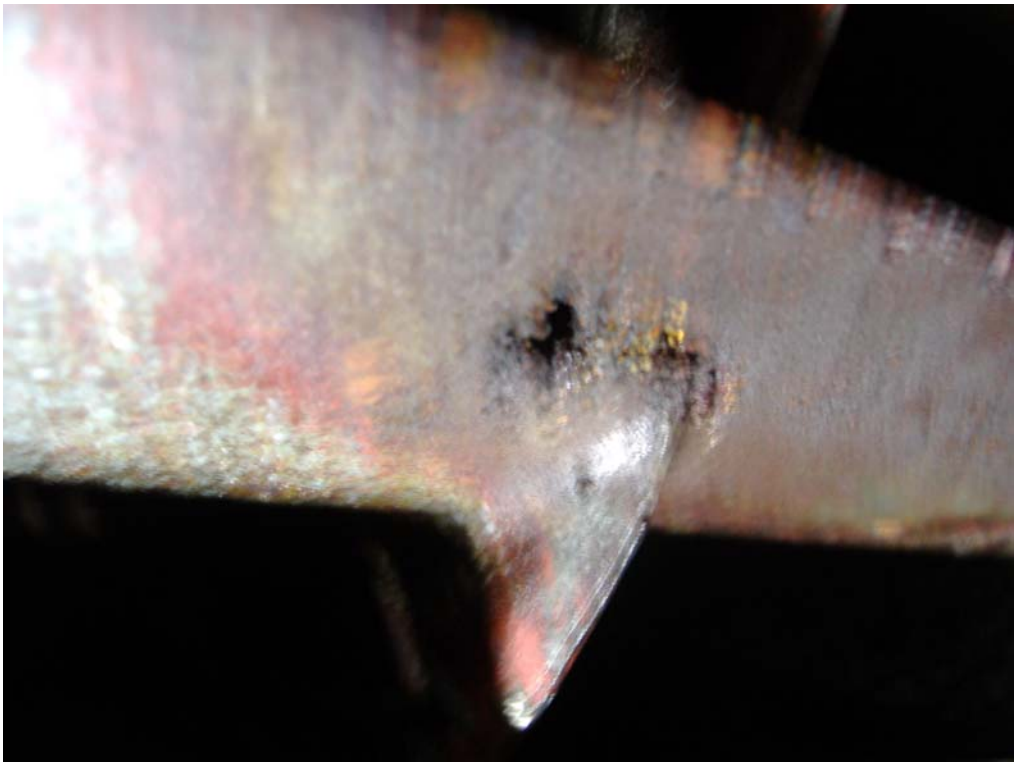


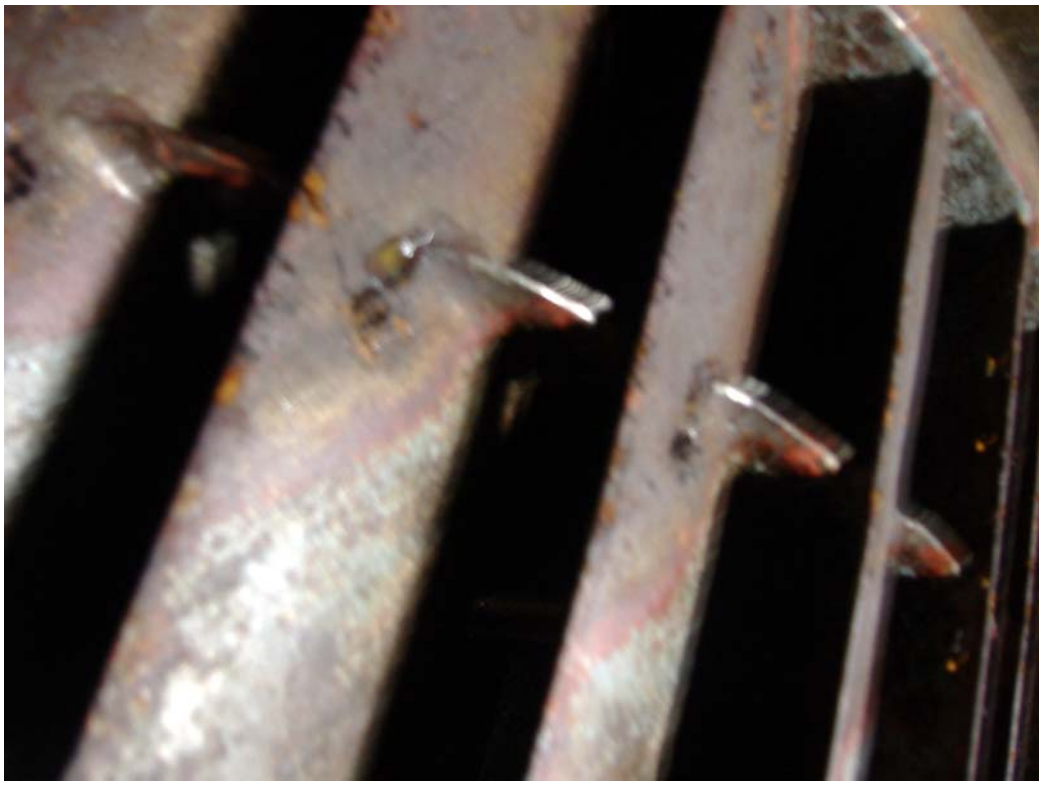






















APPENDIX B

PROPOSAL FOR THE SUPPLY OF A REPLACEMENT RUNNER

HTS-INC
HYDROPOWER TURBINE SYSTEMS, INC.
PO Box 736
Hayes,VA, USA 23072
TEL: 804-360-7992
FAX: 866-552-9946
Email:hts-inc@hts-inc.com

Dec 21, 2009

Mr. Greg Read
NEWFOUNDLAND LABRADOR HYDRO
St. John's, NL
CANADA A1B 4K7

PROPOSAL

REFERENCE NUMBER: P – 2445-1
PROJECT NAME: RODDICKTON HYDRO STATION

We are pleased to offer in accordance with our TERMS AND CONDITIONS OF SALE AND DELIVERY and the INTERNATIONAL CODE FOR THE FIELD ACCEPTANCE TESTS OF HYDRAULIC TURBINES, without engagement:

One Replacement Runner for the OSSBERGER Cross-Flow Turbine, Type SH 62/13g, previously installed at the RODDICKTON Hydro Station in Roddickton, Newfoundland.

Runner will be fabricated at the OSSBERGER manufacturing plant and will consist of one solid, continuous shaft, recessed inside of runner cage for improved flow characteristics, with specially formed integrated runner blades placed circumferentially in slots which are cut from the outside into the intermediate and end disks using a low temperature welding process. A number of intermediate disks will be used for improved strength characteristics, while both of the end disks will be made in forged steel with heavy hubs for the shrink fitting connection to the shaft.

After the machining process, the runner will be statically balanced to prevent development of undesirable vibrations. Finally the runner will undergo a special coating process for corrosion protection.

Runner Design and Materials:
Turbine runner diameter Ø 600 mm, with integrated shaft made of Carbon steel C 45 (1.0503) and runner blades made of cold-rolled airfoil shaped steel sections (1.0038). The runner will be shipped as one complete unit, ready for installation on site.

Shipment includes the following seals/gaskets:

MANNLOCHBAND for pressure and draft tube flanges

HYDROPOWER TURBINE SYSTEMS, INC. (HTS INC)

Bearing housing gasket
Guide vane sleeve gasket
Packing material for runner and guide vane shafts
Felt rings for bearing housing
Installation instructions

Note:
Spherical Roller bearings and conical adapter sleeves for turbine runner are not included.

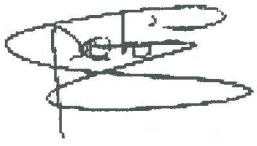
Terms and pricing:
FOB Port of Importation, St. John's, Newfoundland, Canada
Packing and heavy crating for sea freight included
Freight, Insurance, Customs duties and brokerage fees included
Forwarding to site excluded
Installation excluded
Goods and Sales Taxes extra if applicable.

Firm price **USD 38,630**

Currency:	in USD, based on today's exchange rate with the Euro
Delivery:	(4) months after receipt of order, ex factory, subject to OSSBERGER acknowledgement
Payment:	down pay (50%) together with order placement. Balance due upon notification of readiness of shipment from factory and prior to delivery
Warranty:	per General Contractual Terms
Validity:	This quotation is valid for (90) days
Terms:	OSSBERGER's General Contractual Terms apply
Origin:	Germany

Thank you for giving us the opportunity to present our Proposal.
Should you have any questions regarding this product, please feel free to contact us.

HYDROPOWER TURBINE SYSTEMS, INC. (HTS-INC)



Alfred F. Patzig

Enclosure: Sales Terms

3445pl.doc

Project Title: Replace Disconnects

Location: Various Sites

Category: Transmission and Rural Operations – Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project is an ongoing program to replace aging 69 kV and 230 kV disconnect switches in Hydro's terminal stations on the Island Interconnected System. Table 1 lists the disconnect switches planned for replacement in 2011.

Table 1: Disconnect Switches to be replaced in 2011

Location	Number of Units	Disconnect Switch	Voltage (kV)
Holyrood	3	B3L18-1, B11B13, L18G	230
Holyrood	2	T1B1-1, T1B1-2	69
Coney Arm	1	T1	69
TL 225	1	New Switch to be added	69

The budget estimate for this project is shown in Table 2.

Table 2: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	113.0	0.0	0.0	113.0
Labour	74.0	0.0	0.0	74.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	52.0	0.0	0.0	52.0
O/H, AFUDC & Escln.	32.1	0.0	0.0	32.1
Contingency	23.9	0.0	0.0	23.9
TOTAL	**295.0**	**0.0**	**0.0**	**295.0**

The new disconnects will have improved technology over the existing disconnects. The insulator part of the disconnect will be upgraded to high strength material to reduce the risk of the insulators breaking and falling. The new disconnects to be mounted on the wood pole structures will also have stronger supporting frames to maintain the alignment of the switches.

The disconnect switches for this program will be bought under a multi year contract. This will improve the delivery time and price from the manufacturer. The replacement of these switches will be done by contractors.

Existing System:

Disconnect switches are an integral part of the power system. The disconnects are used to isolate a piece of equipment such as a breaker, transformer or transmission line for maintenance or repair. Also, they are used to bypass equipment to prevent customer outages while work is being performed on the equipment.

The basic components of a disconnect switch are the blade, insulators, switch base and operating mechanism. The blade is the main current carrying component in the switch and it moves to open and close the switch. The insulators are made of porcelain and insulate the switch base from the current in the blade. The switch base supports the insulators and is mounted to a metal frame for wood pole structures or on a steel tower structure. The switches are operated either manually using a handle at ground level to open and close the blade or automatically by a motor operated device.

The disconnect switches that are being replaced in 2011 under this program operate at either 230 kV or 69 kV and are a combination of motor operated and manually operated switches. Figure 1 shows a typical arrangement of a disconnect switch on each of the three phases of a 69 kV wood pole structure. The arrows in the diagram point to the operating blades that open and close to control current flow.



Figure 1 – Typical 69 kV Disconnect Switch

Age of Equipment or System

The disconnect switches on the Island Interconnected System range in age from one to forty years. The switches that are scheduled to be replaced are between 20 and 40 years old and have had recurring safety and reliability problems.

Major Work and/or Upgrades

There have been no major replacements of terminal station disconnect switches since they were installed. Repairs have been made on a piecemeal basis as failures occurred. The maintenance history of these disconnects involves repair or replacement of insulators, control systems, drive motors, gearboxes, auxiliary contact cams, brakes, heaters, motor contactors, control arms,

jaws, springs, blades, couplings, and hinges. This history is summarized in Table 3. The hot spot data shown in the table refers to events where operations staff had to respond to overheating conditions resulting from the failure of mechanical and current carrying parts.

Table 3: Work History Summary

Work History Summary (2000 to 2009)				
kV Class	**Replace Insulators**	**Repair Controls**	**Hardware And Mechanical Issues**	**Hot Spots and Emergencies**
230	15	97	117	11
138	10	17	25	6
69	13	5	42	16
Total	38	119	184	33

Anticipated Useful Life

Disconnect switches have an anticipated service life of 30 years, depending on the service environment.

Maintenance History

Table 4 shows the history of maintenance costs for disconnect switches for the period 2005 to 2009.

Table 4: Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	6.8	16.0	22.8
2008	13.6	22.4	36.0
2007	8.8	23.1	31.9
2006	26.0	32.9	58.9
2005	5.1	26.1	31.2

Below is a brief discussion of problems experienced with various disconnect switches. The age of the switches and in some cases environmental conditions have been the main cause of problems. The supply of spare parts for these disconnects has been exhausted.

1) Farewell Head L54G

The original switch is 20 years old. The switch is hard to operate and efforts to adjust the mechanism for easier operation have proven unsuccessful. There is concern the mechanism will break because of the force required to operate it.

2) Holyrood T1B1-1

The original switch is 30 years old. The switch is currently inoperative due to misalignment of arms and jaws. Several attempts have been made to correct and realign the disconnect switch. Each time it has been repaired it fails on the next operation.

3) Bottom Brook B1T1

The original switch is 39 years old. The gear box for this switch has failed and the repairs are not considered to be permanent. New parts are not available. Failure during operation could result in extensive damage to Transformer T1 and associated equipment and extended outages.

Outage Statistics

Hydro does not track outage statistics directly related to failures of disconnect switches. Disconnect switches are a sub-component of major terminal station equipment such as circuit breakers, transformers and station power buses. Outage statistics for the major terminal station equipment reflect disconnect failures but the performance of disconnect switches is not directly measured.

Table 5 lists the 2005 to 2009 average T-SAIFI and T-SAIDI data by region and Hydro corporate value. The table also lists the latest CEA five year average (2003 to 2007).

Table 5: Outage Statistics

Five Year Averages (2005-2009) Forced Outages Only

Delivery Point Affected	T-SAIFI	T-SAIDI
Central Region	0.45	46.89
Northern Region	2.63	100.50
Labrador Region	7.20	114.60
Hydro System	1.01	59.07
CEA (2003-2007)	0.74	130.71

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

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

Industry Experience

Hydro has experienced operational problems with the older disconnects such as misalignment of switch blades, broken insulators falling off structures, corrosion and seizing of moving parts.

Hydro consulted with other major Canadian utilities and has confirmed that they experience similar problems.

Maintenance or Support Arrangements

Maintenance on the disconnect switches is performed by Hydro Operations personnel.

Vendor Recommendations

The vendor recommends replacement of the old disconnects after 30 years in service.

Availability of Replacement Parts

Due to the age of this equipment, original manufacturers are no longer in business and spare parts are unavailable. Hydro's inventory of spare parts has now been depleted.

Safety Performance

Malfunctioning disconnects create safety hazards due to parts breaking off and falling on the personnel working on them or around the pole structure supporting the disconnects. This has happened three times, once at each of Bay d'Espoir, Barachoix and Conne River. Hydro has revised its engineering standard for disconnect switches so that new insulators for the disconnect switches should have a higher cantilever strength in an effort to reduce the risk of parts breaking and falling.

Environmental Performance

There are no environmental concerns related to this project.

Operating Regime

Disconnect switches operate on a continuous basis.

Justification:

The disconnect switches are used to isolate equipment on the Island Interconnected System either for maintenance activities or system operations and controls. Proper operation of the switches is essential to a safe work environment and for reliable and secure system operation. Faulty and/or malfunctioning disconnect switches do not operate properly when required and as such prevent reliable and secure system operation and create a safety hazard. The switches that are being replaced have problems such as misalignment of switch blades, broken insulators falling off structures, corrosion, and seizing of moving parts. In addition, the switches are obsolete and replacement parts are not available.

The condition of the disconnects have deteriorated such that continued piecemeal repair is not

an effective solution for eliminating the safety hazards and ensuring reliable operation. Complete replacement of the disconnects in an orderly, prioritized replacement program is required.

Net Present Value

A Net Present Value calculation was not performed as only one viable alternative exists and that is to replace deteriorated disconnect switches.

Levelized Cost of Energy

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

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for this project.

Historical Information

Table 6 provides a recent history of disconnect switch replacements.

Table 6: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2010F	199.0		5		Replacement of Switches at English Harbour West, Conne River and Corner Brook Frequency Converter
2008	367.6	568.4	16	35.5	Replacement of Switches at Cow Head and Daniels Harbour

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no energy efficiency benefits associated with this project

Losses during Construction

The replacement of the disconnect switches will be coordinated with the normal planned outage schedule for the transmission system. Therefore, there will be no production or revenue losses resulting from this project.

Status Quo

The status quo is not an acceptable alternative. The disconnect switches are old and present safety and reliability issues.

Alternatives

There are no viable alternatives to replacing the disconnect switches.

Conclusion:

Reliable operation of the disconnect switches is essential to a safe work environment and for reliable and secure system operation. Many of the disconnect switches on the system have exceeded their useful lives and have problems related to reliable operation and safety. An orderly, prioritized replacement of the most problematic disconnects is required.

Project Schedule

Project schedule is shown in Table 7.

Table 7: Project Schedule

Activity	Milestone
Initial Planning and Equipment Ordering Tendering	February 2011
Equipment Delivery	August 2011
Equipment Installations and Commissioning	November 2011
Project In Service	November 2011
Project Completion and Close Out	December 2011

Future Plans:

Each year a review of the prioritized list for the replacement of disconnect switches will be made. Based on the condition of the disconnect switches combined with their location on the Island Interconnected System and the availability of outages, the priority of the replacements may change from year to year. Table 8 provides the list of disconnect switches planned for replacement in 2012 to 2015. Also see the five-year plan (2011 Capital Plan tab, Appendix A).

Table 8: Future Disconnect Switch Replacements

Year	Location	Number of Units	Disconnect Switch	Voltage (kV)
2012	Come By Chance	6	B1L07, B2L37, B1T1, B2T2, B1B2-1, B1B2-2	230
2013	Bay d'Espoir	1	B3B4-1	230
2013	Bottom Brook	1	B1T1	230
2013	Holyrood	3	B1T1, B2T2, B3T3	230
2014	English Harbor West	4	L20T1, T1AG, L20-1, L20G	69
2014	Conne River	1	L20-1	69
2014	Farewell Head	1	L54G	69
2015	Bay d'Espoir	5	B13L20-1, B13L20BP, B13T11-1, B13T10, B13T12	69
2015	Barachoix	2	L20T1, T1AG	69

Project Title: Install Voltage Regulators

Location: Conne River and L'Anse au Loup

Category: Transmission and Rural Operations – Distribution

Type: Other

Classification: Normal

Project Description:

This project consists of the establishment of new three-phase voltage regulator banks on the Conne River and L'Anse au Loup distribution systems. The work consists of the tendering and purchase of two sets of three single-phase 7.2/14.4 kV, 200 Amp voltage regulators, the construction of new three-pole structures complete with aluminum platforms, installation and commissioning the new voltage regulators, as well as any necessary clearing and site work. The voltage regulator bank for the Conne River System will be located just outside the Terminal Station on distribution line L1. The voltage regulator bank for the L'Anse au Loup System will be located near the community of Forteau which is approximately 14 kilometres from the L'Anse au Loup Substation. The budget estimate for this project is shown in Table 1 below.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	170.0	0.0	0.0	170.0
Labour	38.0	0.0	0.0	38.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	24.0	0.0	0.0	24.0
Other Direct Costs	6.5	0.0	0.0	6.5
O/H, AFUDC & Escln.	30.2	0.0	0.0	30.2
Contingency	23.9	0.0	0.0	23.9
TOTAL	**292.6**	**0.0**	**0.0**	**292.6**

Existing System:

Conne River – L1

The Conne River Distribution System consists of a single 12.5 kV three-phase distribution feeder, L1. L1 is nearly seven kilometres long extending through the community of Conne River and servicing approximately 400 customers. The feeder is constructed using approximately four kilometres of 1/0 AASC (Montreal) conductor, and approximately three kilometres of #2 AASC (Halifax) conductor to the end of the line.

The feeder is supplied from the Conne River Terminal Station which contains a 69/12.5 kV, 2.5 MVA power transformer. The transformer has an off-load-tap-changer which is set in the nominal tap position[4]. There is no automatic voltage regulation at the Conne River Terminal Station. Voltage levels for the existing Conne River Distribution System are regulated from Bay d'Espoir approximately fifteen kilometres away via the 69 kV transmission system to which it is connected. The transmission system voltage is already at the maximum set point to ensure acceptable voltage is delivered at the end of the transmission line, thus raising the transmission voltage any higher will result in high voltages in Conne River during periods of light load such as at night. Changing the transformer tap to boost the voltage will also result in high voltages on the distribution system. Therefore the existing system is not capable of producing the required voltage regulation.

L'Anse au Loup – L1

The L'Anse au Loup Distribution System consists of two 25 kV three-phase feeders, L1, and L2. L1 is over twenty-six kilometres long and extends from the community of L'Anse au Clair at the Quebec Border to the community of L'Anse au Loup. The feeder is constructed using 4/0 AASC (Vancouver) conductor. It serves the communities of L'Anse au Clair, Forteau, L'Anse-Amour, and L'Anse au Loup and has a total of 390 customers. The complete distribution system provides electrical service to approximately 990 customers.

The feeder can be supplied at both ends via either an interconnection to the Hydro Quebec System at Blanc Sablon or from the L'Anse au Loup Diesel Plant. The diesel plant is the primary supply for the system. The supply from Hydro Quebec is only available to the L'Anse au Loup System when it is not required by customers in their own systems on the Quebec North Shore; it is a secondary energy source. There are currently no automatic voltage regulators on Feeder L1. Voltage control is provided by either a set of voltage regulators owned by Hydro Quebec at the Blanc Sablon Substation, or from the diesel plant at L'Anse au Loup. When taking supply from the diesel plant, the bus voltage can be raised to correct the voltage on the distribution line until

[4] A transformer can have a number of incremental positions in its winding configurations that can be set to either increase or decrease the output voltage from the transformer. Each of these positions is called a tap. An off-load-tap-changer requires that the transformer be taken out of service in order to manually change its tap position. It cannot be used to automatically control the voltage on the distribution line, but rather provides a fixed increase or decrease to the voltage. The nominal tap position is the setting where the output voltage is neither increased (boosted) or decreased (bucked).

about 2017 at which point additional work would be required to improve voltage regulation on the distribution line. The bus voltage at the supply from Hydro Quebec is already at the maximum setpoint and cannot be raised any further.

Age of Equipment or System

The distribution systems at Conne River and L'Anse au Loup were constructed in 1969. This is the first installation of voltage regulators on Conne River distribution feeder L1, and on L'Anse au Loup distribution feeder L1.

Major Work/or Upgrades

There have been no major upgrades to the Conne River Distribution System since it was first constructed.

There have been no major upgrades to the L'Anse au Loup Distribution System in the past five years. The last major upgrades to this system were in 1994 to facilitate the interconnection to Hydro Quebec's Lac Robertson System. That work involved upgrading feeder L1 from single-phase to three-phase, upgrading the conductor on the distribution line to 4/0 AASC (Vancouver) conductor, upgrading the distribution voltage from 12.5 kV to 25 kV, and extending the distribution line down to the Quebec/Labrador border to make the interconnection to the Hydro Quebec System. First power was received from the interconnection on September 28, 1996 following the L'Anse au Loup Rate Hearing.

Anticipated Useful Life

A voltage regulator bank has an estimated service life of 30 years.

Maintenance History

These projects are new installations; therefore, there is no maintenance history available.

Outage Statistics

This is not a reliability driven project, however each installation will require a planned outage of approximately two hours in duration to facilitate the work.

Table 2 below lists the 2005 to 2009 average SAIFI[5] and SAIDI[6] data for Conne River and L'Anse au Loup for all causes as compared to scheduled outages - planned. The table also lists the 2005 to 2009 corporate value and the latest CEA five year average (2004 to 2008) for comparison.

Table 2: Outage Statistics for Conne River and L'Anse au Loup

Five Year averages (2005 to 2009)

SYSTEM	All Causes		Scheduled Outages - Planned	
	SAIFI	SAIDI	SAIFI	SAIDI
Conne River	3.47	7.46	0.42	0.56
L'Anse au Loup System	4.93	5.99	0.39	0.96
Central Interconnected	3.51	8.58	1.03	2.68
Northern Isolated	7.51	6.02	0.71	1.57
Hydro Corporate	5.60	9.23	0.29	0.61
CEA Region 2 (2004-2008)	2.65	7.74	0.28	0.56

Industry Experience

Voltage regulators are widely used by industry for automatically regulating the voltage on a distribution feeder and to correct for abnormal voltages. In many instances, multiple regulator banks are used to increase the capacity of a feeder to serve load growth, and they serve as a low cost alternative to more costly options such as reconductoring a line, or upgrading to a higher distribution voltage (i.e. converting from 4.16 kV or 12.5 kV to 25 kV).

Maintenance or Support Arrangements

Maintenance and inspection of the new voltage regulator banks will be performed by Hydro internal forces.

Vendor Recommendations

An Operation and Maintenance manual is provided with the voltage regulator. This manual provides recommendations on general maintenance and inspections, and as well it lists any

[5] As defined on page C - 132

[6] As defined on page C - 132

replacement parts that should be retained as spares.

Availability of Replacement Parts

Hydro retains a set of spare voltage regulators for new installations and as replacements for voltage regulators that have had in-service failures.

Safety Performance

There are no safety performance issues with this project.

Environmental Performance

There are no environmental performance issues with this project.

Operating Regime

A voltage regulator has a continuous operating regime.

Justification:

This project is justified on the requirement to supply acceptable voltage levels to Hydro's customers serviced from distribution feeder L1 in the Conne River System, and distribution feeder L1 in the L'Anse au Loup System.

Hydro uses the CSA standard *CAN3–C235–83 (R2006) – Preferred Voltage Levels for AC Systems 0 – 50,000 V*[7] as the guide for determining acceptable steady-state voltage limits at customers' service entrances. The limits defined in the standard state that the service entrance voltage must be held from a minimum of 110 V for single-phase customers and 112 V for three-phase customers to a maximum of 125 V for a nominal 120 V service.

[7] CSA Standard *CAN3-C235-83 (R2006) – Preferred Voltage Levels for AC Systems, 0 to 50 000 V*. This is a National Standard of Canada that establishes a guideline for voltage standards for AC Systems in Canada. It was adopted by Hydro as its standard for 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 they function normally and damage does not occur.

Load growth in the community of Conne River will cause lower than acceptable voltage on the distribution line, L1, in 2011. During the annual review of the Conne River Distribution System in 2009, Hydro determined that by 2011, voltage regulation on the feeder L1 would be insufficient to ensure customers receive acceptable steady state voltages at their service entrances during peak load. The supply voltage on the existing system cannot be increased any further without causing high voltage on the system under light load. Therefore a system upgrade is necessary to improve voltage regulation on distribution feeder L1.

Load growth in the L'Anse au Loup Distribution System will cause lower than acceptable voltage on the distribution line, L1, in 2011. During the annual review of the L'Anse au Loup Distribution System in 2009, Hydro determined that by 2011, voltage regulation on the feeder L1 would be insufficient to ensure customers receive acceptable steady state voltages at their service entrances during peak load. The supply voltage on the existing system cannot be increased any further. Therefore a system upgrade is necessary to improve voltage regulation on distribution feeder L1.

Net Present Value

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

Levelized Cost of Energy

The levelized cost of energy is not a consideration for this project.

Cost Benefit Analysis

A Cost Benefit Analysis was not performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

There are no legislative or regulatory Requirements for this project.

Historical Information

In the past five years there have been three capital projects to install voltage regulators in Hydro's Systems, these projects are summarized in Table 3 below.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2010F	170.0	-	3	-	Happy Valley; 200 A, 14.4 kV
2009	123.3	106.6	3	35.5	English Harbour West; 200 A, 14.4 kV
2006	121.9	76.0	3	25.3	Happy Valley; 200 A, 14.4 kV

Forecast Customer Growth

The systems discussed in this project are both growing systems. The growth of each system is discussed below.

Conne River

Load growth on L1 in Conne River has been significant. Over the five year period 2005 through 2009, an average of nine residential customers per year have been connected to the distribution system. This has resulted in approximately four percent per year growth in energy sales. L1 currently supplies power to 400 customers.

Table 4 illustrates the forecast peak load for the next five years as provided by the Market Analysis Section of the Systems Planning Department.

Table 4: Load Forecast for Conne River (April 2009)

Year	2011	2012	2013	2014	2015
Peak (kW)	2,437	2,501	2,566	2,632	2,682

The Conne River Distribution System is a growing system that is expected to continue to grow, as is shown in Table 4, for the foreseeable future.

L'Anse au Loup

There has been significant load growth on the L'Anse au Loup distribution system in the past few years. Over the five year period 2005 through 2009, an average of three residential customers have been added annually, and during the period from 2008 through 2009, 61 of Hydro's existing customers are known to have converted to electric home heating[8]. This is a continuation of a trend experienced since the system was interconnected to Hydro Quebec's Lac Robertson isolated hydro-electric plant in 1996. Over the past five years energy sales have grown by approximately five percent per year. The L'Anse au Loup Distribution System currently supplies power to 990 customers. L1 supplies power to 390 of these customers.

Table 5 illustrates the forecast peak load for the next five years as provided by the Market Analysis Section of the Systems Planning Department.

Table 5: Load Forecast for L'Anse au Loup (Fall 2009)

Year	2011	2012	2013	2014	2015
Peak (kW)	4,901	4,939	5,007	5,060	5,129

The L'Anse au Loup Distribution System is a growing system that is expected to continue to grow, as is shown in Table 5, for the foreseeable future.

Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to the installation of a voltage regulator bank on a distribution system.

Losses during Construction

There are no losses during construction associated with this project.

Status Quo

The status quo is not a viable alternative to doing this project. The existing system will be

[8] Customers are not required to advise Hydro of a switch to electric heat. They are, however, required to advise Hydro if they are upgrading their service because some of Hydro's equipment such as the service drop wire, or distribution transformer may also have to be upgraded to a larger size. In these cases the customer may inform Hydro of their intention to install electric heating.

incapable of delivering voltages within standard at customers' service entrances during periods of peak load.

At Conne River, the current method of using the transmission system to regulate the voltage on the distribution feeder from Bay d'Espoir will no longer provide adequate voltage during peak load by the year 2011. Therefore, a system upgrade is necessary to improve the voltage regulation on the distribution system.

At L'Anse au Loup, the current method of relying on the voltage regulators at Hydro Quebec's Blanc Sablon Substation to regulate the voltage on the distribution feeder will no longer provide adequate voltage during peak load by the year 2011, and voltage regulation on the feeder, when supplied by the diesel plant, will be inadequate by 2017. The voltage set point at the station cannot be raised any further. Therefore, a system upgrade is necessary to improve the voltage regulation on the distribution system.

If the status quo were maintained, voltage provided to customers on these distribution systems would continue to worsen as the system load grows. Low voltage would result in damage to customer equipment. The status quo is not an alternative to doing this project. A system upgrade is necessary to improve the voltage regulation on the distribution feeders Conne River L1, and L'Anse au Loup L1.

Alternatives

To improve the voltage regulation on a distribution feeder, the following alternatives were considered:

Alternative 1: Voltage Regulators

The voltage regulation on a distribution line can be improved by installing voltage regulators. A voltage regulator is a type of transformer with a number of taps (usually sixteen taps with 5/8 percent regulation per tap) on the series winding. The series winding can be reversed so that the voltage regulator can both boost and buck the voltage at its output terminals. A motorized tapchanger mechanism and electronic control panel can change the taps automatically while loaded. Thus it can automatically control the voltage on a distribution line. Voltage Regulators

are commonly used in the distribution utility industry and are the first preferred method to correct for poor voltage regulation in comparison to more expensive methods such as voltage conversions, or conductor upgrades.

Conne River – Install a bank of three single-phase voltage regulators in a three-phase bank at the Conne River Terminal Station, or as close to the station as practically possible. Schedule A1 contains a single line diagram that shows the position of the proposed new voltage regulator bank on L1 in relation to the Conne River Terminal Station. This project has an estimated capital cost of $147,800.

L'Anse au Loup – Install a bank of three single-phase voltage regulators in a three-phase bank near the community of Forteau which is approximately fourteen kilometres from the L'Anse au Loup Substation. Schedule A2 contains a single line diagram that shows the location of the proposed new voltage regulator bank on L1 in relation to the rest of the system. This project has an estimated capital cost of $144,800.

Alternative 2: Conductor Upgrade

The voltage regulation on a distribution line can be improved by increasing the conductor size on that line. This will improve load transfer capabilities of the feeder, and provide better voltage regulation.

Conne River – Upgrade approximately four kilometres of conductor on the main trunk of the distribution line to 4/0 AASC (Vancouver) conductor. This project has an estimated capital cost of $550,000. The upgrade would provide acceptable voltages until the year 2013 at which point additional upgrading would be required. As this project would only provide a short-term solution, and the capital cost is much higher than installing voltage regulators and the savings associated with reduced line losses (about $12,000 to 2013) are not sufficient to make the project competitive over installing voltage regulators, this alternative was not considered any further.

L'Anse au Loup – Upgrade approximately twenty-six kilometres of conductor on the main trunk of the distribution line to 477 ASC (Cosmos) conductor. This project has an estimated capital

cost of $4,165,000. The upgrade would provide acceptable voltages until the year 2016 at which point additional upgrading would be required. As this project would only provide a medium-term solution, and the capital cost is much higher than installing voltage regulators and the savings associated with reduced line losses (about $390,000 to 2016) are not sufficient to make the project competitive over installing voltage regulators, this alternative was not considered any further.

Alternative 3: Voltage Conversion

The voltage regulation on a distribution line can be improved by upgrading to a higher distribution voltage. This will improve load transfer capabilities for the feeder. By distributing power at a higher voltage, the line current is reduced proportionally to the increase in voltage. The subsequent reduction in current will provide better voltage regulation on the distribution line.

Conne River – Upgrade the distribution voltage from 12.5 kV to 25 kV. This project has an estimated capital cost of $1,300,000. The upgrade would provide acceptable voltages for the foreseeable future. As this project is nearly an order of magnitude higher than the capital cost of installing voltage regulators, this alternative was not considered any further.

L'Anse au Loup – The distribution system already operates at a nominal voltage of 25 kV and cannot be upgraded any further.

Alternative 4: Conservation Demand Management (CDM)

An alternative to improve the voltage regulation on a distribution feeder is to reduce the peak load through a Conservation Demand Management (CDM) Program. This program explores the potential for conservation and demand at the customer level so that peak load can be reduced, thereby deferring the capital expenditure of a system upgrade project to a later date. The budget for the CDM program is based on the value of deferring the alternative project for a minimum of one year. For both the Conne River and L'Anse au Loup Distribution Systems, a CDM program does not produce the required reduction in demand to defer the project. Therefore, a CDM program is not a viable alternative in this instance.

Based on the discussion above, Alternative 1, to install voltage regulator banks on the distribution feeders, is the best technical and least cost alternative. The new voltage regulator banks will maintain sufficient voltage regulation on Conne River distribution feeder L1 and L'Anse au Loup distribution feeder L1 for the foreseeable future, and is the least cost solution in comparison to the remaining technically viable alternatives.

Conclusion:

This project is required to provide quality power and voltage to the customers served on the Conne River and L'Anse au Loup distribution systems. Without the upgrades, the existing systems will suffer from poor voltage regulation, and cannot meet the requirements outlined in the *CSA Standard CAN3-C238* for voltages at customer service entrances. When steady-state voltages deviate from the recommendations of the CSA standard, customers' appliances may not work correctly, and can fail prematurely. With increasing load, the voltage regulation on the distribution feeders will get worse. As shown in Table and Table , it is expected that load growth will continue in future years, and therefore the problem must be addressed. To correct the problem, voltage regulation on the existing distribution feeders must be improved, and therefore a system upgrade is necessary.

Four alternatives were considered which can correct for poor voltage regulation on a distribution system. Of the available alternatives, the best technical and least cost solution is to install new voltage regulator banks on the distribution feeders. By installing voltage regulators, the voltage on the distribution line can be controlled and held at a constant level to correct for voltage regulation on the distribution feeder. This will ensure that voltages at customer service entrances remain acceptable for the foreseeable future.

It is recommended that new voltage regulator banks be installed on Conne River distribution feeder L1, and on L'Anse au Loup distribution feeder L1. The addition of the regulators to distribution feeders will improve voltage regulation on the existing system, and ensure it is capable of supplying customers with acceptable voltages beyond the 2015 forecast.

Project Schedule

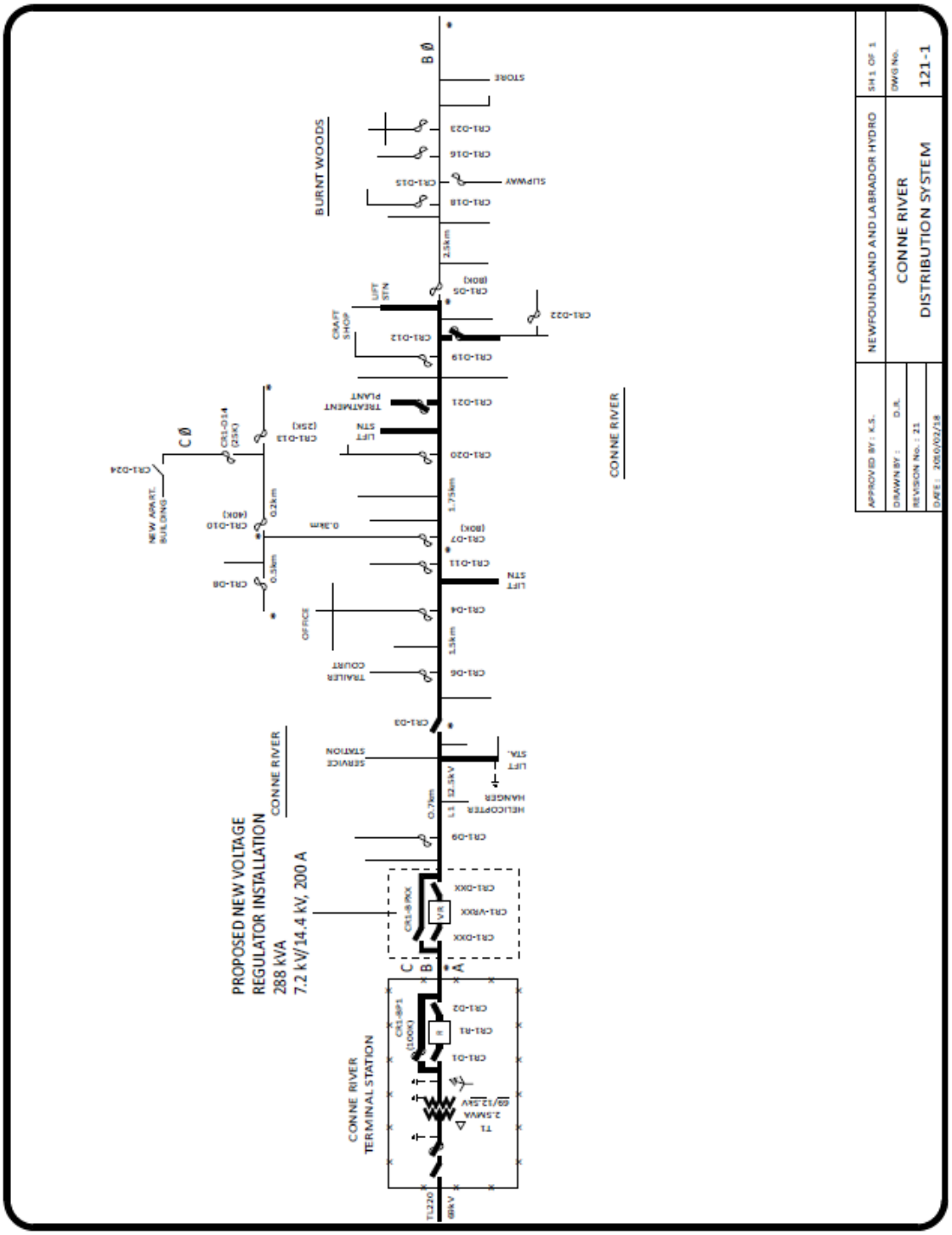
The anticipated project schedule for the Voltage Regulator Installations in Conne River and L'Anse au Loup is shown in Table 6.

Table 6: Project Schedule

Activity	Milestone
Initiation	January 2011
Design Complete	March 2011
Equipment Ordered	April/May 2011
Installation Commences	July 2011
Installation Complete	August 2011
Project Closeout	October 2011

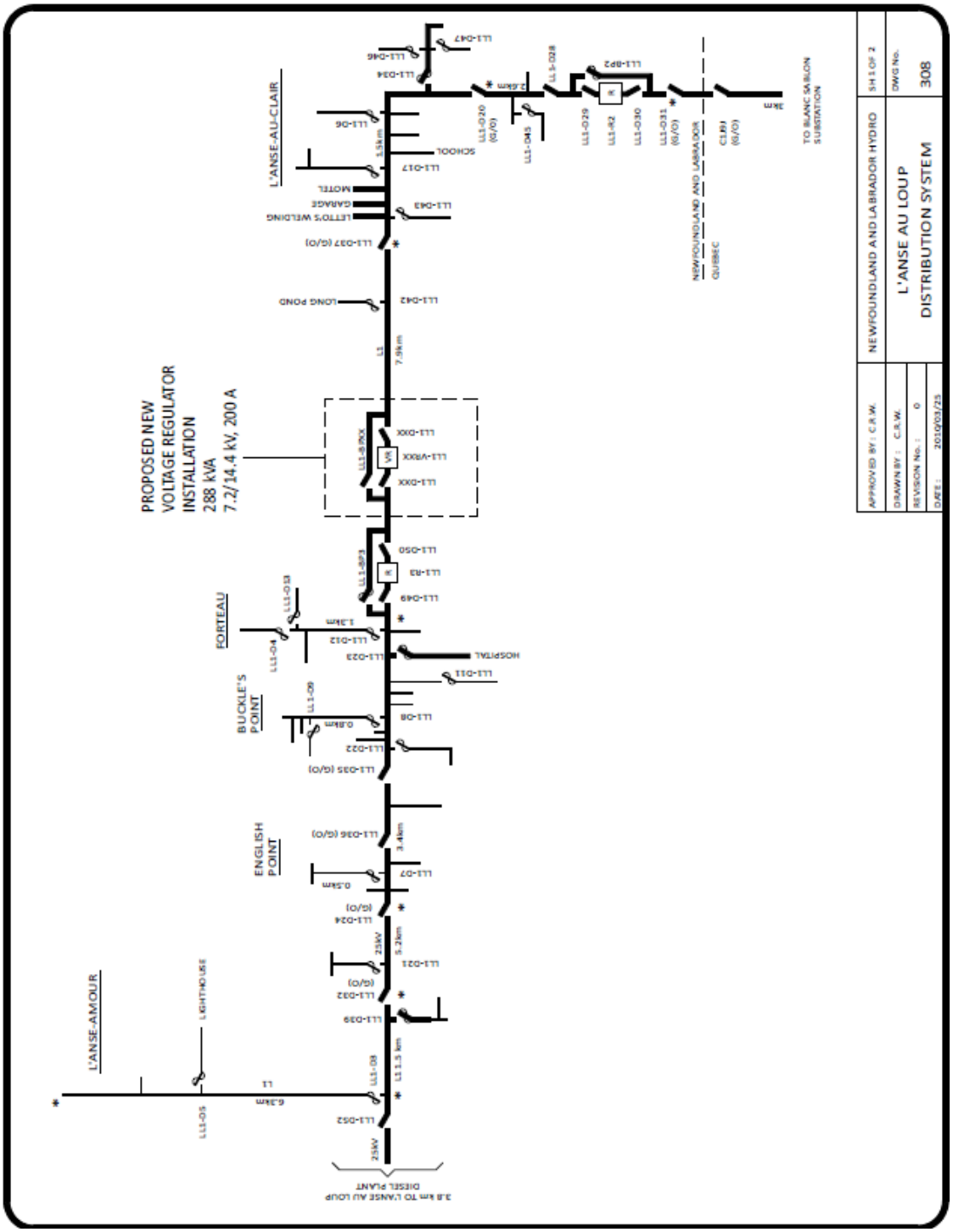
SCHEDULE A1

Conne River L1, Feeder Single Line Diagram



SCHEDULE A2

L'Anse au Loup L1, Feeder Single Line Diagram



Project Title: Replace Compressor, Dryer and Air Piping Header System

Location: Corner Brook Frequency Converter Station

Category: Transmission and Rural Operations - Terminal Stations

Type: Clustered

Classification: Normal

Project Description:

This project is required to replace the compressed air piping and equipment including a compressor, compressed air receiver, and compressed air dryer at the Corner Brook Frequency Converter Station (Frequency Converter). Also included in the project is the installation of a backup air dryer and a dew point monitoring system. The budget estimate for this project is shown in Table 1.

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	123.3	0.0	0.0	123.3
Labour	83.4	0.0	0.0	83.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	1.2	0.0	0.0	1.2
Other Direct Costs	26.7	0.0	0.0	26.7
O/H, AFUDC & Escln.	22.1	0.0	0.0	22.1
Contingency	23.5	0.0	0.0	23.5
TOTAL	**280.2**	**0.0**	**0.0**	**280.2**

Existing System:

The Corner Brook Frequency Converter is a 25 MVA rotating motor-generator set located at the Corner Brook Pulp and Paper mill in Corner Brook. It is owned and operated by Hydro but specifically assigned, for cost of service purposes, to Corner Brook Pulp and Paper. Its function is to convert power generated at Deer Lake Power at a frequency of 50 hertz to a frequency of 60 hertz for use at the Corner Brook Pulp and Paper mill. Appendix A contains the Frequency Converter single line diagram.

The Frequency Converter was placed in service in 1967 and has seen minimal refurbishment work until recent years. In 2008, both the 50 and 60 hertz stators were re-wedged, which re-secures windings that become loose over time, and the 50 and 60 hertz rotors were rewound.

In 2009, the ventilation system inside the terminal station was upgraded; the voltage regulators were replaced; the liquid rheostat used for starting the frequency converter was replaced; and new synchronizing equipment was installed.

Compressed air at the Frequency Converter is generated at 2,480 kilopascals. Through a system of piping and pressure reducing valves, compressed air is supplied at a pressure of 1,380 kilopascals (200 pounds per square inch) for the operation of three Brown Boveri 6.6 kV circuit breakers and ten 6.6 kV disconnect switches. In addition to providing the motive power for operation of the breakers and disconnect switches, compressed air is also used as an arc quenching medium when a breaker has to interrupt the flow of electricity.

Without air pressure, these breakers will move to the closed position and become inoperable. As a result, electrical faults on the station power distribution system that require breaker operation will not be cleared. This would cause a power outage on the distribution system connected to the Frequency Converter and present a risk of damaging the frequency converter. Without air pressure being supplied, the 6.6 kV disconnect switches can only be operated manually, however they were not designed to be operated in this manner. Figures 1 and 2 show parts of the compressed air system at the Frequency Converter.



Figure 1: Compressed Air System Header Piping and Two Compressors



Figure 2: Compressed Air Dryer

This project is required to replace aging compressed air equipment, and piping at the Frequency Converter Station in order to improve air quality and reliability.

Age of Equipment or System

The compressed air system at the Frequency Converter was constructed in 1966/67. Table 2 shows major components of the compressed air system and the year in which each was installed. Sections of tubing and minor components have been replaced as part of minor repairs.

Table 2: Age of Major Components

Equipment	Description	Year of Installation
Air Compressor A	Atlas Copco model LT7	2001
Air Compressor B	Broomwade model TN20	1977
Compressed air dryer	Bowser model DD303EA500	1967
Air receiver	Metropolitan Oil and Gas	1966
Air system piping	Brazed copper tube	1966

Major Work/or Upgrades

The following upgrades have occurred since installation of the compressed air system:

Table 3: Major Work and Upgrades

Year	Major Work/Upgrade	Comments
2008	Partial replacement of header piping	Replacement of deteriorated piping
2002	Replacement of air dryer	Replacement came from the Stony Brook Terminal Station
2001	Replacement of Compressor A	Purchase of new compressor
1993	Replacement of Compressor B	Replacement came from the Grand falls Frequency Converter Station

Anticipated Useful Life

Compressed air systems are depreciated over 40 years. Air compressors of the capacity installed at the Corner Brook frequency converter, however, have a service life of approximately 25 years depending upon their duty cycle and availability of replacement parts.

Maintenance History

Preventive maintenance of the compressed air system includes changing air filters, draining of condensate, changing compressor oil, changing air dryer desiccant, operation checks, and inspection of piping and components for leaks.

Corrective maintenance may involve any component in the system but is usually the result of a failure of compressor or air dryer components.

The five-year maintenance history for the compressed air system is shown in the following table:

Table 4: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2009	5.4	7.3	12.7
2008	6.9	6.4	13.3
2007	9.5	8.2	17.8
2006	7.2	5.5	12.7
2005	2.0	5.1	7.1

Outage Statistics

There are no outage statistics associated with this equipment.

Industry Experience

Though not specific to this project, Hydro has solicited experience from other electric utilities regarding the improvement of compressed air quality for the operation of air blast breakers in a discussion forum managed by Doble Engineering, a company that aids clients in the electric power industry to improve operations and optimize system performance. Utilizing this forum, Hydro posted a questionnaire to other utilities regarding moisture problems for air blast circuit breakers. One respondent to the questionnaire, Manitoba Hydro, addressed air quality issues at their terminal stations by replacing hose and copper piping with stainless steel pipe and welded connections.

Other systems of similar age (30 to 40 years) and construction (brazed copper tube) within Hydro have developed leaks with age. In Hardwoods and Holyrood terminal stations, for instance, sections of tubing have been replaced over the years with flexible hose to address leaks, but which is now known not to be suitable for the purpose. It is now generally accepted that leaks develop in these systems. These leaks increase run time on compressors to replace lost air and provide for the ingress of moisture into the air system. Moisture can cause internal

corrosion and potentially damage equipment. Hydro received approval under Board Order No. P.U. 1 (2010) to replace the copper tube and flexible hose compressed air system at the Holyrood Terminal Station with stainless steel and install a backup air dyer and dew point monitor at a budget estimate cost of $496,000.

Maintenance or Support Arrangements

This equipment is maintained by Hydro.

Vendor Recommendations

There are no relevant vendor recommendations.

Availability of Replacement Parts

Compressor B is a 1977 vintage, Broomwade model TN20 compressor which was relocated from the Grand Falls Frequency Converter Station after failure of the original compressor that was installed in 1966 at the Corner Brook Frequency Converter Station. Replacement parts for this compressor are no longer available for purchase and there are no spares in stores. As the original compressors have been replaced, they have been scavenged to provide spare parts to keep the remaining compressors in service. There are no spare parts remaining. Compressor B is the last original compressor. Figure 3 shows the two compressors at the Frequency Converter.



Figure 3: Compressors A and B at the Corner Brook Frequency Converter Station

The Bowser model DD303EA500 air dryer was manufactured in 1967 and was relocated from the Stony Brook Terminal Station which was replaced with a new air dryer. This air dryer is equipped with mechanical timers and valves that are obsolete, and are the primary source of failures.

Safety Performance

There are no safety performance issues related to this project.

Environmental Performance

There are no environmental concerns related to this project.

Operating Regime

The compressed air system is the only source of compressed air for operation of circuit breakers at the Frequency Converter. Two compressors operate on a lead/lag sequence whereby one compressor is set to operate as first priority upon falling air pressure and if the air pressure continues to fall, the second compressor then operates. The maximum air pressure generated is 2,480 kilopascals. When the pressure drops to 2,340 kilopascals, the first priority compressor

will start operating. If the pressure continues to fall and reaches 2,200 kilopascals, the second compressor will start to operate. Compressor operating priority is set manually at the control panel to evenly distribute operating hours, however, the newest compressor, Compressor A is continually set as first priority operation to minimize run time on the older compressor in order to reduce the risk of a failure which cannot be repaired due to a lack of replacement parts. As a result, the new compressor is experiencing accelerated wear due to higher use.

Justification:

This project is justified on the requirement to replace obsolete infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. Due to the lack of available replacement parts, it is not possible to continue to operate existing equipment.

Net Present Value

A net present value calculation was not performed as there is no viable alternative to replacing the compressed air system.

Levelized Cost of Energy

The levelized cost of energy does not apply as there are no new sources of generation considered.

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for the replacement of this equipment.

Historical Information

There have been no projects involving complete replacement of a compressed air system, however, a list of projects involving replacement of similar equipment is provided below.

Table 5: Major Work/Upgrade

Year	Major Work/Upgrade	Cost (x $1,000)
2009	Installation of Dew Point monitor at Bay D'Espoir Terminal Station 1	34.4
2008	Replacement of backup air dryer at Bay D'Espoir Power House	53.1
2007	Replacement of Cat Arm air dryer	40.8
2006	Replacement of Grand Falls Terminal Station air dryer and compressor 'A'	62.2
2003	Replacement of Corner Brook Frequency Converter Compressor A	35.8

Forecast Customer Growth

Customer load growth has no effect on this project. According to Hydro's five-year Operating Forecast, spring 2010, the Corner Brook Pulp and Paper load forecast will remain constant at 26 MW over the period 2011 to 2015.

Energy Efficiency Benefits

Minor energy efficiency benefits may be realized by the use of energy efficient motors and the elimination of leaks which contribute to compressor run time. Such benefits, however, are minor in relation to the cost of this project and are not quantifiable.

Losses during Construction

To maintain compressed air service, a temporary compressed air plant will be set to prevent any losses during construction.

Status Quo

If this project is not completed, a failure of compressor A will eventually occur. With no replacement parts available, the compressed air system will be reduced to one working compressor and be at risk of complete failure. Upon loss of the compressed air supply, switch gear will become inoperable. The frequency converter will have to be taken out of service until the compressed air system is restored. Restoration of the compressed air system may take up to two weeks for improvised, temporary service. Depending on the nature of the failure, full restoration could take months due to lead times required for new equipment.

An outage of the Frequency Converter will result in trapped generation at the Deer Lake generating station which may result in spilled water. This would have a financial impact upon

Deer Lake Power due to lost revenue and upon Corner Brook Pulp and Paper which would have to purchase additional power from Hydro.

Alternatives

There are no viable alternatives to replacement of the compressed air system.

Conclusion:

This project is necessary in order to provide compressed air service for the continued reliable operation of the compressed air operated circuit breakers and disconnect switches at the Corner Brook Frequency Converter.

Project Schedule

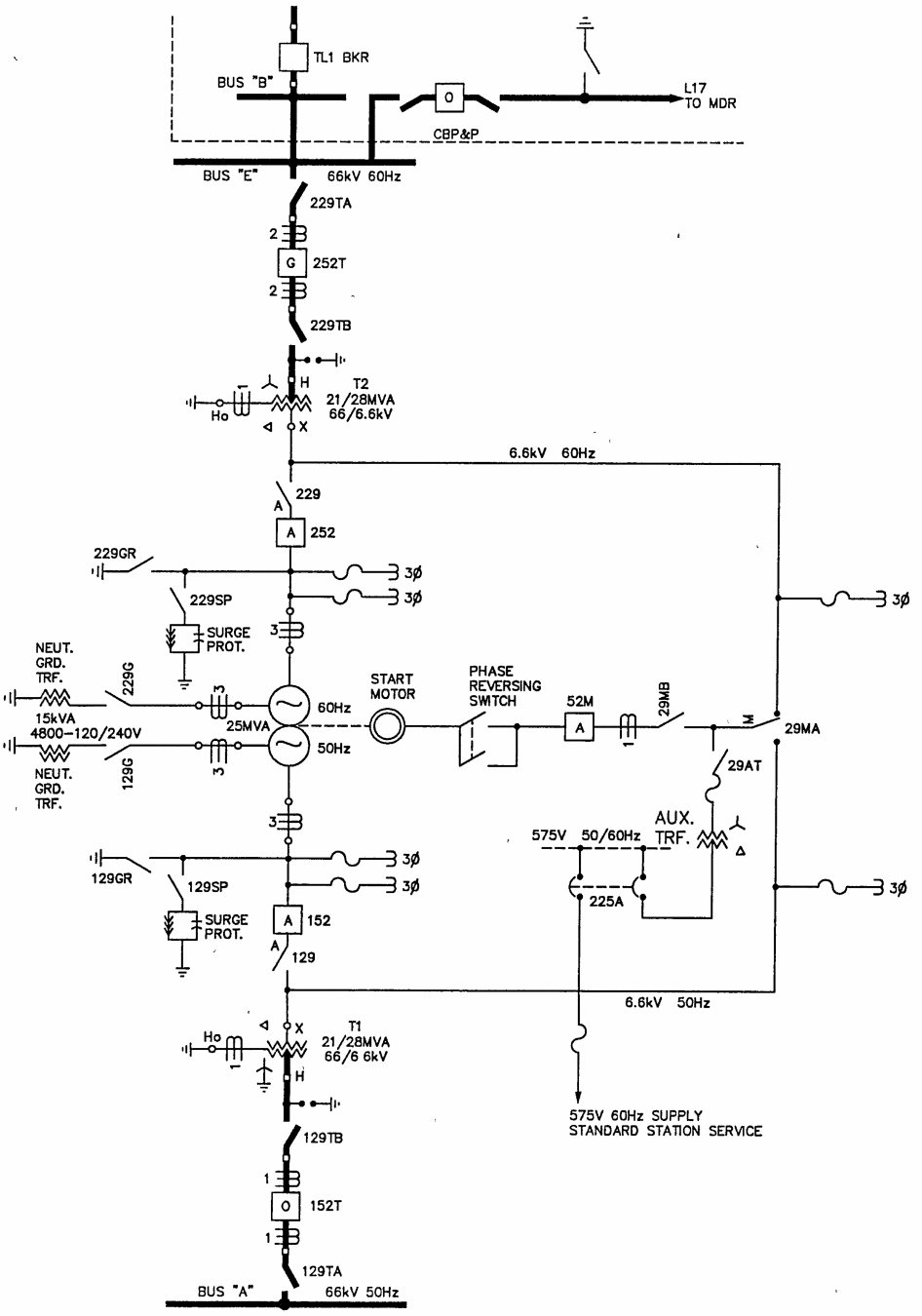
Table 6 shows the anticipated project schedule.

Table 6: Project Schedule

Activity	**Milestone**
Project initiation	March 2011
Design	April 2011
Tendering	May 2011
Construction	August 2011
In Service	September 2011

Appendix A

Frequency Converter Single Line Diagram



Corner Brook Frequency Converter Single Line Diagram

(Equipment Specifically Assigned to CBPP)

Project Title: Replace Recloser Control Panels

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Type: Pooled

Classification: Normal

Project Description:

The Recloser Control Panel Replacement Project is required to replace 36 aging recloser control panels. This is the second year of a five-year program. In 2011, seven recloser control panels will be replaced. The existing control panels are housed in steel enclosures which have deteriorated due to the extreme environment. To prevent future deterioration of the new panels due to weather the Recloser Control Panel Replacement Project uses rack mounted control panels inside control buildings where applicable and control panels located inside stainless steel enclosures where no building exists. The new recloser control panel will also have remote control capability should a future telecommunications network be established at these sites. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	72.7	0.0	0.0	72.7
Labour	90.2	0.0	0.0	90.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	29.2	0.0	0.0	29.2
O/H, AFUDC & Escln.	20.6	0.0	0.0	20.6
Contingency	19.2	0.0	0.0	19.2
TOTAL	**231.9**	**0.0**	**0.0**	**231.9**

In 2011, three rack mounted panels and four pole mounted control panels will be installed as shown in Table 2. For a complete list of the recloser control panels to be replaced under this program see Appendix A.

Table 2: 2011 Recloser Control Panel Replacements

Location	Type	Recloser ID	Year Installed
Barachoix	Pole Mounted	BA1-R1	1979
Barachoix	Pole Mounted	BA4-R1	1979
Roddickton	Rack Mounted	RO1-R2	1985
Roddickton	Rack Mounted	RO1-R3	1981
Roddickton	Rack Mounted	RO3-R2	1985
Roddickton	Pole Mounted	RO4-R1	1984
Main Brook	Pole Mounted	MB1-R1	1989

These recloser control panels have been identified for replacement based on condition and age. In Table 2, the pole mounted units will be replaced with stainless steel enclosures while rack mounted units will be mounted inside the available control building and need no further enclosure. Both these measures will reduce the effect of salt corrosion which is a known factor in these areas.

Existing System:

Newfoundland and Labrador Hydro (Hydro) operates distribution systems throughout Newfoundland and Labrador and supplies power to approximately 36,000 metered customers. A key component of the distribution systems is the distribution automatic recloser. It is the primary fault protective device on distribution feeders. A distribution recloser is set to detect faults on the feeders and to open if a fault occurs. The feeder is put back in service automatically by the recloser and if the fault has been cleared, the feeder will stay in service, minimizing the outage to customers.

This project is to replace aging and weathered distribution recloser control panels on distribution feeders to ensure fault protection reliability is not compromised. Photos of a rusted recloser control panel are shown in Figures 1 and 2.



Figure1: Roddickton Recloser RO1-R2 Control Cabinet



Figure 2: Roddickton Recloser RO1-R2 Control Cabinet

The existing Cooper Recloser control panels are housed in a painted steel design compartment which has been exposed to a highly corrosive coastal environment in many of the recloser

locations.

Age of Equipment or System

Refer to Table 2 for a listing of the age of the assets being replaced.

Major Work/ or Upgrades

Refer to Appendix B for a list of major work and upgrades on various reclosures.

Anticipated Useful Life

The recloser control panel has an anticipated useful life of 20 years.

Maintenance History

Table 3 shows the five-year maintenance history for the reclosers being replaced in 2011. Refer to Appendix C for the five-year maintenance history for all reclosers to be replaced under the program.

Table 3: Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	Barachoix Recloser BA4-R1	1.3	0.0	1.3
2008	Barachoix Recloser BA1-R1	0.6	0.0	0.6
2008	Roddickton Recloser RO4-R1	0.0	0.1	0.1
2006	Barachoix Recloser BA1-R1	0.0	0.8	0.8
2006	Roddickton Recloser RO1-R2	0.3	0.0	0.3
2006	Roddickton Recloser RO4-R1	0.3	0.8	1.1
2006	Roddickton Recloser RO1-R3	0.0	0.2	0.2
2005	Barachoix Recloser BA4-R1	0.8	0.0	0.8
2005	Roddickton Recloser RO3-R2	0.2	0.0	0.2
2004	Barachoix Recloser BA1-R1	1.6	0.0	1.6
2004	Roddickton Recloser RO1-R3	0.0	0.2	0.2
2004	Roddickton Recloser RO4-R1	0.0	0.8	0.8

Outage Statistics

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

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

SAIFI - Indicates the average of sustained interruptions per customer served per year or the average number of power outages a customer has experienced in the respective distribution system per year.

Table 4 lists the 2005 to 2009 average SAIFI and SAIDI data by feeder and distribution system where the Upgrades are proposed. The table also lists the 2005 to 2009 corporate value and the latest CEA five year average (2004 to 2008) for comparison.

Table 4: Outage Statistics

Five Year averages (2005 to 2009)

SYSTEM	All Causes		Defective Equipment	
	SAIFI	SAIDI	SAIFI	SAIDI
Central Interconnected	3.51	8.58	0.39	0.78
Northern Interconnected	4.68	8.12	0.40	0.87
Labrador Interconnected	8.45	11.59	0.50	0.72
Northern Isolated	7.51	6.02	0.30	0.38
Barachoix System	4.38	10.85	0.74	0.72
Barachoix Feeder 1	2.72	7.43	0.21	0.20
Barachoix Feeder 4	5.56	12.80	1.18	1.12
South Brook System	3.18	7.76	0.23	0.48
Cow Head Feeder 1	2.35	5.31	0.15	0.09
Daniel's Harbour Feeder 1	2.76	5.25	0.23	0.79
Glenbernie System	4.31	11.35	0.43	0.72
Glenbernie Feeder 2	4.55	11.43	0.24	0.61
Hawke's Bay System	6.14	8.88	0.16	0.19
Parson's Pond Feeder 1	3.95	5.14	0.00	0.01
Roddickton System	5.58	9.62	0.22	0.18
Roddickton Feeder 1	5.89	9.43	0.20	0.18
Roddickton Feeder 2	3.41	5.14	0.00	0.00
Roddickton Feeder 3	4.10	5.94	0.01	0.07
Roddickton Feeder 4	7.27	16.45	0.60	0.37
St. Anthony System	5.81	9.65	0.65	2.43
St. Anthony Feeder 1	4.75	7.22	0.74	1.74
St. Anthony Feeder 2	4.52	4.72	0.22	0.02
St. Anthony Feeder 3	5.40	5.88	0.60	0.53
L'Anse au Loup System	4.93	5.99	0.36	0.45
Mary's Harbour System	15.68	7.94	0.47	0.81
Port Hope Simpson System	9.11	5.34	0.21	0.05
Hydro Corporate	5.60	9.23	0.42	0.93
CEA Region 2 (2004-2008)	2.65	7.74	0.49	1.28

Hydro's present system for collecting outage information does not record equipment failures by distribution equipment components such as recloser panels. Outages due to recloser control panels along with other defective equipment would be included in the general defective equipment category. The data provided in the table lists the outage statistics for all causes and defective equipment.

Defective Equipment is defined by the CEA as:

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

It does not include planned outages to repair defective equipment.

Industry Experience

The stainless steel enclosure for the control panel or the rack mounted control panel is recommended for installations subject to severe weather or salt contamination.

Maintenance or Support Arrangements

There are no maintenance or support agreements with the manufacturers.

Vendor Recommendations

Cooper Power Systems has advised Hydro that the solution to the severe rust contamination on the recloser control panels is replacement with the latest digital control which is available in a stainless steel panel enclosure, as well as in rack mount configuration. The vendor has also confirmed that the existing recloser itself does not require change out and that only its sensing current transformers (CT) require replacement in order to be compatible with the accuracy of the new digital control.

Availability of Replacement Parts

Hydro has been advised by the Cooper Power Systems that circuit boards and plug-in cards have delivery times of 12-20 weeks, as can be seen below in an excerpt of a vendor email:

> "The existing F3 controls are from 1960's technologies. As many of these devices still exist at Utilities all over the world, Cooper had strategically found new components suppliers in the 80's, had stock-piled required boards and components to support the devices. I am still amazed that we can still obtain parts, as many of the old original manufacturers have long since moved on to more current technologies. I would expect within the next 5-10 years that we may have great difficulty obtaining replacement parts for these old devices. The replacement parts business could be terminated at any time - although Cooper does not have any set time at present. To the best of my knowledge, most of the control boards are still available, but on a 12-20 week delivery basis."

Safety Performance

During a fault, electrical energy enters the earth. These electronic reclosers sense the fault condition and break the electrical path feeding the fault. This quickly limits the electrical energy entering the earth greatly reducing the electrocution hazard.

Environmental Performance

This multi-year project does not have any environmental impact.

Operating Regime

All distribution reclosers listed for upgrade are in continuous operating mode.

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.

Net Present Value

A net present value calculation was not performed in this instance, as there are no viable alternatives to replacing the control panels.

Levelized Cost of Energy

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

Cost Benefit Analysis

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

Legislative or Regulatory Requirements

There are no legislative or regulatory requirements with this project.

Historical Information

Eight recloser control panel replacements were completed in 2008. These consisted of reclosers at the Change Islands Substation (CH2-R1 and CH3-R1), Fogo Island Substation (FO4-R1, FO5-R1, and FO6-R1), and the Bottom Waters Terminal Station (BW1-R1, BW2-R1 and BW3-R1).

Five recloser control panel replacements were completed in 2009. These consisted of reclosers at the Burgeo Substation (BU2-R1, BU3-R1 and BU4-R1) and at the Bottom Waters Terminal Station (BW2-R3 and BW4-R1).

Sixteen recloser control panels are being replaced in 2010. These are South Brook (SB7-R2), English Hr. West (EH1-R1 and EH1-R2), Jackson's Arm (JA1-R1 and JA2-R1), Hampden (HA1-R1), Bear Cove (BC6-R2, BC4-R1 and BC6-R1), Happy Valley-Goose Bay (HV1-R1, HV7-R1, HV8-R1, HV10-R1 and HV16-R1) and Plum Point (PP1-R1 and PP2-R1).

Table 5 contains the historical information for these replacements.

Table 5: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2010F	603.1		16		Project in progress
2009	132.4	107.3	5	21.46	Completed with approved change order[9]
2008	222.5	133.9	8	16.74	Completed with approved change order[10]

[9] A change order to revise the 2009 budget was issued as the amount of field work by operations crew was less than originally estimated. Operations crews retrofitted each rescloser and pre-commissioned it at the terminals maintenance repair facility in Bishop's Falls. This project was completed in conjunction with other work in the region during the same time and thus reduced travel and accommodations costs. The total reduction on the change order was $25,100.

[10] A change order to revise the 2008 budget was issued as the cost for the recloser controls was less than originally estimated and several of the recloser structure modifications were not required as originally anticipated. The amount of field work by operations crews was also significantly reduced by retrofitting each recloser and pre-commissioning it with its new electronic controls in the Hydro terminals maintenance repair facility at Bishop's Falls, thereby reducing operations crews overtime and travel time. The total reduction on the change order was $88,961.

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no energy efficiency benefits associated with this type of project.

Losses During Construction

There may be planned power outages involving those reclosers that require CT replacements. The reclosers will have to be temporarily removed from service.

Status Quo

Maintaining the status quo will result in prolonged outages and by-passed protective devices due to the availability of replacement parts for the existing recloser controls. Such a scheme could also cause unnecessary outages. If a recloser did not operate because it was in bypass or simply didn't operate due to age, an upstream protective device would operate and by doing so, increase the amount of customers affected.

Alternatives

There is no viable alternative to replacement of the control panels for the distribution reclosers listed in Appendix A. Many of the original electronic components for these control panels have very long lead times as per the availability of parts section of this document.

Conclusion:

Replacing each panel with a more modern digital control panel with stainless steel enclosure or rack mounted panels located in a control building is the only option.

Project Schedule

The anticipated project schedule is shown in Table 6.

Table 6: Project Schedule

Activity	Milestone
Project Initiation, Design & Equipment Ordering	April 2011
Field Construction/Installations	October 2011
Commissioning (after installation)	October 2011
In Service	October 2011
Project Completion and Close Out	November 2011

Future Plans:

Future upgrades will be proposed in future capital budget applications. Recloser control panel replacements are planned for the next four years as shown in the five year plan (2011 Capital Plan Tab, Appendix A).

APPENDIX A
Age of Assets

Location	Recloser ID	Asset #	Year Installed
L'Anse au Loup	LL2-R1	95688	1968
Mary's Harbour	MH1-R1	80037	1970
Port Hope- Simpson	PH1-R1	80031	1970
Hawke's Bay	HB3-R1	58178	1971
Shoal Cove N	BC6-R2	80026	1975
L'Anse au Loup	LL1-R1	99933	1975
Cooks Harbour	CH7-R1	80051	1975
St. Anthony	SA1-R3	80042	1975
Happy Valley	HV1-R1	45996	1975
Happy Valley	HV7-R1	45998	1975
Happy Valley	HV8-R1	278417	1975
Happy Valley	HV10-R1	46002	1975
Happy Valley	HV16-R1	46004	1975
South Brook	SB7-R2	41771	1978
Jackson's Arm	JA1-R1	41780	1978
Jackson's Arm	JA2-R1	41782	1978
Hampden	HA1-R1	41781	1978
English Hr West	EH1-R2	41779	1979
Barachoix	BA1-R1	41774	1979
Barachoix	BA4-R1	41806	1979
St. Anthony	SA2-R1	107289	1980
Cow Head	CH1-R1	58187	1981
Daniels Harbour	DH1-R1	58184	1981
Glenburnie	GL2-R1	58181	1981
Plum Point	PP2-R1	58177	1981
Plum Point	PP1-R1	58176	1981
Roddickton	RO1-R3	107301	1981
Bear Cove	BC4-R1	106300	1984
Bear Cove	BC6-R1	105809	1984
Roddickton	R04-R1	106298	1984
Roddickton	RO1-R2	103587	1985
Roddickton	RO3-R2	106299	1985
St. Anthony	SA3-R1	99273	1985
St. Anthony	SA1-R1	97367	1986
English Hr West	EH1-R1	41812	1988
Parsons Pond	PP1-R1	159132	1999

APPENDIX B
Major Upgrades

Date	Recloser	Major Work/Upgrade	Cost
September 2009	Parson's Pond Recloser PP1-R1	Replace power cable	$463
March 2006	Hawke's Bay Recloser HB3-R1	Recloser Control Panel Repaired	$2,086
March 2006	St. Anthony Recloser SA3-R1	Recloser Control Panel Repaired	$2,086
December 2005	St. Anthony Recloser SA3-R1	Recloser Control Panel Failure To Trip	$806
May 2005	Glenburnie Recloser GL2-R1	Replace CT	$407
August 2004	L'Anse au Loup Recloser LL2-R1	Install Sequence Coordination Accessory	$904
July 2004	Roddickton Recloser RO4-R1	Install Sequence Coordination Accessory	$830

APPENDIX C
5 Year Maintenance History

Maintenance History

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	Barachoix Recloser BA4-R1	1.3	0.0	1.3
2009	Glenburnie Recloser GL2-R1	0.0	0.1	0.1
	Total 2009	**1.3**	**0.1**	**1.4**
2008	Barachoix Recloser BA1-R1	0.6	0.0	0.6
2008	Cow Head Recloser CH1-R1	0.3	0.0	0.3
2008	Daniels Harbour Recloser DH1-R1	0.0	0.4	0.4
2008	Roddickton Recloser RO4-R1	0.0	0.1	0.1
2008	St. Anthony Recloser SA3-R1	0.5	1.2	1.7
2008	Parson's Pond Recloser PP1-R1	0.0	0.8	0.8
	Total 2008	**1.4**	**2.5**	**3.9**
2007	L'Anse au Loup Recloser LL2-R1	0.9	0.0	0.9
2007	Port Hope Simpson Recloser PH1-R1	0.4	0.3	0.7
2007	Hawke's Bay Recloser HB3-R1	0.0	1.2	1.2
2007	L'Anse au Loup Recloser LL1-R1	0.7	0.0	0.7
2007	Cooks Harbour Recloser CH7-R1	0.0	0.2	0.2
2007	Daniels Harbour Recloser DH1-R1	0.4	0.0	0.4
2007	Glenburnie Recloser GL2-R1	0.4	1.1	1.5
2007	St. Anthony Recloser SA3-R1	0.0	1.4	1.4
	Total 2007	**2.8**	**4.2**	**7.0**
2006	Port Hope Simpson Recloser PH1-R1	0.4	0.0	0.4
2006	Hawke's Bay Recloser HB3-R1	0.0	2.0	2.0

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2006	St. Anthony Recloser SA1-R3	0.0	0.1	0.1
2006	Barachoix Recloser BA1-R1	0.0	0.8	0.8
2006	Glenburnie Recloser GL2-R1	0.0	0.6	0.6
2006	Roddickton Recloser RO1-R2	0.3	0.0	0.3
2006	Roddickton Recloser RO4-R1	0.3	0.8	1.1
2006	Roddickton Recloser RO1-R3	0.0	0.2	0.2
2006	St. Anthony Recloser SA1-R1	0.0	5.1	5.1
	Total 2006	**1.0**	**9.6**	**10.6**
2005	L'Anse au Loup Recloser LL2-R1	0.0	0.1	0.1
2005	Hawke's Bay Recloser HB3-R1	0.0	1.0	1.0
2005	Cooks Harbour Recloser CH7-R1	0.5	0.0	0.5
2005	Barachoix Recloser BA4-R1	0.8	0.0	0.8
2005	Cow Head Recloser CH1-R1	0.3	0.0	0.3
2005	Daniels Harbour Recloser DH1-R1	0.4	0.0	0.4
2005	Glenburnie Recloser GL2-R1	0.0	0.4	0.4
2005	Roddickton Recloser RO3-R2	0.2	0.0	0.2
2005	Parson's Pond Recloser PP1-R1	0.6	0.0	0.6
	Total 2005	**2.8**	**1.5**	**4.3**
2004	L'Anse au Loup Recloser LL2-R1	0.3	2.1	2.4
2004	Hawke's Bay Recloser HB3-R1	0.0	1.6	1.6
2004	L'Anse au Loup Recloser LL1-R1	0.5	1.1	1.6
2004	Cooks Harbour Recloser CH7-R1	0.0	0.1	0.1

Year	Recloser	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2004	Barachoix Recloser BA1-R1	1.6	0.0	1.6
2004	St. Anthony Recloser SA2-R1	0.5	0.0	0.5
2004	Cow Head Recloser CH1-R1	2.6	0.1	2.7
2004	Glenburnie Recloser GL2-R1	0.4	0.0	0.4
2004	Roddickton Recloser RO1-R3	0.0	0.2	0.2
2004	Roddickton Recloser RO4-R1	0.0	0.8	0.8
2004	St. Anthony Recloser SA1-R1	0.4	0.0	0.4
2004	St. Anthony Recloser SA3-R1	0.4	0.0	0.4
	Total 2004	**6.7**	**6**	**12.7**

Project Title: Replace iSeries Computer and Upgrade Operating System

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

The iSeries machine is the computer server system on which Hydro's corporate Enterprise Resource Planning (ERP) application and Business Intelligence applications reside. The ERP applications include Accounts Payable, Customer Information System, Supply Chain, Human Resources/Payroll, General Ledger and Plant Maintenance/WorkOrder systems. The Business Intelligence (BI) applications include Hydro's Key Performance Indicators (KPI) system and reporting systems.

This project is required to upgrade that iSeries computer and its operating system. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	385.0	0.0	0.0	385.0
Labour	42.2	0.0	0.0	42.2
Consultant	129.6	0.0	0.0	129.6
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	9.2	0.0	0.0	9.2
O/H, AFUDC & Escln.	20.4	0.0	0.0	20.4
Contingency	56.6	0.0	0.0	56.6
Sub Total	**643.0**	**0.0**	**0.0**	**643.0**
Coast Recoveries	**(205.8)**	**0.0**	**0.0**	**(205.8)**
TOTAL	**437.2**	**0.0**	**0.0**	**437.2**

Existing System:

The iSeries computer was originally installed in 2005. The operating system was upgraded in 2007. Since 2005 additional applications such as Business Intelligence applications have been added to this server.

Server utilization has increased as more applications and data have been added to the server. Since 2007, peak computer Central Processing Unit (CPU) utilization has increased to almost 80 percent capacity during the night shift work period when Hydro backs up its network drives and servers unto tape drives for storage. During the same time, peak CPU utilization has increased to approximately 62 percent capacity during the day shift work period. This represents approximately 20 percent growth since 2007.

As this project is for the routine replacement of hardware and software related to Hydro's shared ERP server infrastructure, there is no relevant information or data on the following:

- Major Work or Upgrades;
- Maintenance History;
- Outage Statistics;
- Safety Performance; and
- Environmental Performance.

Age of Equipment or System

The age of the equipment being replaced will be six years at the time of replacement.

Anticipated Useful Life

The iSeries computer hardware and its operating system have an anticipated useful life of five to eight years. Beyond this timeframe, reliability and support are at risk.

Industry Experience

Based on industry standards and operating experience the server should be replaced at an age of five to eight years based on the utilization of the applications running on that server.

Maintenance or Support Arrangements

Support from International Business Machines (IBM) for the operating system is scheduled to end in the first quarter of 2012. Server hardware support can still be maintained by IBM but the server will no longer meet our performance needs for user response times. Delays in user

response times will result in user productivity dropping as screen updates become longer and report generation and updates take longer to complete.

Vendor Recommendations

The vendor IBM recommends that this server should be kept in service as long as it can accommodate the work load of the company. The predicted growth on the current hardware can not be accommodated in 2012.

Availability of Replacement Parts

The vendor has advised that availability of some of the sever components have been withdrawn. Replacements parts would have to be obtained through dealers who remarket previously owned components.

Operating Regime

This server is active on a continuous basis both day and night.

Justification:

This project is justified on the need to continue providing reliable support for Hydro's computer applications. The factors driving the replacement or upgrade of this server include:

- Maintaining vendor support for the operating system; and
- Providing server capacity to handle corporate workload.

Maintaining Vendor Support for operating system:

Vendor support for the operating system is scheduled to end in the first quarter 2012. Without vendor support, the functions and services provided by this server are at risk as support patches for the operating system will no longer be available. As a result, Hydro's ability to support and ensure continuation of these functions and services is impeded. This server provides support in running the day-to-day business of the corporation. The loss of availability of this server would have a negative effect on employee productivity by not allowing access to core software applications.

Providing server capacity to handle corporate workload:

The ability of the existing server to perform adequately under the existing workload has diminished. On going system performance monitoring has indicated the need to increase the capacity of this server. The vendor has performed a capacity sizing exercise and has recommended an upgrade to a new server to satisfy the requirements of existing and future applications.

As this project is for the routine replacement of hardware and software related to Hydro's shared server infrastructure, the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

Net Present Value

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

Cost Benefit Analysis

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

Historical Information

Table 2 shows the historical costs of the Server and Operating System Evergreen Program. There were none in 2008 or 2006.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2010F	11.2		Memory Upgrade
2009	10.5	10.5	Memory Upgrade
2007	102.5	102.5	Operating System Upgrade from V5R3 to V5R4

Status Quo

Hydro must keep this server current in order to adequately support and run the corporate ERP application and our Business Intelligence applications required to operate its business. Failure to keep this infrastructure current will put Hydro at risk in performing day to day business activities.

Alternatives

There are no viable alternatives to this project.

Conclusion:

Support for the iSeries computer will end in the first quarter of 2012. The computer is vital in the day-to-day operations of Hydro's computer applications. Without the replacement of the computer, Hydro is at risk of not being able to run the daily computer applications.

Project Schedule

This project is scheduled to run from April to July of 2011. The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Milestone
Project Start	January 2011
Initial Planning and Equipment Ordering	February 2011
Equipment Delivery	March 2011
Equipment Installations and Commissioning	June 2011
Project In Service	June 2011
Project Completion and Close Out	July 2011

Future Plans:

To maintain this server's performance, replacements and upgrades will be proposed in future capital budget applications. See five-year capital plan (2011 Capital Plan Tab, Appendix A).

Project Title: Replace Personal Computers

Location: Various Sites

Category: General Properties – Information Systems

Type: Pooled

Classification: Normal

Project Description:

The PC Replacement program is an on-going program required to enhance the efficiency of Newfoundland and Labrador Hydro (Hydro) employees by replacing the personal computers (PCs) used for their day to day requirements.

This project will enable Hydro to replace 142 personal computers that were deployed in 2006 and 2007. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	250.6	0.0	0.0	250.6
Labour	40.0	0.0	0.0	40.0
Consultant	63.9	0.0	0.0	63.9
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	13.6	0.0	0.0	13.6
Contingency	35.4	0.0	0.0	35.4
TOTAL	**403.5**	**0.0**	**0.0**	**403.5**

Existing System:

Hydro has over 800 end-user personal computers in service. It is important to refresh this equipment on a regular cycle to keep the technology current to maintain a reliable, efficient and productive workforce. Refreshing is the replacement of end user equipment, such as desktops, laptops and thin clients, on a life cycle depending on the type of device.

Minimum specifications for replacement of personal computers are reviewed on an annual basis to ensure that the PCs in service continue to remain effective. Industry best practices, technology and application trends are taken into consideration when specifications for

computer devices are decided for the current year. The annual review continues the replacement life cycle for laptops of every four years and desktops every five years.

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice the following items under the existing system section are not relevant to the proposal:

- Major Work/Upgrades;
- Maintenance History;
- Outage Statistics;
- Safety Performance;
- Environmental Performance; and
- Operating Regime.

Age of Equipment or System

The existing PCs that are to be replaced under this project will have been in service between five and six years depending on the hardware platform used. No Laptops are being replaced with this budget.

Anticipated Useful Life

According to Gartner[11], 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.

[11] Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

Maintenance or Support Arrangements

Hydro has purchased maintenance agreements with Lenovo Corporation, the manufacturer, that cover laptops for four years and desktops for five years.

Vendor Recommendations

The vendor predicts a 30 percent failure rate on desktops in the sixth year and a 40 percent failure rate on laptops in the fifth year.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements. Once the maintenance agreement has expired there is no guarantee that replacement parts can be obtained.

Justification:

Hydro must keep computers current in order to adequately support and protect the Information Technology applications and information required to operate its business. The replacement and addition of PC components to achieve this goal requires investment over the life cycle of the computers.

The refresh program makes it possible for computers to be replaced in a planned and consistent manner. This allows for even distribution of budgets and ensures that the computers are available and reliable to support the user's applications. Continued review of the computer life cycle allows Hydro to adjust plans based on performance, technology changes and new business requirements.

In addition, the computers to be replaced under this project are approaching the end of their useful lives and failures can be expected. The maintenance agreements for these computers will have expired and replacement parts can no longer be guaranteed.

As this budget proposal is for the routine replacement of computing hardware based on a corporate standard consistent with industry practice the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

Net Present Value

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

Cost Benefit Analysis

This project is subject to a lease or purchase cost benefit analysis to determine the lowest cost alternative. The cost benefit analysis is done in the year of replacement to ensure consideration of incentives or other benefits that may be offered by the providers.

Historical Information

Historical information on computer replacement over the last five years is presented in Table 2.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2010F	406.6		215		
2009	491.4	489.7	230	2.1	
2008	451.4	456.7	215	2.1	
2007	395.0	393.7	102	3.9	Laptops only replaced
2006	0.0	0.0	0.0	0.0	

Status Quo

If the end user infrastructure is not kept current the following scenarios could potentially occur:

- New applications may not run on the old hardware platform;
- Decreased speed may result in lost production;
- Failure rates will exceed 50 percent;
- Maintenance agreements will not be offered by vendor; and
- Operating systems may be unsupported.

Alternatives

The only alternative is to consider leasing the equipment. However, this has been done in the past and has proven to be more expensive and difficult to manage.

Conclusion:

The PC Replacement Program as proposed in this project is the preferred solution for the following reasons:

- It enables the end user equipment to remain current.
- It improves workforce efficiency by providing reliable hardware.
- It allows for a predictable annual budget.

Project Schedule

The project is scheduled to start in March 2011 and be completed before December 31, 2011.

Future Plans:

Future replacements will be proposed in future capital budget applications. Computer replacements are planned for the next four years as shown in the five year plan (2011 Capital Plan tab, Appendix A).

Project Title: Upgrade Ice Protection

Location: Chapel Arm Hill Microwave Site

Category: General Properties – Telecontrol

Type: Other

Classification: Normal

Project Description:

The purpose of this project is to upgrade the ice shields on the telecommunications building and microwave radio antennas at the Chapel Arm Hill microwave site. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	88.0	0.0	0.0	88.0
Labour	42.6	0.0	0.0	42.6
Consultant	38.0	0.0	0.0	38.0
Contract Work	66.0	0.0	0.0	66.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	35.8	0.0	0.0	35.8
Contingency	23.5	0.0	0.0	23.5
TOTAL	**293.9**	**0.0**	**0.0**	**293.9**

Existing System:

This project is required to upgrade the existing ice protection, and add new ice protection, to the Chapel Arm Hill microwave site, in order to prevent damage such as that which occurred in March 2010 at the Four Mile Hill microwave site.

As a result of extreme icing conditions experienced on March 5 and 6, 2010 the microwave radio tower and associated equipment located at Four Mile Hill was severely damaged when the ice was shed from the tower on March 16, 2010. The storm destroyed two microwave radio antennas, and also caused damage to the ice shield and roof of the building, the antenna ice guards, internal cable conduits, the fire protection system, lighting, and the fencing enclosing the site. The loss of the two antennas at Four Mile Hill site caused an extended communications outage. The unavailability of the microwave system and associated teleprotection signals for

transmission lines TL-201 and TL-217 required increased production at Holyrood plant, which cost an estimated $246,000 in additional fuel.

Age of Equipment or System

The Chapel Arm Hill microwave site was constructed in 2001.

Major Work/or Upgrades

There have been no major upgrades since installation.

Anticipated Useful life

Microwave towers and telecommunications buildings are depreciated over 20 years, but may have longer service lives up to 40 years. Hydro's oldest towers are now 30 years old and are expected to last longer.

Maintenance History

There is no normal maintenance required on ice guards.

Outage Statistics

Microwave systems are designed for very high (> 99.999%) availability. There have been no ice storm related outages on the Chapel Arm Hill site.

Industry Experience

Ice damage to towers and supporting infrastructure is relatively common in Newfoundland and Labrador. In January 2010, an entire tower owned by Bell Aliant collapsed due to excessive ice loading, causing an outage of all telephone and data services along the northern coast of Labrador for several weeks.[12] The same storm that caused the Four Mile Hill ice damage

[12] CBC, "Ice Topples Labrador Communications Tower", CBC Website, http://www.cbc.ca/canada/newfoundland-labrador/story/2010/01/11/nl-labrador-tower-100110.html, accessed July 2010.

disrupted electrical power to parts of Eastern Newfoundland for several days[13], caused damage to other towers, buildings, and power lines at Four Mile Hill. The following pictures illustrate the extent of the damage that occurred at Chapel Arm Hill during the March storm.



Figure 1: Four Mile Hill Icing Lower Section March 7, 1010

[13] CBC, "Newfoundland Power Outage Drags On", http://www.cbc.ca/canada/newfoundland-labrador/story/2010/03/07/newfoundland-storm-outage.html, accessed July 2010.



Figure 2: Four Mile Hill Icing Upper Sections March 7, 1010

The following pictures show the extent of the damage at the site when the ice was shed from the tower on March 16, 2010.



Figure 3: Four Mile Hill Damaged Antennas, March 16, 2010



Figure 4, Closeup of Damaged Antenna, March 16, 2010



Figure 5: Closeup of Damaged Antenna, March 16 ,2010



Figure 6: Building Damage March 16, 2010



Figure 7: Fencing Damage March 16, 2010

Maintenance or Support Arrangements

Microwave towers, including ice guards, are inspected annually. Building ice guards are not normally inspected during tower inspections.

Vendor Recommendations

There are no vendor recommendations for this project.

Availability of Replacement Parts

Because ice guards are custom designed and fabricated, availability of replacement parts is not applicable.

Safety Performance

Safety during icing conditions is a major concern.

Environmental Performance

There are no environmental performance issues associated with this work.

Operating Regime

The asset is required to be in service on a continuous basis.

Justification:

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

Net Present Value

A net present value analysis was not performed as the most effective design has been established for the Four Mile Hill site and this project will be similar.

Levelized Cost of Energy

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

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

There are no known legislative or regulatory requirements associated with this work.

Forecast Customer Growth

Customer growth does not affect this project.

Energy Efficiency Benefits

There are no known energy efficiency benefits associated with this project.

Losses during Construction

There are no anticipated energy losses during construction of this project.

Status Quo

Failure to complete this project could result in customer outages and additional costs associated with increased fuel usage, repair, and temporary facilities required to restore communications while the damage is repaired.

Alternatives

There are no viable available alternatives to this project.

Conclusion:

This project is required in order to mitigate ice damage that may occur in future. Based on the experience of 2010 it is prudent to upgrade the ice protection at Chapel Arm Hill in order to ensure that it can protect the antennas, building and equipment from damage.

Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Milestone
Project Initiation	January 2011
Design Complete	March 2011
Commissioning Complete	August 2011
Project Closed	September 2011

Project Title: Replace Peripheral Infrastructure

Location: Various Sites

Category: General Properties - Information Systems

Type: Pooled

Classification: Normal

Project Description:

The Peripheral Infrastructure Replacement Project is an ongoing program to replace the printers, copiers, fax machines and video conference equipment used in the day to day operation of the business. For the year 2011, this project will consist of the replacement of three Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning, as well as 33 Laser Printers. The MFDs are to be replaced at Holyrood, Bishops Falls and Hydro Place. The location of the laser printers to be replaced are as follows: 14 in Hydro Place; one in Deer Lake, six in Holyrood, four in Bay d'Espoir, four in Goose Bay, two in St. Anthony, one in Flowers Cove and one in Stephenville. In addition, eight ceiling mounted projectors require replacement. This budget also includes funds for expanding the Video Conferencing system in Hydro Place, Bay d'Espoir and Bishop Falls.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	212.9	0.0	0.0	212.9
Labour	14.0	0.0	0.0	14.0
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.	8.6	0.0	0.0	8.6
Contingency	22.7	0.0	0.0	22.7
TOTAL	**258.2**	**0.0**	**0.0**	**258.2**

Existing System:

The units scheduled for replacement have been in service for five years or more and normal maintenance contracts have expired. As the devices age, they require increasing maintenance

and service time resulting in loss of reliability and productivity. If these units are kept in service until failure occurs, then the availability of scanning, coping, faxing or high volume printing services is limited. Depending on the location of the unit it may take four to five weeks to replace.

Table 2: Peripheral Devices in Service

Office Location	Number of Printers	Number of Employees	Buildings Per Location
Hydro Place	70	350	1
Bay d'Espoir	18	90	4
Bishop's Falls	17	80	3
Holyrood	20	102	4
Port Saunders	5	22	1

There is no relevant information for:

- Safety Performance;
- Environmental Performance; or
- Operating Regime.

Major Work/Upgrades

There have been no major upgrades since install.

Age of Equipment or System

The units scheduled for replacement have been in service for over five years.

The decision on when to replace a printer or MFD is based on many criteria, including:

- Vendor's product roadmap (new features like secure print and scanning will not support older equipment);
- Users' printing requirements (color need, print volumes & speed);
- Number of users supported by the equipment;
- Availability of alternate printing;
- Available support for the equipment; and
- Age of equipment.

Anticipated Useful Life

According to Gartner[14], the useful life for a color printer is three years while a black/white printer is between three and five years.

Maintenance History

Please refer to the Outage Statistics section.

Outage Statistics

An average of 31 service calls has been made on each of the main printers being replaced. Each service call results from the printer being out of service.

Industry Experience

Industry best practices indicate that the typical service life for a peripheral device is four to five years. Hydro has a similar life cycle plan for peripheral devices as other companies in the utility industry including Newfoundland Power.

Maintenance or Support Arrangements

Hydro has purchased a maintenance agreement with a supplier (Xerox) that covers the larger Multi-Function Devices for five years. Smaller laser printers have only a manufacturer's warranty of one to three years duration.

Vendor Recommendations

The vendor (Xerox) recommends a maximum lifespan of five years.

Availability of Replacement Parts

Replacement parts are readily available for the duration of the maintenance agreements and warranties. Once these agreements and warranties have expired replacement parts may or may not be available.

Justification:

[14] Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

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 2011 have all been in service for five years or more and maintenance contracts and warranties have expired. The manufacturer will only guarantee the operation of these MFDs for a period of five years.

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 expenditures and ensures that these peripherals are available and reliable to support the user's needs. Continued review of the products lifecycle allows Hydro to adjust plans based on performance, technology changes and new business requirements.

Net Present Value

A net present value calculation was not performed in this instance as there is no viable alternative to the planned replacement of peripheral infrastructure.

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

As this budget proposal is for the routine replacement of computer peripherals based on industry accepted standards, the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

Historical Information

Table 3 contains a five-year history of the Peripheral Infrastructure Replacement Project.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit [(1)] ($000)	Comments
2010F	222				
2009	161	161	34	4.7	
2008	159	159	32	5.0	
2007	139	139	10	13.9	
2006	199	196	8	24.5	

(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.

Status Quo

If the peripheral infrastructure is not kept current, there is a risk of increase in failure rates and lack of maintenance agreements offered by the vendor.

Alternatives

The only alternative is to consider leasing the equipment. The lease versus buy decision will be evaluated during the tendering process.

Conclusion:

The ongoing program 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 Schedule

The project is scheduled to start in March 2011 and be completed before December 31, 2011.

Future Plans:

Future replacements will be proposed in future capital budget applications. Equipment replacements are planned for the next four years as shown in the five-year capital plan (2011 Capital Plan tab, Appendix A).

Project Title: Remove Safety Hazards

Location: Various Sites

Category: General Properties - Administrative

Type: Other

Classification: Normal

Project Description:

This project is required to ensure adequate capital funding is available to quickly address capital-related safety hazards as they are identified. In an effort to avoid injury and/or fatality, Newfoundland and Labrador Hydro (Hydro) has initiated a Safe Work Observation Program (SWOP). This program trains employees in the importance of identifying and reporting conditions that can potentially lead to an incident or an accident. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	112.0	0.0	0.0	112.0
Labour	56.0	0.0	0.0	56.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	56.0	0.0	0.0	56.0
O/H, AFUDC & Escln.	28.4	0.0	0.0	28.4
Contingency	0.0	0.0	0.0	0.0
TOTAL	**252.4**	**0.0**	**0.0**	**252.4**

Existing System:

A capital project for removing safety hazards was executed in 2008. Table 2 lists the projects performed under that capital project at a total cost of $130,900:

Table 2: Projects Completed

Location	Project	Costs
Mary's Harbor	Modified overhead crane at the Diesel Plant	$15,200
Upper Salmon	Installed Stairway to Draft Tube Gallery at the powerhouse	7,100
Granite Canal	Installed Stairwell to the fire pump at the powerhouse	10,700
Holyrood	Rerouted the walkway on the 11th floor of the powerhouse	88,500
Nain and Mary's Harbor	Installed Co/Nox Monitors at both diesel plants	2,300
Port Saunders	Installed Fire Fighter Training System	7,100

The work was intended to continue on an annual basis however a capital proposal for 2009 was not submitted due to an oversight. For 2009, Hydro decided that any capital expenditures related to safety would be addressed through the Allowance for Unforeseen Capital. However, no capital expenditures were made in 2009. In Hydro's 2010 Capital Budget Application, the Board of Commissioners of Public Utilities (Board) approved a budget of $252,400 to address safety hazards in the workplace. Hydro has identified several potential safety hazards and through a prioritization process has identified the following to be addressed in 2010.

- Holyrood.
    - Replace Acid Transfer Lines in the Thermal Generation powerhouse at a cost estimate of $151,000.
    - Install a fixed ladder and platform system for emergency egress at the Thermal Generation Powerhouse Building at a cost estimate of $120,000.
- Bay d'Espoir.
    - Install spherical platforms for Hydroelectric Generating Units 1 through 6 at a cost estimate of $27,000.
    - Install disconnect structures at the Victoria and Burnt Dam control structures at a cost estimate of $14,000.
    - Install Emergency Response Equipment at the Bay d'Espoir Generating Station at a cost estimate of $20,000.

As this is an on-going program, other safety hazards may be identified later in 2010 and receive higher priority than those listed above. Hydro plans to continue the program to identify and remove safety hazards on an annual basis.

As this project involves removing safety hazards as they are identified at various sites through the SWOP system there is no relevant data related to:

- Age of Equipment or System;
- Major Work/or Upgrades;
- Anticipated Useful life;
- Maintenance History;
- Outage Statistics;
- Industry Experience;
- Maintenance or Support Arrangements;
- Vendor Recommendations;
- Availability of Replacement Parts; and
- Operating Regime.

Safety Performance

Hydro must comply with the Newfoundland and Labrador Occupational Health and Safety Regulations. Hydro's Safety and Health Program aims to create a safe work environment so that nobody gets hurt.

Environmental Performance

There are no environmental issues associated with removing safety hazards.

Justification:

This project is required to provide a safe work environment for Hydro employees, contractors, visitors and the general public in compliance with Hydro's policies and the Occupational Health and Safety Regulations. The SWOP program involves workers actively looking for safety hazards and spotting problems that may otherwise go unnoticed, and, thus, lead to serious health and/or safety issues for Hydro customers, employees or contractors, and to the general public. The availability of capital funding enables Hydro to respond immediately to address unsafe conditions rather than waiting for the normal capital budget process. This provision allows Hydro to eliminate safety and health risks from the workplace quickly. This project provides Hydro the means to address unsafe situations where capital work is identified as the solution. Some deficiencies have existed in Hydro facilities for years and were acceptable under safety standards that existed when the facilities were constructed. By today's more stringent standards

and greater awareness of hazards, these deficiencies need to be immediately corrected to provide a safe work environment.

Net Present Value

The net present value is not applicable for this project as it is a general proposal to remove safety hazards from the workplace. For each unsafe situation identified if more than one alternative exists to correct the problem, a net present value calculation will be done to determine the least cost solution.

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

Hydro must comply with the Newfoundland and Labrador Occupational Health and Safety Regulations. Each situation identified as a safety hazard will be corrected to comply with current legislative and regulatory requirements.

Historical Information

Hydro removed safety hazards under a capital project in 2008. This was the first year for this program with a budget of $252,300 of which $130,900 was spent. A capital project for 2010 with a budget of $252,400 is ongoing.

Forecast Customer Growth

Customer load growth does not affect this project.

Energy Efficiency Benefits

There are no energy efficiency benefits that can be attributed to removing safety hazards.

Losses during Construction

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

Status Quo

The status quo is not acceptable since there are safety hazards to be identified and corrected.

Alternatives

This project is a general proposal to correct various identified safety hazards in the workplace. Each situation will be evaluated to determine whether one or more alternatives exist to correct the unsafe situation.

Conclusion:

Hydro must remove safety hazards at all of its facilities.

Project Schedule

As this budget relates to unanticipated safety issues, no schedule is available.

Future Plans:

Future Safety Hazards Removal projects will be proposed in future capital budget applications plan (2011 Capital Plan tab, Appendix A).

Project Title: Refurbish Microwave Site

Location: Deer Lake

Category: General Properties - Telecontrol

Type: Other

Classification: Normal

Project Description:

This project involves upgrading the Deer Lake Passive (DLP) microwave radio site by replacing the radome on the existing Microflect passive reflector system, improving site drainage to remove standing water around the tower anchors, and installing cathodic protection at the tower anchors to inhibit corrosion.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	52.6	0.0	0.0	52.6
Consultant	13.5	0.0	0.0	13.5
Contract Work	85.5	0.0	0.0	85.5
Other Direct Costs	9.5	0.0	0.0	9.5
O/H, AFUDC & Escln.	30.0	0.0	0.0	30.0
Contingency	16.1	0.0	0.0	16.1
TOTAL	**207.2**	**0.0**	**0.0**	**207.2**

Existing System:

The microwave radio system carries the critical communications traffic necessary for the operation and support of the Island Interconnected System including high speed teleprotection, remote control Supervisory Control and Data Acquisition (SCADA), voice and administrative data. Teleprotection is a high speed (3 millisecond; the time between sending and receiving a signal), automatic function used to isolate specific lines in the case of line or equipment failure to prevent a grid collapse. SCADA is used for monitoring and Automatic Generation Control (AGC) and manual operation of the power system from the Energy Control Center (ECC) in Hydro Place, St. John's.

Figure 1 shows the complete Hydro telecommunications network, including microwave radio:

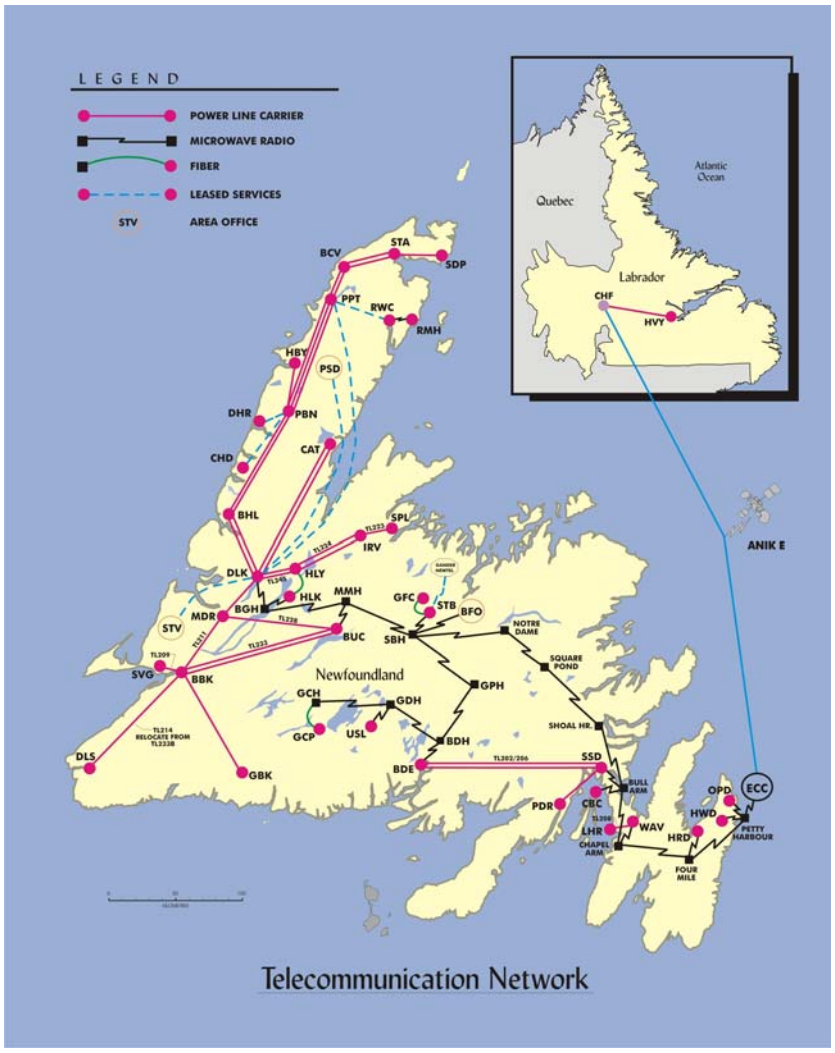


Figure 1: Hydro's Telecommunication Network

Age of Equipment or System

The tower and passive reflector at DLP were installed in 1984.

Major Work/or Upgrades

There have been no major work or upgrades since installation.

Anticipated Useful Life

Microwave towers have an anticipated useful life of 20 years.

Maintenance History

The five-year maintenance history for the DLP site is shown in Table 2:

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2005	6.2	0.0	6.2
2006	4.4	0.0	4.4
2007	7.4	0.0	7.4
2008	6.6	0.0	6.6
2009	0.0	0.0	0.0

Outage Statistics

There have been no outages related to this location.

Industry Experience

There is no available industry experience relevant to this project.

Maintenance or Support Arrangements

Tower inspections are completed every year by an external structural engineering firm at all Hydro sites.

Vendor Recommendations

A tower inspection report performed by a structural engineering firm for Hydro in 2008 recommended the changes contained in this project (see Apendix A).

Availability of Replacement Parts

The manufacturer has indicated that the replacement radome for the passive reflector is readily available.

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 microwave radio system is required to operate continuously.

Justification:

This project is justified based on the requirement to improve site conditions at DLP in order to maximize the life of the towers and passive reflector at the site. Improving site drainage and installing cathodic protection will increase the life of the tower by ensuring that the tower anchors deteriorate less rapidly than would otherwise be the case. Replacing the radome will ensure that the passive reflector is not damaged by weather.

Net Present Value

A net present value calculation was not performed as there is no viable alternative to refurbishing the microwave site.

Levelized Cost of Energy

As there are no new generation sources considered, the levelized cost of energy is not applicable.

Cost Benefit Analysis

A cost benefit analysis was not performed as there are no quantifiable benefits.

Legislative or Regulatory Requirements

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

Historical Information

There is no relevant historical information associated with this project.

Forecast Customer Growth

This project has no effect on customer load growth.

Energy Efficiency Benefits

There are no energy efficiency benefits to be gained from this project.

Losses During Construction

No losses will occur due to construction of this project.

Status Quo

Failure to complete the recommended improvements at DLP will contribute to accelerated deterioration of the tower and anchors at the site.

Alternatives

There are no viable alternatives to refurbishing the site.

Conclusion:

Improving conditions at the DLP site will ensure that the site's useful life is maximized.

Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	**Milestone**
Project Initiation	February 2011
Conduct Site Visits	April 2011
Complete Design Transmittal	June 2011
Installation	October 2011
Project Close-out	November 2011

APPENDIX A

Deer Lake Passive Sub Surface Anchor Investigation &

Tower Alignment Data

Newfoundland

2007

Issued
Jan 22,
2008

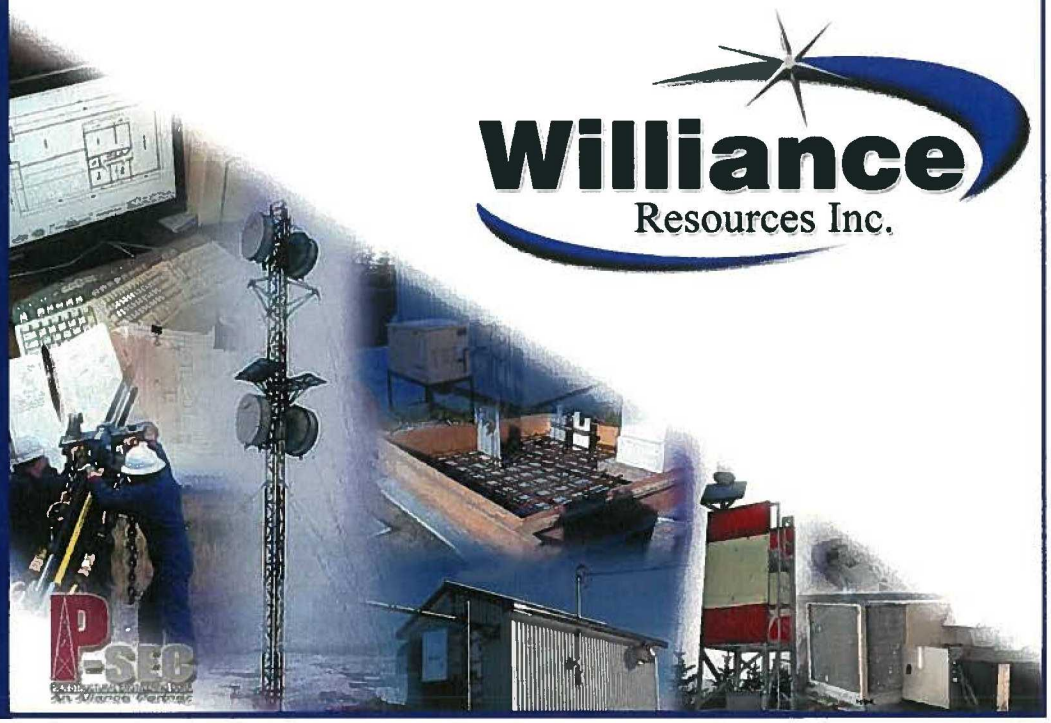
Williance Resources Inc.

Engineering Consultants Project Managers Professional Inspections

HYDRO
THE POWER OF
COMMITMENT

Deer Lake Passive Sub Surface Anchor Investigation & Tower Alignment Data Newfoundland

2007



Williance
Resources Inc.

Deer Lake Passive
Sub Surface Anchor Investigation
2007

69 ft. Guyed Passive Billboard Tower
At Deer Lake, NL

Prepared for:
Newfoundland Hydro

Prepared by:
Williance Resources Inc.

Jan 22, 2008



Distribution: 1 copy - Newfoundland Hydro
1 copy - Williance Resources Inc.

Williance

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1.0 Foreword:

1.1 Scope of Work:

Williance Resources Inc. was engaged to investigate the condition of the anchors and the tower alignments for the Guyed Passive Billboard tower located at the Hydro Deer Lake Passive site with reference to CSA S37-01 *Antennas, Towers, and Antenna-Supporting Structure* as well as to report on the level of corrosion and overall condition of these anchors below ground level.

Note: The investigation was requested to be to a depth of 24 inches, but due to the high water levels at the site (The site is surrounded by marshlands.), the depth was limited to a maximum of 16 inches while one anchor was fully submerged in water and therefore we were unable to investigate subsurface conditions at this one anchor.

1.2 Work Methodology:

The inspection work consisted of a technical visual review of the existing anchor conditions, both above ground and subsurface with a comparison made between each.

For the tower alignment, a three-transit setup was used to shoot the alignment and twist of the two towers which make up the H-structure at this site.

2.0 SITE INFORMATION – ST. JOHN'S

Site Name:	Hydro Deer Lake Passive
Tower Owner:	Newfoundland Hydro
Site Location:	Deer Lake, Newfoundland
Site Access:	ATV - summer, snowmobile - winter
Structure:	Knock-Down Tower, guyed 30 and 69 ft. elevation.
Tower Height:	69 ft.
Face Width:	24 in.
Tower Manufacturer:	Unknown
Tower Erector:	Unknown
Anchors Inspected by:	Fred Bradbury, M.E.T
Personnel on site:	N/A
Weather Conditions:	13°C, overcast, w/ 10 km wind
Date of Inspection:	Nov 21, 2007
Project Manager:	Don Richards, P. Eng.
Report Preparation:	Fred Bradbury, M.E.T.
Report Review:	Shawn R. Williams, P. Eng

Williance Resources Inc.
Unit 50, Hamlyn Road Plaza
Suite 422, St. John's, NF
Canada, A1E 5X7
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2.1 Site Pictures



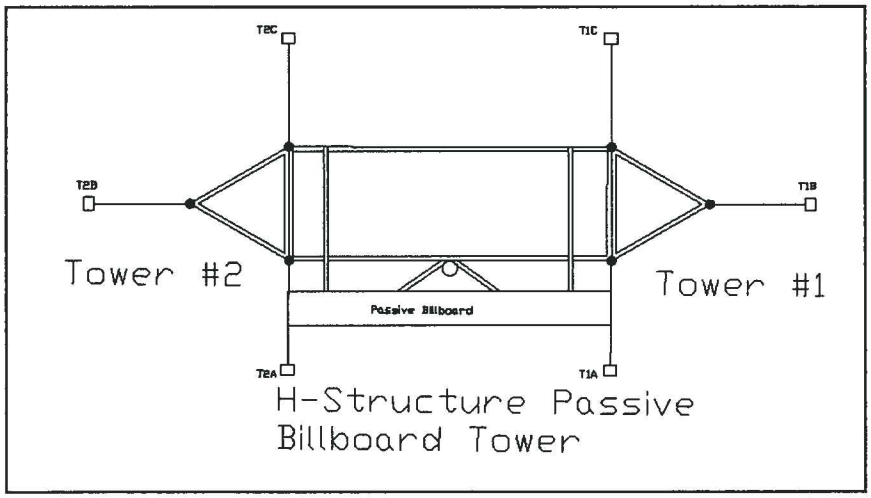
Deer Lake Passive Billboard (69 ft)



Deer Lake Passive Site Approach

2.2 Tower Layout

Figure 1: Tower Overview



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3.0 Observations

The following observations are based on the Nov 21, 2007 investigation performed on the anchors at Deer Lake Hydro Passive tower site.

3.1 General Anchor Conditions, Tower #1

3.1.1 Anchor #1, Tower #1

Observations:

- Anchor is in ground that is above the water level of the surrounding marshlands.
- No significant corrosion was observed above ground level.

An attempt was made to achieve the requested depth of 24 inches for the inspection of the anchor shaft. At a depth of 16 inches, water was discovered and the digging stopped. Due to the surrounding marshlands, it was impossible to achieve the depth requested. Therefore the inspection was completed at this depth.

Observations:

- No significant corrosion was observed between ground level and the 16 inch depth mark.

Photos of Anchor #1, Tower #1:







3.1.2 Anchor #2, Tower #1
Observations:

- Anchor is in ground that is below the water level of the surrounding marshlands and therefore the anchor shaft at ground level is completely submerged in water.
- Light surface corrosion was observed above the water level.
- No pitting was observed above ground level.

No attempt was made to dig this anchor as it was submerged in water and the water was frozen.

Photos of Anchor #2, Tower #1:







3.1.3 Anchor #3, Tower #1
Observations:

- Anchor is in ground that is above the water level of the surrounding marshlands.
- No significant corrosion was observed above ground level.

An attempt was made to achieve the requested depth of 24 inches for the inspection of the anchor shaft. At a depth of 16 inches, water was discovered and the digging stopped. Due to the surrounding marshlands, there is no practical way to achieve the depth requested. Therefore the inspection was completed at this depth.

Observations:

- No corrosion was observed between ground level and the 16 inch depth mark.

Photos of Anchor #3, Tower #1:



3.2 General Anchor Conditions, Tower #2

3.2.1 Anchor #1, Tower #2

Observations:

- Anchor is in ground that is below the water level of the surrounding marshlands and therefore the anchor shaft at ground level is continuously submerged in water.
- No corrosion was observed above water level.

No attempt was made to dig this anchor as it was submerged in water and the water was frozen.

Photos of Anchor #1, Tower #2:



3.2.2 Anchor #2, Tower #2

Observations:

- No significant corrosion was observed above ground level.

An attempt was made to achieve the requested depth of 24 inches for the inspection of the anchor shaft. At a depth of 12 inches, water was discovered and the digging stopped. Due to the surrounding marshlands, there is no practical way to achieve the depth requested. Therefore the inspection was completed at this depth.

Observations:

- No significant corrosion was observed between ground level and the 12-inch depth mark.

Photos of Anchor #2, Tower #2:







3.2.3 Anchor #3, Tower #2

Observations:

- Anchor is in ground that is approximately level with the water level of the surrounding marshlands.
- No significant corrosion was observed above the water level.

An attempt was made to dig this anchor, which resulted in the breaking of the pick handle because the ground was frozen.

Photos of Anchor #3, Tower #2:







Table 1: Anchor Shaft Thickness Measurements in inches

Tower	Anchor	Above Ground Measurement	Below Ground Measurement	Depth of Measurement (in)
1	1	0.95	0.93	16
1	2	0.94	Ground Frozen	-
1	3	0.98	0.94	16
2	1	0.93	Ground below water	-
2	2	0.97	0.93	12
2	3	0.96	Ground frozen, pick broke off	-

Notes:

1. Measurements taken while temperature were approximately 13 degrees Celsius and the ground frozen.
2. Rainy conditions made it difficult to read vernier used for measurements. (Suggest+/- 2% visual accuracy).

3.3 Tower Alignments and Twist Summary

3.3.1 Tower #1

Table 2: Tower Alignment and Twist Summary

	VERTICALITY CALCULATIONS												
		CALCULATED TWIST						CALCULATED ALIGNMENT					
	ELEV FT.	Angle Calc. fr base DEG.	Angle Allow fr base DEG	Status	Angle betw. Elev. DEG.	Angle Allow DEG	Status	R Calc fr base IN.	R Allow fr base IN.	Status	R-Calc betw. Elev. IN.	R-All betw. Elev. IN.	Status
											0.00	0.00	
2	62	6.75	3.10	NOK				2.30	1.49	NOK			
					2.83	1.50	NOK				1.21	0.72	NOK
1	32	3.91	1.60	NOK				1.11	0.77	NOK			
					3.91	1.60	NOK				1.11	0.77	NOK
Base	0	0.00						0.00	0.00				

Note: Clause 11.3.2: *Verticality* of CAN/CSA-S37-01 states that the out-of-plumb between any two elevations on the structure shall not exceed 1 in 500.
Clause 11.3.3: *Twist* of CAN/CSA-S37-01 states that two elevations should not exceed 0.5 degrees in 3 metres. The maximum twist over the structure height shall not exceed 5 degrees.

It is shown above that the tower was calculated to be significantly outside the guidelines set forth by CAN/CSA-S37-01. Note this was first visually noticed by crew on site, when they were completing a pre-climb inspection.

3.3.2 Tower #2

Table 3: Tower Alignment and Twist Summary

	VERTICALITY CALCULATIONS												
		CALCULATED TWIST						CALCULATED ALIGNMENT					
	ELEV FT.	Angle Calc. fr base DEG.	Angle Allow fr base DEG	Status	Angle betw. Elev. DEG.	Angle Allow DEG	Status	R Calc fr base IN.	R Allow fr base IN.	Status	R-Calc betw. Elev. IN.	R-All betw. Elev. IN.	Status
											0.00	0.00	
2	62	0.00	3.10	OK				1.01	1.49	OK			
					-0.65	1.50	OK				0.66	0.72	OK
1	32	0.65	1.60	OK				0.48	0.77	OK			
					0.65	1.60	OK				0.48	0.77	OK
Base	0	0.00						0.00	0.00				

Note: Clause 11.3.2: *Verticality* of CAN/CSA-S37-01 states that the out-of-plumb between any two elevations on the structure shall not exceed 1 in 500.
Clause 11.3.3: *Twist* of CAN/CSA-S37-01 states that two elevations should not exceed 0.5 degrees in 3 metres. The maximum twist over the structure height shall not exceed 5 degrees.

It is shown above that the tower was calculated to be within the guidelines set forth by CAN/CSA-S37-01.

4.0 Recommendations:

1) It is recommended that Tower #1, which is calculated to be outside the standards of CSA-S37-01, have a re-alignment completed ASAP and that the guy tensions inspected at this time. If the guy tensions are outside the standards of CSA-S37-01 than the guys should be re-tensioned. (CSA-S37-01 requires a minimum tension of 10% of the guys breaking strength.)

2) It is recommended that an engineering consultant or consultant of equivalent experience review the surrounding landscape of the Deer Lake Passive tower site to develop a solution that will reduce or eliminate the large quantities of water holding up around the anchors. One possible solution would be to divert the water away from the site using channels and dykes or an equivalent method of drainage.

3) It is recommended that a pull test be completed on the anchors to ensure that they all meet design load capacities. Based on the results, further action may be required to ensure these capacities can be attained.

4) Subsequent to completing the above work , a detailed examination of the tower base, including hand excavation should be completed to ensure no structural issues are present.
5) It is suggested that a cathodic protection system for the anchors at this site be installed using Zinc anodes to ensure that the anchors have the best protection against the elements and the generally acidic nature of bog water.

USE OF INFORMATION IN THIS REPORT

Williance Resources Inc. prepared this report for the client noted on the front cover and inside title page for purposes described in the "Scope of Work" in this report. The material reflects Williance Resources Inc 's best judgment based on the information made available at the time of report preparation and the time allocated to complete the work.

Any use, which a third party makes of this report or reliance on or decisions made based on it are the responsibility of such third parties. Further, any use outside the specific indicated scope, is done so at the full responsibility of the user.

Williance Resources Inc accepts no responsibility for damages, if any, suffered by any third party or use of the report information by anyone, outside the specific indicated scope, as a result of decisions made or actions based on this report.

MAINTENANCE REVIEW SAMPLING PROCEDURES

The inspection is limited to a random visual sampling of the towers (s) and the associated systems and equipment. Sampling is defined as a set of observations and/or measurements on a subset of the whole that may be considered characteristic of the entity as a whole, and thus provides the ability to analyze the entire system. The size of the sample is based on, the scope of work as defined by the client, previous information that is made available and knowledge of the towers and its systems.

The inspection sampling refers to surface inspection observations only, except as noted otherwise. The foundation inspection is limited to an above grade surface inspection of these systems unless noted otherwise.

The specific items that were inspected and reviewed are as noted on the following inspection checklists. These lists are job specific and are developed to provide a "guide" for a general review that can lead to a more extensive review depending on inspection observations.

---------- End Section ----------

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years ($000)	Total	Page Ref
GENERATION					
Purchase Spare Disconnect - Bay d'Espoir		176		176	D - 2
Replace Automatic Transfer Switches - Bay d'Espoir and Hinds Lake		156		156	D - 4
Purchase Hydrometeorological Stations - Various Sites		113		113	D - 7
Replace Fire Alarm System - Hinds Lake		109		109	D - 11
Purchase Laser Alignment Equipment- Holyrood		79		79	D - 13
Upgrade Gas Turbine Operator Console - Stephenville		72		72	D - 16
Install Compressor for Frazil Ice Removal - Upper Salmon		69		69	D - 19
TOTAL GENERATION	0	773	0	773	
TRANSMISSION AND RURAL OPERATIONS					
Replace Instrument Transformers - Various Sites		199		199	D - 21
Install Fall Protection Equipment - Various Sites		198		198	D - 24
Install Alternate Station Services - Stony Brook and Massey Drive		86	109	195	D - 35
Purchase Meters, Equipment and Tanks - Various Sites		186		186	D - 38
Replace Digital Fault Recorder - Bay d'Espoir		169		169	D - 41
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson		155		155	D - 45
Replace Fuel Storage Tank - Francois		131		131	D - 49
Upgrade Fuel Storage - Norman Bay		114		114	D - 51
Legal Survey of Primary Distribution Line Right of Way - Various Sites		79		79	D - 54
Install Waste Oil Storage Tank - St. Lewis		79		79	D - 58
Replace Surge Arresters - Various Sites		75		75	D - 60
Purchase Portable Dissolved Gas Analysis Unit - Bishop's Falls		52		52	D - 62
TOTAL TRANSMISSION AND RURAL OPERATIONS	0	1,521	109	1,630	
GENERAL PROPERTIES					
Replace Radomes - Various Sites		196		196	D - 65
Upgrade Enterprise Storage Capacity - Hydro Place		154		154	D - 78
Upgrade Server Technology Program - Hydro Place		142		142	D - 82
Develop Learning Management System Courses - Hydro Place		84		84	D - 87
Perform Minor Application Enhancements - Hydro Place		82		82	D - 89
Replace Telephone Keyset - Wabush		80		80	D - 91
Replace Humidifiers in Air Handling Units - Hydro Place		76		76	D - 93
TOTAL GENERAL PROPERTIES	0	814	0	814	
TOTAL PROJECTS OVER $50,000 AND UNDER $200,000	0	3,108	109	3,217	

Project Title: Purchase Spare Disconnect

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to design and supply one three phase 4,000 Amps, 13.8 kV disconnect switch for the Bay d'Espoir Generating Station (Bay d'Espoir). Each of the six generating units in Powerhouse 1 has a disconnect switch that is used to isolate the generating unit from the unit's step up transformer. The switches for all six generators are identical. The new switch to be purchased under this proposal will serve as a spare for the existing disconnect switches on all six generators. The switch will be stored in the plant as a capital spare.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	10.5	0.0	0.0	10.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	130.0	0.0	0.0	130.0
Other Direct Costs	1.5	0.0	0.0	1.5
O/H, AFUDC & Escln.	19.4	0.0	0.0	19.4
Contingency	14.2	0.0	0.0	14.2
TOTAL	**175.6**	**0.0**	**0.0**	**175.6**

Operating Experience:

The disconnect switch is used to isolate the generating unit from the unit's step up transformer.

The existing disconnect switches are original equipment installed when the generating units were commissioned in 1967-1968 and 1970. The switches were custom designed for the generating units and manufactured by ITE Manufacturing, a company which no longer exists. There are no spare parts available for the switches and since the original equipment manufacturer no longer exists, replacement parts are not obtainable nor are the original drawings.

A maintenance inspection in the spring of 2008, determined that the disconnect switch for generating Unit 5 was damaged. The disconnects in the other generating units were also inspected. It was found that these disconnects were also showing signs of deterioration. The connecting blade of the disconnect switch for Unit 5, showed evidence of burn marks and pitting as a result of electrical arcing. A temporary repair was made by installing a copper bar in the disconnect so that the generating unit could be brought back to service. This temporary bar did not meet the full specification of the disconnect switch. It took approximately eight weeks to design a new part to fit in the disconnect properly and to meet the proper current rating. This repair cost was $8,000.

There is extensive pitting on the blades and contacts of the other disconnect switches as well and this condition is expected to get worse over time.

Project Justification:

This project is justified on the requirement to ensure the reliable operation of the generating units at Bay d'Espoir. The disconnect switches are critical to the operation of each of the generating units. The failure of one of the switches would cause the shut down of the unit which could last for several weeks while a spare disconnect or disconnect part is being manufactured. If there was a spare switch on site it could be used for spare parts or as a complete replacement if needed. Availability of a spare is important especially if the loss of a generating unit occurred in winter. Without the spare disconnect switch, the unit would be out of service for up to eight weeks. In addition, the drawings that Hydro would receive with the new switch would be used to order spare parts for the other identical switches in the future. Since the original equipment manufacturer no longer exists, spare parts are not available for purchase and Hydro does not have any spare parts for the switches in stock. Also there are no drawings available for the switches.

Future Plans:

None.

Project Title: Replace Automatic Transfer Switches

Location: Bay d'Espoir and Hinds Lake

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace three emergency power supply automatic transfer switches. One will be replaced in Powerhouse 2 at the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) and two will be replaced at the Hinds Lake Hydroelectric Generating Station (Hinds Lake). The existing cables will also be replaced. The new automatic transfer switches will have the same ratings and specifications as the existing switches and will be installed at their present locations.

Table 1 provides the budget estimate for this project.

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	41.0	0.0	0.0	41.0
Labour	74.7	0.0	0.0	74.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	13.8	0.0	0.0	13.8
O/H, AFUDC & Escln.	13.4	0.0	0.0	13.4
Contingency	13.0	0.0	0.0	13.0
TOTAL	**155.9**	**0.0**	**0.0**	**155.9**

Operating Experience:

The automatic transfer switches are used to provide essential station service power whenever the primary source for station service is unavailable. The transfer switch automatically switches to an emergency power supply upon the loss of normal station service power.

At Bay d'Espoir, the existing automatic transfer switch was installed in 1977 and has failed to operate as follows:

- In May 2002, the normal station service power supply breaker incorrectly indicated a closed position although it had remained opened. The switch had to be manually closed in order to

transfer station service to the emergency feed. It was returned to auto mode upon the restoration of the normal station service power.

- In June 2002 operations personnel noted that when the emergency power supply breaker control mechanism for the switch operates, it no longer resets to its normal position. This problem can not be rectified.

At Hinds Lake, the existing automatic transfer switches have also failed to operate:

- The automatic transfer switches failed to transfer to the emergency power supply during an outage in March 2003 and failed to switch to normal operation when the normal station service power was restored after the outage.
- Similar events occurred again in September 2005 and August 2006. Hydro investigated and determined that the motor friction drive mechanism was slipping when the motor was operating. This was temporarily corrected by having custom replacement parts manufactured.
- Also, problems have occurred with the timing relays within the control system not functioning properly. In October 2005, the emergency diesel did not shut down, as is normal, after its cool down period because the timing relay did not operate. Hydro fixed the timing relay but it is not reliable because of the age and the deteriorated condition.

Project Justification:

The automatic transfer switches at Bay d'Espoir and Hinds Lake are used to provide essential station service power whenever the primary station service power sources are unavailable. The switches have deteriorated and although they are not often required to operate, they are a critical component of a generating station when there is an unexpected loss of generation or transmission line supply.

The switch at Bay d'Espoir has failed to operate correctly by not transferring Powerhouse 2 station service load to the emergency feed from Powerhouse 1. An eight hour outage is required to investigate the abnormal operation of the switch. The switch was originally designed and manufactured by ITE. There are no generic spare parts available for this switch. When components are required, a representative from ITE must travel to site to gather information in order to perform measurements and fabricate parts.

The switches at Hinds Lake have failed to operate correctly by not transferring the station service load to the emergency feed from the on site diesel generator. The failures have required manual intervention to transfer to the backup supply. An eight hour outage is required to investigate the failures of the switching mechanism and the timing relays used to control the switching sequence. The switches were originally designed and manufactured by ITE. There are no generic spare parts available for these switches. When components are required, a representative from ITE must travel to site to gather information in order to perform measurements and fabricate parts. This is timely and costly.

The existing switches in both locations have proven to be unreliable. A failure to operate correctly could result in a unit or plant outage. The replacement of these switches is necessary to ensure a reliable station service supply.

Future Plans:

None.

Project Title: Purchase Hydrometeorological Stations

Location: Various Sites

Category: Generation - Hydraulic

Definition: Pooled

Classification: Normal

Project Description:

Hydro uses hydrometric (water level and flow) and meteorological (temperature, precipitation, wind etc) data as key inputs in its production planning and forecasting activities. Hydro currently collects some of these data, contracts collection at other sites to Environment Canada through an agreement with the provincial Department of Environment and Conservation, and uses data from provincial and federal gauges in or near its watersheds. Hydro's watersheds are complex; the differing topography, orientation to predominant wind directions, and distances from the ocean can lead to significant differences in temperature and precipitation at different locations in the watersheds. Ideally there would be several comprehensive meteorological stations in each watershed.

This is the continuation of a program to improve the hydrometeorological network in Hydro's reservoir basins. The program was started in 2008 and each year's plan and expenditures have been reviewed based on the experiences of the previous years.

Installing additional hydrometeorological stations in the watersheds and taking over the stations currently managed by Environment Canada will allow Hydro more direct access to real time data such as water levels, flows, air temperature, precipitation, wind speed, wind direction and snowpack. These data can then be used by Hydro to optimize hydraulic power production and minimize thermal power production from the Holyrood Thermal Generating Station (Holyrood). These data are also used to manage water levels in each of the storage reservoirs to prevent spill and to preserve dam safety. Collection of meteorological data will also assist in improving weather forecasting currently undertaken for the reservoir basins.

The proposed 2011 program is to take over responsibility for the hydrometric and meteorological equipment currently located at the Victoria Spillway, Granite Lake, and the Cat Arm Spillway. These stations are currently managed for Hydro by Environment Canada through a partnership with the Provincial Department of Environment and Conservation.

Table 1 provides the budget estimate for this project.

Table 1: Cost Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	29.1	0.0	0.0	29.1
Labour	23.2	0.0	0.0	23.2
Consultant	3.5	0.0	0.0	3.5
Contract Work	3.5	0.0	0.0	3.5
Other Direct Costs	35.3	0.0	0.0	35.3
O/H, AFUDC & Escln.	9.1	0.0	0.0	9.1
Contingency	9.5	0.0	0.0	9.5
TOTAL	**113.2**	**0.0**	**0.0**	**113.2**

Operating Experience:

The 2008 program included installation of meteorological stations at the intake at the Long Pond Reservoir, at Ebbegunbaeg on the Meelpaeg Reservoir, at the intake at the Cat Arm Reservoir and another in the Cat Arm watershed. The remote station which was installed in the Cat Arm watershed included a snow water equivalent measurement device (snow pillow).

The 2009 program included installation of meteorological stations at the Hinds Lake Control Structure and the Burnt Dam Spillway, and installation of a water level meter at the Burnt Side Hill Canal Weir.

The installation of the snow pillow in the Cat Arm watershed during the 2008 program was a first for Hydro and some problems were encountered with communication of the data from the site to Hydro's data collection centre in St. John's. Although the gauge has been in place since 2008, difficulties with the satellite communications have prevented the use of this data. The 2010 program was to add more snow pillows (in remote locations in the watersheds of the Victoria, Long Pond, Hinds Lake and Meelpaeg reservoirs), however, because of the communication difficulties experienced with the Cat Arm snow pillow it was decided to delay the 2010 program until there was certainty that the data collection issues were resolved and that the data received provides the intended benefit of improved inflow forecasting, likely in 2012.

Data from the remaining new sites – at Long Pond, Ebbegunbaeg, Hinds Lake and Burnt Dam – are being received on an hourly basis and are being used to plan and make decisions regarding operation of the reservoirs.

Project Justification:

This project is justified on Hydro's requirement to provide least cost power. Failure to monitor reservoir storages and properly prepare for the spring runoff can result in spillage. By continuing its program to maintain and install additional hydrometeorological stations, Hydro will obtain critical information on water levels and climate in the reservoir basins, which will help ensure that the reservoirs are operated efficiently. 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.

The proposed 2011 program is to take over responsibility for the hydrometric and meteorological equipment currently located at the Victoria Spillway, Granite Lake, and the Cat Arm Spillway. These stations are currently managed for Hydro by Environment Canada through a partnership with the Provincial Department of Environment and Conservation. The current agreement, in place until December 31, 2011, is for services with respect to six hydrometeorological stations on the island: White Bear River, Grey River, Cat Arm Reservoir, Granite Lake, Victoria Lake and RR Pond (near Granite Lake). The stations at Granite Lake and Grey River are both hydrometric and meteorological stations; the others measure water level and flow. The annual cost for these services is $7,600 for Victoria Spillway, $5,000 for Granite Lake and $3,500 for Cat Arm Spillway. No cost estimate has been received from the Department of Environment and Conservation for a similar agreement after 2011, but discussions have indicated that the costs would be at least double. For the purpose of this comparison, annual cost for the three stations of $33,000 has been assumed.

Using Hydro staff and equipment, and in-house expertise, Hydro can maintain the stations more cost effectively than availing of the services of Environment Canada, and ideally with 24-hour staff availability in case of data problems. Each new station will have an annual communication cost of approximately $1,800. Annual Hydro operation and maintenance costs would be approximately $1,700 for the Cat Arm Spillway station and approximately $6,400 for the Victoria Spillway and Granite Spillway stations, because they require helicopter access. The total annual cost then will be approximately $18,000. This is a cost saving in the order of $15,000 per year when compared to the anticipated costs of the service from Environment Canada.

An additional driver for the project is concern about the availability of data from the stations managed by Environment Canada. In particular, data availability is often poor on weekends, especially holiday

weekends, because the service providers do not provide 24/7 service. Other data issues include inherent data transfer delays of three hours within the service provider's data network. At times of high run-off or during spill management data delays can cause less than optimal decision making or result in poor inflow forecasting which leads to less than optimum generation schedules.

Future Plans:

Additional installations will be proposed in the 2012 and 2013 capital budget applications. The installation of meteorological gauges, including snow water equivalent sensors, that was originally planned for 2010 is now proposed to be completed in 2012 and the original 2012 program delayed to 2013. These plans will be reviewed prior to the budget submission.

Project Title: Replace Fire Alarm System

Location: Hinds Lake

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing fire alarm system control panel located in the Hinds Lake Hydroelectric Generation Station (Hinds Lake). This project includes the replacement of the existing fire protection and detection system including smoke and heat detectors, pull stations, audible alarms and other auxiliary equipment. The new system will be capable of interfacing into the existing controls for the powerhouse ventilation system and the generating unit annunciator. The existing wiring will be used whenever possible. The final system will conform to the applicable standards and codes (CAN/ULC-S537-M86 Standard for the Verification of Fire Alarm Systems, CAN/ULC-S524-M86 Standard for the Installation of Fire Alarm Systems, CSA Canadian Standards Association, Canadian Electrical Code, and Factory Mutual).

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	5.0	0.0	0.0	5.0
Labour	22.0	0.0	0.0	22.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	60.0	0.0	0.0	60.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	11.2	0.0	0.0	11.2
Contingency	8.9	0.0	0.0	8.9
TOTAL	**109.1**	**0.0**	**0.0**	**109.1**

Operating Experience:

Over the last five years, there have been numerous false alarms attributed to this aging fire alarm system (a record of the number of false alarms is not available). These nuisance conditions are sporadic, not repairable and are caused by failures of the system modules, cards, or relays contained within the control panel. The existing fire alarm system is original equipment installed when Hinds Lake was commissioned in December 1980. It has become obsolete and replacement parts are not

available. The anticipated useful life of a fire alarm system in a generating plant is 20 to 25 years. The fire alarm system at Hinds Lake has passed its useful life. Hydro received approval under Board Order No. 30 (2007) to replace a similar fire alarm system at Cat Arm in 2008. The actual cost of that replacement was $81,687. The additional funds included within this budget estimate are required to capture internal labor required to staff the site while the existing fire alarm system is out of service.

Project Justification:

The fire alarm system is a vital part of the generating station and is required for safety purposes. The fire alarm system provides protection to personnel, minimizes fire damage, mitigates the spread of fire, and provides overall protection to the powerhouse. This project is justified on the basis that, as the plant is unattended, it is important that a reliable fire alarm system be installed. As the existing system is obsolete, it needs to be replaced in order to provide a safe workplace when Hydro personnel frequent the plant and also, reliable and accurate plant condition information to Hydro's Energy Control Centre.

Future Plans:

None.

Project Title: Purchase Laser Alignment Equipment

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This proposal is required to purchase new laser alignment equipment to replace the existing obsolete equipment at the Holyrood Thermal Generating Station (Holyrood). The new equipment will include database and reporting functions and will also be expandable to offer capabilities for thermography, motor current analysis and tribology if required at a later date. Thermography is a method of measuring surface temperature or variations in heat emitted from equipment due to the presence of an electric field, radiation or a chemical reaction. Tribology is an analysis of the mechanisms of friction, lubrication and wear of two surfaces in close relative motion to each other. Motor current analysis is the study of variation in electrical power current supply to a machine to correlate abnormal levels to mechanical rotational problems. These capabilities would be required in future to support the collection of data for predictive asset maintenance tactics.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**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.	7.1	0.0	0.0	7.1
Contingency	6.5	0.0	0.0	6.5
TOTAL	**78.6**	**0.0**	**0.0**	**78.6**

Operating Experience:

The coupling of high speed rotating equipment requires precise alignment so that damage does not occur to the equipment. The use of a laser beam has become an industry standard for equipment alignment because of its accuracy and efficiency. The equipment being purchased could be used on other parts of the Hydro system. Other methods of alignment using dial gauges and straight edges do

not provide the accuracy of the laser beam method. Also, the time to ensure that correct alignment is attained through the meticulous use of dial gauges and straight edges is longer than with the use of a laser beam. At Holyrood, laser alignment is used to align the 3,600 rpm rotating shaft that couples the steam turbine to the generator. This includes the conversion of one of the main generators from generation to synchronous condenser mode. Also, the large pumps and their accompanying motors are aligned using the laser beam method. The laser alignment equipment is used annually during the scheduled maintenance outage period between April and October. The current laser system has been used sparingly due to unreliability.

The existing laser alignment equipment at Holyrood is 11 years old. It has past its anticipated useful life of ten years. Operating problems with the existing equipment mainly related to the unit power supply started approximately four years ago. Annual repairs, ranging in cost between $2,000 and $5,000, were required to fix the equipment. Currently, the equipment does not have an original equipment manufacturer service provider and supplier of parts, which leads to delays in work when the laser is not functioning properly. A temporary repair has been provided by a non-original equipment manufacturer service provider but this does not offer long term support. The original equipment manufacturer supplier is also required for software upgrades and support; the current software is obsolete. Also, the current machine does not offer the expansion capabilities for the types of predictive maintenance noted. The equipment is needed to maintain safe and reliable power production. From a safety and reliability perspective, a laser system improves the accuracy of alignment which lessens the possibility of equipment failure due to high vibration on high speed equipment.

Project Justification:

This project is justified on the need to continue providing safe and reliable power generation at Holyrood. The current laser alignment system is obsolete. Replacement parts are no longer available and the equipment is not being serviced or supported by the original equipment manufacturer, Emerson Process Management. The equipment is needed for precision alignment of turbine generators, synchronous drive components and large pumps and motors. It is used in particular, for the conversion of generating Unit 3 between generation and synchronous condenser modes of operation.

Hydro schedules generation at Holyrood to optimize the dispatch of thermal and hydroelectric generation to meet the Island Interconnected System's power needs. Schedules are an annually coordinated effort between System Operations and Holyrood. To meet annual maintenance and environmental targets set for Holyrood, it is imperative that the established schedules be adhered to as closely as possible. The new laser alignment equipment is required to ensure that the schedules are met. Without it, up to five days extra are needed for alignment during work on the generating units. An extra day is needed to do work on the large pumps and motors. In general, alignment using laser is in the order of hours whereas with other methods, alignment can take days. This will have a negative effect on Hydro's efforts to meet its targets for Holyrood. Also, the laser alignment equipment has memory capability to log the data specific for each precision alignment of machinery. This data then is accessible the next time when re-alignment is required, thus reducing overall, the time to complete maintenance work.

Future Plans:

None.

Project Title: Upgrade Gas Turbine Operator Console

Location: Stephenville

Category: Generation - Gas Turbines

Definition: Other

Classification: Normal

Project Description:

This project is required to upgrade the software and hardware of the Operator Console used for local operation and monitoring of the Stephenville Gas Turbine. The upgrade consists of installing the latest versions of the graphics software called PCView and QNX operating system[1] in accordance with specifications supplied by the manufacturer, Asea Brown Boveri Inc. (ABB). Both the software and hardware are proprietary packages of ABB.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	48.0	0.0	0.0	48.0
Labour	12.0	0.0	0.0	12.0
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.	6.5	0.0	0.0	6.5
Contingency	3.2	0.0	0.0	3.2
TOTAL	**71.7**	**0.0**	**0.0**	**71.7**

Operating Experience:

The Operator Console consists of a desktop computer and monitor as shown in Figure 1. It enables the operator to control and monitor the gas turbine and records valuable data such as operating temperatures, engine speeds, oil pressures and vibration levels. The console was installed in 1999 as part of the control systems upgrade at the Stephenville Gas Turbine plant.

The console has experienced two major failures. The console's computer cooling fan failed in 2003 and the computer was returned to ABB for service. In July 2007, the computer's motherboard failed. Each incident resulted in the loss of local control and monitoring and the permanent loss of operating

[1] Comparable to a UNIX operating system and is not a Microsoft Windows operating system

data. When the motherboard failed in 2007, the computer's hard drive was installed, as a temporary measure, in an old computer owned by the local operator so that the console could be returned to operation.



Figure 1: Stephenville Gas Turbine Operator Console

The original software, approximately 11 years old, can only operate on computers of comparable vintage. Late model computers have hard drives that are too large for the existing software to operate due to formatting problems. Therefore, it is difficult to purchase replacement parts for the existing computer. ABB states that the existing software cannot operate on current models of computers. The manufacturer recommends that customers upgrade the computer software and hardware to current technology and ensure that relevant spare parts are available to maintain their systems on current operating technology.

Project Justification:

This project is justified on the need to upgrade technology to maintain the reliability of the Stephenville Gas Turbine. The existing Operator Console is approximately 11 years old and has

experienced major failures. This console is required for local control and monitoring and collecting important system data that is not received at Newfoundland and Labrador Hydro's Energy Control Centre. The old technology is incompatible with late model computers and Hydro has already experienced a problem in finding replacement parts.

Two alternatives were considered for upgrading the Operator Console. Alternative 1 entails an upgrade of the software and hardware utilizing the existing operating system. The graphics and database files will work on the latest version of the existing PCView software. The manufacturer (ABB) will support the upgraded product for ten years. The total installed capital cost of Alternative 1 is $71,700. Alternative 2 entails an upgrade of the Operator Console to a Microsoft Windows based platform. This alternative requires extra engineering work by the manufacturer to convert the existing graphics and database to the new platform. Alternative 2 is estimated to cost $143,700. Given that there is no anticipated difference in the operating and maintenance cost of either alternative, Alternative 1 is the most cost effective alternative.

Future Plans:

None.

Project Title: Install Compressor for Frazil Ice Removal

Location: Upper Salmon

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is required to install an air compressor for the frazil ice removal system at the Upper Salmon intake structure.

Frazil ice is a collection of randomly oriented needle shaped ice crystals that sporadically form in open, turbulent, super-cooled water on clear, cold and windy nights. The ice crystals grow in size and number and, due to their needle like structure, are dispersed throughout the water flow and not just on the surface. The frazil ice adheres to the trash rack on the intake structure and, as the ice accumulates, the water flow is reduced. Eventually, ice may completely block the trash rack and prevent water flow into the penstock.

Hydro personnel monitor the differential pressure across the trash rack to determine the amount of ice build up. Before the ice build presents a risk of a low water flow that could lead to draining the penstock, the generating unit is shutdown. Once the unit has been shutdown it cannot be put back into service until the ice has been removed from the trash rack. An air compressor is used to inject air through a series of pipes to the bottom of the trash rack where it is then released into the water. As the air rises to the surface it causes the warmer water near the bottom to move towards the surface. This warmer water helps to remove the ice from the trash rack, eventually allowing the unit to be put back in service.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	31.5	0.0	0.0	31.5
Labour	22.5	0.0	0.0	22.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.4	0.0	0.0	3.4
O/H, AFUDC & Escln.	6.0	0.0	0.0	6.0
Contingency	5.7	0.0	0.0	5.7
TOTAL	**69.1**	**0.0**	**0.0**	**69.1**

Operating Experience:

The Upper Salmon Generating unit was shutdown twice recently due to frazil ice build up on the trash rack. The incidents occurred in December 2009 and January 2010. Both incidents resulted in the generating unit being unavailable for three days.

During both incidents, a portable general purpose compressor was used to help clear the ice build up. However, had the portable compressor not been readily available at the site, the shutdown would have been longer.

Project Justification:

A portable compressor does not provide the reliability required for frazil ice removal. The frazil ice removal system at the Upper Salmon intake structure requires the installation of a dedicated air compressor. The portable air compressor is used for maintenance work and as a back-up for permanently installed compressors at other hydraulic generating plants. When it is used for frazil ice removal, it is not available for other intended uses. Also, when this compressor is used at another plant, it is not readily available for use on the frazil ice removal system at Upper Salmon. Transportation of the compressor to and from other locations requires a boom truck, a mobile equipment operator and two workers to load it onto the transport vehicle.

A dedicated compressor will ensure that the frazil ice removal system at Upper Salmon is available without delay and without the mobilization costs, thus improving the reliability of the generating station without impeding maintenance work at other locations.

Future Plans:

None.

Project Title: Replace Instrument Transformers

Location: Various Sites

Category: Transmission and Rural Operations – Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is part of an on-going program to replace instrument transformers. It involves the purchase and installation of replacement instrument transformers (potential transformers and current transformers) at various terminal stations as maintenance assessments dictate or failure occurs. Table 1 provides the list of instrument transformers planned to be replaced in 2011.

Table 1: Instrument Transformer Replacements for 2011

Terminal Station Location	Voltage Class	Unit Identification
Upper Salmon	230 kV	L34T1, Phases A, B and C
Stony Brook	230 kV	L05L31-1, Phase A
Stony Brook	138kV	B3T2, Phases A, B and C
Oxen Pond	66 kV	Bus 5, Phases A, B and C
Oxen Pond	66 kV	T1, Phase B
Holyrood	69 kV	Bus 7, Phases A, B and C
Holyrood	230 kV	TL18, Phases A, B and C
Bear Cove	138 kV	Bus 1, Phases A, B and C
Western Avalon	138 kV	64 L, Phase B
Hardwoods	69 kV	B8B9, Phase A, B and C

Table 2 provides the budget estimate for this project.

Table 2: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	137.7	0.0	0.0	137.7
Labour	28.2	0.0	0.0	28.2
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.	16.6	0.0	0.0	16.6
Contingency	16.6	0.0	0.0	16.6
TOTAL	**199.1**	**0.0**	**0.0**	**199.1**

Operating Experience:

Instrument transformers have a typical service life of 30 to 40 years, depending on the service conditions. Units are inspected and tested regularly, and replaced based on these maintenance assessments or in-service failures. The maintenance assessments for instrument transformers include visual inspections and voltage/current checks of the secondary circuits. This proposal also provides for an allowance of $80,000 for testing and replacement of instrument transformers that are determined to be noncompliant with Poly Chlorinated Biphenyls (PCB) regulation, which requires that all equipment with PCB levels above 50 parts per million (ppm) to be taken out of service by 2025. Hydro was notified by Environment Canada until mid 2009 of this requirement therefore the inclusion of this allowance has increased the budget estimates for 2010 and 2011.

Table 3 shows the history of expenditures for this project for the past five years.

Table 3: Budget History

Year	Budget ($000)	Actual ($000)	Units	Average Unit Cost ($000)
2010F	197.0		10	
2009	106.6	128.3	8	16.0
2008	73.7	75.3	7	10.8
2007	79.7	80.1	5	16.0
2006	78.0	81.4	8	10.2
2005	75.0	54.0	7	7.7

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 viable 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. Table 4 shows Hydro's inventory of instrument transformers.

Table 4: Inventory of Instrument Transformers

Voltage Class	Number of Potential Transformers	Number of Current Transformers
230 kV	3	8
138 kV	4	4
66/69 kV	3	6
46 kV	1	1
25 kV	1	0
15 kV	2	0

The project estimate is based on an equal number of units in each voltage class failing, or requiring replacement. It has also been identified that older vintage instrument transformers may contain PCBs, and Hydro has a program in place to reduce PCBs in its assets, requiring PCB filled instrument transformers to be replaced. Based upon preliminary work completed for Hydro's Environmental Management Program for PCB reduction, there will be a requirement to change more than twice the number of units changed historically in a given year to meet the 2025 PCB free date. Based upon this, the investment for instrument transformers will have to be further increased in future years starting in 2015.

Future Plans:

Future replacements will be proposed in future capital budget applications. See 2011 Capital Budget Application, Volume 1, Tab '2011 Capital Plan' for expenditures planned for 2012 – 2015.

Project Title: Install Fall Protection Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Definition: Pooled

Classification: Mandatory

Project Description:

This project is required to design, supply and install fall protection systems at several Hydro facilities. It includes installing roof fall protection systems on the control buildings at the Oxen Pond , Western Avalon and Holyrood Terminal Stations and on the Francois and St. Brendan's Diesel Plants, anchor plates for transformers where needed, ladder cable systems for ladders where needed and railings and roof anchors on two hydraulic structures.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	60.0	0.0	0.0	60.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	55.0	0.0	0.0	55.0
Other Direct Costs	6.0	0.0	0.0	6.0
O/H, AFUDC & Escln.	21.3	0.0	0.0	21.3
Contingency	16.1	0.0	0.0	16.1
TOTAL	**198.4**	**0.0**	**0.0**	**198.4**

Operating Experience:

Hydro initiated a five year program in 2005 to install fall protection systems on transformers, fuel tanks and roofs at its facilities. The last proposal in that program was part of Hydro's 2009 Capital Budget Application to the Board of Commissioners of Public Utilities (Board), pages C-130 to C-136. At the start of the five year plan in 2005, only sites having a high priority need for fall protection systems were identified. During the execution of the program, Hydro developed a comprehensive listing of all sites that needed fall protection systems. Because of the large number of sites, (see Appendix A) Hydro realized that all required fall protection systems could not be installed in the original five year program. Many of the new sites are remote structures. Hydro received approval from the Board under Board Order No. P.U. 1 (2010) to install fall protection systems at the Western Avalon and Sunnyside

Terminal Stations and on the St. Lewis and Williams Harbor Diesel Plants, anchor plates for transformers where needed, hand rail and cat walks on two diesel fuel tanks at the Holyrood Generating site and railings and roof anchors on three hydraulic structures in 2010. 2011 is year seven of the continuation of the program started in 2005.



Figure 1. Roof Fall Protection System

Below is a discussion of the three basic types of fall protection systems installed by Hydro. The photographs illustrate how each system is used.

Roof Fall Protection System

Generally, a fall protection system is not a complex system. Figure 1 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.

Ladder Fall Protection System

In this system, a safety cable is installed vertically on the side of the ladder as shown in Figures 2 and 3 to the right. The workers secure themselves to the ladder fall protection system by attaching themselves to a D ring, as shown in the picture that is attached to a cable grab which in turn rides on the cable. The cable grab allows the worker to move with ease up the ladder but in the event



Figures 2 and 3. Ladder Fall Protection System



of a sudden downward movement, as in a fall, the cable grab is designed to abruptly grab the cable, securing the worker and preventing a fall. This action is similar to the behavior of a seat belt in a car.

Transformer Fall Protection System

Figure 4 illustrates a transformer fall protection system used by the three workers standing on top of a transformer. This system is a portable system. The fall protection system is mounted on a fixed anchor plate welded to the top of the transformer. When work is completed, the fall protection system can be taken to another site.

The three basic types of fall protection systems shown above are for illustrative purposes. Systems may vary when they are installed because of, for example, extra cable arrangements or the need for railings. The systems will be inspected annually. The anticipated useful life of a fall protection system is 20 years.



Figure 4: Transformer Fall Protection System

Fall protection systems are required to perform work safely at elevations above 3.05 meters. Hydro must conform to Section 60 of the Occupational Health and Safety Regulations. The section, “Safety Belts and Lifelines” states in part “the employer shall ensure that fall protection systems are used by

all workers employed over pits, shafts or moving machinery and by all workers working at elevations greater than 3.05 meters above ground or floor level". The complete Section 60 regulations are presented in Table 3. Without proper fall protection systems in place, a worker can refuse to perform his/her assigned duties.

Project Justification:

This project is justified on the requirement to provide a safe work environment and to comply with Section 60 of the Occupational Health and Safety Regulations. The fall protection system program started in 2005 did not provide for installations at all of Hydro's sites where fall protection systems were needed. New sites were identified throughout the program. Table 2 presents annual capital budget and actual expenditures for years 2005 to 2010.

Table 2: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2010	198.4		Ladders, transformers and roofs
2009	321.7	302.7	Tanks, transformers and roofs
2008	404.5	193.9[1]	Tanks, transformers and roofs
2007	250.9	245.2	Tanks, transformers and roofs
2006	268.1	241.9	Tanks, transformers and roofs
2005	206.2	208.7	Tanks, transformers and roofs

[1]Scheduled installation of roof lines on three powerhouse buildings but could be met due to other commitments. It was too late to tender when this was discovered. Also some design changes to the fall protection system for the penthouse roof at the Holyrood Thermal Generating Station also provided significant savings.

This work will continue until all facilities are properly equipped with fall protection systems in compliance with Section 60 "Safety Belts and Lifelines" of the Occupational Health and Safety Regulations.

Table 3: Safety belts and lifelines from Occupational Health and Safety

60.	(1) Where it is impracticable to provide adequate work platforms or staging, the employer shall ensure that fall protection systems are used by all workers employed over pits, shafts or moving machinery and by all workers working at elevations greater than 3.05 metres above grade or floor level in accordance with current standards of the C.S.A. Code with respect to fall protection and fall protection systems. (2) Rep. by 23/99 s2 (2) (3) When a worker is employed under circumstances where he or she might become entrapped by material, or be overcome by another cause, he or she shall wear a safety-belt or safety-harness attached to a lifeline or other device attended by another worker who shall be stationed, equipped and capable of immediately effecting a rescue. (4) Safety-belts, safety straps, lifelines and all interconnecting parts shall be of sufficient strength to support before breaking a weight of 1134 kilograms. (5) All metal fittings used on or with safety-belts shall conform to the metallurgical strength requirement standards as specified by the Canadian Standards Association. (6) Permanent anchors to which safety straps or rope terminals may be attached shall conform to the requirements of subsections (4) and (5). (7) Rope used for lifelines or safety straps shall comply with the requirements of current C.S.A. Code standards with respect to fall protection. (8) When axes or other tools are used which are likely to sever, abrade or burn the lifeline or safety strap, a wire rope or wire cored fibre rope shall be used. (9) Where workers are engaged in work in proximity to energized electrical circuits where conductive safety straps cannot be used, 2 non-conductive safety straps shall be worn to provide the additional protection required. (10) The safety strap shall be so attached to the safety-belt that it cannot pass through the belt fittings should either end become loose from its anchorage. (11) Thimbles shall be installed to protect ropes from chafing at points of connection to eyes, rings and snaps. (12) Safety-belts, safety straps and lifelines shall be arranged to limit the free fall of a worker to 1.22 metres. (13) No more than one worker shall be attached to a lifeline. (14) Belts, straps, harnesses, lifelines and other similar devices shall be kept free from substances and conditions which could contribute to deterioration and this equipment shall be carefully inspected before use. (15) If an impairment of function is detected the defective part shall be removed from service.

Future Plans:

Future fall protection installations will be proposed in future capital budget applications. See five-year capital plan (2011 Capital Plan Tab, Appendix A).

APPENDIX A

Fall Protection Project List

Fall Protection Project List		
Location	**Description**	**Comment**
Bay d'Espoir		
Powerhouse 1	Roof lines	Completed
	Ladder system on roof	Completed
	Safe access to overhead cranes	Completed
	Access ladder attached to mobile crane	Completed
Powerhouse 2	Roof lines	Completed
	Ladder system on roof	Completed
	Overhead crane SE ladder	Completed
	Transformer interceptor ladder	Completed
Cat Arm	Roof lines	Completed
Hinds Lake	Roof lines	Completed
Paradise River	Roof lines	Completed
Upper Salmon	Roof lines	Completed
Holyrood	Rigid rail system for wastewater treatment building	Completed
	Rigid rail system for pumphouse 1	Completed
	Rigid rail system for pumphouse 2	Completed
	Roof railing system on powerhouse	Completed
	Lifeline in powerhouse	Completed
Central		
Stephenvile GT	Ladder cable systems on three tanks	Completed
Grey River	Platform for cleaning out stacks	Completed
Little Bay Islands	Fall protection system on diesel plant roof	Completed
McCallum	Fall arrest anchors on roof	Completed
	Ladder cable system of tank ladder	Completed
Ramea	Fall protection system on diesel plant roof	Completed
Doyles TS	Travel restraint anchor on control building roof	Completed
Hardwoods TS	Travel restraint anchor on control building roof	Completed
Northern		
Charlottetown	Fall protection system on diesel plant roof	Completed
	Ladder cable system on tank ladder	Completed
L'Anse au Loup	Fall protection system on diesel plant roof	Completed
Mary's Harbour	Fall protection system on diesel plant roof	Completed
	Ladder cable system on tank ladder	Completed
Port Hope Simpson	Fall protection system on diesel plant roof	Completed
St. Anthony	Fall protection system on diesel plant roof	Completed
	Fixed ladder and cable ladder system on diesel plant	Completed

Fall Protection Project List		
Location	**Description**	**Comment**
Labrador		
Black Tickle	Fall protection system on diesel plant roof	Completed
	Ladder cable system on tank ladder	Completed
Cartwright	Fall protection system on diesel plant roof	Completed
	Ladder cable system on fixed ladder	Completed
Happy Valley	Fall protection system on North side plant roof	Completed
	Fall protection system on gas turbine plant roof	Completed
	Ladder cable system on gas turbine plant ladder	Completed
Hopedale	Ladder cable system on fixed ladder	Completed
Makkovik	Fall protection system on diesel plant roof	Completed
Nain	Ladder cable system on four tank ladders	Completed
Bay d'Espoir		
General	Ladder system at Burnt Dam spillway	Planned for 2010
	Roof catwalk to provide access to structure ladder	Planned for 2010
	Install ladder cable system at Intakes 1 to 4	Planned for 2010
Cat Arm	Ladder system on powerhouse roof	Planned for 2010
	Insulator access platform	Planned for 2010
Upper Salmon	Walkway and short stair access to the spider area	Planned for 2010
	Ladder system on powerhouse roof	Planned for 2010
Holyrood	Ladder systems for three stacks	Planned for 2010
	Four ladder cable systems for pumphouse	Planned for 2010
Central		
Stephenvile GT	Platform and kick plates on gas turbine modules	Planned for 2010
Various Transformers	Anchor plates for transformers	Planned for 2010
Northern		
Charlottetown	Ladder cable system and roof cable	Planned for 2010
L'Anse au Loup	Fixed ladder on diesel plant	Planned for 2010
Various Transformers	Anchor plates for transformers	Planned for 2010
Labrador		
Black Tickle	Travel restraint system on top of two tanks	Planned for 2010
	5/16" cable replacing 3/8" cable from ladder station to roof post	Planned for 2010
Hopedale	Fall protection system on diesel plant roof	Planned for 2010
Makkovik	Ladder cable system on three tank ladders	Planned for 2010
	Travel restraint system on top of three tanks	Planned for 2010
Nain	Fall protection system on diesel plant roof	Planned for 2010
	Travel restraint system on top of four tanks	Planned for 2010
Rigolet	Ladder cable system on tank ladder	Planned for 2010
	Travel restraint system on top of tank	Planned for 2010

Fall Protection Project List		
Location	**Description**	**Comment**
Central		
Francois	Fall protection system on diesel plant roof	Planned for 2011
St Brendan's	Fall protection system on diesel plant roof	Planned for 2011
Holyrood TS	Fall protection system on control building roof	Planned for 2011
Oxen Pond TS	Fall protection system on control building roof	Planned for 2011
	Fall restraint to ladder on transformer	Planned for 2011
Western Avalon TS	Fall protection system on control building roof	Planned for 2011
Various Transformers	Anchor plates for transformers	Planned for 2011
Bay d'Espoir		
General	Platform Access to hoist control panel at Salmon Spillway	Future projects
	Suitable access to aircraft warning lights at Salmon Spillway	Future projects
	Surge tank ladders	Future projects
	Ladder with barrier to Staffguage at Victoria Control Structure	Future projects
	Ladder to upper deck at Victoria Control Structure	Future projects
Powerhouse 1	Overhead crane NE ladder	Future projects
	Overhead crane SE ladder	Future projects
	Downstream Unit 5(1) ladder	Future projects
	Downstream Unit 5(2) ladder	Future projects
	Downstream Unit 6 ladder	Future projects
	Cable tunnel shelter ladder	Future projects
	Self rescue system from overhead crane	Future projects
	Load ratings for gratings improvements	Future projects
	Fall arrest or restraint system when working atop overhead crane	Future projects
	Recommendations for proper ladder to access cab of overhead crane	Future projects
	Requirements for proper height and standard for cab	Future projects
Powerhouse 2	Overhead crane NE ladder	Future projects
	Sump pit ladder	Future projects
Hinds Lake	Ladder with barrier at east end of powerhouse	Future projects
	Ladder with barrier at west end of powerhouse	Future projects
	Ladder with barrier at draft tube area	Future projects
	Sump pit ladder	Future projects
	Ladder cable system at Intake roof	Future projects
	Ladder cable system at control structure roof	Future projects
	Ladder cable system at warehouse roof	Future projects
Paradise River	Platform for powerhouse overhead crane	Future projects

Fall Protection Project List		
Location	**Description**	**Comment**
Upper Salmon	Ship stair detail	Future projects
	Draft tube crane access	Future projects
	Ladder cable system at Intake roof	Future projects
	Ladder cable system at North Salmon spillway roof	Future projects
	Ladder cable system at West Salmon spillway roof	Future projects
	Ladder cable system at warehouse roof	Future projects
Granite Canal	Ship stair detail	Future projects
Central		
Bishop's Falls	Lifelines on service building	Future projects
	Fall protection system on office building	Future projects
	Fall protection system on salvage stores	Future projects
	Fall protection system on diesel building roof	Future projects
Bottom Brook TS	Fall protection system on control building roof	Future projects
Massey Drive TS	Fall protection system on control building roof	Future projects
Stony Brook TS	Fall protection system on control building roof	Future projects
Sunnyside TS	Fall protection system on control building roof	Future projects
Various Transformers	Anchor plates for transformers	Future projects
Northern		
Charlottetown	Travel restraint system on top of tank	Future projects
Mary's Harbour	Travel restraint system on top of two tanks	Future projects
William's Harbour	Ladder station and fall protection system on diesel building roof	Future projects
Various Transformers	Anchor plates for transformers	Future projects
Labrador		
Happy Valley	Sure-Track ladder system on North side plant ladder	Future projects

Project Title: Install Alternate Station Services

Location: Stony Brook and Massey Drive

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to install an alternate station service power supply at Newfoundland and Labrador Hydro's (Hydro) Stony Brook and Massey Drive Terminal Stations.

At Stony Brook, an alternate station service power supply will be provided from the 230/138/6.9 kV power transformer T2 via the installation of a new three phase 150 kVA , 6900/600 Volt step down transformer and fusible disconnect switch. The alternate supply will be brought into the control building through underground cables. A transfer switch will be installed in the building to facilitate connecting the station service to either the primary or alternate power supply.

At Massey Drive, an alternate station service power supply will be provided through a tap off one of Newfoundland Power's (NP) sub-transmission lines which is supplied from the terminal station Bus B3. The project will involve constructing approximately ten spans, a total length of 600 meters, of 25kV distribution line from the NP system. A 200 kVA, 25000/600 Volt step down transformer and fusible disconnect will connect this new supply through underground cables to the control building. A transfer switch will be installed in the building to facilitate connecting the station service to either the primary or alternate power supply.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	38.0	13.0	0.0	51.0
Labour	27.9	27.3	0.0	55.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	1.5	25.5	0.0	27.0
Other Direct Costs	11.2	11.1	0.0	22.3
O/H, AFUDC & Escln.	7.5	16.8	0.0	24.3
Contingency	0.0	15.5	0.0	15.5
TOTAL	**86.0**	**109.2**	**0.0**	**195.2**

Operating Experience:

At each of the Massey Drive and Stony Brook Terminal Stations there is currently a single station service power supply. Station service is essential to the operation of these stations and is required to maintain auxiliary station equipment such as compressed air systems, battery charging systems, station heating and lighting, and testing equipment. A station service supply interruption can be caused by an equipment failure or an outage to the part of the station where the supply is fed from. If there is only one station service supply in the station and that supply is interrupted, then portable diesel generation is required to keep the terminal station operational. Such portable diesel generation is not always readily available from local rental companies especially when needed in emergency situations. It is now standard design practice for Hydro to have dual station service supplies in all its 230 kV terminal stations.

Project Justification:

A second station service supply is required at both stations to ensure the reliability of station service power during outages to the primary station service supply. Station service power supply is essential to maintaining reliable and secure terminal station operation. If the supply is interrupted then electrical service to customers is in jeopardy. The normal utility practice is to have an alternate or second station service power supply in major terminal stations, 230 kV and greater. Newfoundland and Labrador Hydro (Hydro) has 18 – 230 kV terminal stations on the Island Interconnected System. Sixteen of these have an alternate station service power supply.

The Massey Drive Terminal Station is located off the Trans Canada Highway approximately a kilometer west of Corner Brook. It is a critical tie point to major loads on the west coast of the Island. In the event of a loss of the station, there would be an interruption in customer service in Corner Brook and

surrounding area, interruption to Corner Brook Pulp and Paper and Deer Lake Power and interruption to Cat Arm generation.

Stony Brook Terminal Station is located immediately across the Exploit's River, behind the former Abitibi paper mill in Grand Falls. It is also critical to the Island Interconnected System. Stony Brook is a central point connecting 230 kV loads east and west. In the event of a loss of the station, there would be an interruption in customer service from Grand Falls and west including interruption of the Exploit's Generation.

An alternate station service power supply enables Hydro to be prepared for emergency equipment outages as well as offer flexibility during maintenance outage planning. This secures the reliability of the terminal station operation. The alternate station service power supply ensures station auxiliaries are maintained through all planned operations as well as any unplanned events. While there have been no outages as a result of the lack of an alternate station service supply, the alternate supply provides operations with the capability and flexibility to maintain full station operations thoughout all operating circumstances.

Future Plans:

None.

Project Title: Purchase Meters, Equipment and Tanks

Location: Various Sites

Category: Transmission and Rural operations - Metering

Definition: Other

Classification: Normal

Project Description:

This project is required to purchase 150 electronic 3.0 element demand meters and six Dry-Type 3.0 element Primary Metering Units (Meter Tanks) to replace existing aging and obsolete 2.5 element units. Effective April 2, 2003, legislation requires that all new and the upgrading of any existing 3-phase 4-wire wye configured metering installations must be metered using 3.0 element metering.

Also, this project is required to purchase replacement meters and associated equipment for major customer metering installations which require replacement during each year due to equipment age, technology changes or obsolescence. This also includes labour cost to refurbish, calibrate, seal and install 1,500 residential meters that have been displaced by the implementation of Automated Meter Reading (AMR) meters.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	107.5	0.0	0.0	107.5
Labour	46.1	0.0	0.0	46.1
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.	16.7	0.0	0.0	16.7
Contingency	15.4	0.0	0.0	15.4
TOTAL	**185.7**	**0.0**	**0.0**	**185.7**

Operating Experience:

There are 80 oil-filled metering tanks of which 41 are in service and 39 in storage as critical spares. Aside from all being 2.5 element units, they range in age from 20 to 39 years. In the last ten years, there have been five tanks removed from service due to deterioration from the outside environment or due to failure of components.

Project Justification:

Approximately 80 percent of Hydro's metering tanks are reaching the end of their useful life of 40 years and require replacement to prevent failures. Refurbishment and replacement of existing units is not permitted by Measurement Canada as all existing units are a 2.5 element design and Measurement Canada requires all new and reconstructed applications to use 3.0 element design. The 2.5 element design uses two potential transformers rather than three which are used in the 3.0 element design, thus introducing the potential for inaccuracies in metering. See Measurement Canada's explanation below.

As per Measurement Canada Bulletin E-24-E (rev.1), the following quote explains the reason for the change from 2.5 element meter design to 3.0 element meter design.

"2.5 element meters along with the 2.5 element metering tanks were designed to reduce costs associated with metering, by using one less instrument transformer and associated components internal to the meter. Although 2.5 element metering is a legal and approved form of metering used in Canada for existing services, there is a potential for error as a result of its non-compliance to Blondel's theorem when certain conditions of application are not met. Blondel's Theorem states that in a system of N conductors, N-1 meter elements, properly connected, will correctly measure the power or energy taken. The connection must be such that all potential coils have a common tie to the conductor in which there is no current coil. Also for the application of 2.5 element meters, users are advised of the potential for error due to zero sequence voltage.

Due to the above concern with 2.5 element metering, a national survey was completed by industry representatives of the Canadian Electricity Association and supported by Measurement Canada to determine the actual impact of 2.5 element metering on the Canadian market. The results of that survey were discussed by Measurement Canada and industry during the Canadian Forum on Trade Measurement in 2001 and a number of recommendations were agreed on to reduce the impact of this potential error. Subsequently, effective April 2, 2003;

(a) all new and

(b) all reconstruction of existing, 3-phase 4-wire wye configured metering installations shall use metering that is compliant to Blondel's theorem such as 3-element metering. An example of a reconstructed metering installation may include service upgrades and, or instrument transformer replacement."

Furthermore, there are environmental benefits of having dry-type metering units versus oil-filled units due to the fact that there is the potential for environmental hazards from oil leaks.
The purchase of spare and replacement meters and associated equipment is needed because of obsolescence and failure of existing units.

The 1,500 refurbished meters will be used to replace electromechanical meters that have been identified through previous compliance sampling test results to be reaching the end of their life cycle as demonstrated by declining accuracy. Compliance Sampling is a process where a sample is chosen from a group of meters based on homogeneity and group size. Once chosen and removed from service, these meters are tested at the Meter Shop and the test results recorded. The test results of meters identified for this project were found to be poor on at least two separate sampling occasions and need to be removed from service.

Future Plans:

This is the first year of a five year plan to ensure compliance to the Electricity and Gas Inspection Act and Regulations. This will be required to replace existing stock and maintain critical spares to cover requirements from 600 Volts to 25,000 Volts and from 25 to 1,000 Amps metering applications. See five-year Capital Plan (2011 Capital Plan Tab, Appendix A).

Project Title: Replace Digital Fault Recorder

Location: Bay d'Espoir

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is required to replace the existing fault recorder in Terminal Station 1 at the Bay d'Espoir Generating Station with a new Mehta Tech Transcan 32 channel digital fault recorder (DFR). The DFR records individual phase and equipment voltages and currents which can be reviewed after an electrical disturbance has occurred. This information assists Hydro in analyzing events and faults on the system to identify the cause of the disturbance and access the operation of the protective relays.

During commissioning, on site supervision will be provided by a manufacturer's representative to ensure the proper operation of the unit.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	58.1	0.0	0.0	58.1
Labour	65.2	0.0	0.0	65.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.3	0.0	0.0	12.3
O/H, AFUDC & Escln.	19.3	0.0	0.0	19.3
Contingency	13.6	0.0	0.0	13.6
TOTAL	**168.6**	**0.0**	**0.0**	**168.6**

Operating Experience:

The existing fault recorder has experienced failures since it was installed in 1992. It has passed the end of its useful life which is approximately 15 years. Some components such as batteries and hard drives have a shorter life of 5-12 years. The failures have caused the recorder to be out of service and present unreliable erratic data. Specific instances of these failures are:

- On five occasions the power supply has been faulty and has been required to be replaced three times to resolve such faults.
    - Power supply replaced January 2004 to resolve issue of printer continuously spooling paper (related to note below on printer fault).
    - Power supply replaced October 2003 to resolve issue of incorrect waveforms being received
    - Power supply fault caused improper indication reading. Power cycle resolved issue April 2004.
    - Power Supply fault causing DFR to not power on, December 2009.
    - Power supply failed and required replacement, July 2009 (related to note below on unavailability of correctly sized replacement power supply)
- Temporary solutions have been implemented twice due to the supplier no longer carrying the required spare parts.
    - Sensor failed and required replacement November 2006. Hathaway no longer carrying necessary part so failed sensor recalibrated and is still in use.
    - Power Supply failed and properly sized 120W replacement was unavailable. Installed 75W spare. Manufacturer notes this should be acceptable.

- Communication equipment was upgraded in October 2001 to fix a failure, as well as meet current standards.
- The printer, used for recording disturbances, has malfunctioned twice and been replaced once.
    - Printer continuously spooling paper, January 2004
    - Printer feed damaged resulting in frequent jams, August 2006.
    - Printer replaced April 2009 to resolve above issue.
- All the digital event calibration factors were erroneously reset through no action of the operators. Once re-entered further work was required to ensure the values were displaying correctly. The cause of the error was not determined as of August 2006 when this recalibration was completed.

Table 2 shows the locations where Hydro has previously installed the Mehta Tech digital fault recorders.

Table 2 – Historical Information

Date Installed	Location
2009	Massey Drive
2009	Oxen Pond
2009	St. Anthony
2008	Buchans
2005	Bottom Brook
2004	Holyrood
2004	Bay d'Espoir TS2
2002	Stony Brook
2001	Hinds Lake
2000	Sunnyside
1997	Western Avalon
1995	Plum Point
1994	Hardwoods

In addition to those listed above, Hydro received approval of its 2010 Capital Budget proposal to install a similar digital fault recorder at the Deer Lake Terminal Station. Historical costs of digital fault recorder installations in other terminal stations over the past five years are shown in Table 3.

Table 3 - Historical Cost Information

Year	Terminal Station Location	Budget ($000)	Actual ($000)	Units	Unit Cost
2010	Deer Lake	166.4			
2009	Massey Drive Oxen Pond and St. Anthony	461.9	328.5	3	109.5
2008	Buchans	130.0	104.2	1	104.2
2005	Bottom Brook	122.0	91.0	1	91.0

Project Justification:

The digital fault recorder in Powerhouse 1 at the Bay d'Espoir Generating Station needs to be replaced because it has become obsolete and unreliable.

The existing digital fault recorder was installed in 1992 and has passed its anticipated useful life. The new digital fault recorder represents modern technology and thus has more analysis and communication capabilities.

The availability of support and spare parts has become a major issue over the past three or four years due to the obsolescence of the existing type of fault recorder.

Functional problems with the recorder have caused it to output inaccurate readings or be brought out of service. A digital fault recorder is required to provide data for a complete analysis of a system disturbance. If the recorder is not operational, data pertaining to system disturbances are lost and cannot be recovered.

Future Plans:

Future digital fault recorder installations/replacements will be proposed in future capital budget applications.

Project Title: Install Sequence of Events Monitor in Diesel Plant

Location: Port Hope Simpson

Category: Transmission and Rural Operations - Generation Northern

Definition: Other

Classification: Normal

Project Description:

This project is required to install a Sequence of Events (SOE) and data acquisition system within the Port Hope Simpson diesel generating plant. The project will include the installation of a Remote Terminal Unit (RTU), a supervisory junction box and other auxiliary equipment such as relays and terminal blocks that will enable accurate time stamped data and historical trending capabilities in each of these plants. The RTU will contain 32 hard wired SOE inputs and will also be connected directly to the Programmable Logic Controllers (PLC) already installed in these plants. This direct connection will allow the RTU to access additional information from the existing Plant PLC Automation System. The RTU will also contain a remote uplink port that will enable this real time information to be collected and stored in a central database located at Hydro Place in St. John's. Access to this information will be available for maintenance crews, production crews, engineering services and system planning. This information will enable Hydro personnel to analyze the cause of an outage, to troubleshoot problems before total failures occur, trend diesel engine performances and statistics.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	33.7	0.0	0.0	33.7
Labour	67.5	0.0	0.0	67.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	21.9	0.0	0.0	21.9
O/H, AFUDC & Escln.	19.5	0.0	0.0	19.5
Contingency	12.3	0.0	0.0	12.3
TOTAL	**154.8**	**0.0**	**0.0**	**154.8**

Operating Experience:

The Port Hope Simpson Diesel Plant was constructed in 1995. The plant contains three diesel generating units whose specifications and ages are shown in Table 2.

Table 2: Plant Engine Overview

Diesel Engine Summary					Capacity	
Location	**Unit #**	**Model #**	**Genset (KW)**	**Install Date**	**Installed (kW)**	**Firm (kW)**
Port Hope Simpson	2073	Cat. 3456	455	2005	1365	910
	2042	Cat. 3412	455	1996		
	2043	Cat. 3412	455	1996		

Port Hope Simpson is a remote community located on the southeast coast of Labrador and is isolated from the Island and Labrador Interconnected Systems. The diesel plant is required to be in continuous operation since it is the only source of electrical generation for the community. Although the plant is fully automated to start and stop engines based on community loading, there is no SOE or data acquisition systems installed in the diesel plant.

During a system fault or an unexpected unit outage, there may be insufficient data to determine the source of the problem. This often leads to troubleshooting delays in identifying the cause. Since the diesel plant is automated and not fully attended on a twenty-four basis, the operator may be unable to tell exactly why an outage occurred, why a unit shut down or what actually happened inside the plant. For example, in a diesel plant, if a unit breaker tripped, the diesel engine could go into an overspeed condition resulting in a generating unit tripping off-line. Upon troubleshooting this problem, personnel would not know if the engine tripped due to an overspeed condition which caused the unit breaker to trip or if the unit breaker tripped resulting in the unit going into an overspeed condition. Sequence of event monitoring will accurately time stamp each of these events independently with one millisecond precision and will thereby enable operators and maintenance crews to know exactly what sequence of events took place leading to a failure.

Operators will often run an extra engine or a larger generating unit than what is normally required after a failure that resulted in a customer outage. This is a practice used to reduce the number of outages in the community while trying to determine the source of a problem.

In Port Hope Simpson, there are three diesel generators that enable operators to have the capability to appropriately size on line capacity to meet community loading. This practice ensures that diesel fuel is being burned as efficiently as possible. The Sequence of Events Monitoring System will enable Hydro personnel to more accurately trend total community loading versus the number and size of engines online to determine if the plant is being operated in the most efficient manner.

From a maintenance perspective, the engines are often operated until an alarm occurs, resulting in it being shut down by the Plant Automation System. There are currently no means available to trend process variables in real time. Using the SOE technology, Hydro personnel will have the capability to automatically trend key process variables over time and pinpoint potential failures before they occur. For example, coolant temperature is often a leading indicator that an engine is running hot and is about to fail. With the existing system, operators are not informed of an overheating issue until they received a high coolant temperature alarm which leads to the engine being shut down. With the proposed SOE system, personnel will have the capability to compare operational data from previous years to predict potential failures before engines or generating units actually fail. This ability will allow parts to be ordered in advance and will allow maintenance crews to foresee and correct potential deficiencies while on site rather than having to return to site later to fix a problem, thereby incurring extra cost.

When maintenance crews are called to site to fix a potential problem, they rarely know what to expect when they arrive. Oftentimes, the only information that is available is that an engine tripped or the community experienced an outage. Usually, maintenance crews after several hours or days of troubleshooting find the problem but need additional spare parts to fix it. The new SOE system will allow maintenance crews to have insight into the operating conditions that led up to a failure as well as the sequence of events during a failure. This will allow crews to pinpoint the source of a problem before going to site. In turn, using this system, the appropriate required tools and spare parts can be brought to site.

Project Justification:

This project is justified on the need to obtain more accurate information to improve the reliability of the operation of the diesel units in Port Hope Simpson. Table 3 lists the 2005 to 2009 average SAIFI and SAIDI data for Port Hope Simpson for all causes as compared to Loss of Supply outages[1]. SAIFI is

defined as the average number of sustained interruptions per consumer during a year and SAIDI is the average duration of sustained interruptions per consumer (measured in hours) during the year. Loss of Supply outages apply specifically to the loss of the diesel generating unit. The table also lists the 2005 to 2009 corporate value and the latest CEA five year averages (2004 to 2008) for comparison.

Table 3: Five Year Averages (2005 to 2009)

SYSTEM	All Causes		Loss of Supply[1]	
	SAIFI	SAIDI	SAIFI	SAIDI
Port Hope Simpson	8.88	4.81	7.40	2.93
Northern Isolated	7.49	6.02	5.22	1.80
Hydro Corporate	5.65	9.27	3.20	3.57
CEA Region 2 (2004 – 2008)	2.65	7.74	0.53	0.70

[1]Loss of Supply is defined by the CEA as:
Customer interruptions due to problems in the bulk electricity supply system such as underfrequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle. In this case it applies to the loss of the diesel plant.

A SOE and data acquisition system will enable operators and Hydro Personnel outside of the actual plant to fully understand what conditions led up to a failure or an outage. It will allow maintenance crews to fully understand what caused a trip and how a trip affected the rest of the system. An SOE and data acquisition system can ultimately reduce troubleshooting requirements, increase fuel efficiency in the community, extend the life of engines and reduce maintenance and travel costs. It also allows operations to trend historical data to predict future failures thereby potentially reducing the total number of generating related outages in the community.

Future Plans:

This is a three year program to upgrade the Port Hope Simpson Diesel Plant in the first year, Mary's Harbour Diesel Plant in the second year and St. Lewis Diesel Plant in the third year.

Project Title: Replace Fuel Storage Tank

Location: Francois

Category: Transmission and Rural Operations - Generation Central

Definition: Other

Classification: Mandatory

Project Description:

This project is required to purchase and install a 10,000 litre double wall, vacuum sealed fuel storage tank for the existing diesel plant in Francois, located on the south coast of the Province. Work includes installation of a new steel pipe 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. Minor site work may be required to level the site for the new tank.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	27.0	0.0	0.0	27.0
Labour	29.5	0.0	0.0	29.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	40.0	0.0	0.0	40.0
Other Direct Costs	8.8	0.0	0.0	8.8
O/H, AFUDC & Escln.	15.5	0.0	0.0	15.5
Contingency	10.5	0.0	0.0	10.5
TOTAL	**131.3**	**0.0**	**0.0**	**131.3**

Operating Experience:

When the Storage and Handling of Gasoline and Associated Products (GAP) Regulations were enacted in 1996, 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 diesel plant sites and place the existing tanks within the dykes. Since that time secondary containment has progressed to covered steel dykes and now double wall, vacuum sealed tanks which eliminate the need for steel dykes. The existing open dyke has a makeshift wooden cover to help prevent rain and snow entering the dyke. However, monitoring and maintenance is required to ensure

that the dyke does not fill up with rain and snow. The last visual inspection was carried out in 2003. At that time the tank was determined to be suitable to return to service. The existing tank was fabricated and installed in 1988 and has passed its useful life of 20 years. The tank is showing signs of deterioration mostly in the form of rusting, and should be replaced.

A similar project to install a 45,400 litre double wall, vacuum sealed fuel storage tank, including replacement of the existing fuel header system, in Cartwright, Labrador was completed in 2009. The budget for this project was $139,000 and the actual cost was $142,000. In addition, through the Fuel Storage Enhancement Program bulk storage tanks in Cat Arm, Upper Salmon (three sites), Burnt Damn/Ebbegunbaeg, and Hinds Lake have been replaced with double wall tanks.

Project Justification:

The existing tank was fabricated and installed in 1988. The steel dyke is of the old design, with a makeshift wooden cover to help prevent the accumulation of rain, snow, and ice in the dyke. However, rain and snow have penetrated the cover. The operators check the dyke as part of their daily inspections and accumulations of rain are removed as soon as practical through use of the dyke drain valve. Accumulation of snow and ice are more difficult to remove and are often left in the bottom of the dyke. The resulting accumulation reduces the capacity of the dyke which in turn makes it in non-conformance with GAP regulations. This project is justified on the need to have the fuel storage facility conform to the GAP regulations.

GAP 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 existing situation requires continuous observation and remedial action, as needed, which would be eliminated with the installation of the new double wall tank.

Future Plans:

None.

Project Title: Upgrade Fuel Storage

Location: Norman Bay

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Mandatory

Project Description:

This project is required to purchase and install a 20,000 litre double wall, vacuum sealed fuel storage tank at Hydro's diesel generating plant in Norman Bay, Labrador. Work includes modifications to the existing fuel header system to accommodate the new tank. This involves installation of new piping, pipe supports, painting, pressure testing of the new piping system, and installation of a new pressure treated timber foundation.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	29.5	0.0	0.0	29.5
Labour	22.5	0.0	0.0	22.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	35.0	0.0	0.0	35.0
Other Direct Costs	5.5	0.0	0.0	5.5
O/H, AFUDC & Escln.	12.0	0.0	0.0	12.0
Contingency	9.3	0.0	0.0	9.3
TOTAL	**113.8**	**0.0**	**0.0**	**113.8**

Operating Experience:

Currently there is 64,800 litres of on site fuel storage available at the Norman Bay Diesel Plant, which consists of two 32,400 litre fuel storage tanks. The tanks were installed in 2007 at a total cost of $164,000. The tanks were installed to replace two tanks that did not meet the requirements stipulated by the Storage and Handling of Gasoline and Associated Products (GAP) Regulations, 2003 regarding the tank dyke's ability to contain a potential leak. The latest fuel consumption projections are shown in Table 2 below, and indicate that current fuel requirements have exceeded the on site storage capacity.

Project Justification:

This project is justified on the need to have sufficient fuel storage to meet the energy requirements of Hydro's customers in Norman Bay. In isolated systems served by diesel generation, there must be sufficient fuel storage available on-site to last over the winter period for nine months. Ice conditions throughout winter and into spring prevent tankers from gaining access to the site, and therefore deliveries cease in the fall and do not recommence until the spring after the ice has broken up. The duration between fall and spring fuel deliveries can be as long as nine months. This criterion ensures that the system will have sufficient fuel on site to last over the winter between the fuel deliveries. Table 2 below shows the fuel storage forecast for Norman Bay as well as a comparison to the available fuel storage. As shown in Table 2 fuel requirements are expected to remain constant over the five-year period to the 2014/2015 winter season. Comparing the available fuel storage to the nine-month fuel storage forecast, there is an anticipated shortfall in fuel storage capacity of approximately 6,000 litres. Due to the violation of the nine-month fuel storage capacity criteria in 2010, Hydro recommends that a 20,000 litre double wall, vacuum sealed fuel storage tank be installed in 2011 to meet long term fuel storage requirements for the community. It is prudent to install a 20,000 litre tank rather than a smaller capacity tank to account for sensitivity to changes in the fuel forecast and the remoteness of the community. One additional customer would be a significant growth on this system. Also, based on Hydro's previous experience, the purchase of a lower capacity tank (example, 10,000 litres) would only be approximately $5,000 less which is not a significant cost to the overall project.

Table 2: Norman Bay Fuel Storage Forecast, Fall 2009

Year	9-month Fuel Usage (litres) (A)	Existing Storage Capacity (litres) (B)	Additional Storage Req'd (litres) (A) - (B)
2010 / 2011	70,800	64,800	6,000
2011 / 2012	70,800	64,800	6,000
2012 / 2013	70,800	64,800	6,000
2013 / 2014	70,800	64,800	6,000
2014 / 2015	70,800	64,800	6,000

An alternative to installing a new tank is the opportunity for a Conservation Demand Side Management (CDM) based capital deferral. This program explores the potential for conservation at

the customer level so that fuel consumption can be reduced, thereby deferring the capital expenditure of installing the new tank to a later date. This alternative was reviewed and it was determined that since the system has only a small customer base of 14 domestic customers, a CDM program could not provide enough of a reduction in consumption to guarantee the success of the program. Therefore, CDM is not a viable alternative in this instance.

Future Plans:

None.

Project Title: Legal Survey of Primary Distribution Line Right of Way

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

Newfoundland and Labrador Hydro (Hydro) owns and operates approximately 2,250 km of distribution lines located on Crown land, which is owned by the provincial government.

In 2004, Hydro initiated a program to obtain easements on the land on which these lines are located. Since 2004, a total of 863 km of distribution line has been surveyed and is being processed through the Department of Environment and Conservation, Lands Division (Crown Lands). Table 3 provides the details of the length of lines surveyed to date. This project is required to continue the program to acquire legal surveys and prepare documentation to acquire Crown Land easements for approximately 180 km of primary distribution line in operation throughout the Province.

Easements are granted for a term of 50 years. Hydro can renew the easements granted for a further period of 50 years if the renewal is requested in writing before the expiration of the existing easement.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	1.5	0.0	0.0	1.5
Labour	54.5	0.0	0.0	54.5
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.	9.6	0.0	0.0	9.6
Contingency	6.3	0.0	0.0	6.3
TOTAL	**78.7**	**0.0**	**0.0**	**78.7**

Operating Experience:

Older distribution lines were constructed without obtaining easements. The effort to obtain easement title to the primary distribution lines on Crown Land began in 2004. Assuming continued funding, title for the distribution systems located on Crown Land will be in place by the end of 2015.

Table 2 shows the history of expenditures for this project for the past five years and Table 3 shows the length of lines surveyed to date.

Table 2: Budget History

Year	Budget ($000)	Actual ($000)
2010F	65.4	
2009	56.0	54.5
2008	52.0	54.0
2007	50.8	47.9
2006	49.9	51.2
2005	49.6	93.4[1]

[1] Additional costs were required to obtain the surveys for Nain, Hopedale, Postville, Makkovik and Rigolet. This work was originally planned for future years.

Table 3: Length of Lines Surveyed

Year	Length (km)	Comments
2004-2006	350	Baie Verte Area (Four Distribution Systems Completed)
2007	160	Northern Distribution Lines
2008	43	Northern Distribution Lines
2009	150	Northern Distribution Lines
2010	160	

In 2007, Crown Lands performed a review of the Hydro surveys, which were completed by an outside consultant during the period 2004 through 2006. Hydro's surveys required editing to comply with current Crown Lands Standards, and in 2008, Hydro spent much of the approved capital budget to have Hydro's outside consultant edit and correct these drawings for re-submission to Crown Lands. Issues included surveying roads and including them in the drawings, adding a legend on the drawings, and editing features to make them more distinctive. Due to Sections 33 and 34 of the Land Surveyors Act, 1991, Hydro could not use its own surveyors to make corrections to these drawings. The Land

Surveyors Act, 1991, Section 33, Use of Seal states that "A Land Surveyor shall not affix his or her seal to a plan or document prepared in the practice of land surveying unless the plan or document was prepared by or under the personal supervision, direction or control of that Land Surveyor." Furthermore, Section 34, Survey Plan Documents, states that "(1) A master plan and duplicates of all survey plans, records and documents prepared by or under the direction of a Land Surveyor shall be retained by that Land Surveyor; (2) A person shall not, without the prior written consent of the Land Surveyor who prepared a land survey plan, alter, add to or delete from that plan or a copy or reproduction of that plan; and (3) A person who contravenes subsection (2) commits an offence."

There are approximately 2,250 kilometers of distribution lines for which Hydro has no title. Applications for title to surveyed lines have been submitted to Crown Lands and are currently being processed. Since 2004, 863 kilometers of distribution line has been surveyed. The legal surveys are being completed and obtaining title is currently in progress for these surveyed lines.

Project Justification:

The distribution lines occupy Crown land without title, contrary to the Crown Lands Act. Lack of adequate title is a risk to the operation of the lines should competing requirements for the lands arise. In addition, maintenance and upgrading of the lines could be cumbersome and costly without appropriate legal easements when these lands become privately owned. Property owners are reticent to have Hydro accessing their land. The sole purpose of these surveys is to obtain easements over Crown Land to prevent other parties from getting title to the land, thereby potentially complicating maintenance of the lines.

Upon purchase of Crown Land, a resident receives title and it becomes private land. Although Hydro's access to Crown Land has not been directly challenged, private land owners have requested Hydro to move poles and lines off private land in instances where Hydro has not acquired easements. Hydro has obliged since it has no right to cross the land to access the poles and lines.

Maintaining the status quo is unacceptable. In the absence of title, other parties may be able to construct, develop or otherwise use the property on which Hydro's lines are located without Hydro being consulted. Obtaining title ensures that developments do not interfere with Hydro operations.

Future Plans:

Approximately 1,387 kilometers of distribution lines remain to be surveyed. Table 4 presents Hydro's future plan for surveying lines.

Table 4: Length of Lines to be Surveyed

Year	Budget ($000's)	Length Surveyed (Km)	Length to be Surveyed (Km)
2011	78.7	180	1,207
2012	155.1	360	847
2013	159.6	360	487
2014	164.1	360	127
2015	88.0	127	0

Future projects for legal surveys will be proposed in future capital budget applications. See five-year plan (2011 Capital Plan Tab, Appendix A).

Project Title: Install Waste Oil Storage Tank

Location: St. Lewis

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Mandatory

Project Description:

This project is required to purchase and install a 5,000 litre, double wall, vacuum sealed waste oil storage tank for the diesel plant in the Southern Labrador community of St. Lewis. Work will also include the installation of a steel pipe header system from the waste oil storage tank to the diesel units inside the plant. The header will be constructed as a double wall system for secondary containment of the primary line, complete with a leak detection device on the secondary containment. Lube oil transfer pumps will also be purchased and installed in the header systems to pump the used oil from the engines to the storage tanks. Low oil level indication and cut-out switches will also be installed to provide pump protection.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	12.5	0.0	0.0	12.5
Labour	27.5	0.0	0.0	27.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	12.0	0.0	0.0	12.0
Other Direct Costs	10.8	0.0	0.0	10.8
O/H, AFUDC & Escln.	9.4	0.0	0.0	9.4
Contingency	6.3	0.0	0.0	6.3
TOTAL	**78.5**	**0.0**	**0.0**	**78.5**

Operating Experience:

Hydro's preventive 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 St. Lewis produces 1,400 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 an 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.

Table 2 provides a list of waste oil storage tank installations that have been approved by The Board of Commissioners of Public Utilities (Board). Hydro received its latest approval from the Board under Board Order No. P.U. 1 (2010) to install a similar waste oil storage tank in Port Hope Simpson in 2010 with a budget of $84,100.

Table 2: Historical Information

Project Cost: *($ x1,000)*	**Year**	**Budget**	**Actual**
Port Hope Simpson	2010F	84.1	
Mary's Harbour	2009	84.2	70.4
Charlottetown	2008	45.6	54.4
Cartwright	2008	53.3	61.7

Project Justification:

This project is justified on the need to comply with environmental regulations regarding the storage of used oil. 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 (2011 Capital Plan Tab Appendix A).

Project Title: Replace Surge Arresters

Location: Various Sites

Category: Transmission and Rural Operations – Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project consists of the purchase and installation of replacement surge arresters at various Hydro terminal stations on the Island Interconnected System. These units are in the 66, 138 and 230 kV classifications.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	52.7	0.0	0.0	52.7
Labour	9.6	0.0	0.0	9.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	6.0	0.0	0.0	6.0
Contingency	6.2	0.0	0.0	6.2
TOTAL	**74.5**	**0.0**	**0.0**	**74.5**

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.. Hydro has approximately 440 surge arresters in service in all three voltage classes ranging in age from one year to approximately 40 years.

Table 2 shows the history of expenditures for this project for the past five years.

Table 2: Budget History

Year	Budget ($000)	Actual ($000)	Units	Average Unit Cost ($000)
2010F	73.4		12	
2009	81.1	80.0	15	5.3
2008	67.1	73.5	21	3.5
2007	71.3	84.8	9	9.4
2006	70.0	66.9	24	2.8
2005	68.4	79.7	21	3.8

Project Justification:

Surge arresters provide critical overvoltage protection of power system equipment from lightning and switching surges. When the arresters fail they are not repairable. Replacement is the only option available. Surge arresters are regularly inspected and tested, and replacements are made based on these maintenance assessments as well as in-service failures. When a surge arrester fails, it must be replaced immediately, otherwise the major equipment is exposed to serious damage from lightning surges. Failure of any major equipment will result in major system disturbances which could result in system outages and interruption of service to customers.

Future Plans:

Future replacements will be proposed in future capital budget applications. Surge arrester replacements are planned for the next four years as shown in the five year plan (2011 Capital Plan Tab, Appendix A)

Project Title: Purchase Portable Dissolved Gas Analysis Unit

Location: Bishop's Falls

Category: Transmission and Rural Operations - Tools & Equipment

Definition: Other

Classification: Normal

Project Description:

This proposal is required to purchase one Portable Dissolved Gas Analysis (DGA) unit. This test set will be used to provide immediate information to field staff to help make decisions to either remove or keep transformers in service.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
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.	1.6	0.0	0.0	1.6
Contingency	0.0	0.0	0.0	0.0
TOTAL	**51.6**	**0.0**	**0.0**	**51.6**

Operating Experience:

When a transformer is suspected of having combustible gases present in its insulating oil an outside laboratory is currently used to test oil samples for dissolved gases. The oil samples are delivered to an airport and flown to Morgan Schaffer‘s laboratory in Montreal for testing. The results are then emailed or placed in an online database for viewing by Hydro Operations personnel. Due to flight delays and samples being lost by the Airline carrier this process can, at times, take up to two days, which can delay a critical transformer from going back in service.

Project Justification:

A portable DGA unit would be an invaluable tool during forced outages of transformers when gas is detected in the insulating oil. This unit can be used to take samples and have the results available

within hours which will help with decisions to take transformers off line or keep the unit online with further sampling. In recent years there have been numerous examples where the use of this unit would have allowed more timely decisions to be made during transformer gassing problems. The information provided by this test set would assist in providing the information required to determine the course of action in making repairs to a transformer when gas is detected, which could also reduce outage times. Listed below are examples of transformer problems that were delayed awaiting the DGA results from the outside laboratory.

- Transformer T5 (the main transformer for the Hardwoods Gas Turbine) at Hardwoods Terminal Station (March 7th, 2010) - During normal operation, gas was detected by the gas relay and the transformer was taken offline. Samples were taken and flown to the lab in Montreal via Air Canada. The carrier misplaced the samples but later found them resulting in a delay in determining the best course of action to repair the transformer. From the time gasing was discovered to the time results were accessed approximately 48 hours had elapsed. Also once the repair was made and the transformer was placed back into service more samples were taken to confirm the effectiveness of the repair. Information was again delayed by 24 to 36 hours.
- Transformer SS1 at Upper Salmon (January 26, 2009) - During operation gas was detected and the unit taken offline. Samples were sent to the lab and results obtained approximately 30 hours later. The results showed that the gassing was due to a blockage in the conservator pipe which caused air to accumulate in the gas relay. Repairs were made and the transformer put back in service.
- Transformer GT1 at Massey Drive: (Feburary 10, 2009) - During normal operation gas was detected and the unit taken offline. Samples were sent to the lab and results obtained approximately 24 hours later. The results showed that the gassing was due to low oil level which led to repairs to the conservator and oil was added.
- Transformer T1 at Upper Salmon (May 20, 2007) - Gassing was discovered shortly after replacing a low voltage bushing. The unit was taken offline and samples sent to the lab. The results showed air accumulation possibly from air trapped after the replacement and the air was bled off the transformer. The results were received approximately 48 hours after the discovery of gas. This was a very critical situation as this unit transformer was keeping an 88 MVA generator offline as well.

In general when responding to gassing issues on transformers this portable DGA unit would allow analysis within four or five hours. This would considerably reduce outage times compared to the current procedure and provide a means of on site trending and aid in decision making for maintenance staff.

Future Plans:

None.

Project Title: Replace Radomes

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Pooled

Classification: Normal

Project Description:

To reduce the probability of system outages resulting from radome failure, Hydro has initiated a radome replacement program for the microwave antennas of the corporate network. This is an ongoing program to replace microwave antenna radomes, the protective covers that enclose the delicate components of the microwave antennas in Hydro's microwave radio system. The radome replacement program proposed by Hydro is based on operational experience and manufacturer's recommendation. Due to financial and operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimal.

Radomes are replaced at different sites throughout the network each year, depending on age and condition. The radome replacement schedule for 2011-2015 is provided in Appendix A. Ten radomes are scheduled to be replaced in 2011. Historically, this project has been performed through the joint effort of an external contractor who performs the actual work and internal forces that perform project management and provide technical support. This joint effort will be continued in 2011.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	31.6	0.0	0.0	31.6
Labour	43.5	0.0	0.0	43.5
Consultant	12.0	0.0	0.0	12.0
Contract Work	62.0	0.0	0.0	62.0
Other Direct Costs	7.1	0.0	0.0	7.1
O/H, AFUDC & Escln.	24.1	0.0	0.0	24.1
Contingency	15.6	0.0	0.0	15.6
TOTAL	**195.9**	**0.0**	**0.0**	**195.9**

Existing System:

Hydro has a network of microwave radio, by which corporate communications and system data are transmitted. The microwave radio system provides the backbone for all corporate voice and data communications. Traffic carried over the microwave system includes:

- Teleprotection signals for the provincial transmission system;
- Data pertaining to the provincial Supervisory Control and Data Acquisition (SCADA) system;
- Data pertaining to the corporate administrative system; and
- Operational and administrative voice systems.

Microwave radio signals are transmitted from one location to the next using parabolic antennas attached to towers. These antennas are mounted up to heights of 120 meters and range in diameter from 2 meters to 5 meters. At such extreme heights, the antennas are subjected to high wind and ice loading when storms occur, and must be protected. To provide this protection, the delicate components of the antennas responsible for sending and receiving microwave radio signals are covered using a shell known as a radome. These covers are made of advanced plastics known as Hypalon and Teglar that prevent the accumulation of ice and snow which could bend or break these elements. The white cover illustrated in Figure 1 is an example of a radome on an uninstalled antenna.



Figure 1: Microwave Antenna with Radome

Damage to radomes can occur in several ways. Exposure to wind, sun, rain, and ice causes the radomes to deteriorate over time. When the radome weakens, tears form in the fabric, as shown in Figure 2. Left unchecked, the tears quickly grow in size (Figure 3) and the material can be torn free by wind. Such tears may result in severe damage to the delicate antenna components.

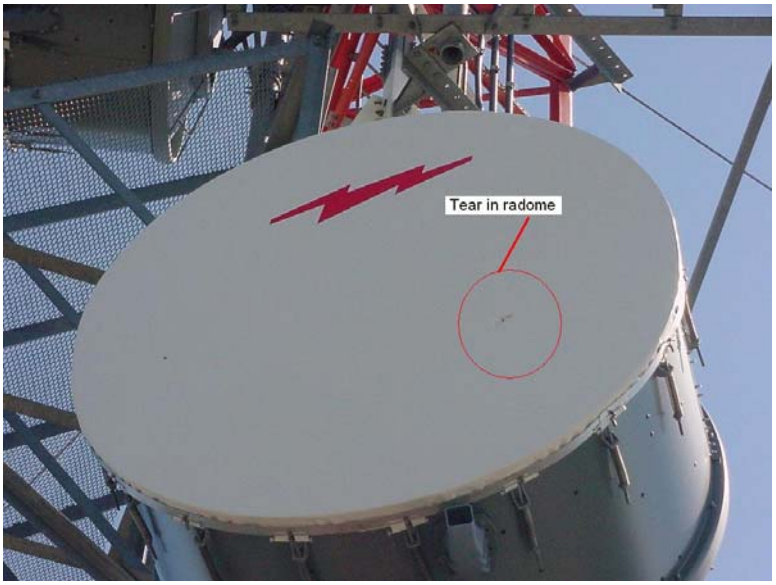

Figure 2: Tear in Radome



Figure 3: Heavily Damaged Radome

Other modes of failure are less common. Ice falling from the tower can damage radome components, such as the hardware that hold the radome in place, as shown in Figure 4. Vandalism by the use of

shotguns, rocks, or other projectile has also occurred at sites that are accessible by road. Each of these occurrences has the potential to damage the radome and make it prone to complete failure.

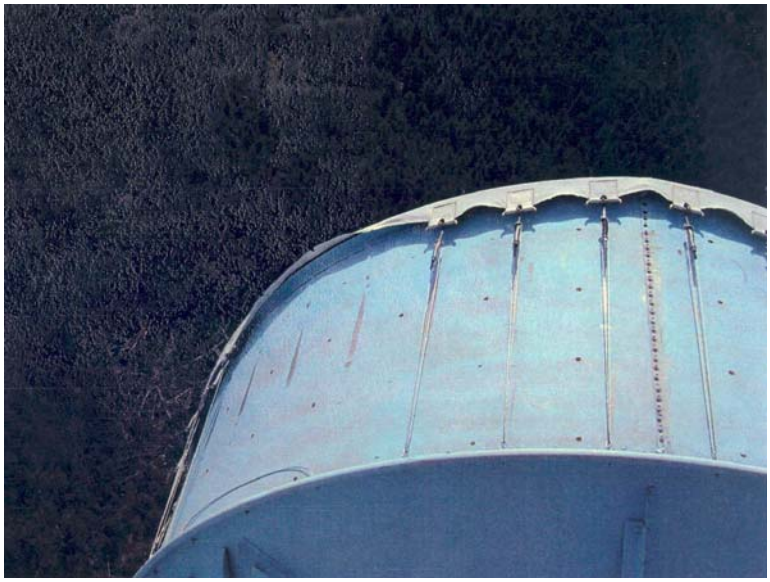

Figure 4: Missing Radome Mounts

There are 80 radomes throughout Hydro's system. They are installed on towers from St. John's to Deer Lake, and south to Bay d'Espoir. Figure 5 shows Hydro's Telecommunication Network.

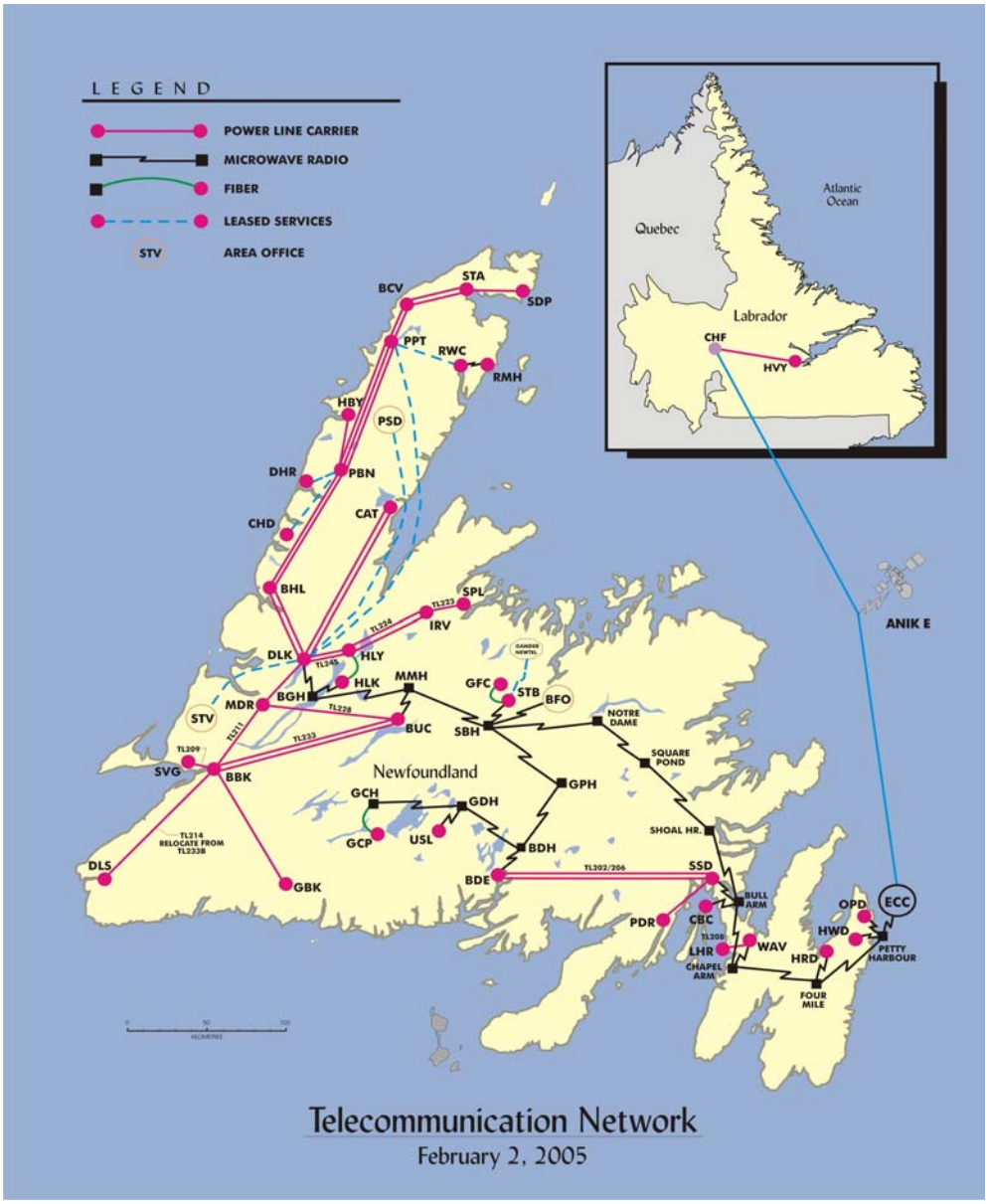

Figure 5: Location of Towers

Age of Equipment

Refer to the Installed/Last Replaced column of Appendix A for the ages of the radomes being replaced.

Major Work and/or Upgrades

There are no upgrades available for a radome. They must be replaced based upon the estimated useful life of the individual radome or upon observed damage during inspection.

Anticipated Useful Life

Hydro's microwave antennas are supplied primarily by two manufacturers, Andrew Solutions and CableWave. Each manufacturer uses a different radome. Radomes used on antennas manufactured by CableWave have a useful life of seven years, and the radomes used on Andrew antennas have a useful life of eight years.

For calculating depreciation expense, radomes are assumed to have an economic life of ten years.

Maintenance History

Radome maintenance consists of inspection when the tower is inspected. Because radomes cannot be repaired, damaged radomes are replaced when identified.

Outage Statistics

In the winter of 1996, a wind storm caused a significant and sustained outage to a part of Hydro's communications network as a result of the failure of two separate radomes at the Sandy Brook Hill and Mary March Hill Microwave Sites. Despite routine inspections, the radomes were torn and the material of the shells became entangled in the antenna feed horns. As a result, critical components at both sites were irreparably damaged and the antennas required replacement. Once the storm cleared and the cause of the outage was identified, antennas could not be replaced until three weeks later, due to lead times associated with material procurement and weather related delays.

In total, the microwave radio system was out of service for approximately six weeks. During that time, temporary leased services were procured and installed, resulting in unanticipated labour and materials costs.

Industry Experience

Industry experience information is not available.

Maintenance or Support Arrangements

There are no maintenance or support arrangements associated specifically with radomes. Radome inspection is included as part of an overall periodic tower inspection which occurs annually.

Vendor Recommendations

As a result of the costs and outage time associated with the 1996 storm, personnel from Hydro consulted with manufacturers to develop a proactive radome replacement plan. Based on discussions with representatives from radome manufacturers Andrew Solutions and CableWave, the following conclusions were met:
CableWave radomes (made of Hypalon material) should be replaced on a seven-year cycle;
Andrew Solutions radomes (made of Teglar material) should be replaced on an eight-year cycle.

Andrew Solutions radomes, with a slightly longer life, cannot be substituted for CableWave radomes on CableWave antennas on account of the structural differences associated with each type of antenna.

Availability of Replacement Parts

A radome consists of one piece of material with mounting hardware to connect it to an antenna. Mounting hardware is available should a piece be found missing or damaged. If a radome must be replaced, the mounting hardware is typically not re-used on account of wear and tear.

Safety Performance

There is no known safety performance issues associated with the radomes.

Environmental Performance

There are no environmental performance concerns or environmental code violations associated with the operation of microwave radomes.

Operating Regime

A microwave antenna, and by extension its radome, is in continuous use and has a 100 percent duty cycle.

Justification:

One of the challenges associated with the development of the radome replacement schedule is that many of Hydro's microwave sites were installed in the same year. For example, during the installation of the East Cost Microwave System in 2001, approximately 20 antennas were installed. To avoid the financial and logistical challenges that would be created by replacing each of these radomes in the same year, Hydro decided that the replacement program for these sites would be distributed over seven years, from 2007 – 2013 with the program continuing beyond 2013 as required.

The decision to distribute the replacement of radomes presents another obstacle: some radomes will be left in service for periods longer than recommended. In response to this issue, Hydro has initiated an inspection program that allows for the identification of radomes which are torn or otherwise damaged, as illustrated in Figure 2. These radomes must be replaced as soon as the damage is identified to ensure that the integrity of the microwave system is maintained.

The cost of a microwave failure today would be far more significant than the incident of 1996 due to the fact that teleprotection signals, which protect transmission lines in the event of a system disturbance, are now transmitted using the microwave network. Today, protection signals for 17 of Hydro's 24 critical 230 kV transmission lines are carried on the microwave network. Because of this, a microwave failure would cause the Energy Control Centre to lose control of the system stations and likely cause and/or extend customer outages.

Net Present Value

A net present value calculation has not been done as there is no viable alternative to replacing the radomes.

Levelized Cost of Energy

As the radomes are not related to generating units, the levelized cost of energy is not applicable.

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 associated with radome replacement.

Historical Information

Table 2 shows the historical information for the Radome Replacement Program which commenced in 2007.

Table 2: Capital Budget and Expenditures for the Last Five Years

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2010F	195.9		12		
2009	129.7	110.5	9	12.3	
2008	123.8	111.0	9	12.3	
2007[2]	26.9	9.2	1	9.2	Labour only. No replacement.

Forecast Customer Growth

Radomes are not impacted by forecast customer growth.

Energy Efficiency Benefits

There is no projected energy efficiency benefits related to the replacement of radomes.

Losses During Construction

There is no system outage required for this project.

Status Quo

The status quo is unacceptable. Allowing radomes to stay in service until failure will cause protracted outages on Hydro's communications system and will increase the likelihood of power system outages.

[2] First year of replacement program.

Alternatives

No viable alternatives exist to radome replacement.

Conclusion:

Hydro's Radome Replacement Program is necessary in order to prevent outages caused by radome damage.

The radome replacement program proposed by Hydro is based on operational experience and manufacturer's recommendations. Historically, this project has been executed by external contractors and supported by internal resources and this joint effort will continue in 2011.

Due to financial and operational risks associated with the failure of corporate microwave equipment, this project is a proactive approach to ensuring that the likelihood of failure of microwave antenna radomes is minimal.

Project Schedule

The proposed project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Milestone
Project Initiation	February 2011
Installation & Commissioning Complete	October 2011
Project Closed	November 2011

Future Plans:

Future replacements will be proposed in future capital budget applications. Radom replacements are planned for the next three years as shown in the five-year capital plan (2011 Capital Plan Tab, Appendix A).

APPENDIX A

2011-2015 Radome Replacement Schedule

2011 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
STB	SBH	2001	1.8m(6')	CW	DA6-71hp
MMH	BUC	2001	1.8m(6')	CW	DA6-71hp
BAH-main	SHH-main	2004	2.4m(8')	Andrew	HP8-71GE
BAH-div	SHH-div	2004	2.4m(8')	Andrew	HP8-71GE
CBC	BAH	2001	1.8m(6')	Andrew	HP6-71E
SSD	BAH	2001	1.8m(6')	Andrew	HP6-71E
WAV	WAP	2001	1.8m(6')	Andrew	HP6-71E
FMH-main	PHH-main	2001	3.0m(10')	Andrew	HP10-71D
PHH	HWD	2001	1.8m(6')	Andrew	HP6-71E
PHH	OPD	2001	1.8m(6')	Andrew	HP6-71E

2012 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
GDH-main	GCH-main	2004	3.0m(10')	Andrew	HP10-71D
GDH-div	GCH-div	2004	2.4m(8')	Andrew	HP8-71D
GDH	USL	2004	3.0m(10')	CW	DA10-71hp
GDH	BDH	2004	3.0m(10')	CW	DA10-71hp
GCH-main	GDH-main	2004	3.0m(10')	Andrew	HP10-71D
GCH-div	GDH-div	2004	2.4m(8')	Andrew	HP8-71D
DLK	DLP	2001	4.5m(15')	Gabriel	SR15-71B
BFI	SBH	2004	2.4m(8')	Andrew	HP8-71GE
NDH-main	SPH-main	2004	3.6m(12')	Andrew	HP12-71E
NDH-div	SPH-div	2004	3.6m(12')	Andrew	HP12-71E
NDH-main	SBH-main	2003	3.6m(12')	Andrew	HP12-71E
NDH-div	SBH-div	2003	3.6m(12')	Andrew	HP12-71E
HRP	FMH	2001	2.4m(8')	Andrew	HP8-71D
OPD	PHH	2001	1.8m(6')	Andrew	HP6-71E

2013 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
SHH-main	SPH-main	2003	3.6m(12’)	Andrew	HP12-71E
SHH-div	SPH-div	2003	3.6m(12’)	Andrew	HP12-71E
SHH-main	BAH-main	2003	2.4m(8')	Andrew	HP8-71GE
SHH-div	BAH-div	2003	2.4m(8')	Andrew	HP8-71GE
MMH	BGH	2004	2.4m(8')	CW	DA8-71hp
MMH	SBH	2004	3.6m(12')	CW	DA12-71hp
BGH	DLP	2004	3.6m(12')	CW	DA12-71hp
BGH	MMH	2004	2.4m(8')	CW	DA8-71hp
SPH-main	NDH-main	2004	3.6m(12')	Andrew	HP12-71E
SPH-div	NDH-div	2004	3.6m(12')	Andrew	HP12-71E
SPH-main	SHH-main	2004	3.6m(12')	Andrew	HP12-71E
SPH-div	SHH-div	2004	3.6m(12')	Andrew	HP12-71E
ECC	PHH	2001	1.8m(6')	Andrew	HP6-71E
HWD	PHH	2001	2.4m(8')	Andrew	HP8-71E

2014 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
BDH	GPH	2006	1.8m(6')	CW	DA6-71hp
BDH	GPH	2006	2.4m(8')	Andrew	HP8-71D
BDH	BDE	2006	1.8m(6')	CW	DA6-71hp
BDH	GDH	2006	3.0m(10')	CW	DA10-71hp
BDE	BDH	/006	1.8m(6')	CW	DA6-71hp
SBH	MMH	2004	3.6m(12')	CW	DA12-71hp
MMH	SBH	2006	3.0m(10')	Andrew	HP10-71D
HLP	HLK	2007	2.4m(8')	CW	DA8-71hp
HLP	BGH	2007	2.4m(8')	CW	DA8-71hp
HLK	HLP	2007	1.8m(6')	CW	DA6-71hp

2015 Radome Replacement

Antenna Site	Antenna Direction	Installed/ Last Replaced	Diameter	Manufacturer	Model Number
SBH	NDH-main	2003	3.6m(12')	Andrew	HP12-71E
SBH	NDH-div	2003	3.0m(10')	Andrew	HP10-71D
SBH	BFI	2003	2.4m(8')	Andrew	HP8-71GE
BUC	MMH	2008	1.8m(6')	CW	DA6-71hp
BGH	HLP	2008	2.4m(8')	CW	DA8-71hp

Project Title: Upgrade Enterprise Storage Capacity

Location: Hydro Place

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project is required to provide an additional five terabytes (TB) of disk storage to the existing DS4800 Storage Area Network (SAN) to serve the Intel Enterprise Servers and to add a second DS5100 SAN Controller and five TB of disks to the system. The existing DS4800 SAN was installed in 2008 to provide the efficient management and growth of the disk storage for the Intel Enterprise Servers. This unit is now nearing its maximum capacity and provisions are required to provide Hydro with the capacity to anticipate and mitigate the data growth.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	150.0	0.0	0.0	150.0
Labour	30.0	0.0	0.0	30.0
Consultant	20.0	0.0	0.0	20.0
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.	6.6	0.0	0.0	6.6
Contingency	20.0	0.0	0.0	20.0
Subtotal	**226.6**	**0.0**	**0.0**	**226.6**
Cost Recoveries	**(72.5)**	**0.0**	**0.0**	**(72.5)**
TOTAL	**154.1**	**0.0**	**0.0**	**154.1**

Operating Experience:

Disk capacity has grown at a rate of approximately 40 percent per year over the last two years and is projected to grow at this rate or faster into the future. This is slightly below the industry standard growth rates (50-70 percent per year). Storage Resource Management Tools, installed in 2007, allow Hydro to effectively manage data and disk usage.

As this budget involves the upgrade of an existing piece of software the following items are not considered relevant to the proposal:

- Outage Statistics;
- Industry Experience;
- Vendor Recommendations;
- Availability of Replacement Parts;
- Safety Performance;
- Environmental Performance; and
- Operating Regime.

Age of Equipment or System

The DS4800 SAN is three years old.

Major Work/or Upgrades

The upgrades listed in Table 2 have occurred since installation. Costs associated with these upgrades are shown in Table 3 of the Historical Information section of this report.

Table 2: Major Work and Upgrades

Year	Major Work/Upgrade	Comments
2010F	Capacity Increase	Additional Disk storage space installed
2008	Additional SAN installed	Additional disk storage space installed.
2007	Tivoli Productivity Center (TPC) installed	A storage management toolset was purchased and installed to allow better management of the SAN.

Anticipated Useful life

The disk capacity expansion for the DS4800 will have an estimated service life of six years.

Maintenance or Support Arrangements

The Disk Drives for the DS4800 will be covered by the current maintenance agreement with IBM. The maintenance agreement will cover hardware failures.

Justification:

The servers that are attached to the Storage Area Network are used by Hydro employees in running the business on a daily basis. A reduction in the performance of these servers due to unavailable disk space would negatively affect employee productivity and customer service. The additional disk capacity added to the DS4800 SAN will provide for the efficient management and growth of the disk storage for the Intel Server Infrastructure.

As this budget proposal is for an upgrade for an existing piece of hardware the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Energy Efficiency Benefits; and
- Losses during Construction.

Legislative or Regulatory Requirements

The Management of Information Act and Statute of Limitations Act require Hydro to retain relevant data for a six year period. This requires systems to be backed up regularly onto tapes for off-site storage. Hydro's policy is to retain this data for a period of seven years.

Forecast Growth

The projected data growth for the storage system is approximately 40 percent per year with data remaining at current anticipated levels.

Net Present Value

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

Cost Benefit Analysis

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

Historical Information

Table 3 shows the historical costs of the Storage Area Network.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2010F	241.4		5TB capacity increase and replace 8 LTO-4 Tape Drives
2009	0.0	0.0	No capacity increase required
2008	261.7	260.8	Installed DS4800 SAN
2007	148.6	148.6	Management Tool Set
2006	0.0	0.0	No capacity increase required
2005	463.5	463.5	SAN Disk and Tape Library Expansion

Status Quo

If the Disk capacity of the DS4800 SAN is not increased Hydro could run into disk space limits which would degrade the performance of the system and the productivity of employees.

Alternatives

There are no viable alternatives that can be incorporated into the existing system.

Project Schedule

The project is scheduled to start in February 2011 and be completed by the end of June 2011.

Future Plans:

Future upgrades will be proposed in future capital budget applications. Enterprise storage upgrades are planned for the next four years as shown in the five year plan (2011 Capital Plan Tab, Appendix A).

Project Title: Upgrade Server Technology Program

Location: Hydro Place

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project is a part of the Server and Operating System Evergreen Program which involves the replacement, addition and upgrade of hardware components and software related to Hydro's server infrastructure and upgrades to the server-based office productivity tools.

The scope of the proposed project includes the replacement of 18 servers.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	135.0	0.0	0.0	135.0
Labour	30.0	0.0	0.0	30.0
Consultant	20.0	0.0	0.0	20.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	5.9	0.0	0.0	5.9
Contingency	18.5	0.0	0.0	18.5
Sub-Total	**209.4**	**0.0**	**0.0**	**209.4**
Cost-Recoveries	**(67.0)**	**0.0**	**0.0**	**(67.0)**
TOTAL	**142.4**	**0.0**	**0.0**	**142.4**

Operating Experience:

There are approximately 130 servers 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 Hydro staff in running the business on a day to day basis.

Based on the age of existing servers, each year an appropriate number of servers will be replaced. This ensures that the Corporation has a reliable and secure infrastructure environment required to support efficient operations.

As this budget proposal is for the routine replacement of hardware and software related to the corporations shared server infrastructure, the following items are not relevant to this proposal:

- Major Work / Upgrades;
- Maintenance History;
- Outage Statistics;
- Safety Performance; and
- 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 may become problematic. Hydro has a replacement cycle of six to seven years for all but the most critical servers. These are replaced on a five year cycle.

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

IBM support has been discontinued for the 18 servers to be replaced. Hydro has determined that the standard three year manufacturer warranty is not sufficient for its Intel Server Infrastructure. Therefore, all servers, beginning in 2010, are purchased with a five year manufacturer warranty. When the existing warranty expires, the servers will be placed on a year by year maintenance contract with IBM.

Vendor Recommendations

IBM recommends that servers be replaced in a five year lifecycle.

Availability of Replacement Parts

Parts may not be available after five years for the 18 servers to be replaced depending on the component that fails.

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:

This project is justified on the need to continue providing reliable computer service. The factors driving the replacement or upgrade of Hydro's server environment include:

- Addressing obsolescence/maintaining vendor support;
- Providing security/managing the infrastructure; and
- Supporting current versions of applications.

Addressing obsolescence/maintaining vendor support:

Without vendor support, the functions and services reliant on the server infrastructure are at risk as security and support patches for the operating system will no longer be available. As a result, Hydro's ability to support and ensure continuation of these functions and services is impeded. At this time, the vendor support and inventory of spare parts are discontinued. As the servers are used by Hydro employees to provide support in running the business on a daily basis, loss of availability of these servers would have a negative effect on employee productivity by not allowing access to software applications.

Providing security/managing the infrastructure:

As technology advances, there are built-in architectures and devices that improve the security of the servers and allow for better management of them.

Supporting current versions of applications:

As applications are upgraded and new applications implemented throughout the organization, many are built to take advantage of technologies only present in the newer servers. An example would be an application built to take advantage of the new Hyper-threading Technology, if it is present, would have an increased processing speed.

As this budget proposal is for the routine replacement of hardware and software related to the Corporations shared server infrastructure, the following items are not relevant to the justification of this proposal:

- Levelized Cost of Energy;
- Legislative or Regulatory Requirements;
- Forecast Customer Growth;
- Energy Efficiency Benefits; and
- Losses during Construction.

Net Present Value

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

Cost Benefit Analysis

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

Historical Information

Table 2 shows the historical costs of the Server and Operating System Evergreen Program.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Unit Cost ($000)[1]
2010F	196.6			
2009	272.6	272.6	14	19.5
2008	249.2	249.2	21	11.9
2007	81.8	81.8	5	16.4
2006	0.0[2]	0.0	0	0.0

[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 evergreen program was deferred by a year.

Status Quo

Hydro must keep its servers current in order to adequately support and protect the Information Technology infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned outages, possible data loss, and data corruption. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

Alternatives

The alternative to a server refresh program is to replace servers as they fail. This would put the infrastructure at risk of unplanned outages, possible data loss, and data corruption. This alternative would also cause a significant increase in maintenance costs as repairs are undertaken and spare equipment is kept on hand. This is not a viable alternative.

Project Schedule

The project is scheduled to start in April 2011 and be completed by the end of November 2011.

Future Plans:

This is an ongoing refresh program to maintain server performance. Future replacements and upgrades will be proposed in future capital budget applications. See five-year capital plan (2011 Capital Plan Tab, Appendix A).

Project Title: Develop Learning Management System Courses

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

Safety is the primary concern when work is performed at Newfoundland and Labrador Hydro (Hydro) . This project is required to develop online learning courses with respect to safety in the following areas:

- Transportation of Dangerous Goods, including PCB Storage and Handling;
- Hazard and Risk Identifications (Tailboard Safety);
- Arc Flash Awareness; and
- Asbestos Awareness.

Five hours of online course material will be made available for Hydro employees through this project. The courses will be delivered through the Intranet.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	20.4	0.0	0.0	20.4
Consultant	87.5	0.0	0.0	87.5
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.	4.7	0.0	0.0	4.7
Contingency	10.8	0.0	0.0	10.8
Sub-Total	**123.4**	**0.0**	**0.0**	**123.4**
Cost Recoveries	**(39.5)**	**0.0**	**0.0**	**(39.5)**
TOTAL	**83.9**	**0.0**	**0.0**	**83.9**

Operating Experience:

Starting in 2008, Hydro began moving elements of its training program to an online (e-learning) format. Three courses were made available in 2008. In 2009, Environmental Management Systems courses were made available. Also, a Work Protection Code course was developed in 2009-2010. The current project is needed to continue the effort to make courses that are critical for safe operations readily available to employees.

Project Justification:

This project is justified on the basis of safety. Initial formal safety training for newly hired employees is often delayed because there are too few in numbers to warrant an instructor to teach a class. The new employees have to wait possibly for months before receiving training in the four areas identified in the Project Description section. Therefore, they are at a safety risk. An online program would eliminate the waiting period and reduce the safety risk by enabling employees to begin practical training much earlier.

Besides new hires, 400 to 600 existing Hydro employees (depending on the need) will have access to the training so that safety awareness will be a top priority in the Hydro workplace.

The training offers additional benefits through a reduction in the amount of scheduling and coordination required to provide this training, a reduction in travel and accommodation requirements associated with training; and delivering a consistent message regarding safety across all training developed.

Future Plans:

Developing courses in online format for core training requirements in addition to safety related ones. Further developments will be proposed in future capital budget applications. Please see the five year Capital Plan (2011 Capital Plan Tab, Appendix A).

Project Title: Perform Minor Application Enhancements

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

Hydro's many computer applications are used daily by employees to run the business. Examples of these applications include the JD Edwards Enterprise Resources Planning Suite, the Lotus Notes Email and Collaboration Suite, the Showcase Business Intelligence and Reporting Suite, and the Microsoft Office Productivity Suite. This project is necessary to enhance these applications to support changing business requirements. The application enhancement project provides for minor enhancements to applications in response to unforeseen requirements such as regulatory and changing business needs.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	21.0	0.0	0.0	21.0
Labour	67.2	0.0	0.0	67.2
Consultant	17.2	0.0	0.0	17.2
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	4.8	0.0	0.0	4.8
Contingency	10.5	0.0	0.0	10.5
Sub-Total	**120.7**	**0.0**	**0.0**	**120.7**
Cost Recoveries	**(38.6)**	**0.0**	**0.0**	**(38.6)**
TOTAL	**82.1**	**0.0**	**0.0**	**82.1**

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 2009, the most recent year for which actual data is available, the following application enhancements were made:

- upgrade and migration of the Treasury Management System to an externally hosted solution,
- functional enhancement to the forms creation tool to enable EPay and EBilling,
- upgrade and install Internal Audit software,

- enhancements to the Employee Annual Performance Review application, and
- additional Lotus Notes application development.

Project Justification:

This project is justified on the basis of operational efficiency and response to regulatory and legislative requirements. As part of normal Information Systems department work, this project is necessary to enhance existing applications to support changing business and regulatory requirements.

Table 2 shows upgrades that have occurred from 2006-2010F.

Table 2: Application Enhancements

Year	Budget ($000)	Actual ($000)	Comments[1]
2010F	120.7[2]		Upgrade
2009	120.2[2]	120.6	Upgrade
2008	372.5[2]	369.8	Upgrade
2007	148.5[2]	148.5	Upgrade
2006	780.0[3]	390.0	Upgrade

1 Upgrade refers to adding or extending functionality of applications.

2 Previous Budgets included the Intranet and/or Internet Refresh Proposals. These have now been moved to distinct proposals.

3 The "Enhancements to the Capital and Operating Process Applications" component of this budget was cancelled. The budgeted amount for this component was $390,000.

Future Plans:

Future enhancements will be proposed in future capital budget applications. See five-year capital plan (2011 Capital Plan Tab, Appendix A).

Project Title: Replace Telephone Keyset

Location: Wabush

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project consists of replacing the existing Nortel Norstar telephone system at Hydro's Wabush office with an Avaya Private Branch Exchange (PBX) system. The system is used by office staff and line personnel for daily telephone communication. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	22.5	0.0	0.0	22.5
Labour	23.5	0.0	0.0	23.5
Consultant	0.0	0.0	0.0	0.0
Contract Work	12.0	0.0	0.0	12.0
Other Direct Costs	6.0	0.0	0.0	6.0
O/H, AFUDC & Escln.	9.1	0.0	0.0	9.1
Contingency	6.4	0.0	0.0	6.4
TOTAL	**79.5**	**0.0**	**0.0**	**79.5**

Operating Experience:

The telephone system was originally installed in 1990 by Newtel Communications and rented by Hydro. In 1995, Hydro purchased the system and all maintenance since this date has been performed by Hydro's internal personnel. This system has performed well with minimal failures, however, it has reached its full capacity and cannot meet Hydro's current needs. Also, the existing system is discontinued. The telephone system has an anticipated useful life of ten years.

Project Justification:

The existing telephone system has a fixed capacity and cannot be expanded. Three more additional telephone lines are required in the Wabush office. The new system has voice mail capabilities and

automated attendant features such as routing calls to the appropriate persons without assistance of a switchboard operator. These features improve the efficiency of the office clerical staff.

Future Plans:

None.

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 final year of a four-year program that started in 2008 to replace the eight humidifiers in the air handling systems at Hydro Place. Each humidifier has reached the end of its useful life. This project is required to replace the last two humidifiers.

Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**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	54.0	0.0	0.0	54.0
Other Direct Costs	0.0	0.0	0.0	0.0
O/H, AFUDC & Escln.	7.3	0.0	0.0	7.3
Contingency	6.2	0.0	0.0	6.2
TOTAL	**75.6**	**0.0**	**0.0**	**75.6**

Operating Experience:

Hydro Place, the corporate headquarters of Hydro, is a six storey building that was constructed in 1989. Ventilation air throughout Hydro Place is provided by ten air handling systems that control temperature, humidity and air flow. The existing humidifiers in the air handling systems were installed when Hydro Place was constructed. In 2008 and 2009, two humidifiers were replaced each year. Hydro received approval in its 2010 Capital Budget Application to replace two more in 2010 at a budget estimate of $75,200.

The humidifiers have reached the end of their 20-year useful lives. The controls for the existing humidification systems are obsolete. One humidifier is out of service because parts are no longer available to repair its failed control system.

Project Justification:

This project is justified on the need to preserve air quality at Hydro Place. All heating, ventilation, and air conditioning (HVAC) equipment at Hydro Place has been regularly serviced under a contract with Johnson Controls since the building opened in 1989. Johnson Controls recommends the replacement of all humidifiers associated with the building's air handling systems based on the following:

- The control system is obsolete.
- The humidifiers contain disposable plastic water bottles that cannot be cleaned but has to be disposed of after use.
- New humidifiers are more energy efficient because of improved insulation that results in better heat retention.

Replacement parts are not available because of the obsolescence of the control system.

Mineral deposits foul the water bottles requiring them to be replaced at least annually. The new humidifiers will have stainless steel bottles that can be cleaned easily, thereby, offsetting the annual replacement costs of $400 to $600 each for the plastic bottles.

Because of the improved insulation properties of the new humidifiers, water stored in the bottles can retain heat better resulting in energy savings.

Future Plans:

None.

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Type
			($000)		
MANDATORY PROJECTS					
Replace Fuel Storage Facility - Postville		2,007		2,007	Other
Perform Grounding Upgrades - Various Sites		321	1,336	1,657	Pooled
TOTAL MANDADORY PROJECTS	0	2,328	1,336	3,664	
NORMAL PROJECTS					
Upgrade Terminal Stations to 25 kV - Labrador City	2,983	3,500	3,507	9,990	Other
Voltage Conversion - Labrador City	1,089	3,501	4,810	9,400	Other
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	1,324	3,367	5,995	Other
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake		1,214	2,895	4,109	Pooled
Upgrade L2 Distribution Feeder - Glenburnie	267	578	2,711	3,556	Other
Upgrade Stack Breaching Unit 1 - Holyrood		3,553		3,553	Other
Provide Service Extensions - All Service Areas		3,385		3,385	Pooled
Replace Vehicles and Aerial Devices - Various Sites		2,351	639	2,989	Other
Replace Programmable Logic Controllers - Holyrood	1,208	747	902	2,857	Other
Refurbish Fuel Storage Facility - Holyrood		2,638		2,638	Other
Upgrade Distribution Systems - All Service Areas		2,499		2,499	Pooled
Perform Wood Pole Line Management Program - Various Sites		2,019		2,019	Pooled
Perform Arc Flash Remediation - Various Sites		430	1,586	2,016	Other
Upgrade Distribution Lines - Roddickton and Makkovik	218	1,645		1,863	Other
Upgrade Distribution Systems - Francois, Rigolet and Happy Valley		1,068	652	1,720	Pooled
Complete Condition Assessment Phase 2 - Holyrood		1,672		1,672	Other
Replace Guy Wires TL-215 - Doyles to Grand Bay		289	1,198	1,487	Other
Corporate Application Environment - Upgrade Microsoft Products	526	473	475	1,473	Other
Overhaul Gas Turbine - Holyrood		1,291		1,291	Other
Upgrade Line TL-244 - Plum Point to Bear Cove	141	1,055		1,196	Other
Replace Off-Road Track Vehicles - Bishop's Falls and Fogo		494	609	1,104	Pooled
Upgrade Substation - Wabush		459	626	1,086	Pooled
Replace Pumphouse Motor Control Centres - Holyrood	50	999		1,049	Other
Upgrade Burnt Dam Access Road Phase 2 - Bay d'Espoir		998		998	Other
Replace Battery Banks and Chargers - Various Sites		978		978	Other
Replace Poles - Various Sites		882		882	Pooled
Upgrade Power Transformers - Various Sites		866		866	Pooled
Replace Relay Panels Unit 3 - Holyrood		277	554	831	Other
Upgrade Intake Gate Controls - Bay d'Espoir		352	468	820	Other
Upgrade Generating Station Service Water System - Cat Arm		360	440	800	Other
Upgrade Station Reliability and Safety - Rocky Harbour		435	360	795	Pooled
Construct Transmission Line Equipment Off-Loading Areas - Various Sites		791		791	Other
Replace 69 kV SF_6 Breakers - St. Anthony Airport		490	290	780	Other
Replace Light Duty Mobile Equipment - Various Sites		757		757	Other
Replace MDR 6000 Microwave Radio (West) - Various Sites		72	683	755	Other
Replace Boiler Blowdown Tanks - Holyrood		750		750	Other

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years ($000)	Total	Type
NORMAL PROJECTS (cont'd.)					
Replace Network Communications Equipment - Various Sites		737		737	Other
Replace Breaker, Structures and Disconnects - Hawke's Bay		687		687	Other
Upgrade Electrical Equipment - Holyrood		188	491	679	Pooled
Replace Compressed Air System - Bay d'Espoir		84	564	648	Other
Replace 230 kV Circuit Breaker - Sunnyside		41	590	631	Other
Replace Unit 566 and 2001 - Francois	168	450		618	Other
Replace Steam Seal Regulator Unit 2 - Holyrood		175	438	613	Other
Upgrade L2 Voltage Conversion to 25 kV - Gaultois	82	511		593	Other
Upgrade Glycol System - Stephenville	261	299		560	Other
Replace Steam Seal Regulator Unit 1 - Holyrood	335	214		549	Other
TOTAL NORMAL PROJECTS	8,633	48,579	28,856	86,068	
JUSTIFIABLE PROJECTS					
Upgrade Hydrogen System - Holyrood		1,192	800	1,992	Other
Upgrade Synchronous Condenser Unit 3 - Holyrood		484	406	889	Other
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood		843		843	Other
Install Automated Meter Reading - Labrador City and Port au Choix		451	88	539	Other
TOTAL JUSTIFIABLE PROJECTS	0	2,970	1,294	4,263	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years	Total	Type
			($000)		
NORMAL PROJECTS					
Upgrade Trailer Mobile Substation - Bishop's Falls	30	468		498	Other
Replace Compressed Air Piping and Install Dewpoint Monitoring - Holyrood	79	417		496	Other
Replace Substation Infrastructure - Burgeo		128	368	496	Other
Replace Unit 2018 - McCallum	19	421		440	Other
Replace iSeries Computer and Upgrade Operating System - Hydro Place		437		437	Other
Replace Personal Computers - Various Sites		404		404	Pooled
Replace Insulators - Various Sites		401		401	Pooled
Purchase Excavators - Bishop's Falls		361		361	Pooled
Upgrade Air Blast Circuit Breakers - Various Sites		334		334	Pooled
Replace Mini Hydro Turbine - Roddicton		87	235	322	Other
Replace Fire Pump Diesel - Holyrood	112	195		307	Other
Replace Disconnects - Various Sites		295		295	Other
Upgrade Ice Protection - Chapel Hill Microwave Site		294		294	Other
Install Voltage Regulators - Conne River and L'Anse au Loup		293		293	Other
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station		280		280	Clustered
Replace Peripheral Infrastructure - Various Sites		258		258	Pooled
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir		258		258	Other
Remove Safety Hazards - Various Sites		252		252	Other
Replace Recloser Control Panels - Various Sites		232		232	Pooled
Install Weatherhoods for Vent Fans - Holyrood		208		208	Other
Refurbish Microwave Site - Deer Lake		207		207	Other
TOTAL NORMAL PROJECTS	240	6,230	604	7,074	

PROJECT DESCRIPTION	Expended to 2010	2011	Future Years ($000)	Total	Type
MANDATORY PROJECTS					
Install Fall Protection Equipment - Various Sites		198		198	Pooled
Replace Fuel Storage Tank - Francois		131		131	Other
Upgrade Fuel Storage - Norman Bay		114		114	Other
Install Waste Oil Storage Tank - St. Lewis		79		79	Other
TOTAL MANDATORY PROJECTS	0	522	0	522	
NORMAL PROJECTS					
Replace Instrument Transformers - Various Sites		199		199	Other
Replace Radomes - Various Sites		196		196	Pooled
Install Alternate Station Services - Stony Brook and Massey Drive		86	109	195	Other
Purchase Meters, Equipment and Tanks - Various Sites		186		186	Other
Purchase Spare Disconnect - Bay d'Espoir		176		176	Other
Replace Digital Fault Recorder - Bay d'Espoir		169		169	Other
Replace Automatic Transfer Switches - Bay d'Espoir and Hinds Lake		156		156	Other
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson		155		155	Other
Upgrade Enterprise Storage Capacity - Hydro Place		154		154	Other
Upgrade Server Technology Program - Hydro Place		142		142	Other
Purchase Hydrometeorological Stations - Various Sites		113		113	Pooled
Replace Fire Alarm System - Hinds Lake		109		109	Other
Develop Learning Management System Courses - Hydro Place		84		84	Other
Perform Minor Application Enhancements - Hydro Place		82		82	Other
Replace Telephone Keyset - Wabush		80		80	Other
Legal Survey of Primary Distribution Line Right of Way - Various Sites		79		79	Other
Purchase Laser Alignment Equipment- Holyrood		79		79	Other
Replace Humidifiers in Air Handling Units - Hydro Place		76		76	Other
Replace Surge Arresters - Various Sites		75		75	Other
Upgrade Gas Turbine Operator Console - Stephenville		72		72	Other
Install Compressor for Frazil Ice Removal - Upper Salmon		69		69	Other
Purchase Portable Dissolved Gas Analysis Unit - Bishop's Falls		52		52	Other
TOTAL NORMAL PROJECTS	0	2,586	109	2,695	

Type	Number	($000)
Clustered	1	280
Pooled	21	23,298
Other	77	80,707
Total	**99**	**104,285**

***** *Includes multi-year projects but excludes contingency fund*

2011 LEASING COSTS

THERE ARE NO ITEMS FOR THIS SECTION

	ACTUALS				BUDGET					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GENERATION	7,557	9,636	13,703	9,592	21,630	21,516	27,834	22,768	13,138	7,686
TRANSMISSION AND RURAL OPERATIONS	19,249	19,150	24,711	32,988	29,060	35,804	32,445	31,194	36,182	44,772
GENERAL PROPERTIES	14,411	6,883	7,832	11,572	11,638	7,737	9,879	11,704	11,175	11,925
TOTAL CAPITAL EXPENDITURES	41,217	35,669	46,246	54,152	62,328	65,058	70,159	65,667	60,496	64,384

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures
GENERATION	505	18,333	4,034	18,114	(219)
TRANSMISSION	969	11,276	2,712	11,325	49
RURAL SYSTEMS	5,366	16,133	5,616	17,499	1,365
GENERAL PROPERTIES	1,640	10,982	2,466	10,982	0
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	397	1,000	0
PROJECTS APPROVED BY PU BOARD	2,101	4,392	430	4,392	0
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	0	44	0	44	0
TOTAL CAPITAL BUDGET	**10,581**	**62,159**	**15,655**	**63,354**	**1,196**

2010 Capital Budget Approved by Board Order No. P.U. 1 (2010)*	51,225
Carryover Projects 2009 to 2010	8,902
Changes to Multi-year Projects in 2009 affecting 2010**	(840)
New Project Approved by Board Order No. 31 (2009)	389
New Project Approved by Board Order No. 33 (2009)	1,795
New Project Approved by Board Order No. 34 (2009)	644
New Project Approved by Board Order No. 16 (2010)	0
2010 New Projects under $50,000 Approved by Hydro	44
TOTAL APPROVED CAPITAL BUDGET	**62,159**

* The total Capital Budget for $52,775,000 was approved less the proposal to Upgrade Plant Access Road – Bay d'Espoir for $1,550,000. That project has been cancelled since this cost cannot be recovered from ratepayers.

** a) The project to increase generation – L'Anse au Loup was approved by Board Order No. P.U. 36 (2008) with a budget of $23,000 for 2009 and $821,000 for 2010. On August 20, 2009 Hydro filed documentation indicating a change in scope resulting in a budget increase for the project with $1,002,000 to be spent in 2009 and $517,000 in 2010. Therefore the 2010 budget is reduced by $304,000.

b) The project to replace diesel units – Norman Bay, Postville and Paradise River is a multi-year project to be completed in 2010, however, the genset being replaced in Postville failed prematurely and was replaced in 2009 reducing the 2010 budget by $536,000.

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures
GENERATION					
HYDRO PLANTS	406	10,057	2,919	9,614	(443)
THERMAL PLANT	99	6,637	1,082	6,862	224
GAS TURBINES	0	1,638	33	1,638	0
TOTAL GENERATION	**505**	**18,333**	**4,034**	**18,114**	**(219)**
TRANSMISSION					
TERMINAL STATIONS	360	5,768	1,032	5,817	49
TRANSMISSION	609	5,474	1,670	5,474	0
TOOLS AND EQUIPMENT	0	33	10	33	0
TOTAL TRANSMISSION	**969**	**11,276**	**2,712**	**11,325**	**49**
RURAL SYSTEMS					
CONSTRUCTION PROJECTS	1,548	11,544	4,167	12,335	791
GENERAL	3,817	2,396	848	2,970	575
METERING	1	558	188	558	0
TOOLS AND EQUIPMENT	0	1,636	413	1,636	0
TOTAL RURAL SYSTEMS	**5,366**	**16,133**	**5,616**	**17,499**	**1,365**

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures
GENERAL PROPERTIES					
INFORMATION SYSTEMS	0	2,008	399	2,008	0
TELECONTROL	531	5,105	1,606	5,105	0
TRANSPORTATION	0	2,299	180	2,299	0
ADMINISTRATIVE	1,109	1,570	281	1,570	0
TOTAL GENERAL PROPERTIES	**1,640**	**10,982**	**2,466**	**10,982**	**0**
ALLOWANCE FOR UNFORESEEN EVENTS	0	1,000	397	1,000	0
PROJECTS APPROVED BY PU BOARD	2,101	4,392	430	4,392	0
PROJECTS APPROVED FOR LESS THAN $50,000	0	44	0	44	0
TOTAL CAPITAL BUDGET	**10,581**	**62,159**	**15,655**	**63,354**	**1,196**

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
HYDRAULIC PLANTS						
Install Meteorological Stations 2009 - Various Sites	268	(16)	9	(16)	0	
Replace 50kW Diesel Generator - Bay d'Espoir	7	317	24	317	0	
Purchase Spare Stator Windings Units 2 - Bay d'Espoir	131	2,711	2,688	2,711	0	
Replace and Purchase Stator Winding - Bay d'Espoir		4,687	0	4,687	0	
Install Meteorological Stations 2010 - Various Sites		443	0	0	(443)	1
Upgrade Units 5 and 6 Cooling Water Systems - Bay d'Espoir		305	27	305	0	
Upgrade Intake Gate Controls - Upper Salmon		284	89	284	0	
Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg - Bay d'Espoir		236	18	236	0	
Purchase Spare Spherical Valve Seal and Ring Assemblies - Bay d'Espoir		223	4	223	0	
Replace A/C Units in Control Room and Communications Room - Upper Salmon		197	0	197	0	
Replace Human Machine Interface (HMI) Computer - Paradise River		158	4	158	0	
Upgrade Fuel Storage - Hinds Lake		149	5	149	0	
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir		81	0	81	0	
Install Air Conditioning at Burnt Spillway - Bay d'Espoir		48	0	48	0	
Replace 21 Inch Metal Cutting Lathe		80	0	80	0	
Purchase Tools and Equipment Less than $ 50,000	0	154	51	154	0	
TOTAL HYDRAULIC PLANTS	**406**	**10,057**	**2,919**	**9,614**	**(443)**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
THERMAL PLANT						
Install Motorized Stack Winches - Holyrood	49	125	61	125	0	
Condition Assessment and Life Extension Study - Holyrood	50	1,846	519	1,846	0	
Refurbish Fuel Storage Facility - Holyrood		2,500	174	2,500	0	
Replace Programmable Logic Controllers - Holyrood		1,208	215	1,432	224	2
Replace Pumphouse Motor Control Centres - Holyrood		50	26	50	0	
Replace Steam Seal Regulator Unit 1 - Holyrood		335	2	335	0	
Replace Diesel Fire Pump - Holyrood		112	0	112	0	
Install Cold Reheat Condensate Drains and High Pressure Heater Trip Level Units 1 and 3 - Holyrood		231	72	231	0	
Install Warm Air Make-up Access - Holyrood		170	6	170	0	
Improve On Site Paving and Drainage - Holyrood		59	7	59	0	
Purchase Tools and Equipment Less than $ 50,000	0	0	0	0	0	
TOTAL THERMAL PLANTS	**99**	**6,637**	**1,082**	**6,862**	**224**	
GAS TURBINES						
Upgrade Gas Turbine Plant Life Extension - Hardwoods		1,305	0	1,305	0	
Upgrade Glycol Systems - Stephenville		261	0	261	0	
Upgrade Fuel Tank Farm Controls - Happy Valley		72	33	72	0	
TOTAL GAS TURBINE PLANTS	**0**	**1,638**	**33**	**1,638**	**0**	
TOTAL GENERATION	**505**	**18,333**	**4,034**	**18,114**	**(219)**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TERMINAL STATIONS						
Upgrade Great Northern Peninsula Protection - Various Sites	68	124	126	173	49	
New 25 kV Terminal Station - Labrador City	292	2,882	197	2,882	0	
Upgrade Power Transformers - Various Sites		816	107	816	0	
Upgrade Circuit Breakers - Various Terminal Stations		342	460	342	0	
Replace Insulators - Various Terminal Stations		399	10	399	0	
Replace Instrument Transformers - Various Sites		197	44	197	0	
Replace Disconnects - Various Sites		199	4	199	0	
Perform Grounding Upgrades - Various Sites		291	24	291	0	
Upgrade Trailer and Mobile Substation - Bishop's Falls		30	0	30	0	
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood		79	0	79	0	
Replace Surge Arrestors - Various Sites		73	48	73	0	
Install Digital Fault Recorder - Various Sites		166	10	166	0	
Replace Air Compressors - Various Sites		97	1	97	0	
Replace 230 kV Breaker Controls - Massey Drive and Buchans		73	1	73	0	
TOTAL TERMINAL STATIONS	**360**	**5,768**	**1,032**	**5,817**	**49**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TRANSMISSION						
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	609	1,323	414	1,323	0	
Construct Transmission Line Equipment Off-Loading Areas - Various Sites	0	990	24	990	0	
Perform Wood Pole Line Management Program - Various Sites	0	2,308	1,199	2,308	0	
Replace Guy Wires TL-215 - Doyles to Grand Bay		301	19	301	0	
Upgrade Line TL-244 - Plum Point to Bear Cove		141	0	141	0	
Upgrade Anchors on C Structures TL-259 - Parson's Pond		353	10	353	0	
Install Remote Ice Growth Detector Beams - Various Sites		58	4	58	0	
TOTAL TRANSMISSION	**609**	**5,474**	**1,670**	**5,474**	**0**	
TOOLS AND EQUIPMENT						
Purchase Tools and Equipment Less than $50,000	0	33	10	33	0	
TOTAL TOOLS AND EQUIPMENT	**0**	**33**	**10**	**33**	**0**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
DISTRIBUTION						
Provide Service Extensions - All Service Areas	0	2,428	1,528	3,268	840	3
Upgrade Distribution Systems - All Service Areas	0	2,572	1,023	2,572	0	
Upgrade Distribution System - Various Sites	0	485	11	485	0	
Replace Poles - Various Sites	0	1,083	201	1,083	0	
Voltage Conversion - Labrador City	0	1,089	526	1,089	0	
Replace Recloser Control Panels - Various Sites	0	603	154	603	0	
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois	0	82	0	82	0	
Install New Voltage Regulators - Various Sites	0	170	0	170	0	
TOTAL DISTRIBUTION	**0**	**8,512**	**3,443**	**9,352**	**840**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	445	347	296	347	0	
Replace Diesel Units - Norman Bay, Postville and Paradise River	6	1,304	88	1,304	0	
Replace Switchgear - Cartwright	314	308	228	408	100	4
Increase Generation Capacity - L'Ance Au Loup	783	736	112	736	0	
Replace Diesel Unit 2001 and Engine 566 - Francois	0	168	0	168	0	
Replace Diesel Unit 2018 - McCallum	0	19	0	19	0	
Replace Main Bus Splitter - Postville	0	149	0	0	(149)	5
TOTAL GENERATION	1,548	3,032	724	2,983	(49)	
TOTAL CONSTRUCTION PROJECTS	**1,548**	**11,544**	**4,167**	**12,335**	**791**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
GENERAL						
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	2,791	528	234	528	0	
Replace Accom, Septic Sys and Upgrade Plant Communications Sys - Cat Arm	733	521	224	1,005	484	6
Build New Maintenance Shop - St. Anthony	293	307	290	307	0	
Upgrade Properties - Port Hope Simpson	0	71	0	71	0	
Install Fall Protection Equipment at Hydro Facilities - Various Sites	0	198	51	198	0	
Install Pole Storage Ramps - Various Sites	0	90	4	90	0	
Legal Survey of Primary Distribution Line Right of Way - Various Sites	0	65	0	65	0	
Install Waste Oil Storage Tanks - Various Sites	0	84	15	84	0	
Install Transformer Storage Ramps - Various Sites	0	89	4	89	0	
Upgrade Accommodations - Norman Bay and Ebbegunbaeg	0	196	26	287	91	
Upgrade Fire Protection System - Bishop's Falls	0	158	0	158	0	
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls	0	88	0	88	0	
TOTAL GENERAL	**3,817**	**2,396**	**848**	**2,970**	**575**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
METERING						
Purchase Meters and Equipment 2010 - Various Sites	0	34	0	34	0	
Install Automatic Meter Reading - Various Sites	1	490	155	490	0	
Purchase Meters and Equipment 2009 - Various Sites	0	33	33	33	0	
TOTAL METERING	**1**	**558**	**188**	**558**	**0**	
TOOLS AND EQUIPMENT						
Replace Off Road Track Vehicles - Various Sites		685	0	685	0	
Replace Light Duty Mobile Equipment - Various Sites		554	295	554	0	
Replace Heavy Duty Forklift - Unit 9799 - Bishop's Falls		166	0	166	0	
Tools and Equipment Less than $ 50,000	0	232	118	232	0	
TOTAL TOOLS AND EQUIPMENT	**0**	**1,636**	**413**	**1,636**	**0**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
NEW INFRASTRUCTURE						
Perform Minor Application Enhancements - Hydro Place	0	121	44	121	0	
Cost Recoveries	0	(36)	0	(36)	0	
Work Protection Software Design	0	71	0	71	0	
Cost Recoveries	0	(21)	0	(21)	0	
Upgrade Intranet - Hydro Place	0	66	0	66	0	
Cost Recoveries	0	(20)	0	(20)	0	
UPGRADE OF TECHNOLOGY						
Corporate Application Environment - Upgrade Microsoft Product	0	751	0	751	0	
Cost Recoveries	0	(225)	0	(225)	0	
Upgrade Business Intelligence Toolset Software - Hydro Place	0	84	8	84	0	
Cost Recoveries	0	(25)	0	(25)	0	
TOTAL SOFTWARE APPLICATIONS	**0**	**765**	**52**	**765**	**0**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
PC Replacement Program - Various Sites	0	406	102	406	0	
Replace Peripheral Infrastructure - Various Sites	0	222	167	222	0	
Upgrade Enterprise Storage Capacity - Hydro Place	0	241	0	241	0	
Cost Recoveries	0	(72)	0	(72)	0	
NEW INFRASTRUCTURE						
Develop Learning Management System Safety Courses - Hydro Place	0	138	0	138	0	
Cost Recoveries	0	(41)	0	(41)	0	
Smart Card Implementation - Various Sites	0	133	0	133	0	
Cost Recoveries	0	(40)	0	(40)	0	
Upgrade Security SCADA Intrusion Prevention System - Hydro Place	0	62	0	62	0	
Upgrade Security Vulnerability Management System - Hydro Place	0	81	0	81	0	
Cost Recoveries	0	(24)	0	(24)	0	
UPGRADE OF TECHNOLOGY						
Upgrade Server Technology Program - Various Sites	0	197	78	197	0	
Cost Recoveries	0	(59)	0	(59)	0	
TOTAL COMPUTER OPERATIONS	**0**	**1,243**	**347**	**1,243**	**0**	
TOTAL INFORMATION SYSTEMS	**0**	**2,008**	**399**	**2,008**	**0**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Customer Service Application - Hydro Place	400	780	812	780	0	
Public Address System - Holyrood	122	1,156	11	1,156	0	
Install Fibre Optic Cable - Hinds Lake	9	683	120	683	0	
Replace Radomes - Various Sites	0	212	0	212	0	
Upgrade Remote Terminal Units - Various Sites	0	190	245	190	0	
Purchase Tools and Equipment less than $50,000	0	109	47	109	0	
NETWORK INFRASTRUCTURE						
Replace Stationary Battery Banks and Chargers - Various Sites	0	717	184	717	0	
Replace Network Communications Equipment - Various Sites	0	131	27	131	0	
Install Mobile Communications - Port Hope Simpson, Charlottetown	0	208	0	208	0	
UPGRADE OF TECHNOLOGY						
Replace Radio Link with Fiber - Bay d'Espoir	0	489	160	489	0	
Upgrade Private Automated Branch Exchange (PABX) - Various Sites	0	339	0	339	0	
Upgrade Operator Training Simulator - Hydro Place	0	92	0	92	0	
TOTAL TELECONTROL	**531**	**5,105**	**1,606**	**5,105**	**0**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
TRANSPORATION						
Replace Vehicles and Aerial Devices 2009 - Various Sites	0	112	28	112	0	
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites	0	31	35	31	0	
Replace Vehicles and Aerial Devices 2010 - Various Sites	0	2,156	117	2,156	0	
TOTAL TRANSPORATION	**0**	**2,299**	**180**	**2,299**	**0**	
ADMINISTRATION						
Upgrade System Security 2009 - Various Sites	488	981	171	981	0	
Purchase Spare Transformer - Hydro Place	511	21	12	21	0	
Replace Air Conditioning Units 2008 - Hydro Place	6	50	43	50	0	
Replace Fire Protection Panels - Hydro Place	104	10	8	10	0	
Remove Safety Hazards - Various Sites	0	252	6	252	0	
Replace Humidifiers in Air Handling Units - Hydro Place	0	75	3	75	0	
Purchase Tools and Equipment less than $50,000	0	180	38	180	0	
TOTAL ADMINISTRATION	**1,109**	**1,570**	**281**	**1,570**	**0**	
	1,640	**10,982**	**2,466**	**10,982**	**0**	

	Expenditures Prior To 2010	PUB Approved Budget 2010	2010 Expenditures To Jun.30	Expected Total Expenditures 2010	Var. from Approved to Expected Expenditures	Variance Explanation Ref. Page
ALLOCATION FOR UNFORESEEN EVENTS						
TL # 208 Structure Failure		249	345	249	0	
FMH - Microwave Radio Site Ice Storm Damage		445	52	445	0	
Allocation for Unforeseen Events		**306**	**0**	**306**	**0**	
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	**0**	**1,000**	**397**	**1,000**	**0**	
PROJECTS APPROVED BY PUB						
CARRYOVER						
Come By Chance	0	227	0	227	0	
Cost Recovery - North Atlantic Refining Limited	0	(227)	0	(227)	0	
Upgrade Continuous Emission Monitoring System - Holyrood	7	697	362	697	0	
Nain Diesel Plant Rehabilitation	2,068	1,041	(9)	1,041	0	
Gas Turbine Refurbishment - Stephenville	0	2,086	30	2,086	0	
Hinds Lake Powerhouse Slope Stabilization	0	432	19	432	0	
Work Protection Code Elearning Program	92	135	28	135	0	
Cost Recovery - Nalcor Energy, Churchill Falls	(66)	0	0	0	0	
NEW						
Voisey's Bay Nickel - Long Harbour Power Supply	0	3,605	81	3,605	0	
Cost Recovery - Vale Inco	0	(3,605)	(81)	(3,605)	0	
TOTAL PROJECTS APPROVED BY PUB	**2,101**	**4,392**	**430**	**4,392**	**0**	
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Replace Generator Unit 2066 - Black Tickle	0	18	0	18	0	
Replace Domestic Water Pump - Upper Salmon	0	26	0	26	0	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**0**	**44**	**0**	**44**	**0**	

1. Install Meteorological Stations 2010 – Various Sites

Part of the Install Meteorological Stations project for 2008 approved by Board Order No. P.U. 30 (2007) included the installation of a remote station in the Cat Arm watershed with a snow water equivalent measurement device (snow pillow). This installation of the snow pillow was a first for Hydro and some problems were encountered with communication of the data from the site to Hydro's data collection center in St. John's. Although the gauge has been in place since 2008, difficulties with the satellite communications have prevented the use of this data. The 2010 program was to add more snow pillows (in remote locations in the watersheds of the Victoria, Long Pond, Hinds Lane and Meelpaeg reservoirs), however, because of the communication difficulties experienced with the Cat Arm snow pillow it was decided to cancel the 2010 project and resubmit it when there was certainty that the data collection issues were resolved and that the data received provides the intended benefit of improved inflow forecasting.

2. Replace Programmable Logic Controllers – Holyrood

There are safety related deficiencies in the burner management control system that were not identified during the preparation of this proposal. The modifications required to correct these deficiencies will result in an additional $107,000 for completion and commissioning. As well, the tender was $103,000 greater than expected. This will result in additional interest and overhead costs as well.

3. Provide Service Extensions – All Service Areas

The increase in this budget is due to the growth in the Labrador Interconnected system. There are three new subdivisions being developed in Happy Valley and Sheshatshui with an additional 90 homes being developed in total. Housing developments in the Labrador West area has resulted in an additional 130 new houses planned for that area.

4. Replace Switchgear - Cartwright

Originally all project engineering work was to be done by Hydro personnel, however, due to resource constraints within Engineering Services, outside technical assistance is required for the automation portion of this project. The work to be outsourced includes onsite installation of the automation equipment as well as commissioning of the switchgear system followed by operator training. This will increase the cost by approximately $65,000. Project construction costs are also forecast to increase by $25,000 due to additional changes required for the plant Direct Current (DC) system as well as the

remediation of arc flash levels. These cost increases will result in additional overhead and interest costs as well.

5. Replace Main Bus Splitter - Postville

The scope of this project was to upgrade the main plant splitter from a 400 amp rating to meet load growth in the community. During the initial development stage of this project, it was determined that the main plant splitter is actually rated at 800 amp which is adequate to meet the load requirements for Postville for the foreseeable future. Therefore this project has been cancelled.

6. Replace Accommodations, Septic System and Upgrade Plant Communications System - Cat Arm

The installation contract which included the foundation, placement of the units, as well as electrical and mechanical work was higher than the estimated amount of $730,000 by approximately $450,000. This will result in additional interest and overhead costs as well.



Plan of Projected Operating

Maintenance Expenditures

2011 - 2020

For Holyrood Generating Station

Newfoundland & Labrador Hydro

July 2010

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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 10 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 2011 to 2020 inclusive. With respect to these expenditures it must be noted that Units 1 and 2, as well as two of the main fuel storage tanks and other associated ancillary equipment, are in excess of 40 years old. Unit 3 is in excess of 30 years old, along with its associated equipment, including the other two main fuel storage tanks. While many components of this equipment have been replaced and additional items added through the maintenance and capital program over the years, numerous pieces of equipment and components are original.

An accurate ten year plan of system equipment maintenance is difficult to complete given the harsh operating environment, varied production requirements and the age of the units. This report, however, outlines for the next ten years, maintenance items that are anticipated at this time. This plan, of course, will change as time progresses. The operating condition of the equipment will be continuously reviewed and, undoubtedly, events will occur that are not foreseen at this time, which will require changes in the currently anticipated annual maintenance. As can be seen from this report, there must be variation in annual operating costs for the Holyrood 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's ten 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).

Turbine major and minor overhauls are, effectively, long-term predictive and preventive maintenance activities. A turbine major overhaul is a major disassembly, inspection and repair of the whole turbine. Since this is a very expensive and time consuming activity, the time between these overhauls is extended to minimize the recurring cost and maximize the equipment operating time, and thus useful life of the internal wearing components. Prior to 1988, these major overhauls were carried out at four-year intervals; a subsequent assessment of the risk and cost savings resulted in extending these overhauls to six-year intervals.

In 2003, a study was undertaken by Hartford Steam Boiler Insurance Company, using their proprietary program called Turbine Overhaul Optimization Program (TOOP). This assesses the causes of failure, the risk of failure and the maintenance history of the Turbines, and then proposes the optimum frequency between major overhauls. This assessment concluded that the Turbine major overhaul interval could be extended to nine years from the major overhaul of Unit 1 in 2003, the major overhaul of Unit 2 in 2005 and the major overhaul of

Unit 3 in 2007, providing that certain upgrades of internal components are made. These recommendations have been accepted and all upgrades are now completed.

Turbine valve overhauls are carried out at three-year intervals, between major overhauls. This has been found necessary, due to the critical nature of the safety and reliability aspects of these valves to the turbine operation and integrity, and will continue to be maintained on this three-year interval between major overhauls.

As of 2008, the Preventive Maintenance program has been enhanced to include the extra costs associated with plant cleaning in areas where Asbestos and Heavy Metals have been identified as potential health hazards.

2) Corrective Maintenance

In addition to the preventive maintenance tactics outlined in (1) above, there are also corrective maintenance requirements. These include repairs to equipment as it fails or reaches the point where preventive maintenance has identified that the equipment is approaching the end of its useful service life (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). 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 were replaced in 2008.

As of 2008, the Corrective Maintenance program has been enhanced to include the extra costs associated with plant cleaning in areas where Asbestos and Heavy Metals have been identified as potential health hazards.

3) 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 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 which 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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
No. 1		Major			Minor			Minor		
No. 2	Minor			Major			Minor			Minor
No. 3			Minor			Major			Minor	
General Cost	↓	↑	↓	↑	↓	↑	↓	↓	↓	↓

Similarly, major operating projects, because of their extended maintenance intervals (years) or non-repeatability also add to the annual fluctuations of the system equipment maintenance costs and have to be executed when plant conditions allow.

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.

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 2011 to 2020. Appendices 2 to 9, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Overhauls and Major Operating Projects for each of the major equipment groupings containing SEM costs.

This plan was prepared using the 2010 preventive, corrective and overhaul data and the current 2011 to 2015 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 2008 Hydro forecast. A single annual escalation rate of 2.5%was used in this exercise and assumed a 50% weighting of Labour escalation and 50% of Material escalation.

Appendices 2 to 9 list the categories of SEM costs for the years 2011 to 2020 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
Operating Projects	Non-capitalized projects, justified on the basis of Safety, Environment, Reliability or Cost Benefit Analyses.

Appendices 2, 3 and 4 (for Units 1, 2 and 3 respectively) use all of the foregoing categories. Appendices 5 to 9 are for the remaining equipment groupings of Common Equipment, Building and Grounds, Water Treatment Plant, Waste Water Treatment Plant and Environmental Monitoring and use only Preventive, Corrective and Major Operating Projects.

It must be noted that the Appendices do not itemize preventive and corrective items. The preventive maintenance program consists of approximately 1,200 protective maintenance work order 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 2015. For the period 2016 to 2020, Hydro used an average per unit of the project budgets for the three units over the years 2011 to 2015 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 2016 to 2020.

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 2011 system equipment maintenance budget. As with any forecast, it is subject to change depending on the operating demands of the plant, the results of inspections and assessments of changing equipment conditions.

The Plan takes into account up-to-date maintenance tactics and known restoration and inspection work. As can be seen from the Plans, fluctuations in the annual cost cannot be eliminated due to the nine-year Turbine Overhauls and three-year Valve Overhauls, as well as the large but infrequent Major Operating projects.

APPENDICES

APPENDIX 1

TOTAL HOLYROOD SEM[1] 10 YEAR MAINTENANCE EXPENDITURES ESCALATED (K)

	($000)										
	Base Year 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
UNIT 1 Total SEM	$1,851	$3,950	$1,835	$2,114	$2,493	$2,018	$2,580	$2,560	$2,173	$2,226	
UNIT 2 Total SEM	$2,650	$1,897	$1,916	$4,057	$2,001	$2,695	$2,501	$2,280	$2,176	$2,229	
UNIT 3 Total SEM	$1,746	$1,788	$2,335	$2,035	$2,054	$4,285	$2,336	$2,488	$2,722	$2,294	
Common Equipment Total SEM	$3,338	$2,650	$2,097	$2,150	$2,203	$2,259	$2,315	$2,373	$2,432	$2,492	
Buildings and Grounds Total SEM	$674	$547	$560	$575	$588	$604	$619	$634	$650	$667	
WT Plant Total SEM	$189	$194	$274	$204	$238	$299	$219	$225	$324	$227	
WWT Plant Total SEM	$127	$140	$133	$147	$140	$154	$147	$163	$154	$170	
Environmental Monitoring Total SEM	$315	$323	$478	$339	$349	$394	$490	$375	$424	$393	
Total Holyrood SEM	$10,890	$11,489	$9,628	$11,621	$10,066	$12,708	$11,207	$11,098	$11,055	$10,698	
Total Operating Projects	$2,259	$1,411	$1,040	$1,083	$1,041	$1,321	$1,648	$1,381	$1,094	$955	
Total Operating Projects Less Asbestos Abatement	$917	$807	$1,040	$1,083	$1,041	$1,321	$1,648	$1,381	$1,094	$955	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$344	$352	$361	$370	$379	$389	$398	$408	$418	428	
Corrective – Yearly	$422	$433	$444	$455	$466	$478	$490	$502	$515	$528	
Turbine Major Overhaul		$2,081									
Turbine Valve Overhaul					$409			$440			
Boiler Annual Overhaul	$980	$1,005	$1,030	$1,056	$1,082	$1,109	$1,137	$1,165	$1,195	$1,224	
Operating Projects											
Boiler Chemical Clean							$390				
Overhaul Boiler Feed Pump East					$116						
Overhaul Boiler Feed Pump West	$105						$122				
Overhaul Cooling Water Pump East				$83							
Overhaul Cooling Water Pump West											
Overhaul Extraction Pump North		$79									
Overhaul Vacuum Pump North											
Overhaul Extraction Pump South				$83							
Overhaul Vacuum Pump South				$28							
Projects – Lump Sum for Future Years				$40	$41	$42	$43	$44	$45	$46	
Total – Unit No. 1	$1,851	$3,950	$1,835	$2,114	$2,493	$2,018	$2,580	$2,560	$2,173	$2,226	
Total Operating Projects Unit 1	$105	$79	$0	$234	$157	$42	$555	$44	$45	$46	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$344	$352	$361	$370	$379	$389	$398	$408	$418	$429	
Corrective - Yearly	$422	$433	$444	$455	$466	$478	$490	$502	$515	$527	
Turbine Major Overhaul				$2,133							
Turbine Valve Overhaul	$370						$430				
Boiler Annual Overhaul	$980	$1,005	$1,030	$1,056	$1,082	$1,109	$1,137	$1,165	$1,195	$1,224	
Boiler 2 Amortized Repair Cost	$456										
Operating Projects											
Unit 2 Boiler Chemical Clean						$381					
Overhaul Boiler Feed Pump East		$108						$125			
Overhaul Boiler Feed Pump West						$119					
Overhaul Cooling Water Pump East						$87					
Overhaul Cooling Water Pump West	$77										
Overhaul Extraction Pump North						$87					
Overhaul Extraction Pump South			$81								
Overhaul Vacuum Pump South								$32			
Overhaul Vacuum Pump North					$29						
Projects - Lump Sum for Future Years				$43	$44	$45	$46	$47	$48	$49	
Total - Unit No. 2	$2,650	$1,897	$1,916	$4,057	$2,001	$2,695	$2,501	$2,280	$2,176	$2,229	
Total Operating Projects Unit 2	$77	$108	$81	$43	$73	$719	$46	$204	$48	$49	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$344	$352	$361	$370	$379	$389	$398	$408	$418	$429	
Corrective – Yearly	$422	$433	$444	$455	$466	$478	$490	$502	$515	$527	
Turbine Major Overhaul						$2,297					
Turbine Valve Overhaul			$389						$451		
Boiler Annual Overhaul	$979	$1,004	$1,029	$1,054	$1,081	$1,108	$1,136	$1,164	$1,195	$1,223	
Auxiliary Equipment Annual Overhaul											
Operating Projects											
Unit 3 Boiler Chemical Clean								$400			
Overhaul Cooling Water Pump East										$100	
Overhaul Cooling Water Pump West							$89		$128		
Overhaul Boiler Feed Pump East				$114			$120				
Overhaul Boiler Feed Pump West			$112								
Overhaul Extraction Pump North							$89				
Overhaul Extraction Pump South					$85						
Overhaul Vacuum Pump North					$29						
Overhaul Vacuum Pump South				$28							
Projects – Lump Sums for Future Years				$13	$13	$14	$14	$14	$15	$15	
Total - Unit No. 3	$1,746	$1,788	$2,335	$2,035	$2,054	$4,285	$2,336	$2,488	$2,722	$2,294	
Total Operating Projects Unit 3	$0	$0	$112	$155	$127	$14	$312	$414	$143	$115	
Total SEM for all Three Units	$6,247	$7,635	$6,086	$8,206	$6,548	$8,998	$7,417	$7,328	$7,071	$6,749	
Total Project Work for Three Units	$182	$187	$193	$432	$357	$775	$913	$662	$236	$210	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$286	$293	$300	$308	$315	$323	$331	$340	$349	$357	
Corrective – Yearly	$1,642	$1,683	$1,725	$1,769	$1,813	$1,858	$1,905	$1,952	$2,000	$2,051	
Operating Projects											
Asbestos Abatement	$1,342	$604									
Pipe Surveillance	$53	$54	$55	$57	$58	$59	$61	$62	$64	$65	
Plant Color Coding	$16	$16	$17	$17	$17	$18	$18	$19	$19	$19	
Total Common Equipment	$3,338	$2,650	$2,097	$2,150	$2,203	$2,259	$2,315	$2,373	$2,432	$2,492	
Total Operating Projects Common Equipment	$1,410	$674	$72	$74	$75	$77	$79	$81	$83	$84	
Total Operating Projects less Asbestos Abatement	$68	$70	$72	$74	$75	$77	$79	$81	$83	$84	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$179	$183	$188	$192	$197	$202	$207	$212	$217	$223	
Corrective	$126	$129	$132	$136	$139	$143	$146	$150	$154	$158	
Operating Projects											
Coat Interior Liner Panels	$105	$108	$110	$113	$116	$119	$122	$125	$128	$131	
Repair & Repaint Structural Steel	$95	$97	$99	$102	$104	$107	$110	$112	$115	$118	
Exhaust Stack Maintenance	$170	$30	$30	$32	$32	$33	$34	$35	$36	$37	
Total – Buildings and Grounds	$674	$547	$560	$575	$588	$604	$619	$634	$650	$667	
Total Operating Projects Buildings and Grounds	$370	$235	$240	$247	$252	$259	$266	$272	$279	$286	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$56	$57	$59	$60	$61	$63	$65	$66	$68	$69	
Corrective	$84	$86	$88	$91	$93	$95	$97	$100	$103	$105	
Operating Projects											
Resin Replacement (A Train)						56					
Resin Replacement (B Train)	49						57				
Resin Replacement (C Train)		51						59			
Resin Replacement (Mixed Bed A)			52						$61		
Resin Replacement (Mixed Bed B)				53						$53	
Resin Replacement (U1 Polisher)					83						
Resin Replacement (U2 Polisher)			75						$92		
Resin Replacement (U3 Polisher)						85					
Total WT Plant and Environmental	$189	$194	$274	$204	$238	$299	$219	$225	$324	$227	
Total Operating Projects WT Plant	$49	$51	$127	$53	$83	$141	$57	$59	$153	$53	
Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

APPENDIX 8											
	($000)										
Waste Water Treatment Plant	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$74	$75	$77	$79	$81	$83	$85	$87	$89	$91	
Corrective	$32	$32	$33	$34	$35	$36	$37	$37	$38	$39	
Operating Projects											
WWTP Periodic Basin Cleaning & Inspection	$22		$23		$24		$26		$27		
WWTP Continuous Basin Clean-Out		$23		$24		$25		$27		$28	
Filter Fabric Replacement-Plate Press		$10		$10		$11		$11		$12	
Total WWT Plant	$127	$140	$133	$147	$140	$154	$147	$163	$154	$170	
Total Operating Projects WWT Plant	$22	$32	$23	$34	$24	$35	$26	$38	$27	$40	
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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
Preventive – Yearly	$26	$27	$28	$28	$29	$30	$30	$31	$31	$32	
Corrective	$63	$65	$66	$68	$70	$71	$73	$75	$77	$79	
Operating Projects											
Emissions Monitoring	$158	$162	$166	$170	$174	$178	$183	$187	$192	$196	
Stack Emissions Testing			113				$124				
CEMS RATA Testing	$63	$65	$66	$68	$70	$71	$73	$75	$77	$79	
OPEP Exercise	$5	$5	$6	$6	$6	$6	$6	$6	$7	$7	
Tube Bundle Replacement – All Units			$35			$37			$40		
Total Environmental Monitoring	$315	$323	$478	$339	$349	$394	$490	$375	$424	$393	
Total Operating Projects Environmental Monitoring	$226	$232	$385	$243	$250	$293	$386	$269	$316	$282	
Escalation Rate (%)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	

	2009 ($000)	2008 ($000)
Capital Assets	2,082,459	2,044,398
Less:		
Accumulated Depreciation	632,085	603,363
Contributions in Aid of Construction	96,749	96,143
	728,834	699,506
Net Capital Assets	1,353,625	1,344,892
Balance Previous Year	1,344,892	1,349,694
Average Capital Assets	1,349,259	1,347,293
Working Capital	2,965	3,548
Fuel	20,817	34,389
Supplies Inventory	23,567	22,561
Average Deferred Charges	76,869	81,996
Average Rate Base	1,473,477	1,489,787

2011
Capital Budget
Application

REPORTS
1-10

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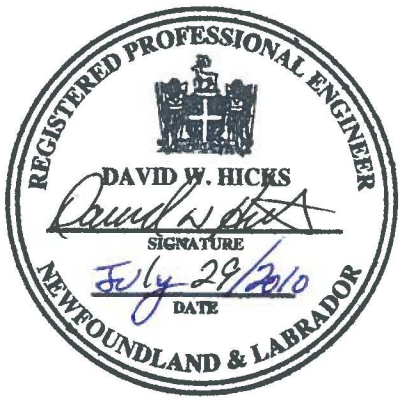	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

REPLACE STATIC EXCITATION SYSTEM FOR GENERATING UNITS AT

Upper Salmon, Hinds Lake and Holyrood

April 2010

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

The Upper Salmon Hydroelectric Generating Station (Upper Salmon) and the Hinds Lake Hydroelectric Generating Station (Hinds Lake) are two of the nine hydroelectric generating sites owned and operated by Newfoundland and Labrador Hydro (Hydro). Upper Salmon is located in the Bay d'Espoir watershed area, approximately 52 kilometers from the Bay d'Espoir generating site. Upper Salmon has one generating unit rated at a capacity of 84 MW. 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 also has one generating unit rated at a capacity of 75 MW.

The Holyrood Thermal Generating Station (Holyrood) has three generating units. Units 1 and 2 are rated at 170 MW each and Unit 3 is rated at 150 MW.

A generator has two main components, a stator and a rotor. The stator is the stationary component of the generator. When a magnetic field passes through the stator windings a voltage is induced in the windings, creating power. The rotor is the rotating component of the generator. The purpose of the rotor is to supply the magnetic field required to induce a voltage in the stator windings. In order to create this magnetic field, copper coils are wrapped around a steel core and a direct current (DC) is applied to the coils creating an electromagnet. The purpose of the static excitation system is to supply the DC to the rotor to create this magnetic field.

Over the past 15 years Hydro has replaced static excitation systems due to three factors; end of service life, limited availability of spare parts, and limited engineering support from the original equipment manufacturer. To date, Units 1 through 7 at the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir), Units 1 and 2 at Holyrood and Unit 1 at the Cat Arm Hydroelectric Generating Station (Cat Arm) have had the static excitation systems replaced. There are three remaining excitation systems that are beyond their useful service

lives and require replacement. These are the systems for the generators at Upper Salmon, Hinds Lake, and Holyrood Unit 3.

The Westinghouse static excitation systems in operation for the Upper Salmon, Hinds Lake, and Holyrood Unit 3 generators were installed in 1982, 1980 and 1979 respectively. These systems have now exceeded their 25 year useful service lives, and are due for scheduled replacement.

This report describes the justification for the replacement of the Westinghouse static excitation systems for the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators.

2 PROJECT DESCRIPTION

This project is required to remove the existing static excitation systems, and design, supply and install new static excitation systems for the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators. Additionally, all power and control cabling and connections between the excitation systems and the generators will be replaced.

Hydro intends to tender the supply of the three static excitation systems under a single tender as these systems are very similar in design. The existing excitation systems will be removed from service and disposed of, as they have no salvage value.

3 EXISTING SYSTEM

The existing static excitation systems for the Upper Salmon, Hinds Lake, and Holyrood Unit 3 generators were manufactured by Westinghouse, and installed during construction of the generators. These systems have provided service for 28 to 31 years but have come to the end of their service lives and will not receive further engineering support from the original manufacturer. The original manufacturer, Westinghouse, has been dissolved and sold to other companies. Siemens Canada Limited (Siemens) provides support for Westinghouse static excitation systems, however, due to the age of the systems, replacement parts are no longer stocked by Siemens, and the systems are no longer directly supported by Siemens. Siemens has contracted with a retired former Siemens employee to provide support to these older excitation systems. This individual is currently working under a one-year contract as a consultant. Siemens has stated that due to the ages of the excitation systems, there will be no more in house training for their staff to support these excitation systems and after the consultant's contract has expired, Siemens will no longer offer support.

3.1 Age of Equipment or System

The Westinghouse static excitation systems in operation for the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators were installed in 1979, 1980 and 1982 respectively.

3.2 Major Work and/or Upgrades

Since their installation there have been no major upgrades performed on the static excitation systems for the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators.

3.3 Anticipated Useful life

Static excitation systems have an anticipated useful service life of 25 years.

3.4 Maintenance History

Exact maintenance costs cannot be determined as Hydro does not track maintenance costs to the level of the components of the excitation systems. The costs are tracked for the generating units only.

3.5 Outage Statistics

In the last five years, there have been no outages which were the direct result of the static excitation systems of the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators.

3.6 Industry Experience

Westinghouse manufactured the existing type of static excitation system from the early 1970s to the mid 1980s. Historically the useful life on this type of equipment has been 25 years however modern digital electronic equipment now in use tends to become obsolete within 10 to 15 years. After approximately 20 years, there is expected to be little manufacturer support remaining for the equipment and replacement parts are difficult to procure. For these reasons, the majority of Westinghouse static excitation systems of this vintage have already been replaced.

3.7 Maintenance or Support Arrangements

All maintenance performed on the static excitation systems has been done by Hydro personnel, with support and technical advice being provided by Siemens.

3.8 Vendor Recommendations

Siemens has supported Westinghouse static excitation systems since the Westinghouse generation division was taken over by Siemens in the mid 1990s. Approximately ten years

ago, Siemens began to phase out parts and service support for this type of Westinghouse system. Siemens no longer stocks parts or trains staff to service the systems. It is the recommendation of Siemens that the systems be replaced.

3.9 Availability of Replacement Parts

Siemens no longer guarantees parts or technical support. All parts have been discontinued and are obsolete. Hydro's inventory has only one spare of most critical parts remaining. After all spare parts are exhausted, Hydro would have to get custom manufactured parts by a third party.

3.10 Safety Performance

There are no specific safety issues related to this project.

3.11 Environmental Performance

There are no specific environmental issues related to this project.

3.12 Operating Regime

The Westinghouse static excitation systems for the Holyrood Unit 3, Hinds Lake and Upper Salmon generators operate whenever the generating unit is running. The systems in Hinds Lake and Upper Salmon are in near continuous operation, while the Holyrood Unit 3 system has been cyclical depending on seasonal load requirements.

4 JUSTIFICATION

This project is justified on the requirement to maintain system reliability by strategically replacing the static excitation systems for Holyrood Unit 3, Hinds Lake, and Upper Salmon generators before failure which would impair Hydro's ability to provide least-cost, reliable electrical service. In the case of Holyrood, if an infeed is brought on to Newfoundland, from Labrador, the Holyrood plant will be utilized as a synchronous condenser to support system stability for the Island Interconnected system. Regardless of whether the plant is operating in generation mode, or in synchronous condense mode, the DC excitation system will be required. Therefore, when the infeed is realized, these upgrades will still be required.

The Westinghouse static excitation systems in operation in the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators were installed in 1979, 1980 and 1982 respectively. These systems have now exceeded their 25 year useful service lives and are obsolete. They are due for scheduled replacement.

The excitation systems have been supported by Siemens. However, approximately ten years ago, Siemens began phasing out the stocking of parts for these systems because of technology changes. Over the past ten years, the availability of spare parts has declined to the point where Siemens no longer stocks replacement parts. If the excitation system fails and replacement parts are not available, the generating unit will become inoperable.

Siemens has ceased training employees to provide service for these systems. Within a year Seimens will no longer support the existing technology of the excitation systems. The static excitation systems for Holyrood Unit 3, Hinds Lake, and Upper Salmon must be replaced in order for Hydro to ensure reliable least cost power to its customers.

4.1 Net Present Value

A net present value calculation was not performed as there is no viable alternative to replacing the excitation systems.

4.2 Levelized Cost of Energy

The replacement of these static excitation systems will have no direct effect on the levelized cost of energy.

4.3 Cost Benefit Analysis

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

4.4 Legislative or Regulatory Requirements

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

4.5 Historical Information

Hydro has replaced the excitation systems on other generating units. Table 1 provides the replacement dates and costs.

Table 1: Replacement of Excitation Systems

Excitation Systems Replaced	Year	Cost ($000)
Bay d' Espoir Unit 7	2003	648.7
Cat Arm Unit 1	2002	600.2
Holyrood Unit 1	2000	671.3
Holyrood Unit 2	1999	790.2
Bay d' Espoir Unit 1 and 2	1998	661.2
Bay d' Espoir Unit 3 and 4	1997	667.2
Bay d' Espoir Unit 5 and 6	1994	808.1

4.6 Forecast Customer Growth

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

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits anticipated from this project.

4.8 Losses during Construction

As the static excitation systems will be replaced during scheduled outages during the summer months, there will be no losses during construction.

4.9 Status Quo

The status quo is not acceptable because the static excitation systems for Holyrood Unit 3, Hinds Lake and Upper Salmon generating units are beyond their useful service lives. All replacement parts have been discontinued and the systems are obsolete

4.10 Alternatives

There are no viable alternatives to this project.

5 CONCLUSION

The static excitation systems for the Holyrood Unit 3, Hinds Lake, and Upper Salmon generators have been in service since their commissioning. These static excitation systems have now reached the end of their useful service lives, are obsolete, and are no longer supported by the manufacturer. For these reasons, these static excitation systems must be replaced.

5.1 Budget Estimate

The budget estimate for the project is shown in Table 2.

Table 2: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**2013**	**Total**
Material Supply	575.0	700.0	425.0	1700.0
Labour	187.0	187.0	187.0	561.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	250.0	280.0	250.0	780.0
Other Direct Costs	21.0	21.0	21.0	63.0
O/H, AFUDC & Escln.	101.3	225.0	350.9	677.2
Contingency	80.0	115.0	132.9	327.9
TOTAL	**1,214.3**	**1,528.0**	**1,366.8**	**4,109.1**

5.2 Project Schedule

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Milestone
Design of static excitation system for Upper Salmon	April 2011
Production of static excitation system for Upper Salmon	July 2011
Transportation of static excitation system to Upper Salmon	August 2011
Installation of static excitation system for Upper Salmon	October 2011
Design of static excitation system for Holyrood Unit 3	January 2012
Production of static excitation system for Holyrood Unit 3	April 2012
Transportation of static excitation system to Holyrood	May 2012
Installation of static excitation system for Holyrood Unit 3	July 2012
Design of static excitation system for Hinds Lake	February 2013
Production of static excitation system for Hinds Lake	May 2013
Transportation of static excitation system to Hinds Lake	June 2013
Installation of static excitation system for Hinds Lake	September 2013

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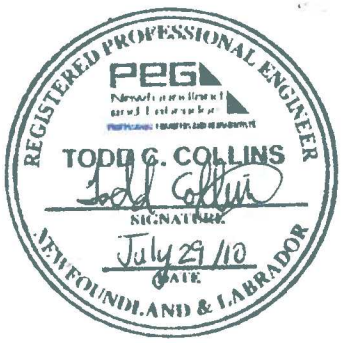	Electrical
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UPGRADE UNIT 1 STACK BREECHING

Holyrood Thermal Generating Station

April 2010

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

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



Figure 1: Holyrood Thermal Generating Station

The three main components of each generating unit are the boiler, turbine, and generator. During operation, stack breeching conveys the boiler hot flue gas safely outside the plant to the boiler exhaust stack where it is then discharged into the atmosphere. After exiting the boiler, the hot flue gas passes through heat exchangers, known as air pre-heaters, which are used to heat the incoming combustion air before entering the boiler furnace. The boiler is

equipped with two air pre-heaters known as the East and West air pre-heaters. The Unit 1 stack breeching, referred to as the East and West stack breeching, is connected to the outlet of each air pre-heater and conveys the hot flue gas to the boiler exhaust stack. The Unit 1 East and West stack breeching is illustrated in Figure 2.



Figure 2 – Unit 1 Stack Breeching

2 PROJECT DESCRIPTION

This project is required to upgrade the stack breeching serving Unit 1. The existing stack breeching was constructed from carbon steel with an exterior protective coating and insulated internally with borosilicate (glass) blocks. The project will replace existing stack breeching with newly designed breeching that will be fabricated from high temperature carbon steel and insulated externally with water repellent insulation complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching in order to protect the external insulation from damage caused by ice falling from the stack and the plant power house. The project will be completed simultaneously with the regular annual maintenance work for the Unit 1 boiler.

3 EXISTING SYSTEM

The general arrangement of the existing Unit 1 stack breeching is illustrated above in Figure 2. The breeching has a rectangular cross section that is constructed from carbon steel plate and is insulated internally on the sides and top with borosilicate (glass) block. The breeching sections are coated externally with a protective film to inhibit corrosion. In addition, the breeching sections have a silicate concrete floor. A typical cross section of the Unit 1 stack breeching is illustrated in Figure 3.

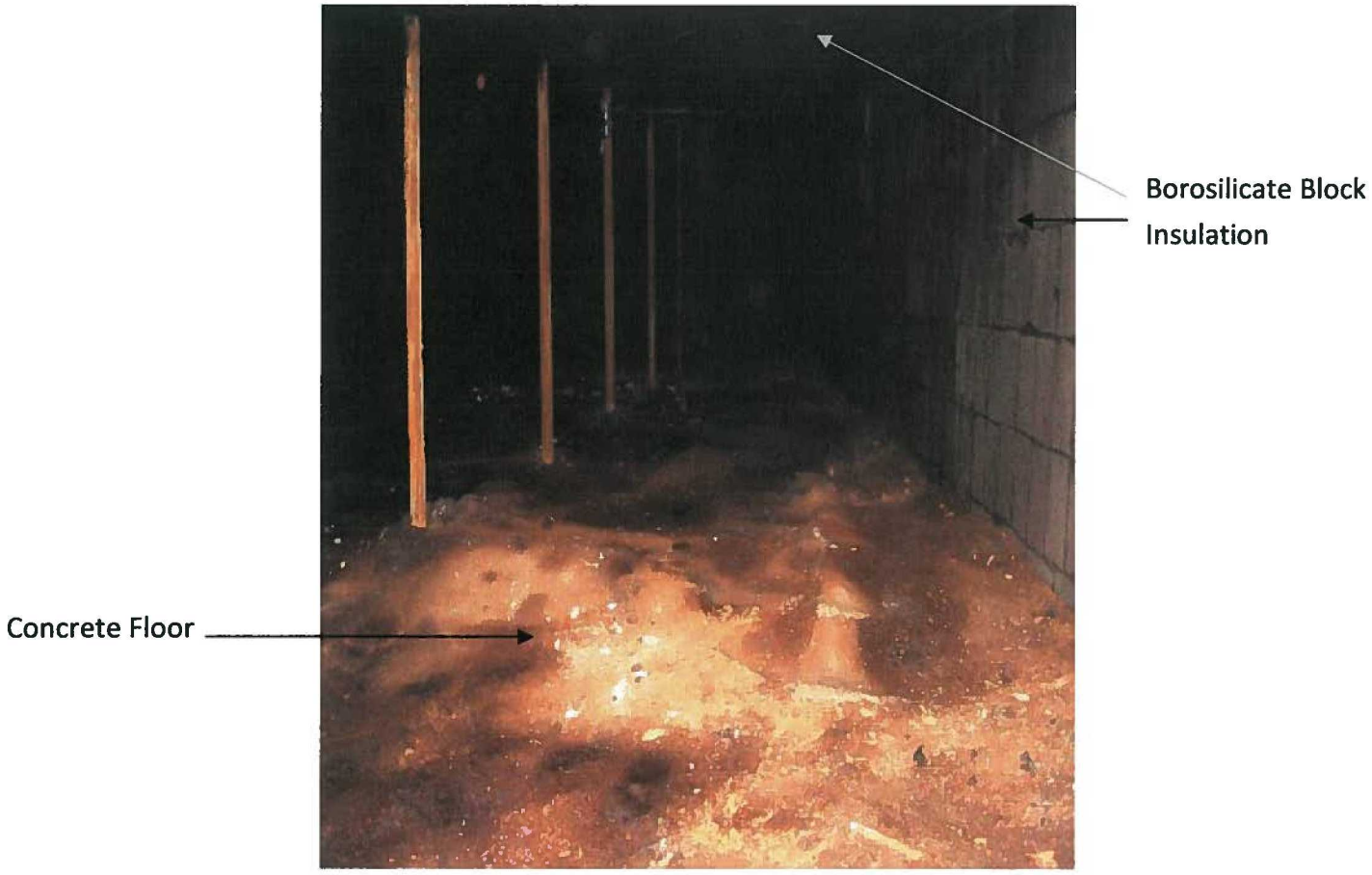

Figure 3 – Typical Stack Breeching Cross Section

The existing Unit 1 stack breeching was installed in 1990 replacing the original stack

breeching installed when Unit 1 was commissioned in 1971. In 1988, Unit 1 was up-rated to produce 170 MW. At that time, it was necessary to increase the capacity of the two Forced Draft (FD) fans in order to increase the volumetric flow rate of combustion air to the boiler servicing Unit 1. Each FD fan contains air intake and discharge ductwork which is connected to the fan casing air intake and discharge zones respectively. During operation, the intake ductwork conveys ambient air to the FD fan from both inside and outside the plant. After this air passes through the FD fan, the discharge ductwork then conveys it to the boiler furnace where it is mixed with the boiler fuel oil for combustion. Following combustion, the hot flue gas exits the boiler and passes through the air pre-heaters prior to entering the stack breeching.

After the modifications to the FD fans were complete and the Unit 1 breeching had been in service for a one year period, an internal inspection of the breeching took place. The inspection revealed considerable erosion damage to the borosilicate insulation. Some of the borosilicate blocks had fallen away from the walls and ceiling. The erosion was attributed to the increased FD fan capacity which delivered an increased volume of air at a higher average flue gas velocity of 50 feet per second compared to the original velocity at 43 feet per second. Erosion of the internal borosilicate insulation liner has been an ongoing issue inside the Unit 1 stack breeching since Unit 1 was up-rated.

In addition to the erosion of the borosilicate insulation, cracks in the internal insulating liner and concrete floor have developed. Cracks in the concrete floor and insulation blocks falling away from the walls and ceiling allow flue gas to contact the steel plates underneath the insulation and concrete. The flue gas condenses to form sulfuric acid which causes localized corrosion that necessitates steel plate repairs. The internal insulation liner and steel plates underneath have required repairs on an annual basis that have resulted in high maintenance costs (see Table 1) during scheduled annual outages. Typical steel plate and insulating block repairs are illustrated below in Figures 4 and 5 respectively. Concrete floor cracking is illustrated in Figure 6.



Figure 4 – Unit 1 Breeching Plate Repairs

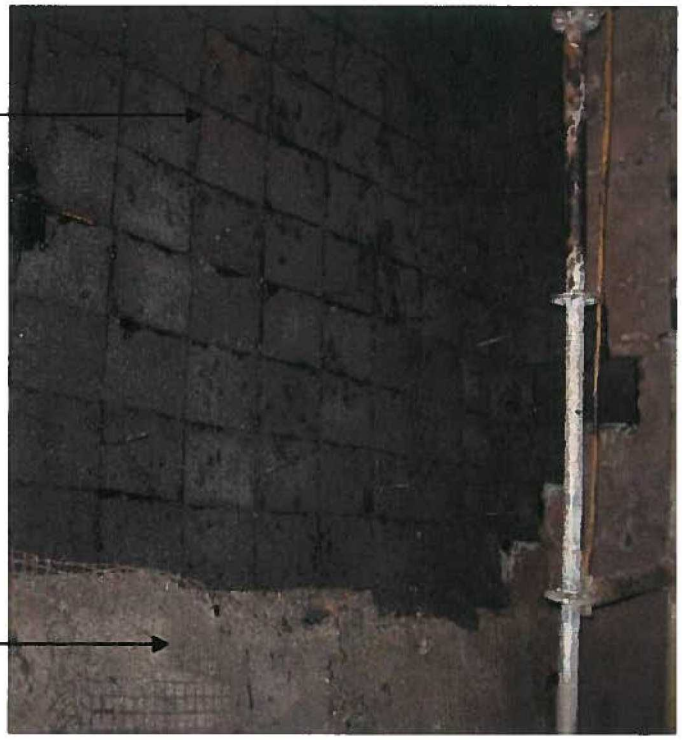

Figure 5 – Unit 1 Insulating Block Replacement



Figure 6 – Unit 1 Breeching Concrete Floor

Also, failure of the internal insulation blocks is caused by the breakdown of the adhesive membrane that bonds the blocks to the breeching plate. The temperature limit of the membrane is 200 degrees Fahrenheit. This limit is exceeded by the actual flue gas outlet temperature which is approximately 311 degrees Fahrenheit when Unit 1 is operated at full load.

In addition, controlling outlet flue gas temperature from the air pre-heaters has contributed to deterioration of the stack breeching on Unit 1. Unit 1 utilizes steam coil air heaters (SCAH) to maintain the outlet temperature of the flue gas to a minimum requirement as it exits the air pre-heaters and enters the stack breeching. The flue gas temperature should be at least 50 degrees Fahrenheit above the sulfuric acid dew point of the gas. Sulfuric acid dew point is the temperature at which condensation occurs to cause the formation of sulfuric acid which is an extremely corrosive liquid. Sulfuric acid dew point is a function of the sulfur content in the boiler fuel oil and will increase as the fuel oil sulfur content increases. Increasing the dew point increases the likelihood of forming sulfuric acid during operation. SCAHs have been used to keep the average outlet gas temperature entering the stack breeching above the sulfuric acid dew point. However, during past operation, poor control of the flue gas outlet temperature through the SCAHs in conjunction with burning

fuel oil with a sulfur content of 2.0 to 2.5 percent has contributed to the deterioration of the breeching by allowing corrosive sulfuric acid to form inside the breeching when the gas temperature is below the acid dew point. In recent years, Hydro has switched to fuel oil with a sulfur content of 0.7 percent. Using 1 percent as the sulfur content in the boiler fuel oil, the sulfuric acid dew point and flu gas safe guard outlet temperature are 280 and 330 degrees Fahrenheit respectively.

3.1 Age of Equipment or System

Unit 1 was commissioned in 1971. The existing oil fired boiler and steam turbine are 39 years old. The original stack breeching servicing Unit 1 was replaced in 1990 after 19 years of service. The existing stack breeching is approximately 20 years old.

3.2 Major Work and/or Upgrades

The original stack breeching was replaced under a 1990 capital program at a cost of $656,777.

3.3 Anticipated Useful life

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

3.4 Maintenance History

Stack breeching maintenance is a component of the annual maintenance strategy for Unit 1. During the annual shutdown, Hydro uses a boiler service contractor, Alstom Power, to

perform preventative maintenance inspections and corrective maintenance repairs on the stack breeching. Typical maintenance repairs have included replacing missing or loose borosilicate insulating blocks on the breeching interior and the installation of steel plate patches on the breeching exterior to cover holes caused by extensive corrosion. The cost of maintenance for the stack breeching is a component of the total maintenance cost for the whole unit. The ten year maintenance history for the Unit 1 stack breeching is shown in Table 1.

Table 1: Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	1.0	0.0	1.0
2008	1.0	36.0	37.0
2007	1.0	8.0	9.0
2006	1.0	320.0	321.0
2005	1.0	3.0	4.0
2004	1.0	15.0	16.0
2003	1.0	5.0	6.0
2002	1.0	64.0	65.0
2001	1.0	0.0	1.0
2000	1.0	70.0	71.0

Alstom Power completed a preventative maintenance inspection of the stack breeching in 2009. The inspection revealed that extensive repairs to the internal insulating liner were required and the cost to complete the repairs was estimated to be $100,000. However, Hydro decided not to complete the repairs in 2009 in light of the stack breeching upgrade capital project scheduled for 2011. Therefore, no corrective maintenance repairs were completed in 2009.

3.5 Outage Statistics

There have been no outages on Unit 1 caused by problems with the stack breeching.

3.6 Industry Experience

The utility industry recognizes that boiler stack breeching may need replacement periodically, either completely or partially, after a twenty year life span. In 2009, Hydro had a condition assessment of the Holyrood stack breeching completed by Alstom Power. The assessment report (see Appendix A, page 9) indicates that breeching systems in the utility industry are mainly constructed from carbon steel with external insulation, although in some cases internal insulation liners are utilized. Externally insulated breeching is generally much easier to inspect, clean, and maintain.

3.7 Maintenance or Support Arrangements

Hydro currently has a service contract with Alstom Power to perform boiler maintenance during the annual scheduled outage. Unit 1 stack breeching repairs are included under the boiler service contract.

3.8 Vendor Recommendations

Based on the twenty year service life of the existing Unit 1 stack breeching and the extended exposure to past prevailing conditions along with the history of extensive plate corrosion/thinning and internal insulation block repairs, Alstom Power indicates that deterioration may continue at the same pace or worsen if some upgrades are not implemented (see Appendix A, page 9).

Alstom Power states that the preferred long term solution for replacing the breeching is to construct the breeching from one-quarter inch Corten or equivalent high temperature carbon steel plate. These steel plates have typically been used for boiler stack breeching applications because of their improved corrosion resistance as compared to mild carbon steels. However, in order to minimize the rate of future corrosion, Hydro will continuously monitor and control the flue gas temperature inside the stack breeching through the SCAH's during boiler operation to ensure that it does not drop below the sulfuric acid dew point, thereby preventing the formation of sulfuric acid. In addition, Hydro recently has switched to fuel oil with a sulfur content of 0.7 percent which has reduced the sulfuric acid dew point of the flue gas, thereby reducing the likelihood of forming sulfuric acid during operation. Ice protection shelters will also be constructed above the breeching to protect the external insulation and cladding from damage caused by falling ice.

3.9 Availability of Replacement Parts

Replacement parts for the existing Unit 1 stack breeching have been supplied by Alstom Power.

3.10 Safety Performance

There are no safety code violations with the current operation of the existing Unit 1 stack breeching. However, the deterioration of the breeching plate could potentially allow the boiler flue gas that contains sulpher dioxide to escape inside the plant and has become a major safety concern for plant personnel.

The internal insulation liner materials include borosilicate blocks, adhesive membrane, and surface primer. According to Alstom Power, these materials are a safety concern for plant personnel working during the annual maintenance outage and can cause headaches,

dizziness, nausea, loss of coordination, and even cancer if disturbed and inhaled. In addition, the condition of the concrete floor structure is a safety concern as it is expected that significant hidden corrosion may render it unsuitable to support the load of maintenance personnel and equipment while working inside.

3.11 Environmental Performance

There are no environmental code violations with the operation of the existing Unit 1 stack breeching.

3.12 Operating Regime

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

4 JUSTIFICATION

The stack breeching servicing Unit 1 has been in service for twenty years and has deteriorated to a point where a complete replacement is necessary. The utility industry recognizes that boiler stack breeching has a limited life span and needs replacement periodically, either completely or partially, after twenty years. Past operating conditions has led to extensive corrosion of the breeching plate and deterioration of the internal insulating liner and concrete floor.

The existing condition of the breeching has become a safety concern. Deterioration of the breeching plate due to extensive corrosion has the potential to discharge the boiler flue gas that contains sulfur dioxide inside the plant. The internal insulation liner materials include borosilicate blocks, adhesive membrane, and surface primer. These materials have been contaminated by boiler exhaust gases and are a safety concern for plant personnel during annual maintenance outage and can cause headaches, dizziness, nausea, loss of coordination, and even cancer if disturbed and inhaled. In addition, the condition of the floor structure can not be easily determined and it is expected that significant localized corrosion may have rendered it unsuitable to support the load of maintenance personnel and equipment while working inside.

A complete replacement of the stack breeching is necessary for the reliable operation of Unit 1. Failure of the breeching during operation can result in an unplanned unit outage with a four week duration. An unscheduled unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System which represents approximately 11 percent of the Island Interconnected System's capacity. This would necessitate Hydro to operate standby gas turbine generators located at Hardwoods and Stephenville in order to meet the customer load demand, resulting in additional operating cost as high as $2,691,879 (see Section 4.3 – Cost Benefit Analysis). Also, an additional forced outage on the Island Interconnected System while Unit 1 is offline

will increase the potential for unsupplied energy to the system, due to the unavailability of additional standby generation.

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

4.1 Net Present Value

A Net Present Value (NPV) calculation was not done. However, a cost benefit analysis (CBA) was completed on two alternatives over a study period of ten years. See Cost Benefit Analysis Section 4.3 for details.

4.2 Levelized Cost of Energy

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

4.3 Cost Benefit Analysis

A CBA was completed on two alternatives. The study period for the CBA was 10 years. This is the minimum service life expected of the breeching system which is dependant on the future of Holyrood as a generating station. If the development of the Lower Churchill (LC) project proceeds, it is estimated that Holyrood will be required as a generating station until 2020. However, if the LC project does not proceed, it is projected that Holyrood will be required to continue operating as a generating station beyond 2020 for the foreseeable future.

<u>Alternative 1 – Replace Unit 1 Stack Breeching, Support Structure, and Install Ice Protection:</u>
This alternative replaces the existing breeching with a new system incorporating a better

design that is more common to the industry today and is estimated to have a minimum service life of 20 years. The replacement breeching will be fabricated from high temperature carbon steel and will be insulated externally with water repellent insulation complete with water tight cladding and flashing. Ice protection shelters will also be constructed above the replacement breeching in order to protect the external insulation from damage caused by ice falling from the stack and the plant power house. Upon completion of Alternative 1, the annual operating and maintenance (O&M) cost was estimated at $1,000 per year which would cover stack breeching preventative maintenance inspections. It is anticipated that corrective maintenance repairs to the Unit 1 stack breeching will not be required during the 10 year study period. There are no quantifiable benefits associated with Alternative 1. The Cumulative Present Worth (CPW) of this alternative is a cost of $3,296,230.

Alternative 2 – Refurbish Unit 1 Stack Breeching, Replace Support Structure, and Install Ice Protection:

This alternative refurbishes the existing breeching and modifies the design by partially removing the internal insulation, replacing a limited amount of steel casing with similar grade material, installing new support structures, installing an external insulation system, and installing an ice protection shield. Upon completion of Alternative 2, the annual O&M cost was estimated at $53,000 per year. This was based on an average of the 10 year Maintenance History located in Section 3.4 – Table 1 of this report which includes stack breeching preventative maintenance inspections and corrective maintenance repairs. In addition, following the refurbishment of the existing Unit 1 stack breeching in 2011, it is anticipated that extensive reoccurring repairs will be required in subsequent years on a 2 year frequency. The reoccurring repair cost was estimated at $499,200 and was based on a recommendation from Alstom Power located in Appendix B.

It is also anticipated that a forced outage may occur on Unit 1 during the study period due to failure of the stack breeching, given the 19 year service life and existing condition of the

breeching. A forced outage is more likely to occur during the peak winter load requirement when Unit 1 is operating at full load and the static pressure of the flue gas inside the breeching is at the highest level. In order to meet the requirements of the Island Interconnected System during the peak load requirement, a forced outage on Unit 1 would necessitate Hydro to operate gas turbines at Hardwoods and Stephenville. The duration of the forced outage was estimated at four weeks and was assumed to occur in January of the year 2013. The projected Island Interconnected System loads for January of 2013 were determined by prorating the actual system loads that occurred in January of 2009. The additional cost to operate the gas turbines during the outage period was calculated at $2,691,879, based on an energy requirement of 23 Gwh during the forced outage period using the incremental cost of consuming diesel fuel as opposed to No.6 fuel oil.

There are no quantifiable benefits associated with Alternative 2. The CPW of this alternative is a cost of $5,154,093.

The CBA indicates that Alternative 1 is the least cost option. Alternative 2 predicts the requirement for significant reoccurring refurbishment cost and a forced outage within the 10 year study period and the magnitude of the refurbishment cost is difficult to estimate as it is dependent on the rate of deterioration. It is possible that the reoccurring refurbishment cost may be significantly higher than the reoccurring cost that was used in the CBA. Alternative 1 will provide a solution to upgrade the breeching servicing Unit 1 for the next 10 years that will require less attention to maintain and will provide a system that is projected to have at least an additional 10 years of service life available if required.

The results of the CBA are illustrated below in Table 2.

Table 2: Cost Benefit Analysis

HRD Stack Breeching Alternative Comparison *Cumulative Net Present Value* *To The Year* 2020		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Replace Refurbish	3,296,230 5,154,093	0 1,857,863

4.4 Legislative or Regulatory Requirements

There are no current legislative or regulatory requirements to upgrade the Unit 1 stack breeching.

4.5 Historical Information

The original stack breeching servicing Unit 1 was constructed from one-quarter inch carbon steel plate and insulated externally. The cladding on the insulation was damaged by ice falling from the stack and the power house. This allowed moisture to penetrate the insulation which led to a break down of the insulation that enabled severe corrosion of the carbon steel breeching. In addition, poor control of the flue gas temperature exiting the air pre-heaters allowed the temperature to drop below the sulfuric acid dew point, enabling the formation of acid inside the breeching.

The condition of the original breeching had deteriorated to a point where a complete replacement was deemed necessary. In 1987, Hydro conducted a study to evaluate various

options for the stack breeching replacement. Following the study, a design that included carbon steel breeching insulated internally with borosilicate blocks and a protective coating on the exterior was selected. The original stack breeching was replaced under the capital program in 1990 at a cost of $656,777. Since 1990, breeching problems such as erosion and cracking of the internal insulating blocks and concrete floor have developed. Insulation blocks have fallen away from the ceiling and walls and have allowed the flue gas to contact the steel plates underneath. The cooling of the flue gas formed acidic condensate causing localized corrosion and thinning of the plates.

4.6 Forecast Customer Growth

Customer load growth does not affect this project.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits resulting from this project.

4.8 Losses during Construction

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

4.9 Status Quo

The status quo is not an option. An upgrade to the stack breeching is necessary to ensure reliable operation of Unit 1. A forced outage on Unit 1 due to a failure of the stack breeching would result in four weeks of downtime on Unit 1. An unscheduled failure during the peak winter load demand could result in a loss of 170 MW of power which represents approximately 11 percent of the Island Interconnected System's capacity. This would

necessitate Hydro to operate standby gas turbine generators located at Hardwoods and Stephenville in order to meet the customer load demand, resulting in additional operating cost as high as $2,691,879 (see Section 4.3 – Cost Benefit Analysis). Also, an additional forced outage on the Island Interconnected System while Unit 1 is offline will increase the potential for unsupplied energy to the system, due to the unavailability of additional standby generation.

4.10 Alternatives

There are no viable alternatives to this project.

5 CONCLUSION

This project is an upgrade of the existing stack breeching servicing Unit 1 at Holyrood. The breeching is twenty years old and has deteriorated to a point where complete replacement is necessary in order to maintain the reliability of Unit 1. In addition, the condition of the existing breeching is a safety concern for Holyrood personnel.

Failure to upgrade the breeching increases the likelihood of unscheduled downtime on Unit 1 and increases the risk of being unable to meet customer demands during the peak winter load requirement.

5.1 Budget Estimate

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

Table 3: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	114.4	0.0	0.0	114.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	2,880.6	0.0	0.0	2,880.6
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	256.7	0.0	0.0	256.7
Contingency	299.7	0.0	0.0	299.7
TOTAL	**3,553.4**	**0.0**	**0.0**	**3,553.4**

5.2 Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Milestones

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

APPENDIX A

Condition Assessment of Stack Breeching

At Holyrood Thermal Generating Station

Units 1, 2, and 3

ALSTOM

Final Report

to

Newfoundland & Labrador Hydro

of an

Engineering Study

on

Condition Assessment of Stack Breeching

at

Holyrood G.S.
Units #1, 2, & 3

Prepared by

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EXECUTIVE SUMMARY

Environmental and operational conditions in Holyrood G.S. have precipitated severe corrosion of the original, externally insulated breeching that has necessitated intensive and costly maintenance. Initially, the corrosion of the ductwork was more prevalent in Units 1 and 2, since Unit 3 was built ten years later. In replacing the breeching at the time of the 1989 boiler upgrades, Newfoundland & Labrador Hydro has turned to an alternative design featuring internal borosilicate lining along with an outside protective coating, which carried a promise of low maintenance cost.

Although the changeover to internal insulation partially solved the corrosion predicament, it has created a worse problem of having to repair and replace the broken and dislodged glass insulation blocks; during winter operation, gas cooling below the dew point may be occurring at those locations causing corrosion of the duct shell. The cost of maintaining the internal liner in a serviceable condition is becoming prohibitive, and it seems to be far offsetting the benefits of eliminating the icefall damage of the breeching exterior. Less expensive and more reliable materials could probably replace the current insulating blocks and refractory, but the underlying concern – no access for inspection of the duct plate and potential for localized corrosion - would remain.

A more serious root cause of the internal corrosion may have been the operating conditions of the units that prevailed until the recent change to a more sulphur "friendly" fuel (1% max. limit). At the full-load operation and with no controls employed, the outlet gas temperatures would come very close to the sulphuric acid dew point of fuels containing 2.5% or more sulphur, and the situation would become worse at low-load operation. The steam coils, used to control the average cold end temperature (ACET) of the pre-heaters, did not have adequate capacity for winter operation until the boiler uprates in 1998 when they were upgraded.

It is conceivable that the initial corrosion and maintenance problems would not have been so severe under the current operating conditions, i.e., lower sulphur content and improved outlet gas temperature control, providing the external insulation was protected from the elements and well maintained.

A number of options are provided with varying capital costs and associated anticipated maintenance requirements as shown in the "SUMMARY AND RECOMMENDATIONS" section. Also included is an overview of the condition of the Unit 3 expansion joints and suggested options to deal with the problems.

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INTRODUCTION AND PROBLEM DEFINITION

Units 1 and 2 at the Newfoundland and Labrador Hydro (NLH) Holyrood G.S. are pressurized units of Alstom (formerly CE) design from 1968; Unit 3 is a B&W boiler, constructed in 1979. Units 1 and 2 were up-rated from 150 to 175 MW in 1989, and part of the upgrade was a replacement of the breeching section between the air pre-heater and the stack.

The original breeching was a typical back end duct design constructed of 1/4" carbon steel and insulated externally. From the information available it appears that the cladding was continually damaged by ice falling from the powerhouse and stacks, allowing moisture to penetrate in insulation, which led to insulation break down and severe corrosion of the carbon steel ducting. The cost of repairing/replacing the corroded duct sections was deemed to be too high and a decision was made by the plant management to replace the breeching.

A NLH internal study opted for a design that provided for internal insulation of borosilicate blocks and a protective coating on the breeching exterior. The promise of the new system was a much-reduced maintenance cost by comparison to the original ducting. Replacement of the breeching of the two Alstom units was completed in late 1990. Since there is no specific information available one can only speculate that it was done at the same time as Units 1 and 2.

Early into the operation (1991), the new ducts developed problems such as erosion wastage and cracking of the insulation and the concrete layer. Later, problems with the liner began to mount – the insulation blocks would break and fall out allowing the gas to penetrate to the duct plate, cool and cause localized corrosion of the duct plate. As the records show, the internal liner requires frequent repairs, and the cost of keeping the insulation blocks in good order has proven to be considerably higher then anticipated. One of the reasons for the internal liner degrading may be the specified service temperature limit of the adhesive membrane of about 200°F that is easily exceeded if in contact with the flue gas (through cracks initially), which in turn may explain dislodged silicate blocks.

To make the situation worse, the exact sites of the corrosion damage are difficult to find under the insulation layers and the protective coating outside until the plate is corroded through. Cleaning the duct floors has become difficult with the floor concrete layer broken or otherwise damaged.

Alstom was commissioned to evaluate the current situation, reflect on the latest practices in the industry, and propose alternatives to minimize the breeching corrosion problems and high maintenance cost.

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CONDITIONS LEADING TO DUCT REPLACEMENT

The decision to replace the breeching was made in 1987-88, and concerned mainly units 1 and 2. The move was driven by corrosion related maintenance problems and associated maintenance cost. Unit 3 ducting, which is of a different layout, was eventually replaced as well although it was only 10 years old at the time and presumably had not experienced the same degree of deterioration. The underlining problem seemed to have been a severe corrosion condition created by formation of acidic condensate due to flue gas temperatures dropping below the acid dew point. The sub-cooled gas temperatures may have been a result of boiler operation and/or a contact with poorly insulated ducting.

It appears the condition of the external insulation contributed significantly or may have even been instrumental to the ductwork deterioration. As it happened, insulating materials on the two older units were not identical: Unit 1 was insulated with 2-1/2" of calcium silicate rigid insulation with a 1/8" flintcote 110-26 mastic applied over the blocks and reinforced with fibreglass mesh set in the mastic; Unit 2 was covered with soft bat exterior insulation and protective cladding. It is not known if there were differences in the degree of deterioration and maintenance between the two ducts.

Based on the information available (plant personnel recollection and a 1990 technical paper presented at CEA workshop), the problems with the original breeching stemmed from damaged external insulation leading to a severe corrosion of the duct plate. Moisture would penetrate into the insulation through damaged outer protection (mastic or cladding) – presumably damaged by ice falling from the stack and powerhouse (Fig. 6-7), rending the insulation ineffective. In addition, the wet insulation on sidewalls likely sagged, creating pockets of no or very little insulating material. It is believed that the degraded condition of the insulation caused considerable corrosion of ducting from outside. To further exacerbate the situation, a lack of insulating allowed the gas in contact with the duct plate to cool below the acid dew point causing in turn widespread internal corrosion (Fig's 1-5). Deterioration of expansion joints was an added irritant, which needed to be addressed.

In 1987 the condition of breeching was such that replacement was deemed necessary. An in-house study produced four replacement alternatives:

1) Modified existing design (modifications referred to expansion joints)
2) Borosilicate lining inside and corrosion resistant coating on the exterior
3) Sheets of corrosion resistant alloy material welded to the carbon steel ducting plate c/w external insulation
4) Liquid fluorocarbon coating inside and insulation outside.

Based on cost analysis, the plant management favoured to second option mainly because of the promise of dependable service and low maintenance cost. The breeching ducting was replaced in 1989-1990 with ducts insulated inside with borosilicate (glass) insulation blocks and additional layer of silicate concrete on the floor. The new breeching went into operation at the end of 1990.

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CONDITION ASSESSMENT OF CURRENT BREECHING

Shortly after start up, the new breeching developed erosion and cracking problems requiring costly repairs, which later escalated as the concrete floors began breaking up and the insulation blocks falling out. Following is an overview of the problem history of the current breeching, based on information made available (see also Fig's 8-26):

Past history of problems

Inspection of breeching in 1991- brief summary:
(Ref.: Internal inspection report, Wayne Rice, Nov. 1991)

- Installation of the new breeching in Unit 1 was completed in the fall of 1990
- The unit operated from Dec 1990 to April 1991; subsequent inspection of the ducting uncovered erosion wastage of the lining in the upper half of the elbow – the material loss amounted to 1/4" to 1/2" over a 4-month period
- Test blocks were selected to monitor the erosion rate; second measurement in October 1991 showed loss of another 1/16" to 3/16"
- The problem was linked to the fans capacity increase required for the boiler uprate, delivering higher air volume, which in turn increased the gas velocities to 50 fps from the previous 43 fps. For comparison, the supplier (Autochem) affirmed the material suitability for up to 120 fps flow
- Unit 2 was first inspected in the fall of 1990 and no erosion was found. The unit operated erosion free for one year with the original impeller until the fan was upgraded during the 1991 outage (possibly April or May). An inspection in October 1991 uncovered similar lining loss as in Unit 1
- Erosion affected approximately 3% off the total surface area of each duct in question
- Repair cost for both units was quoted at $55,000 by a contractor on site
- Some cracks in the lining were found and repaired
- External protective coating started to show signs of rust discoloration

Operating period 1992-2000

No inspection and maintenance records available for review

Summary of breeching repair work 2000-2008:
(Ref.: Breeching history summary, J. Adams, Alstom)

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Unit 1:

After eleven years in operation, extensive repairs to the insulation blocks were required. There was no significant work done in 2001, but repairs were required in the following years. In 2006, a new floor was poured by C&E Refractories. Another major insulation block replacement was carried out in 2008.

Unit 2:

In 2000, approximately 750 ft^2 of insulation was replaced. Some insulation block replacement was done in the years 2003-2005. The floor has deteriorated significantly, but to date no major work was done to correct the situation.

Unit 3:

Very little repair work was carried out until 2002. After that, insulation blocks were replaced and holes patched as required. In 2007 a new material was used for replacements, Pennguard 55 (as opposed to Pennguard 28), on trial basis. Inspection in 2008 found the Pennguard blocks in very good condition.

Current breeching condition – inspection summary
(Ref.: 2008 Inspection Report, J. Adams, Alstom Canada)

Unit 1:

West breeching

A large quantity of ash was found on top of the duct floor, but the refractory was intact. The horizontal section appeared to be in good condition - there were no holes found and no evidence of leaks. The sidewall insulation blocks were in excellent to good condition. The ceiling was good overall, but there were a few small isolated sections requiring repair - about 10 blocks were replaced. All bracing was found in good condition.

The pantleg (inclined) section had a few blocks fallen off from the overhead panel between the expansion (EJ) joint and the stack, and up to 6-10 blocks near the EJ were damaged or fallen out. A few blocks were loose and others in questionable condition on the sidewalls. The refractory at the upward bend was in acceptable condition.

East breeching

Ash has accumulated on the floor, but the refractory appeared in good condition. No major damage was found in the horizontal section, only a few isolated small sections overhead were slightly damaged needing repair. Above the up-bend, about 60 blocks had fallen off exposing the mesh. Ash and debris has accumulated between the refractory and the casing. Initially two through holes were spotted, but 12 holes were found when the loose blocks were removed and the casing cleaned.

The expansion joint has deteriorated considerably: cover plates were hanging loose, mostly separated from the sides. Behind the cover plates, the inner layers of the fabric element (insulation layers) and the inside of what appeared to be the outer belt could be seen.

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The condition of the liner above the expansion joint was difficult to ascertain because no scaffolding was erected for access. However, there appeared to be loose blocks overhead and on the sides that should be replaced. This could amount to a significant repair work. Loose blocks in area of EJ were replaced, holes in breeching were patched from outside and rods were welded to the inside of the duct shell to secure the mesh for refractory, and the EJ cover plates were repaired.

A hole was found in the bottom corner of the expansion joint and repaired. The ladder inside the breeching is severely corroded and should be removed completely. A total of about 230 blocks were installed in the east breeching.

External breeching inspection

A great degree deterioration of the expansion joints is obvious – failed corners, evidence of leaks. A more detailed inspection is needed, but that would require removal of the cover plates. Corrosion was visible under the coating.

Unit 2:

West breeching

There were a number of blocks to be replaced on the south and north walls under the air heater. The breeching floor was cracked near the hopper and lifting up. It is quite thin – only about 1½" to 2". This floor was done in 2005, and may have to be replaced again in the near future.

Overall, the internal lining was in acceptable condition. There were isolated small areas requiring attention. The pantleg area appeared to be in good condition except for a section of relatively new blocks on the north wall that seemed to be separating from the duct. There was no access for a closer look – scaffolding was not erected. Very little ash was found on the duct floor. One brace in the horizontal section had separated from the duct on the bottom.

Approximately 15 blocks were replaced. Three other small locations with loose blocks were identified but could not be stripped due to the slime deposit on all surfaces (condensation). Two of these were in the horizontal section while the other was in the pantleg. Without scaffold it was difficult to better assess the pantleg condition. However, each location appeared to require between 4 and 6 block replacements.

East breeching

The floor was in poor condition, but the rest of the block liner was sound with only a 9-block section replaced. However, the blocks appeared wet and soft overhead at the beginning of the up-bend. No leaks were found.

External breeching inspection

On the east side, the expansion joint had a leak at the bottom flange. The cover plate does not cover the entire flange to provide adequate protection from the environment. Also there are many locations on top

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of the cover where water is allowed to pool. The fabric element behind the cover plate appeared to be intact, but it would be necessary to remove the cover plate for a proper assessment.

On the west side, the protective coating broke down in small, localized areas and at a brace attachment showing corrosion. The expansion joint element has failed along the top, and a leak was found in the flange at the bottom. Again, water was pooling on top of the cover plate. Relatively minor rust discoloration was noted on the coating of the horizontal section. Also, a patch on top of the flue, welded from the inside, had not been sealed from outside.

Unit 3:

Internal breeching

Test patches of Pennguard 55 insulation material, installed in 2007, do not exhibit any deterioration or damage. Another new material, Smoothkote refractory, may also be a viable option, as the test patch remained in good condition after one year of operation. The Pennguard 55 block differs very little from the normally used Pennguard 28, and is about 30% cheaper. However, the currently used material may have been in equally good condition after one year of operation, and more time is required to draw a conclusion regarding possible use in the future.

Overall, the block liner is in acceptable condition. The blocks, replaced previous year, show no appreciable damage. However, there were new sites identified where the lining has degraded: the inspection identified about 40 silicate blocks requiring replacement.

It was noted that ash has accumulated in the expansion joint near the stack and this was causing the cover plates to be pushed outward. It was recommended that the plates be removed temporarily to allow the ash to be removed. Not much ash was found in the breeching.

External breeching inspection

The breeching appears in good condition from the outside. There were no indications of leaks in the corner areas or on top where they have been found in recent years. On the west side, a hole could be seen that had been patched from the inside, but not sealed from the outside, which allows moisture to pool inside the cavity and cause external corrosion. Also, the top of the breeching near the stack should be re-painted. The crotch area looked good.

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UNIT OPERATION CONSIDERATIONS

Operation of the boiler and back end equipment is believed to have contributed significantly to creating conditions leading to deterioration of the original breeching as well as of the breeching installed as part of units 1 and 2 upgrade. The back end system, as designed, relies on steam coil air heaters (SCAH) to control the gas temperature leaving the Ljungstrom air pre-heater. The general recommendation is that the flue gas temperature be at least 28°C (50°F) above the sulphuric acid dew point of a fuel.

Although the target sulphur content in the fuel has always been 2.2% according to Alstom personnel on site, the Holyrood records typically refer to 2.5% sulphur content (an analysis of a 1987 bunker C oil sample showed as much as 2.8% sulphur content) for which the acid dew point was calculated to be 148°C (298°F), commanding a "safe" temperature of the gas of at least 177°C (350°F). Fluctuations in sulphur content is echoed in the increase or decrease of the safe temperatures needed to avoid acid formation in the duct. The current limit on sulphur content in the fuel stands at 1%, which corresponds to 138°C (280°F) and 166°C (330°F) dew point and safe outlet gas temperatures respectively.

Without SCAH intervention, the acid dew point of the flue gas would come close to the gas design outlet temperature of approximately 150°C (302°F) for the original MCR (150 MW) and approximately 155°C (311°F) for the uprated load condition (175 MW). The temperature would drop below the dew point at low loads in off peak operating periods, possibly falling to 115-120°C. The boilers seldom operate at full load; typical loads may vary between 70 and 140 MW, but could operate as low as 50 MW (30% MCR), which means that gas temperatures would be below the dew point for a large portion of the unit operating time. As an example, in 2007 the averaged output of Unit 1 was 70 MW (40 %MCR), Unit 2 put out 110 MW (63 %MCR) and Unit 3 put out 89 MW (69 %MCR).

The steam coils have always been used in Holyrood striving to keep the average cold end temperature (ACET) of the air pre-heater at a target temperature of approximately 107°C (235°F) with a corresponding gas outlet temperature of 164°C (327°F). This would not have been a safe gas temperature for the pre-2006 fuel (needed 177°C), but would be acceptable for the new fuel composition criterion. By comparison, the target ACET for 1.0% sulphur oil is 105°C (221°F).

It was recognized in the early years of the units' operating life that the SCAH's did not have adequate capacity to support the air pre-heater requirements in winter operation with the cold air drawn from the outside, which in turn caused the outlet gas temperatures be much lower than the design. The remedy was to draw the combustion air from inside the powerhouse at the expense of creating another set of problems – because of the considerable vacuum created by the fan intake, air from outside the building would enter from all available openings and cause frequent freeze-ups throughout the plant, and opening of doors was difficult causing the doors slam shut endangering the plant personnel (Re: 1990 CEA paper). The SCAH's have been upgraded following the uprate in 1989 - a second bank was added effectively doubling their capacity. Also, a "warm air make-up system" has since been added that helps feed the combustion air into the plant in a controlled fashion that helps to avoid the freeze-up problems.

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SUMMARY AND RECOMMENDATIONS

In the utility boiler industry, it is a recognized fact that breeching ducting has a limited life and may need replacement periodically, either completely or partially. Although a twenty-year life span of ducting is not unusual, controlling or preventing the adverse conditions leading to early deterioration, both inside and outside, can extend it.

Most breeching systems employed by the utilities surveyed are of carbon steel plate construction with adequate external insulation, and only in extreme cases or in some old utilities internal insulation liners are employed. Externally insulated ducts are generally much easier to inspect, maintain and clean. Alstom does have a standard design for internal lining, typically consisting of 4" calcium silicate blocks with expanded metal mesh and 3/4" layer of Super 3000 (Alstom hi-temp refractory) on top, but the design is rarely used being maintenance intensive. Internal insulation or corrosion resistant steel liners are used in pulp and paper industry and by HRSG's. From the operation perspective, there is no advantage to insulating ducts inside rather then externally.

The chronic corrosion of the original breeching in Holyrood appears to have been rooted in deteriorated external insulation, and in operating conditions, such as low-load operation, that drove the gas outlet temperatures below the sulphuric acid dew point.

The new breeching, fitted with internal borosilicate lining, was expected to alleviate both the corrosion problems and the high maintenance cost, but failed to do either. Not only did the internal and external corrosion problems continue, although at a reduced rate, but the corroded sites became difficult to inspect and access for repairs, and the bulk of the maintenance has shifted to replacing and repairing the internal liner blocks. The projected annual maintenance cost burgeoned from the expected $8K per duct (extracted from the 1988 internal cost analysis) to a sizable multiple of that at times (e.g., in 2003, replacement of 350 sq.ft. of the silicate block liner in Unit 2 cost $90K). For comparison, the projected cost of maintaining a breeching as per the original design was $21K per year per duct.

To have a real chance of succeeding in minimizing the corrosion problem, any solution alternative selected has to embrace continuous gas temperature control at all loads. That means the ACET should be subordinate to maintaining the gas outlet temperature at 166°C (330°F) or higher at all times to avoid formation of sulphuric acid, assuming the upper limit of sulphur in the fuel (1%) is adhered to. External corrosion problems have to be addressed in parallel with controlling the internal conditions.

Considering the fact that the acid dew point has been lowered by virtue of a lower maximum allowed sulphur content in the fuel, the conditions for acid corrosion would have been somewhat mitigated already, which should reflect in lower duct maintenance in the future. However, due to the length of the service life (almost twenty years) and extended exposure to the past prevailing conditions, deterioration of the current liner may continue at the same pace or worse, if some upgrades are not implemented. The low service temperature of the adhesive membrane is likely to remain a contributing factor to the insulation block failures.

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The breeching expansion joints are in a poor condition and need a major overhaul as an interim solution, but a replacement in kind should be in the planning.

A separate issue to be dealt with is the deteriorating condition of the seven metallic expansion joints – all bellows type joints - on the hot air outlet duct from the air pre-heater. These are the original components and have been in operation for almost 30 years. Although air duct expansion joints are not exposed to as harsh environment as the gas touched components, time and service demands eventually took their toll - they all appear heavily rusted and are cracking, likely due to fatigue, in the bottom sections (see Fig.'s 30-32). The joints could be repaired piecemeal as required, but as a long-term solution, it is advisable to replace them with properly engineered cloth joints. Some of the alternatives shown below have already been considered in earlier discussions with NLH.

Solution alternatives - Breeching

Note: Indicative Pricing has been provided in Appendix 2. This indicative pricing is intended to provide an indication of relative supply and erect costs for budgeting purposes, approximately ±30%, and in not intended as an offer to provide services. Should Newfoundland & Labrador Hydro wish to pursue an option, Alstom would then provide a Proposal for such scope based on conditions at that time.

The "*Solution*" reference for each option refers to the "Breeching Solution" as outlined in the Indicative Pricing Estimate in Appendix 2.

A) Current ducts are in serviceable condition and remain in place:

1) Keep current duct arrangement, repair duct and lining as required (*Breeching Solution A1*); use cheaper insulation material to replace borosilicate blocks (e.g., Pennguard 55 vs. Pennguard 28)

   Pros: no capital investment, no time lost to upgrading ducting; potential for reducing maintenance cost by changing insulation block material;

   Cons: break-down of the insulation material and adhesive membrane will likely not subside, may become worse; prohibitive cost of repairs will remain; difficulties accessing the sites of corrosion damage and leaks under insulation and the outer protective coating will not change; cleaning ash and debris from the duct floor remains impaired; erosion wastage of lining may still be a problem

2) Keep current duct arrangement, but add 4" of external water repellent insulation and a watertight cladding (*Breeching Solution A2*); repair internal lining as required, and have the overall concept - materials and specs - reviewed for possible improvements – less expensive insulation blocks, increased concrete layer and block thickness, etc; protect external cladding against falling ice (catwalk grating, hood, etc., see B below) if that remains a genuine problem. The external surface should be cleaned of rust before installing the insulation..

   Pros: the external insulation will help prevent gas cooling even if lining damaged; potential for reducing maintenance cost by changing insulation block material; corrosion of the duct

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shell due to gas cooling through contact with the duct plate will be minimized or eliminated if external insulation is maintained; degradation of borosilicate lining less critical with external insulation added

Cons: added cost of external insulation and cladding c/w protection against damage; break-down of the internal insulation material and adhesive membrane will likely not subside, may become worse; the internal liner will still have to be maintained, therefore prohibitive cost of repairs will remain; continuing difficulties accessing the sites for inspection; cleaning ash and debris from the duct floor remains impaired;

3) keep current duct, add 6" of external insulation and remove internal liner blocks and silicate concrete (*Breeching Solution A3*); protect external cladding against falling ice (catwalk grating, hood, etc., see B) below) if that remains a problem. The external surface should be cleaned from rust before installing the insulation.

Pros: the upgraded external insulation will provide adequate insulation to prevent gas cooling, assuming it is kept in good serviceable condition; reduced maintenance cost by comparison to current situation – no insulation blocks to replace; corrosion due to gas cooling will be minimized or eliminated if external insulation is maintained; improved access for duct inspection and cleaning

Cons: added cost of external insulation and cladding c/w protection against damage; added cost of internal liner removal; access for duct inspection somewhat impaired if remnants of internal liner remain (e.g., adhesive membrane)

A modified Option 2 above (*Breeching Solution A2*) would be a preferred long-term solution **if the breeching is to be left in place**, i.e., the external insulation 6" thick (as opposed to 4" in Option 2) with the internal lining left alone initially and removed only if the silicate block degradation continued unabated. This way, no upgrade of external insulation (to the 6" thickness) would have been required if the internal liner were removed, as in Option 3.

B) Replace the entire breeching:

1) original duct design, made of

a) (*Breeching Solution B1a*) - ¼" mild carbon steel plate (G40.21 or equivalent) c/w 6" of external water repellent insulation c/w watertight high quality cladding and flashing

b) (*Breeching Solution B1b*) - ¼" Corten or equivalent high temperature carbon steel c/w 6" of external water repellent insulation c/w watertight high quality cladding and flashing

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c) *(Breeching Solution B1c)* - 3/16" stainless steel (e.g., 304, 316L, 904L, HASTELLOY C276) c/w 4" of external water repellent insulation c/w watertight high quality cladding and flashing

d) *(Breeching Solution B1d)* - 3/16" Avesta plate (2205) plate c/w 4" of external water repellent insulation c/w watertight high quality cladding and flashing

Pros: a) if properly designed and maintained, the insulation offers adequate protection against gas cooling; standard ducting material used; reduced maintenance cost compared to the current breeching; reduced load on supports and ducting plate compared to inner liner; good access for duct inspection; insulation not susceptible to cracking

b) same as a) above, but offers some protection against corrosion if gas temperature drops below acid dew point (higher chrome content – min. 0.7%)

c) and d) same as a) above, but the materials are corrosion resistant and therefore not susceptible to corrosion problems if the gas temperature is not maintained; less insulation required; less plate material used

Cons: a) does not address the original problem of insulation being damaged by falling ice; will suffer corrosion problems if outlet gas temperature is not maintained above acid dew point

b) does not address the original problem of insulation being damaged by falling ice; higher material cost;

c) and d) do not address the original problem of insulation being damaged by falling ice; high material cost; design check required due to thinner plate

2) original duct design, construction alternatives as per 1), with **added protection** against damage caused by ice falling from stack and powerhouse, as shown below:

a) *(Protection Solution B2a)* - light-weight (LW), 1½" catwalk grating on the top panels (over aluminium cladding) attached to stack and side panels

b) *(Protection Solution B2b)* - U-shaped 7 ga. plate encasement slid over the top panels (possibly with ice-breaker ribs)

c) *(Protection Solution B2c)* - 3/16" carbon steel hood over the duct, attached to the duct sidewalls

d) *(Protection Solution B2d)* - extra heavy gage, ribbed aluminium or steel cladding on the top panels

Pros: same as 1) but addresses the original problem of insulation being damaged by falling ice; less maintenance required for the external insulation if prevented from being damaged,

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relatively simple design needed for the protection; option d) would not require a special design for added protection

Cons: same as 1) except the falling ice protection; added cost of material and design of the falling ice protection, danger of creating heat sinks where protection attached to the duct

3) 1/4" Corten or equivalent hi-temp carbon steel duct, internal insulation c/w stainless steel liner *(Breeching Solution 3)* - similar to HRSG construction (3" cerwool or mineral wool insulation bats, 304L or 316L stainless steel 10 ga liner held in place with studs), no external insulation but protection coating

Pros: works well in HRSG application; less prone to external corrosion because of better plate material; insulation stays in place, traditionally low maintenance once settled

Cons: access for inspection restricted; installation sensitive; high installation cost, condensation may by a problem on bottom panel

Other options could include alloy or stainless steel cladding applied directly on the duct plate or a layer of polymer coating inside combined with external insulation, but these options were already explored by NLH and found expensive to apply and maintain, and were rejected.

The preferred long-term solution for **replacing the breeching** would be Breeching Solution B1b, with the Protection Solution B2b. Hi-temp carbon steels such as Corten have been used in the past for back end (breeching) ductwork, even if the gas temperature did not require it, because of their improved resistance to corrosion compared to low carbon steels. An additional 1/8" corrosion allowance could be added to extend the life of the ducting.

Solution alternatives – Hot air duct expansion joints, Unit 3

1) Repair or replace sections as required *(Expansion Jt Solution 1)*: the bellows could be weld repaired as required, or partially replaced, specifically the bottom part of the joints. Considering the service life and the overall condition of the joints, this should be only a short-term maintenance fix. It may however prove difficult to weld-repair the joints because of the general condition of the expansion joint material.

2) Install cloth seal over the metallic expansion joints *(Expansion Jt Solution 2)*: this interim solution would replace repairing the ailing metallic joints. It would not have any effect on the function of the current joints, but would prevent leaks. Care must be taken to evaluate correctly the movements as not the cause failure of these joints as well.

3) Replace the expansion joints in kind *(Expansion Jt Solution 3)*: this alternative would see the expansion joints replaced as originally designed and built. No engineering is required, but the probable shortcomings of the current design would be copied.

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4) Replace with metallic joints, but review the selection *(Expansion Jt Solution 4)*: engineering review would be required to confirm or repudiate the current selection, and possibly come up with a better system to prevent the current failures.

5) Replace the expansion joints with cloth joints, properly engineered *(Expansion Jt Solution 5)*: cloth expansion joints are widely used and are the preferred solution in most ducting systems. They do not exert reaction forces to the system supports, and would not be subject to fatigue-induced cracking.

From engineering and operation standpoint, Option 5 is the preferred solution.

POST MEETING FOLLOW-UP

A meeting was held at Holyrood site on March 5, 2009 to review the findings of the Study as issued in Revision 1 dated March 4, 2009.

Based on discussions during the review meeting, it is recommended that replacement of the breeching is preferred over repairing the existing materials. This is supported by the fact that the current breeching is approximately 20 years old, the original breeching on Units 1 & 2 lasted approximately 20 years, and the fact that a lifespan of 20 years is quite typical for breeching.

For reference purposes, it was decided to select two options (Modified A2, and B1b) along with extended ice protection (B2b) option for more detailed installation estimate. Include repair of support structure for the repair option (Modified A2) and replacement of support structure in the replacement option (B1b).

The existing support structure on Units 1 & 2 breeching requires some repair and should be replaced if the breeching is replaced. It was determined after the meeting that the pricing for the supports is not in the current estimate. Also, fairly extensive repairs would be required to the support structure. For pricing purposes, only a replacement is to be priced.

Appendix 1 – Figures & Tables

Year	Unit 1	Unit 2	Unit 3
2008	West side no scaffold - difficult to assess pantleg. However appeared to be sections where liner has failed above and adjacent to expansion joint. 40 to 50 blocks estimated but could be worse than appears. Horizontal section good – about 10 blocks replaced. East side many holes - duct patched from outside at north side of bend. Refractory in bend also failed. 230 blocks replaced in bend area. Horizontal section good. Scaffold up to expansion joint only. Above expansion joint liner is questionable condition. Could be a significant repair required. Expansion joints have failed both sides.	The refractory floor on both sides now in poor condition and requires replacement. West side approx 15 blocks replaced. No scaffold installed. Three other locations about 4 blocks each looked loose but not replaced due to condensation/sweat problem. East side one 9 block section was replaced. Block also wet and apparently soft overhead and up the pantleg in sections. Expansion joint in poor condition on both sides.	Test patches of Pennguard 55 block and refractory both in good condition after one year. About 40 blocks replaced – scaffold was erected. Debris noted in expansion joint should be cleaned out. Looked OK from external inspection.
2007	Minor repairs only – about 40 blocks total. Cost about $5k	East floor in poor condition – not replaced. About 90 blocks on each side replaced – all in horizontal section – no scaffold required. 3 holes patched in west side. Total cost about $16k.	Blocks replaced overhead and at both side corners – about 200 sqft. 15 holes patched (welded inside – Devcon outside). Trial patch of Pennguard 55 and Smoothkote refractory installed. Total cost about $25k
2006	C&E Refractories poured new floor east side and block both sides. Total about 760 sqft. 5 holes in west and 12 in east side patched from inside and sealed with Devcon outside. Expansion joint cover plates bad. Total cost about $320k	East floor in poor condition – not replaced. Block good both sides.	About 40 blocks to replace overhead but not done – no scaffold. 15 blocks that were accessible were replaced. No cost captured.
2005	East floor bad. Block to replace overhead and north on east side not done. West small quantity of block replaced but more to do with scaffold. Cost about $2k captured.	Mount Pearl Painting hired to replace refractory on west floor and block on both sides. Many holes found on both sides and repaired from outside. Total cost about $290k.	Hole found in top near stack. Patched from outside. No scaffold installed – accessible block replaced as required. About 90 blocks replaced and 15 not accessible. Total about $5k.
2004	East floor bad – not replaced. East side scaffolded and block replaced. Hole in expansion joint patched. Cover plates bad. West side small quantity of block replaced – no scaffold. Cost about $15k	Just a couple of blocks replaced	Block replaced overhead and at corners (higher than 2003). No holes found. Scaffold erected. Total cost about $10k.
2003	East floor starting to fail. Few blocks to replace. Supposedly repaired by another contractor working on the stack	Approximately 350 sqft of block replaced mostly on east side. Scaffold erected. Through holes patched. Done by C&E Refractories. Cost about $90k.	Holes found on both sides. Scaffold erected and holes repaired. Block replaced as required. Costs not captured.
2002	Damage repaired by C&E Refractories. This included replacement of the west floor refractory. Don't know cost.	No significant work	Very small quantity of block replaced with no scaffold. Scaffold recommended to replace block next year.
2001	No significant work	No significant work	No work done. Minor repairs recommended.
2000	Significant work done to replace block. 540 hours reported – estimated around $35k	C&E Refractory replaced about 750 sqft of block. Don't know cost.	Minor repair to borosilicate block liner

Table 1: J. Adams, Breeching History Summary 2000-2008



Fig. 1: Original Breeching, floor in horizontal section – Unit 1 or 2



Fig. 2: Original Breeching, pantleg inlet – Unit 1 or 2



Fig. 3: Original Breeching, sloping section – Unit 1 or 2



Fig. 4: Original Breeching, bend section – Unit 1 or 2



Fig. 5: Original Breeching, entrance to horizontal section (at heater) – Unit 1 or 2

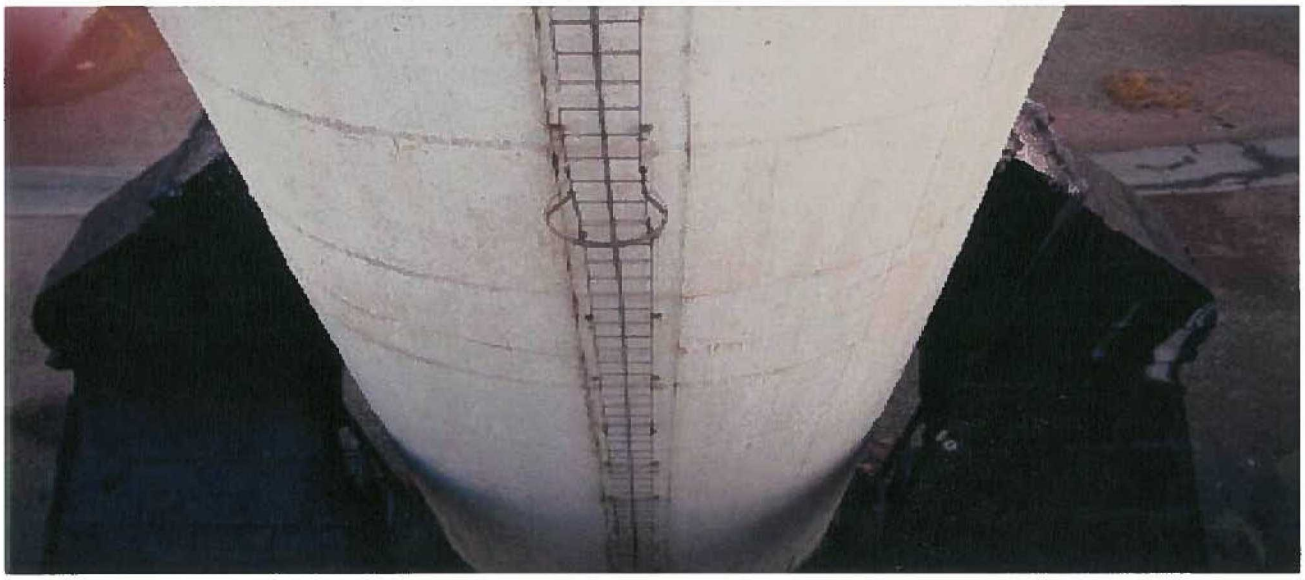

Fig. 6: Original Breeching, top view – Unit 1



Fig. 7: Original Breeching, elevation view – Unit 1

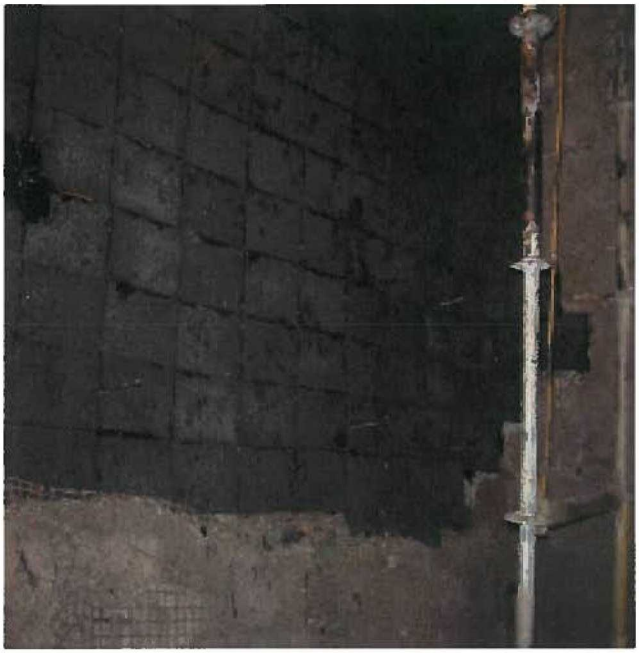

Fig. 8: Unit 1 – Insulating block replacement



Fig. 9: Unit 1 – Duct corroded through



Fig. 10: Unit 1 – Sloped section as found



Fig. 11: Unit 1 – Sidewall and floor



Fig. 12: Unit 1 – Replaced blocks



Fig. 13: Unit 1 – Missing block overhead



Fig.14: Unit 1 – Ash accumulated on the floor



Fig. 15: Unit 1 – Damaged expansion joint



Fig. 16: Unit 1 – External duct repairs



Fig. 17: Unit 1 – External duct repairs



Fig. 18: Unit 2 – Missing insulation blocks

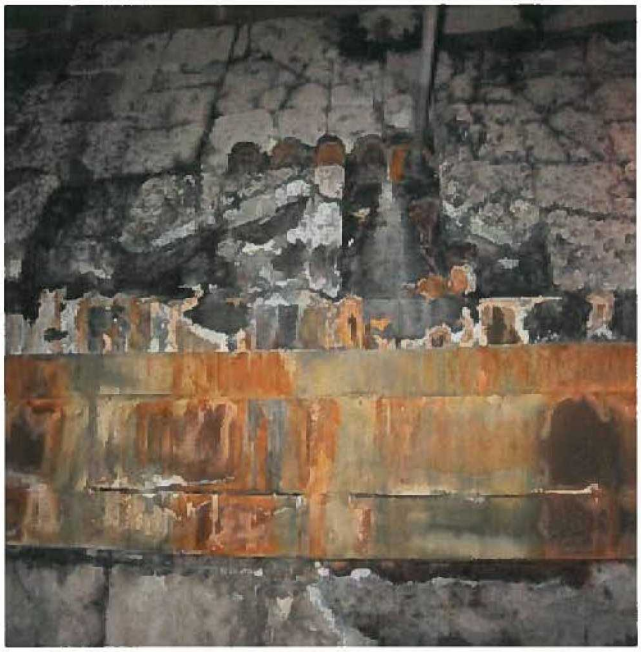

Fig. 19: Unit 2 – Missing insulation blocks



Fig. 20: Unit 2 – Cracked cement floor



Fig. 21: Unit 2 – Cracked cement floor



Fig.22: Unit 2 – External coating break down



Fig. 23: Unit 3 – Repairs 2007



Fig. 24: Unit 3 – Crotch repairs



Fig. 25: Unit 3 – Patched casing (from inside)

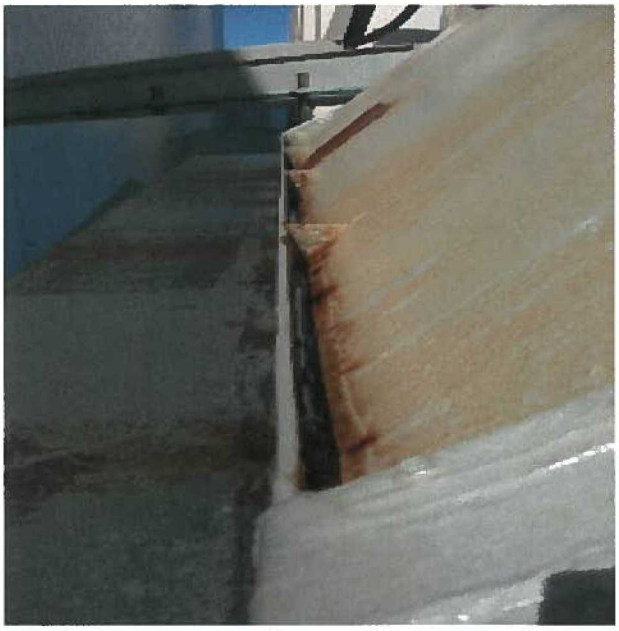

Fig. 26: Unit 3 – Top near the stack

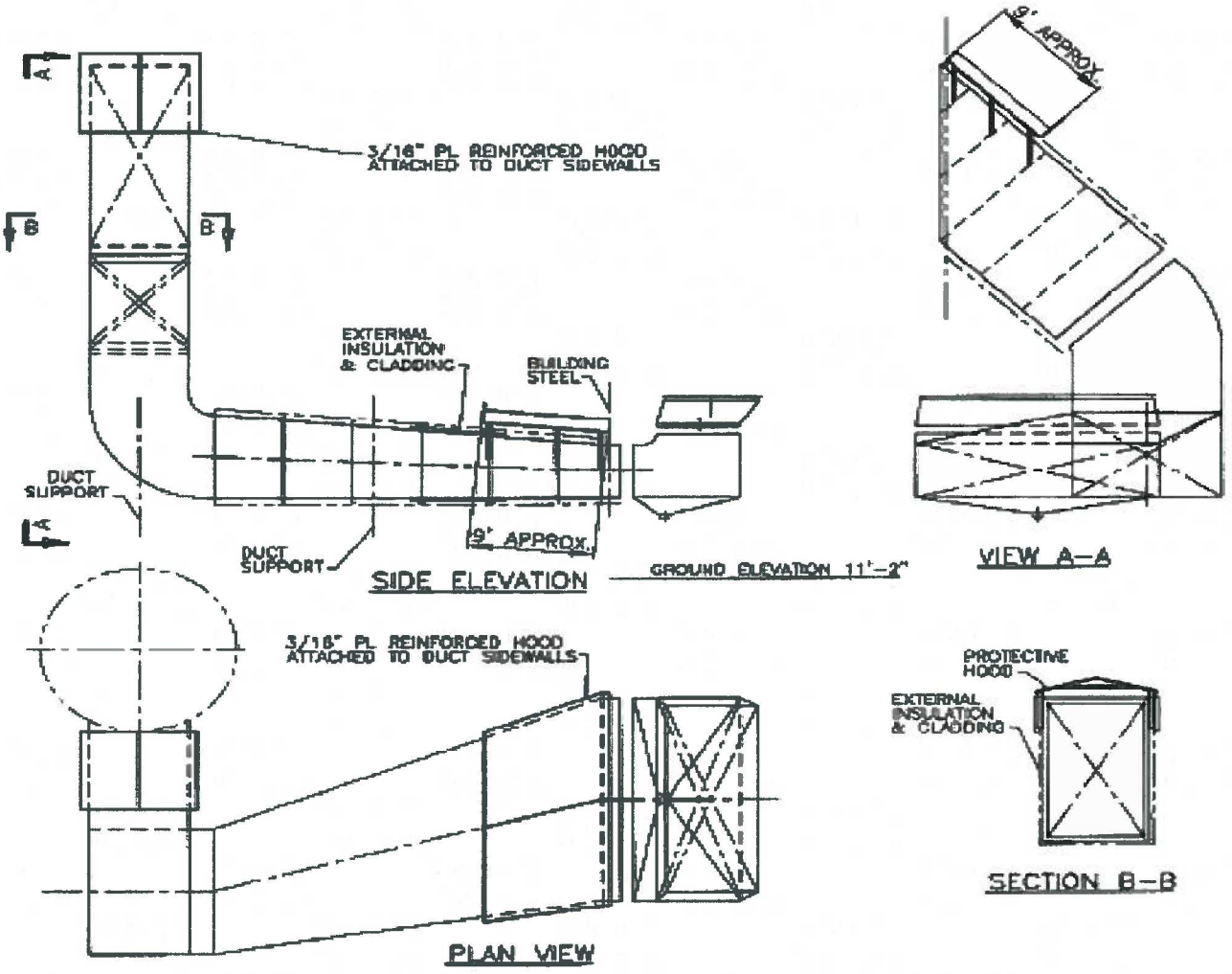

Fig. 27: Proposed cladding protection – protective hood

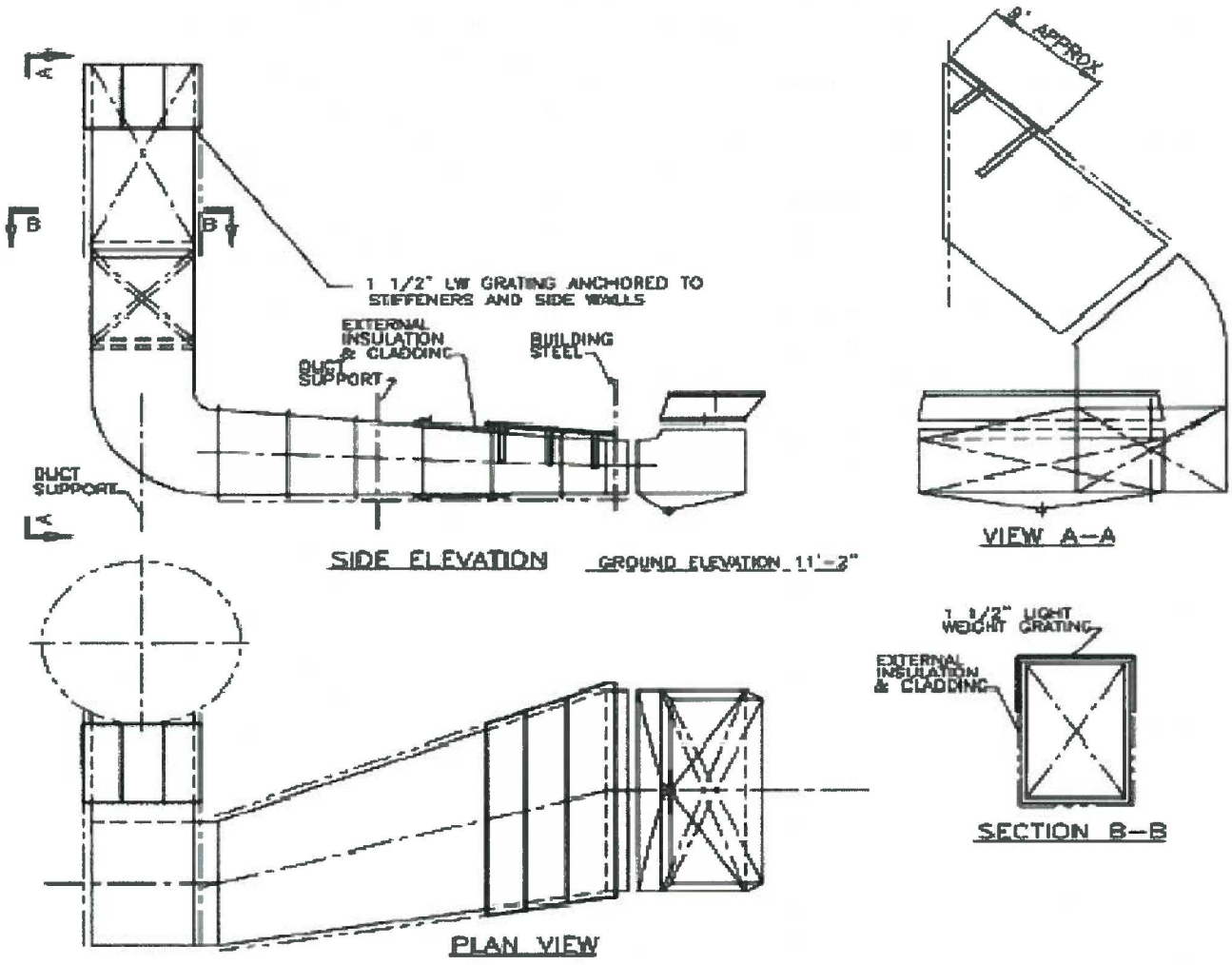

Fig. 28: Proposed cladding protection – catwalk grating

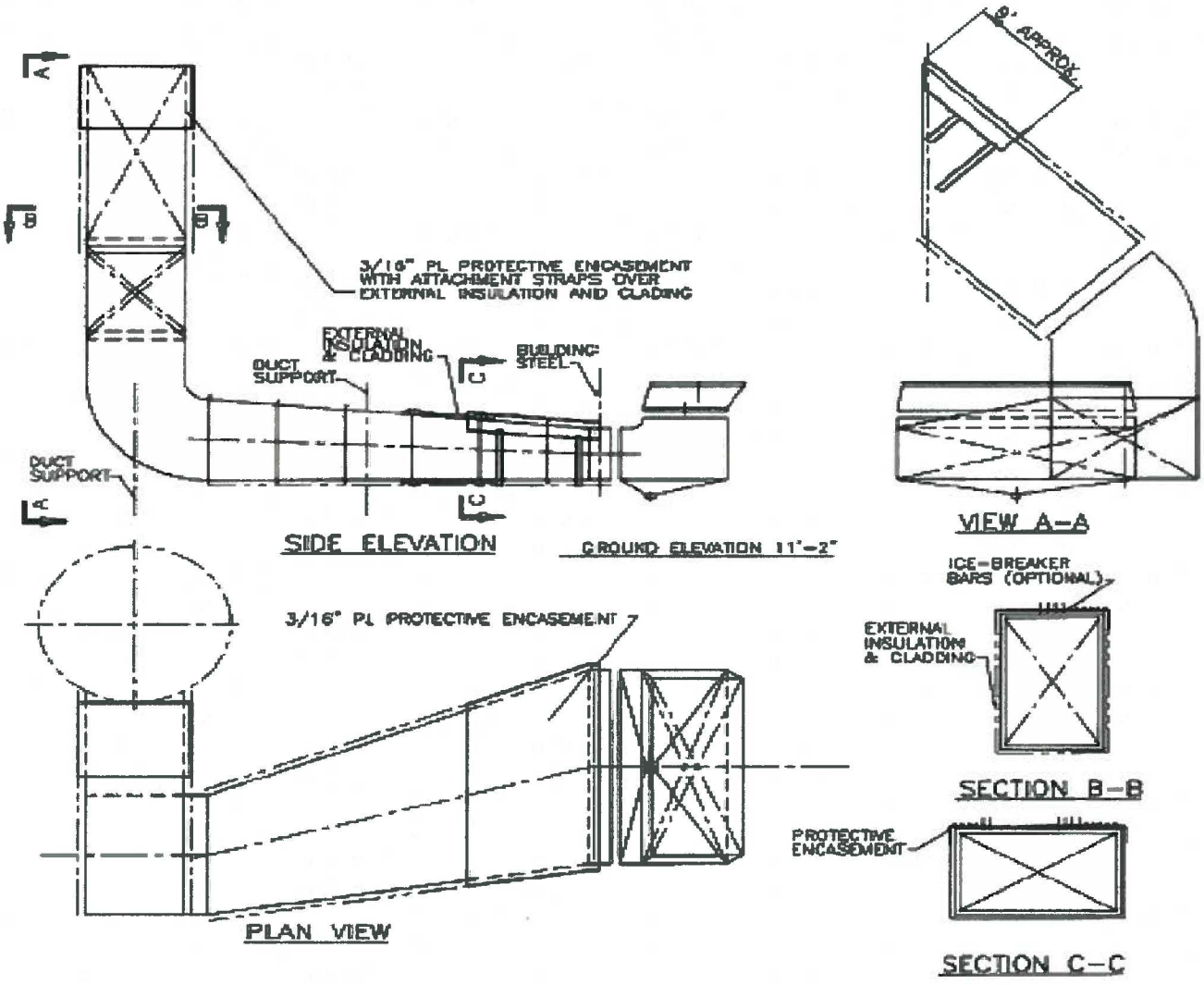

Fig. 29: Proposed cladding protection – 7ga. plate encasement



Fig. 30: Unit 3 – Expansion joint, hot air duct from air heater

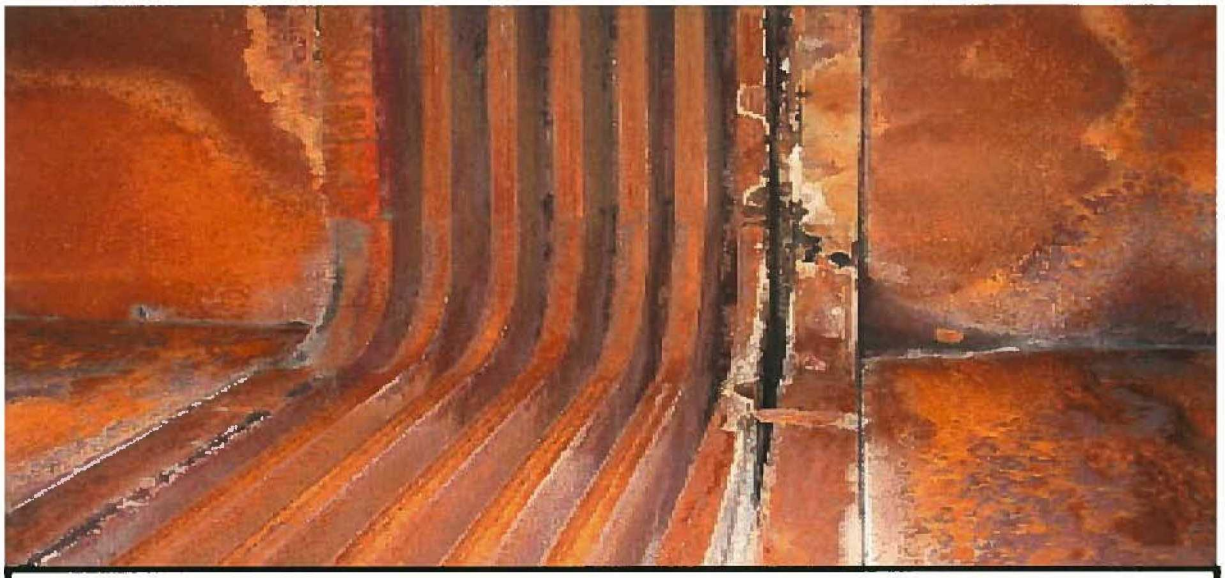

Fig. 31: Unit 3 – Expansion joint, hot air duct from air heater



Fig. 32: Unit 3 – Expansion joint #4, hot air duct from air heater

Appendix 2 – Indicative Pricing

ALSTOM Power Service

INDICATIVE PRICING ESTIMATE

CONTRACT #:	40833010	ESTIMATE TYPE:	INDICATIVE
CUSTOMER:	NLH	PROJECT TYPE:	SUPPLY & ERECT
SITE:	Holyrood, NF	DATE:	19-Aug-2009
PROP. DWG:			Rev 2 - 29/06/2010
SCOPE:	Air Heater to Stack Breeching Study		

Breeching Solution Alternatives For U1, U2 & U3	S&E (Indicative Prices)
Breeching Solution A2 Mod - Remove Rogue Insul. Blocks and Repair Casing As Req'd. Add 6" New External Insulation. - U1,U2 & U3 - Based on removing 1610 ft² of blocks. (Assumed) - Casing and expansion joints repairs are not included due to unknown condition. These repairs can be done during annual maintenance. - To be done at the same time as annual maintenance.	**$1,318,080**
Breeching Solution B1b - New 1/4" Corten Breeching with New Exp jts and New 6" External Insulation. - U1, U2 & U3 - Corten Skin, mild steel stiffeners, primed - 6" mineral Fibre board and finish with 0.040" box rib aluminium jacket for water tight cladding. - Scaffolding Included	**$7,678,456**

Ice Protection Solution Alternatives For U1 & U2	S&E (Indicative Prices)
Protection Solution B2b - U-shaped 7 ga Plate Encasement Slide Over Top Panels, U1 & U2 Only: - Primed and top coat - C.S. material	**$214,252**

Breeching Support Structure Replacement For U1 & U2	S&E (Indicative Prices)
Replace Breeching Support Structure for U1 & U2 Only: - SP-6 blast c/w primer and top coat - End frames are assembled as a unit - Welding CWB 47.1 - Material G40.21 44W - To be installed at the same time with B1b breeching solution only. Additional cost is required with A2 breeching solution since the existing breeching is not removed.	**$153,661**

Notes:

(1) Construction estimate on ice protection and expansion joint is based on being on site in conjunction with the maintenance work.

(2) For Unit #3 (B&W), we have no drawings. For future firm price proposal, we are expecting NLH to provide the necessary drawings of the existing ducting for us to work from.

(3) For Solution A2 Mod. Casing repair because the condition is not known, it should be done during annual maintenance.

(4) This budget proposal gives a preliminary indication of the basis of which [services/deliveries] can be undertaken, and does not constitute an offer to carry out those [deliveries/services]. In particular, any prices, delivery times or performance figures mentioned are given without commitment at this stage. Nevertheless we trust the information provided is sufficiently detailed to enable you to assess the benefits which you can obtain by utilising our Company's services/deliveries, and we confirm our keen interest in working with you. To this end we look forward to discussing with you the content of this proposal and, when appropriate, submitting an offer to you.

(5) Breeching support replacement pricing is applicable only with B1b breeching solution. Additional cost is required with A2 breeching solution since the existing breeching is not removed.

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APPENDIX B

Alstom Power

Supplementary Comments

POWER
THERMAL SERVICES

ALSTOM

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Ottawa, Ontario, Canada K1J 9N2
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2010-07-02

Newfoundland Labrador Hydro

Attn: Todd Collins

Re: Stack Breeching Study - 40833010

Dear Mr. Collins:

As a follow-up to our conference call earlier this week, and in reference to our above referenced report, we offer the following clarifications and opinions.

As stated in the Study Report, this additional commentary was carefully prepared on the basis of Alstom observation and analyses, and any conclusions and recommendations are based on Alstom experience and judgement.

The Company disclaims all warranties in respect to services rendered in connection with this Contract whether express, statutory, oral, written or implied.

The Company disclaims any and all liability arising from damage or loss sustained by the Purchaser or by any third party in the event that the Company's recommendations, conclusions or opinions, as contained in the Study Contract, are implemented, acted upon or applied by any third party or by the Purchaser acting on its own without further involvement of the Company. The Purchaser shall indemnify the Company against all third party claims, damages and losses in this respect.

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Should the Purchaser subsequently retain Alstom to perform any of the work related to recommendations contained in this report, a separate contract governing such work shall be executed appropriately.

This commentary is furnished for the Purchaser's benefit only, and not for the benefit of any third party.

Repair Solution Modified Option A2

The estimated pricing provided in Rev 4 is the Modified A2 option as discussed on page 11 of the report. As stated in the report, this is the preferred option "if the breeching is to be left in place". The previous estimated price was based on the A2 option. With the modified A2 option, the external insulation is upgraded to 6". As a result of this upgrade, the internal block liner becomes redundant and replacement is not required. Consequently, installation of new block is not included in the price. Removal of 1610 ft^2 total of the block liner for inspection and repair of casing in suspect areas is included. This represents 12% of the total liner area in each breeching and this figure was assumed based on previous repair history. A more conservative assumption could be used. For example, removal of 50% of the liner would increase the estimated cost by approximately $157,000 total over three units. This might be a reasonable upper end assumption.

Replacement of the expansion joints and repairs to the casing would be required with this option but were not included in the estimate because the overall condition is not known in detail. However it is our opinion that this cost could be in the neighbourhood of about $200,000 per unit (or $600,000 total) when labour, materials, crane, etc... are included. This would increase if more of the block liner is removed and more extensive repairs are completed. For 50% liner removal we assume that this cost could double.

Anticipated longevity of repairs versus replacement

With a full replacement in accordance with option B1b, and with ice protection and replacement of support structures, it is our opinion that the new breeching would last 10 to 20 years with little or no O&M costs other than inspection and cleaning. This assumes that

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the external insulation is maintained in good condition and that operating parameters are maintained within established guidelines (especially average cold-end gas temperature).

It is far more difficult to predict the longevity of the repair option and certainly, it will depend on the amount of block removed for casing inspection and repair. If all of the block is removed (old Option A3) and extensive repairs are completed to essentially restore the ductwork to like new condition, then a life of 5 years or longer with relatively minor annual repair costs might be a reasonable assumption. With less block removal and less repair, then 2-3 years might be a reasonable expectation before extensive repairs would be again required.

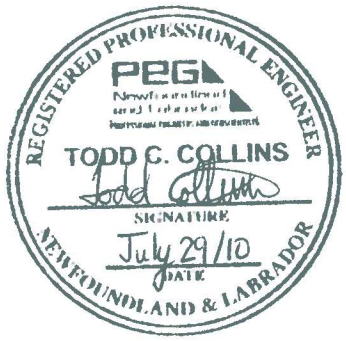
Major repair cost after this time would not include expansion joint replacement or new external insulation but would include casing replacement and repair and also removal of block liner as required. Removal and replacement of external insulation would be required to replace any sections of plate that could not be restored effectively from the inside. Repair costs in the $200,000 to 300,000 range per unit might be a reasonable assumption.

Yours truly,

Jim Kearns
Engineering Study Manager
ALSTOM Power & Transport Canada Inc.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

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

REFURBISHMENT OF THE FUEL OIL STORAGE FACILITY

Holyrood Thermal Generating Station

April 2010

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

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

A study completed by SGE Acres entitled *"Evaluation of Fuel Oil Storage Tanks, Associated Pipelines and Dyked Drainage System, Holyrood Thermal Generating Station"*; dated March 2006 identifies a number of deficiencies requiring corrective action. This study was filed as part of Hydro's 2008 Capital Budget Application, Section H, Tab 2. This project is part of a multi-year plan to refurbish the Fuel Oil Storage Facility based on the SGE Acres report, which involves refurbishing Tank 3.

A leak or spill of No. 6 fuel from Tank 3 could cause major environmental and operational issues. The fuel oil storage tanks have deteriorated due to corrosion and require immediate attention to provide a useful life comparable to that of the rest of Holyrood.

Upgrade work previously approved by the Board of Commissioners of Public Utilities (the Board) for the Fuel Oil Storage Facility includes:

- A 2008 capital project was approved by Board Order No. P.U. 30 (2007) for the refurbishment of Tank 2.
- A 2009 capital project was approved by Board Order No. P.U. 36 (2008) to upgrade the drainage system and pipe supports.
- A 2010 capital project was approved by Board Order No. P.U. 1 (2010) to refurbish fuel oil storage Tank 4 and is currently in progress.

2 PROJECT DESCRIPTION

This project involves the upgrade of existing components within the Fuel Oil Storage Facility at Holyrood for the purpose of extending its useful life, ensuring system reliability, increasing the level of safety and reducing environmental risks within the facility. The scope of the work is to clean, inspect, replace floor plates, paint floor and install a roof platform for Tank 3. A similar project to upgrade Tank 4 was approved by Board Order P.U. No. 1 (2010) and the work is currently in progress. Table 1 provides the direct cost to upgrade Tank 3 which is based on the actual tendered pricing associated with the upgrade of Tank 4.

The project will also include the installation of a fuel oil level indication system on Tank 3 that will provide accurate fuel tank level feedback to the Holyrood control room and reduce or eliminate the need to complete manual fuel reconciliations. In addition, the project will also include the installation of access steps over the fuel oil and steam piping system that runs north and south between Tanks 1 and 2 and also between Tanks 3 and 4 in order to enable plant personnel to safely access the roadway located on the west side of the tank farm.

Table 1: Refurbishment of Fuel Oil Tank 3 and Miscellaneous Works

Description	Cost ($000)
Floor Coating	229
Replace Floor Plate	881
Tank Cleaning	320
Roof Platform	136
Third Party Inspection	29
Fuel Oil Level Indication System	190
Access Steps	81
Total:	1,866

The fuel oil storage tanks and associated components are inspected and upgraded in accordance with American Petroleum Institute (API) Standard 653 "Tank Inspection, Repair,

Alteration, and Reconstruction" which is the upgrade standard for tanks specified under API Standard 650 "Welded Steel Tanks for Oil Storage". Inspections are made after fuel has been transferred to another tank. During these inspections, preventative and corrective maintenance is performed to remedy the deficiencies, such as patching holes found in the steel roof and steel floor.

3 EXISTING SYSTEM

There are four above ground fuel oil storage tanks containing No. 6 fuel (Bunker C) and associated pipelines at Holyrood. Each tank has a storage capacity of 200,000 barrels and is 55 metres (180 feet) in diameter and 15 metres (48 feet) high. A significant concern identified by the SGE Acres' inspection in 2003 was corrosion of the floor in Tank 3.

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

3.1 Age of Equipment or System

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

3.2 Major Work and/or Upgrades

An inspection by SGE Acres in 2003 identified the requirement for the installation of patch plates to repair the floor of Tank 3. This work was completed in 2003 and extended the life of the floor on Tank 3 for five years. SGE Acres recommended replacement of the floor plate and the installation of a protective coating in 2010. No further inspection of Tank 3 has been carried out.

3.3 Anticipated Useful life

The anticipated useful life of the fuel storage facility is 35 years. The existing facilities are at

the end of their useful lives. The recommended upgrades to the tanks are expected to extend the useful life of the storage facility by 20 years, or at least until the fuel storage facility is no longer required if the Lower Churchill project receives sanction. Should the Lower Churchill Project proceed, this facility must remain in operating condition until 2020.

3.4 Maintenance History

Tank 3 was cleaned and inspected in 2003 at a cost of $538,140. The work included:

- internal cleaning;
- internal inspection;
- installation of 195 patch plates on the tank floor;
- repair of holes in the roof plates;
- installation of bird screens on storage tank roof vents; and
- exterior painting.

The tank inspection was the basis for the recommendations made in the SGE Acres Report for Tank 3. These recommendations provide the scope of work for this capital project.

3.5 Outage Statistics

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

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

environmental risk during the operating months. A project to upgrade Tank 4 was approved by Board Order P.U. No. 1 (2010) for $2,500,200 and is currently in progress.

3.6 Industry Experience

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

3.7 Maintenance or Support Arrangements

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

3.8 Vendor Recommendations

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

3.9 Availability of Replacement Parts

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

3.10 Safety Performance

There are no safety issues associated with the operation of Tank 3.

3.11 Environmental Performance

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

3.12 Operating Regime

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

4 JUSTIFICATION

This project is justified on the requirement to replace a failing and deteriorated fuel oil storage infrastructure in order for Holyrood to provide safe, environmentally responsible, least-cost, reliable electrical service. Tank 3 has deteriorated to a point where there is a significant risk for oil leakage and inoperability. Corrective action must be taken.

The installation of a fuel oil level indication system on Tank 3 will provide accurate fuel tank level feedback to the Holyrood control room and reduce or eliminate the need to complete manual fuel reconciliations. In addition, the installation of access steps between Tanks 1 and 2 and also between Tanks 3 and 4 will enable Holyrood personnel to safely access the roadway located on the west side of the tank farm as opposed to climbing over steam/fuel oil piping and a berm to access the roadway from these locations.

4.1 Net Present Value

A net present value calculation was not performed in this instance as there are no viable alternatives to refurbishing Tank 3.

4.2 Levelized Cost of Energy

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

4.3 Cost Benefit Analysis

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

4.4 Legislative or Regulatory Requirements

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

4.5 Historical Information

Table 2 shows the history of the fuel oil storage facilities refurbishment projects for the past three years.

Table 2: Historical Information

Year	Budget ($000)	Actual ($000)	Comments
2010F	2,500		Tank 4 upgrade
2009	2,867	2,086	Drainage system and pipe supports
2008	500	776	Tank 2 upgrade

The upgrade to Tank 4 in 2010 is more extensive than the upgrade to Tank 2 in 2008. The upgrade to tank 2 involved patch work replacement to the tank floor while the complete floor of tank 4 is being replaced in 2010.

4.6 Forecast Customer Growth

Customer growth has no impact on this project.

4.7 Energy Efficiency Benefits

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

4.8 Losses during Construction

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

4.9 Status Quo

The status quo is not an acceptable option. The existing system has deteriorated components that require upgrades to extend their useful lives and to ensure compliance with regulatory requirements established by GAP and API. Table 6.2 of the SGE Acres Report recommends the upgrades to be completed in 2010. The project will already be one year behind the recommended completion date and should not be delayed any further.

4.10 Alternatives

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

5 CONCLUSION

The fuel storage system has deteriorated to a point where action must be taken to correct deficiencies. Tank 3 will be upgraded in accordance with API standard 653 to minimize the risk of any leaks or spills.

5.1 Budget Estimate

The budget estimate for this project is $2.6 million. Table 3 summarizes the costs.

Table 3: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	204.5	0.0	0.0	204.5
Consultant	158.0	0.0	0.0	158.0
Contract Work	1,866.0	0.0	0.0	1,866.0
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	184.3	0.0	0.0	184.3
Contingency	223.1	0.0	0.0	223.1
TOTAL	**2,637.9**	**0.0**	**0.0**	**2,637.9**

5.2 Project Schedule

Table 4 provides the anticipated project schedule.

Table 4: Project Schedule

Activity	Milestone
Prepare Tender Documents	March 2011
Invite Tenders	April 2011
Award Tender	May 2011
Complete Construction	October 2011
Closeout Project	December 2011

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

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

UPGRADE HYDROGEN SYSTEM

Holyrood Thermal Generating Station

April 2010

newfoundland labrador hydro
a nalcor energy company

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APPENDIX A A1

APPENDIX B B1

APPENDIX C C1

1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) plays an essential role in the province's power system. With three units providing a total capacity of 490 MW, the plant provides power generation for the Island Interconnected System. Holyrood was constructed in two stages. In 1971, 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 I and 2 were up-rated to 170 MW. Holyrood (illustrated in Figure 1) represents approximately one third of Hydro's total Island Interconnected System generating capacity.



Figure 1: Holyrood Thermal Generating Station

As part of normal operation, all electrical generators produce a significant amount of heat. The amount of heat produced is relative to the load on the generator and the rotational speed of the generator. Without cooling, the generators would overheat and fail. Likewise,

as the amount of heat generated varies, so does the method of cooling. The most common cooling mediums are air and hydrogen gas. Worldwide, close to 70 percent of all generators greater than 60 MW utilize hydrogen gas cooling. Hydrogen gas is preferred over air because its physical characteristics better facilitate the dissipation of heat from the generator. However, there are safety concerns associated with the use of hydrogen gas. Safety risks associated with hydrogen use and the hydrogen system at Holyrood are detailed in Section 3.10, Safety Performance of this report.

In a thermal generating station, the four of the main components needed to produce electricity are the boiler, turbine, generator and exciter. The boiler provides steam pressure to turn the turbine which is connected by a shaft to the generator. The generator is connected to an exciter which provides a magnetic field for the rotor of the generator. A casing encloses the generator and contains hydrogen used for cooling. Hydrogen gas pressure inside the casing is maintained at approximately 30 pounds-force per square inch gauge (psig). Where the shaft penetrates each end of the casing, shaft seals are utilized to prevent leakage of hydrogen to the outside.

2 PROJECT DESCRIPTION

This project is required to upgrade the hydrogen gas system at Holyrood to enhance its safety and reliability. The project will be completed over two years. In 2011, work includes the installation of a hydrogen electrolyzer and low pressure hydrogen bulk storage tanks, and replacement of three hydrogen gas control panels. Work in 2012 includes the installation of automatic hydrogen venting systems on generating Units 2 and 3 and replacement of the manual gas control valves and piping.

3 EXISTING SYSTEM

The hydrogen system at Holyrood supplies hydrogen gas to all three generators for cooling. The hydrogen system was constructed in two phases, in conjunction with the generating units. The majority of the hydrogen system was placed in service upon completion of Stage I in 1971. The remainder of the system was completed in 1977, when Stage II was completed. The original hydrogen supply consisted of 24 individual high pressure (2,000 psig) cylinders, each manually connected by piping to a common supply header. However, over time this arrangement was recognized to be a safety risk due to the possibility of leaks occurring at the manual connections. Hydrogen gas leaking into external air will form a highly combustible environment. As a result, in the mid 1980s, Hydro changed the arrangement from individual cylinders to the current supply system of hydrogen bulk packs. A bulk pack consists of sixteen cylinders, in a four by four arrangement, pre-connected at the factory. By utilizing bulk packs only one manual connection is made to the hydrogen supply header, reducing the likelihood of leaks.

The upgrade of the hydrogen system is required to enhance the safe and reliable operation of the Holyrood Thermal Generating Station. Appendix A shows a detailed diagram of the existing hydrogen gas control system.

3.1 Age of Equipment or System

The existing hydrogen system for generating Units 1 and 2 was installed in 1971 and for generating Unit 3 in 1977.

3.2 Major Work and/or Upgrades

Table 1 lists the upgrades that have occurred to the hydrogen system since its installation.

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2009	Installation of Automatic Hydrogen Vent Valves on Unit 1	FM Global, Hydro's Insurer, directed Hydro to complete this project.
1985	Conversion to Hydrogen Bulk Packs	Project completed to reduce risks of leaks with previous system of individual cylinders.

The major upgrade in 2009 cost $213,200. The cost for the 1985 upgrade is not available.

3.3 Anticipated Useful life

The hydrogen system has an estimated service life of 30 years. The system will be required to operate Holyrood as a synchronous condenser station when the infeed from the Lower Churchill project is in service.

3.4 Maintenance History

Since 2005, annual maintenance costs have been between $5,700 and $43,600. Of the total $116,400 spent to maintain the hydrogen system in the last five years, $84,600 was spent to repair the generator gas control panels. The remainder was spent on the repair of leaks from various parts of the hydrogen system. The five-year maintenance history for the hydrogen system at Holyrood is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2009	30.6	13.0	43.6
2008	0.3	10.2	10.5
2007	1.8	31.0	32.8
2006	0.2	23.6	23.8
2005	1.5	4.2	5.7

3.5 Outage Statistics

There have been no outages attributed to the hydrogen system.

3.6 Industry Experience

Hydro is a member of the Thermal Generation Interest Group (TGIG), a program area of the Centre for Energy Advancement through Technological Innovation (CEATI). CEATI is a user-driven organization committed to providing technological solutions to its electrical utility participants. From its affiliation with TGIG, Hydro has learned that other utilities have replaced their hydrogen bulk packs with some form of low pressure bulk storage tank and some have installations of hydrogen electrolyzers for electrical generators.

3.7 Maintenance or Support Arrangements

The majority of the hydrogen system at Holyrood is maintained by operations personnel at the plant. This includes all piping, valves, instrumentation and gas control panels. Also, Holyrood has a service contract with Air Liquide Canada to supply and maintain all hydrogen bulk packs.

3.8 Vendor Recommendations

Proton Energy Systems, Inc., the manufacturer of proton exchange membrane (PEM) on-site hydrogen generation systems, recommends the replacement of the existing control panels and the installation of hydrogen generation and low pressure hydrogen storage to allow for better hydrogen purity control. Environment One (E/One) Utility Systems, the manufacturer of Generator Condition Monitors (GCM's) and Generator Gas Analyzers (GGA's) for monitoring purity within hydrogen-cooled electric power generators, also recommends replacement of the existing control panels.

3.9 Availability of Replacement Parts

Replacement parts are readily available for the existing hydrogen system.

3.10 Safety Performance

Since the year 2000, there have been 28 reported unsafe work conditions related to the Holyrood hydrogen system. Eleven of these incidents were hydrogen leaks from various parts of the hydrogen system. Out of these 11, seven incidents directly affected the operation of a generating unit because of low hydrogen pressure or contamination of the hydrogen gas.

The hydrogen system at Holyrood has several inherent safety risks. The major concern with hydrogen is the possibility of a fire or explosion. Hydrogen, when mixed with air at concentrations of four percent to 74 percent, forms an explosive mixture. In order to ensure that concentrations in this range do not occur in or around the hydrogen system, it is necessary to ensure there are no leaks from the system and that all surrounding equipment is intrinsically safe. However, the design of the hydrogen system in Holyrood

greatly increases the risk of a leak. Currently, when the installed hydrogen bulk pack is emptied, a piping connection is manually broken to allow the bulk pack to be changed. Each time a connection is broken on this system there is a risk of a leak. There have been numerous incidents in the power generating industry where either human error or an improper design resulted in the release of hydrogen gas and/or a major incident such as an explosion. One such incident occurred at the Muskingum River Plant on the morning of January 8, 2007. This explosion resulted in the fatality of the hydrogen delivery driver, injury of nine plant workers and significant damage to the north wall of the plant. See Figures 2 and 3 for the extent of damage to the plant.



Figure 2: Exterior Damage – Mukingum



Figure 3: Interior Damage - Muskingum

At this power plant, like at Holyrood, maintenance on the storage facility was preformed by an outside contractor. The attributing factor for the incident was determined to be inadequate maintenance, human error and improper system design. The risk of an incident such as this occurring in Holyrood is unacceptable and must be mitigated by performing adequate maintenance, removing the possibility of human error and installing a better designed hydrogen system. The installation of a hydrogen electrolyzer and low pressure bulk storage will virtually eliminate the risk of human error. Once an electrolyzer is installed in the hydrogen system, no mechanical connection will be required to be broken on a

regular basis. This will eliminate the chance of a leak due to human error. By eliminating the probability of leaks due to human error the safety of the hydrogen system will be greatly enhanced.

The use of high pressure hydrogen bulk packs has its own inherent safety concerns that must be eliminated. Each bulk pack consists of 16 high pressure cylinders. The hydrogen gas is stored at a pressure of 2000 psig. Due to these storage pressures the hydrogen cylinders must be kept in excellent condition and must be kept away from heat sources. Should a cylinder fail a major incident would occur. The severity of the incident would largely depend on if ignition of the hydrogen gas occurred. Even if the gas did not ignite, the cylinder would become a projectile with enough energy to damage buildings and injure workers. The damage of one such incident at a Praxair facility can be seen in Figure 4.



Figure 4: Building Damage due to High Pressure Cylinder Failure

However, if ignition occurred an explosion would most likely occur causing a massive amount of damage to the surrounding equipment and facilities. One such incident occurred at a Praxair facility in St. Louis in 2005. The propylene cylinders in the facilities storage yard overheated due to the high ambient temperatures. The result was a major explosion and fire that damaged the Praxair facility, as well as the neighbouring community, see Figures 5 and 6. The risk of these types of incidents is unacceptable and must be eliminated by

installing an electrolyzer and low pressure bulk storage.



Figure 5: Praxair Storage Yard Fire



Figure 6: Praxair Storage Yard Fire picture 2.

3.11 Environmental Performance

There are no environmental issues associated with upgrading the hydrogen gas system at Holyrood.

3.12 Operating Regime

Holyrood has the capability to operate in generation or synchronous condenser modes. Holyrood operates in generation mode each year from fall to spring, with Unit 3 operating as a synchronous condenser during the summer. The hydrogen system is required to operate whether the units are in generation or synchronous condenser modes.

4 JUSTIFICATION

This project is justified on the requirement to replace deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. The hydrogen system in Holyrood is a key component of the safe and efficient operation of the plant, as detailed below. The existing hydrogen system is largely original and requires extensive amounts of work to operate in a safe and reliable manner.

Installation of a hydrogen electrolyzer and low pressure bulk storage.

The installation of a hydrogen electrolyzer and bulk storage is required to mitigate the safety and operational risk associated with the current hydrogen supply. The current hydrogen supply consists of a hydrogen bulk pack of 16 high pressure hydrogen cylinders, connected to a common hydrogen supply header. The hydrogen bulk packs are supplied and maintained by Air Liquide Canada. The hydrogen gas supplied by Air Liquide Canada is not produced in the province of Newfoundland and Labrador. This has caused some reliability issues with respect to shipment of hydrogen gas to site. There have been numerous instances when hydrogen gas has been almost completely exhausted at the plant. The most recent incident occurred on June 4, 2010. Without hydrogen, the plant would have to shutdown due to lack of generator cooling. To prevent a shutdown, the operators reduce the flow of hydrogen to the generators. The casing purity and pressure drop once the flow is reduced as the hydrogen control panel continue scavenging hydrogen. In March 2007, as part of developing a Business Continuity Plan, Hydro engaged Risk Management Services Group, Aon Reed Stenhouse Incorporated to conduct a workshop with key Hydro operations personnel to identify potential naturally occurring or man-made risks that posed danger to critical processes in normal operations. The loss of hydrogen supply due to supply side transportation problems was identified as a high risk. Appendix C contains an excerpt from Hydro's Business Continuity Plan detailing the risks associated with the hydrogen system.

Replacement of the hydrogen control panels.

The hydrogen control panels control and monitor the purity of the hydrogen gas inside the generator casing. As a generator continues operating, the purity of the hydrogen gas in the casing decreases because of the induction of air into the casing through the turbine shaft sealing oil. Generator manufacturers recommend that the purity level should not drop below 97 percent pure hydrogen. Generator purity at Holyrood has reached levels as low as 85 percent. Hydrogen purity levels this low are typically experienced due to the depletion of the hydrogen supply and lasts until new bulk packs are supplied from Air Liquide Canada. Hydrogen purity levels this low result in the inefficient operation of the generators because of the reduction in cooling ability of the gas mixture. A potentially dangerous environment is created if the purity level drops to 74 percent. Hydrogen, when mixed with air at concentrations from four percent to 74 percent, forms an explosive mixture and creates a high risk of a fire occurring.

Since a shaft is required to penetrate the generator casing, a shaft seal is required on either end of the casing. The shaft seals utilize oil from the turbine lubrication system to prevent hydrogen leaks from the generator casing. However, during the normal operation of the generators, air is liberated from the shaft sealing oil into the hydrogen atmosphere inside the casing. The air mixing with the hydrogen reduces the purity of the hydrogen atmosphere. However, it is possible to vent this gas mixture directly to the outside atmosphere by allowing for a small continuous flow from the generator casing to the outside atmosphere while continuously replacing the mixture with pure hydrogen from the supply. This process, known as scavenging, is how hydrogen purity is maintained in Holyrood. The hydrogen gas control panel measures the purity of the scavenged hydrogen and displays the information to the operators. The flow is adjusted manually depending on the gas purity level.

The existing gas control panels are original material, have exceeded their useful life and are

no longer reliable. On average, there have been discrepancies of approximately three percent in the analysis of the purity level between the control panel purity monitor and the portable purity monitors also used by operations as a check on the installed control panel monitors. Inaccurate purity monitoring results in inappropriately set scavenge gas flow rates. This leads to efficiency losses in generators if the purity of the hydrogen is actually lower than displayed on the monitor, or increased hydrogen consumption if the purity is higher than displayed. In the last five years, in an attempt to correct this situation, each of the three gas control panels were calibrated at an average cost of $15,000 each.

The existing hydrogen gas control panels, because of their age, are not intrinsically safe. In the past five years, there have been seven leaks inside the gas control cabinets. This creates a potentially explosive environment and is unacceptable and must be eliminated. By replacing the existing control panel with a more modern safe control panel, the scavenged gas rates can be automatically controlled by the gas control panel. This would result in consistent hydrogen gas consumption and purity in the generator, better generator efficiency, and reduced risk of a major incident. Also, over the past five years, the gas control cabinets have required $84,600 in maintenance which is equivalent to approximately one-third of the material cost of three new gas control panels.

Installa*tion of automatic hydrogen vent valves.*

The installation of automatic hydrogen vent valves is required to supplement the existing manual valves with electrically controlled valves to allow for remote operation from the control room in the event of an emergency situation. The existing design of the emergency control valves for generating Units 2 and 3 pose a safety risk to both personnel and equipment. Currently, the operators have to manually operate the emergency vent valve when an emergency situation, such as a fire, occurs. This brings the operators in close proximity of a fire or a potentially explosive work area. Also, the current system configuration does not allow for rapid emergency response, as the operators must travel to

the turbine from the plant control room. FM Global, Hydro's insurance carrier, has deemed this to be a hazard that must be eliminated and has issued Holyrood a directive to install emergency hydrogen vent valves to allow for rapid removal of hydrogen from the generator to minimize the risk of equipment damage. Appendix B provides the details of FM Global's recommendation in item number 00-11-004. As a result of FM Global's recommendations, automatic hydrogen vent valves were installed on Unit 1 in 2009.

Replacement of Manual Control Valves

The existing manual control valves and piping are required to ensure safe and reliable operation of Holyrood. The control valves and piping are original and have exceeded their useful life. The manual control valves on generating Units 1 and 2 are installed on the generator pedestal underneath the generators which are located on level 3 in the plant. This area is exposed to moderate levels of high frequency vibration which has a tendency to wear valves, fittings and cause high cycle fatigue in piping and cause hydrogen leaks. A leak at or near the manual control valves could create an explosive environment into which, an operator would have to go to isolate the leak. This puts the operators at an unacceptable risk for injury. To mitigate this risk the manual control valves on generating Units 1 and 2 will be relocated to the ground floor of the plant where the chances of a hydrogen rich environment forming are greatly reduced and the vibration from the generators is less severe. The manual control valve for generating Unit 3 is located on the ground level of the plant.

4.1 Net Present Value

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

4.2 Levelized Cost of Energy

A levelized cost of energy analysis is not applicable since no new generation sources are being evaluated.

4.3 Cost Benefit Analysis

A cost benefit analysis was completed, comparing the project with electrolyzer and low pressure bulk storage or without electrolyzer and high pressure bulk storage. The cost benefit analysis shows that the capital cost required for the hydrogen electrolyzer and bulk storage installation has a payback period of eight years. An assumption is made that the operation of Holyrood remains constant with no changes in consumer demand. An increase in consumer demand makes the installation of the hydrogen electrolyzer and bulk storage more favorable. Table 3 below shows the benefit of the hydrogen system upgrade including the electrolyzer has a benefit of $275,836.

Table 3: Cost Benefit Analysis

Holyrood Hydrogen System Upgrade **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2030**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Upgrade with Electrolyzer	1,684,511	0
Upgrade without electrolyzer and Bulk Storage	1,960,347	275,836

4.4 Legislative or Regulatory Requirements

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

4.5 Historical Information

There is no applicable historical information available.

4.6 Forecast Customer Growth

Whether customer load grows or declines, hydrogen consumption at Holyrood will increase. Without the Lower Churchill project coming on stream, Holyrood will have to increase its output levels to meet increased load. Alternatively, with the Lower Churchill project, generation at Holyrood will be reduced, but there will be an increased requirement for synchronous condenser operation. In either case, there will be increased hydrogen consumption and a higher demand on the hydrogen system.

4.7 Energy Efficiency Benefits

There are potential energy efficiency benefits related to the installation of a modern hydrogen gas control panel. This panel will automatically maintain the pressure in the generator casing at the recommended 30 psig pressure. For every 1 pound-force per square inch gauge (psig) below 30 psig, a decrease in output of 0.5 percent will be experienced until 15 psig. For every 1 psig below 15 psig, a decrease in output of one percent will be experienced. Stable pressure in the casing will provide the correct cooling of the generator, thereby, optimizing its operating efficiency.

4.8 Losses during Construction

This project will be completed during scheduled annual unit outages. Therefore, there will be no losses during construction.

4.9 Status Quo

The status quo is not acceptable. There is risk to the safety of equipment and personnel, as well as to the reliability of plant operation associated with the current system design. These risks are unacceptable and must be mitigated to ensure the safe and reliable operation of Holyrood.

4.10 Alternatives

There are no viable alternatives to the proposed project.

5 CONCLUSION

The hydrogen system must be upgraded to ensure the safe and reliable operation of Holyrood. The existing hydrogen system is mainly original and poses serious risks to the safe and reliable operation of the plant. These risks must be reduced or eliminated where possible. All aspects of this project reduce the risk of injury to personnel and damage to property. The installation of automatic hydrogen vent valves reduces the risk of a dangerous fire inside the generator casing, while eliminating the requirement for operators to enter a dangerous environment to extinguish the fire. The relocation of the manual control valves eliminates the risk of operators entering a hydrogen rich environment and reduces the risk of hydrogen leaks caused by high frequency vibration from the generators. The existing high pressure bulk storage has risks associated with the manual handling of the equipment as well as the storage pressures. By installing low pressure bulk storage and hydrogen generation both of these risks are reduced. Finally, the supply chain for the hydrogen bulk packs has been identified as a high risk factor associated with the operation of Holyrood. The current hydrogen supply is produced in Quebec and transported to Newfoundland and Labrador via truck. This results in long lead times and potential delays due to weather and other uncontrollable factors. Should the hydrogen supply be exhausted, the plant would not be able to generate. Should a total plant outage such as this occur during peak operation, Hydro would be unable to meet customer load. This operational risk can be eliminated by installation of the hydrogen electrolyzer and low pressure bulk storage. All of these risks are unacceptable and must be mitigated by upgrading Holyrood's hydrogen system as proposed.

5.1 Budget Estimate

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

Table 4: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	585.0	174.0	0.0	759.0
Labour	202.2	245.0	0.0	447.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	250.0	40.0	0.0	290.0
Other Direct Costs	15.5	6.0	0.0	21.5
O/H, AFUDC & Escln.	139.2	183.6	0.0	322.8
Contingency	0.0	151.8	0.0	151.8
TOTAL	**1,191.9**	**800.4**	**0.0**	**1,992.3**

5.2 Project Schedule

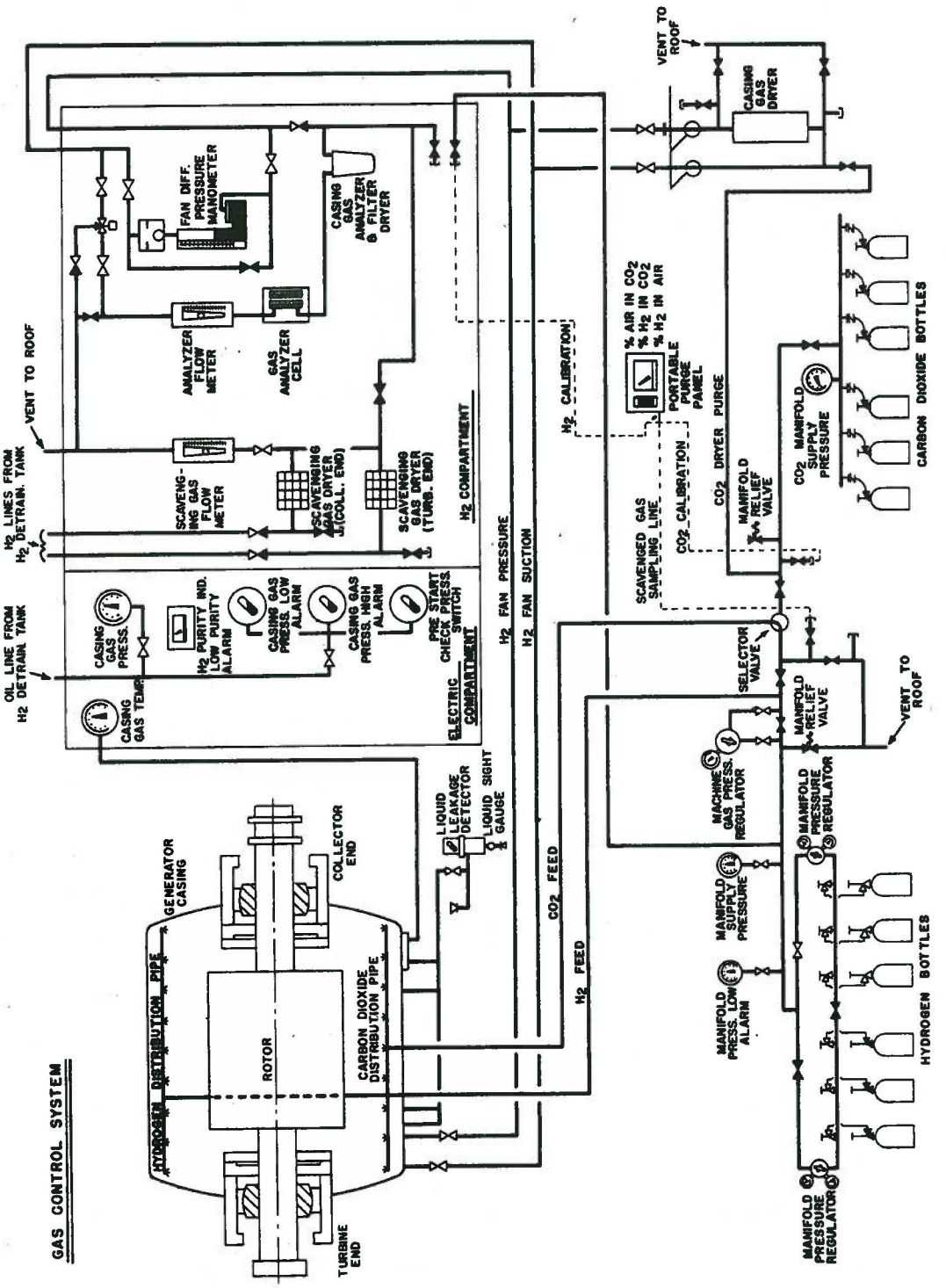
The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity	Milestone
Project Initiation	January 2011
Design and tender for control panels, electrolyzer and bulk storage	March 2011
Field Construction/Installations of control panels, electrolyzer and bulk storage.	September 2011
Commissioning of electrolyzer, control panels and bulk storage	September 2011
Design and tender of Automatic Vent Valves and manual control valves	March 2012
Field Construction	September 2012
Commissioning of manual control valves and automatic vent valves	October 2012
In Service	October 2012
Project Completion and Close Out	November 2012

APPENDIX A

Hydrogen Gas Control System Diagram


GAS CONTROL SYSTEM
GENERATOR CASING
COLLECTOR END
TURBINE END
ROTOR
HYDROGEN DISTRIBUTION PIPE
CARBON DIOXIDE DISTRIBUTION PIPE
LIQUID LEAKAGE DETECTOR
LIQUID SIGHT GAUGE
ELECTRIC COMPARTMENT
H2 COMPARTMENT
CASING GAS TEMP
CASING GAS PRESS.
H2 PURITY IND. LOW PURITY ALARM
CASING GAS PRESS. LOW ALARM
CASING GAS PRESS. HIGH ALARM
PRE START CHECK PRESS. SWITCH
OIL LINE FROM H2 DETRAIN TANK
H2 LINES FROM H2 DETRAIN. TANK
VENT TO ROOF
SCAVENGING GAS FLOW METER
SCAVENGING GAS DRYER (COLL. END)
SCAVENGING GAS DRYER (TURB. END)
ANALYZER FLOW METER
GAS ANALYZER CELL
FAN DIFF. PRESSURE MANOMETER
CASING GAS ANALYZER & FILTER DRYER
H2 FAN PRESSURE
H2 FAN SUCTION
CO2 FEED
H2 FEED
H2 CALIBRATION
CO2 CALIBRATION
SCAVENGED GAS SAMPLING LINE
% AIR IN CO2
% H2 IN CO2
% H2 IN AIR
PORTABLE PURGE PANEL
CO2 DRYER PURGE
MANIFOLD RELIEF VALVE
CO2 MANIFOLD SUPPLY PRESSURE
CARBON DIOXIDE BOTTLES
SELECTOR VALVE
MANIFOLD RELIEF VALVE
VENT TO ROOF
MACHINE GAS PRESS. REGULATOR
MANIFOLD PRESSURE REGULATOR
MANIFOLD SUPPLY PRESSURE
MANIFOLD PRESS. LOW ALARM
HYDROGEN BOTTLES
MANIFOLD PRESSURE REGULATOR
CASING GAS DRYER
VENT TO ROOF

APPENDIX B

FM Global Recommendation

04-10-001 continued

Technical Detail	Several new valves still need to be added to the weekly and monthly valve checklist.
Risk*Mark* Points	To significantly increase the location Risk*Mark* score, multiple recommendations must be completed.
Status	Outside valves are physically checked every 3 months and there are no intentions of increasing the frequency at this time. However, snow should be cleared around valves always. Efforts will be made to ensure weekly visual inside checks continue.

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 soon.
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 isolate electrical equipment in the fire area. The insured stated that this will be considered and if approved for the 2009 capital budget, it should be completed by 2010.
Risk*Mark* Points	Completion of only this recommendation will result in a Risk*Mark* score increase of 1.05 Points.

APPENDIX C

Business Continuity Risk Plan

4. Critical Processes and Associated High Risks

A Risk Assessment Workshop was held at Holyrood in March, 2007. Key Hydro supervisory and management personnel with expertise in the operation of generating plants, transmission lines and terminal stations attended the workshop. The workshop was lead by a senior member of the Risk Management Services Group, Aon Reed Stenhouse Incorporated. An extensive list of potential naturally occurring and man-made risks was studied to determine which risks posed danger to critical processes in normal operations causing an unwanted event. The expertise of the workshop attendees was drawn on to analyze (i) the *Frequency* of occurrence of the event (on a scale of 1-5 from 'Not Likely' to 'Near Certain'), (ii) the *Impact* of the event on Operations (on a scale of 1-5 from "Low Impact' to 'High Impact', and (iii) the *Degree of Certainty* on the level of precision around the Frequency and Impact of the event. Subjectively, the precision would be 'High' if the chosen levels of Frequency and Impact ratings were considered exact; 'Medium' if the levels were accurate within some margin of error; and 'Low' if completely uncertain about the event, thus, a mere guess only could be made. The analysis of the above three components produced a risk level associated with each critical process identified. The following are the identified critical processes that are at a high risk for business disruption and whose recovery time is beyond a maximum acceptable downtime. The processes are categorized according to the specific high risk factor affecting the process. Five high risk factors have been identified.

1. Risk of ***Accident in the Transportation of Hydrogen*** affecting operation of facilities:
    - Generator, Exciter, Stator/Rotor, H_2 System, PT Cubicles, ISO Bus or VDE (Lube Oil, Seal Oil System)

2. Risk of ***Loss of Clarification Process due to Equipment Failure or Improper Maintenance*** affecting operation of facilities:
    - Common Systems (Fire Systems, Pumps, Sprinklers, Service Air, Instrument Air or Station Services)

3. Risk of ***Loss of Transportation (Lack of Hydrogen Supply Due to Supply Side Transportation Problems)*** affecting operation of facilities:
    - Common Systems (Fire Systems, Pumps, Sprinklers, Service Air, Instrument Air or Station Services)

4. Risk of ***Failure of Escalated Response from Support Fire Services*** affecting operation of facilities:
    - Common Systems (Fire Systems, Pumps, Sprinklers, Service Air, Instrument Air or Station Services)

5. Risk of ***Failure of Raw Water Supply Line*** affecting operation of facilities:

- Common Systems (Fire Systems, Pumps, Sprinklers, Service Air, Instrument Air or Station Services)

5. Rationalization for the High Risk Factors

Operations personnel at Holyrood provided the rationalization for the 5 high risks identified.

- Risk of ***Accident in the Transportation of Hydrogen***
  Transportation of Hydrogen falls under regulations governing the transportation of dangerous goods. Operations personnel are concerned over security issues and supply of goods.

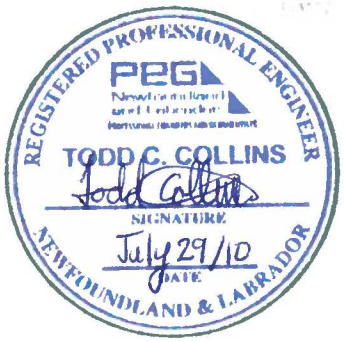
- Risk of ***Loss of Clarification Process due to Equipment Failure or Improper Maintenance***
  Loss of clarification process will result in some equipment constraints (5 days temporary replacement from the US).

- Risk of ***Loss of Transportation (Lack of Hydrogen Supply Due to Supply Side Transportation Problems)***
  Operation experience has indicated that a high risk exists for the lack of hydrogen supply due to supply side transportation problems.

- Risk of ***Failure of Escalated Response from Support Fire Services***
  Past experience with previous incidents have shown that support services do not have a complete knowledge of the protocol involved.

- Risk of ***Failure of Raw Water Supply Line***
  Operating personnel have had past failure experience regarding raw water supply line. Serious problems would arise if the failure is not managed well.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

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

Condition Assessment and Life Extension Study

HOLYROOD THERMAL GENERATING STATION

May 2010

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) plays an essential role in the province's power system. With three units providing a total capacity of 490 MW, the plant provides load support for the Island Interconnected System. Holyrood was constructed in two stages. In 1971 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 I and 2 were up-rated to 170 MW. Holyrood (illustrated in Figure 1) represents approximately one third of Hydro's total Island Interconnected System generating capacity and each unit represents approximately 11 percent of that total.



Figure 1: Holyrood Thermal Generating Station

The life expectancy of a thermal generating station is 30 years, with the plant operating continuously and downtime only occurring to perform routine repairs and maintenance. The 30 year life expectancy can vary depending on the capacity factor (CF) of a plant and how well it has been maintained over the years. However, after a plant has reached or exceeded its life expectancy, life extension work is required to continue operating with a

high degree of reliability.

The CF of a power plant is the ratio of the actual output of a power plant over a period of time to the output if it had operated at full nameplate capacity for the entire time. The maximum CF for a plant such as Holyrood operated on the Island Interconnected System is about 75 percent. To achieve a CF of 75 percent, the plant would operate at near full capacity year round with scheduled downtime as required to address maintenance items. Holyrood has experienced CF's from the 30 percent to 50 percent range since the plant went into service, with a typical average CF at approximately 35 percent. Hydro has extensive hydro-electric generating resources and there is usually sufficient power and energy from those other resources to permit Hydro to run Holyrood at low loads, or not at all, from late spring to late fall each year.

Recent changes in load and supply on the Island Interconnected System has reduced requirements for Holyrood generaion and this is not expected to change significantly until completion of the nickel processing facility at Long Harbour in 2013. When the Lower Churchill infeed is completed, Holyrood will operate as a synchronous condensing facility. However, it will be maintained and staffed to be able to operate as a generating plant for the initial years of operation of the DC link until the reliable operation of that system has been established. Synchronous condensing is necessary to ensure balance and stability to the power grid serving the island portion of the province. However, until the Lower Churchill development is completed, other sources of generation will be required and Holyrood will be required to continue producing at the higher CF.

As stated previously, Holyrood meets approximately 33 percent of the Island Interconnected System's power and energy requirements during the peak winter months. Due to the age of the plant, Hydro commenced a comprehensive condition assessment and life extension study of the facility in 2009. The study will identify the measures that need to be taken to ensure high reliability as the plant continues to operate as a thermal generating

station to the year 2016, as a standby generating plant for several years following 2016, and as a synchronous condensing station thereafter. If the plant is required to continue operating as a base loaded thermal generating station after 2016, a more extensive and comprehensive study will be required to assess the cost of significantly extending the operating life of the systems required for steam production and usage (i.e. boilers, turbines, high energy piping and fuel systems).

2 PROJECT DESCRIPTION

This project is the second phase of a condition assessment and life extension program which began in 2009. It will provide a more detailed investigation of the generators and associated balance of equipment (BOP) required for long term operation of Holyrood as a synchronous facility and make recommendations for work that will be required to extend its useful life as a reliable synchronous condensing facility. The project will include a Level II study as per the guidelines of the Electrical Power Research Institute (EPRI). During the 1970's and 1980's, EPRI developed a three-level methodology for performing condition assessment and life extension studies within the utilities industry in which the level of sophistication and detail increases progressively through Level I, Level II, and Level III studies. During a Level II assessment, the condition of equipment is assessed by performing more detailed inspections, utilizing non-destructive testing (NDT) techniques, and taking material samples and performing metallurgical analysis. An overview of the EPRI condition assessment and life extension process as it relates to boiler condition assessments is located in Appendix A.

While this process is well understood within the utility industry, implementing the process at Holyrood is complicated by the uncertainty surrounding the long term operating mode for the facility. The present age and condition of the facility, combined with its importance in the current generation mix of the Island Interconnected System, and its known importance for at least the next ten years, required Phase 1 of the condition assessment and life extension process to begin immediately during the year 2009. The program is structured in phases to ensure that the work recommended is tailored to the expectations placed on Holyrood by the needs of the Island Interconnected System and the development plan for the Lower Churchill Project.

Phase 1 of the Holyrood condition assessment and life extension study is currently ongoing and includes a Level I study as per the EPRI guidelines. In 2009, Hydro issued a request for proposals to perform the Phase 1 study. The proposals were evaluated and the contract

was awarded to the engineering firm AMEC Americas Limited. A Level I condition assessment and life extension study is intended to quickly determine the basic condition of a power plant, to roughly assess its useful life, and to identify components, systems or facilities which require attention. It helps the utility to select which components require additional investigation and assists personnel in selecting the sampling and testing methodologies to be used in Level II and Level III assessments. The failure history is established by reviewing maintenance records. For a Level I assessment, only a cursory dimensional review is performed. A dimensional review is the comparison of present dimensions to the original dimensions of components subject to wear, erosion or creep (deformation which occurs due to prolonged high temperature and high stress operation). The apparent condition of a plant is assessed by reviewing the adequacy of maintenance practices, major component repair and replacement records, and by an external inspection of the equipment. Internal inspections are not performed, unless the equipment happens to be open for other purposes at the time of the external inspection. Operating pressures and temperatures are reviewed to determine if material properties such as creep have been compromised by operation outside of established normal operating limits. Material samples are not taken for the determination of properties and in-situ tests are not performed. A Level I assessment provides a rough estimate of the useful life of a power plant and makes recommendations for a more detailed investigation as part of a Level II study. The final report for Phase 1 of the condition assessment and life extension program will be submitted to Hydro during 2010.

The Phase 1 study was based on the following assumptions:
Holyrood will be required to operate as a generating facility at a CF between 30 percent and 75 percent until 2016;
Holyrood will be placed in standby generation mode from 2016 until 2020; and
Holyrood will be converted to a synchronous condensing facility prior to 2016 and will operate as such beginning in 2016 and into the future.

Prior to receiving the final report for the Level I study, scheduled to be delivered in 2010, Hydro recently received preliminary documentation from the consultant recommending work to be completed as part of the Level II study. This document is located in Appendix B. The Level II study will include recommendations with cost estimates to complete asset refurbishment tasks to maintain reliable operation of the plant in the future based on synchronous operation requirements as noted above in the list of assumptions related to Phase 1 of the program. It is anticipated that the proposed 2011 project will have a 12 month duration commencing in January and ending in December.

Following the completion and review of Phase 2 of the condition assessment and life extension program to be completed in 2011, the next phase of the program will be identified. The scope of the next phase will depend on whether Holyrood continues to operate as a generating facility or is converted to a synchronous condensing facility. Phase 3 of the condition assessment and life extension program would include completion of the recommended asset refurbishment tasks identified in Phase 2 that are required to extend the plant's useful life reliably into the future.

3 EXISTING SYSTEM

The existing system is the complete Holyrood Thermal Generating Station facility. The study is required to determine the scope of work and associated cost to operate the plant as a synchronous condensing facility reliably into the future.

3.1 Age of Equipment or System

Holyrood was built in two stages. Stage I, comprising Units 1 and 2 and site auxiliary facilities, was commissioned in 1971. Stage II, comprising Unit 3 and its auxiliary equipment, was commissioned in 1979. In 1986, Unit 3 was modified to permit the generator to be decoupled from the turbine for operation as a synchronous condenser. As of May 31, 2010, the operating hours for each unit are as follows:

Unit 1	168,904 hrs
Unit 2	161,037 hrs
Unit 3	127,678 hrs
Unit 3 (as a synchronous condenser)	36,089 hrs

3.2 Major Work and/or Upgrades

There have been a number of major upgrades to the plant since it was constructed. Please refer to Appendix C for a listing of the major upgrades.

3.3 Anticipated Useful life

A typical thermal generating station has an estimated service life of 30 years when operated at annual capacity factors in excess of 50 percent. Holyrood Stage 1 is approaching 40 years of service and considering that it has operated 4,000 to 5,000 hours per year, or more, it is approaching the end of its useful life (Note: Certain components of Unit 3 operate for

significantly more hours; see Section 3.1). It is typical for thermal plants to experience more frequent equipment failures when approaching the end of their useful lives and such failures have been experienced at Holyrood in recent years (see Appendix E for outage statistics). Normally it is financially viable to extend the life of a thermal plant such as Holyrood rather than decommission it and build a new one. Considering the age of the plant and the increasing number of unexpected equipment failures in recent years it is justified to proceed with Phase 2 of the condition assessment and life extension program in select areas that are required for the long term. The results of this study will assist Hydro in determining what measures need to be taken to ensure Holyrood continues to operate as a reliable generating plant to 2016 and a synchronous condensing plant thereafter.

3.4 Maintenance History

The five-year maintenance history for Holyrood is provided in Appendix D.

3.5 Outage Statistics

A list of outages is provided in Appendix E.

3.6 Industry Experience

As power generating plants age, it is common practice in the industry to perform condition assessment studies to determine what actions need to be taken to extend the generating plants life. When Hydro proposed to begin the condition assessment and life extension program in 2009 it was familiar with two similar studies that had recently been performed on other generating stations. One study was performed on a three-unit plant similar to Holyrood with the exception that the boilers were not included in the scope of work. The cost of that study was $2.2 million. The other study was completed by another utility on a single-unit plant and the cost was $1.5 million. Hydro does not have information on the level of detail at which each study was performed.

In 2009 when Hydro solicited proposals from engineering firms to complete a Level I study, the five proposals received all cited similar type work it had performed on thermal generating stations in recent years. The firm selected by Hydro, AMEC Americas Limited, is presently performing similar work for B.C. Hydro at their Burrard generating station.

3.7 Maintenance or Support Arrangements

Service agreements with external contractors are in place for certain systems in operation at Holyrood. A list of those service agreements is provided in Appendix F.

3.8 Vendor Recommendations

The scope of work for this project will include more detailed investigation of vendor recommendations. In particular, consultations will be made with major equipment suppliers such as ALSTOM Canada Inc., GE Canada, and Hitachi Canadian Industries Ltd.

3.9 Availability of Replacement Parts

The scope of work for the study will include more detailed investigation into the availability of existing equipment replacement parts. Hydro has had difficulty acquiring replacement parts for some pieces of equipment.

The study will provide more detailed assessment to determine the need to stock "critical" and "capital" spare parts. Critical parts are those that are expected to be used at some time during the operating life of the equipment as components fail (i.e. shaft bearings). Capital spares are more expensive and are long term delivery items that are not expected to be required but are necessary to maintain generation capacity (i.e. cooling water recirculation pumps).

3.10 Safety Performance

This project is not intended to mitigate any particular safety concerns. However, identification of deficiencies in the area of safety and health and recommendations to eliminate them will be included in the scope of work.

3.11 Environmental Performance

This project is not intended to mitigate any particular environmental concerns. However, identification of environmental deficiencies and recommendations to eliminate them will be included in the scope of work. It should be noted, however, that assuming all three generating units at Holyrood are shut down after the Lower Churchill in-feed comes into service, the environmental performance of the plant will improve dramatically.

3.12 Operating Regime

Holyrood operates in a seasonal regime. Full plant capacity is needed to meet the winter electrical requirements of the Island Interconnected System. Conversely, for a period of time during the summer when customer demand is at its lowest, no generation is required. In recent years, this normally lasts for approximately two to three months. During the spring and fall seasons the plant operates at less than 100 percent load. In the spring of each year, as the last of the three units is removed from service, Unit 3 is converted to a synchronous condenser and operates in that capacity continuously until a unit is returned to generation mode in the fall. As a result, the generator and its auxiliary equipment and systems for Unit 3 operate for significantly more hours each year than the other two units.

4 JUSTIFICATION

This project is required to enable Hydro to operate an aging generating plant as a synchronous condensing facility past its normally expected life, thereby providing least-cost and reliable electrical power. The project will include the preparation of recommendations with cost estimates to complete asset refurbishment tasks in order to maintain reliable operation of the plant as a synchronous condensing facility into the future.

4.1 Net Present Value

A net present value calculation was not performed as there is no viable alternative to completing the condition assessment.

4.2 Levelized Cost of Energy

As no new source of energy is being considered, this project will have no effect on the levelized cost of energy.

4.3 Cost Benefit Analysis

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

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements for the completion of this project.

4.5 Historical Information

In its Board Order No. P.U. 28 (2009), Hydro received approval to complete Phase 1 of the Holyrood condition assessment and life extension study. The project was budgeted for

$1,895,000. The Phase 1 study is currently in progress and the final report will be submitted to Hydro on during July 2010.

4.6 Forecast Customer Growth

Customer load is expected to steadily increase in the coming years with incremental increases in residential load and the potential for new large industrial block loads being added such as the nickel processing facility at Long Harbour.

See 2010 Capital Budget Application, Volume 2, Tab 38 for Hydro's Generation Planning Issues 2010 Mid Year Update.

4.7 Energy Efficiency Benefits

Energy efficiency benefits, if any, may be identified through the completion of this study.

4.8 Losses during Construction

There are no production or revenue losses anticipated from the completion of this study.

4.9 Status Quo

Holyrood is reaching the end of its useful life. As one of the major generating plants on the Island Interconnected System, it would be imprudent to not assess the condition of the key balance of plant systems required for synchronous condensing and plan for the next phase of its life. Failure to perform this condition assessment and life extension study may result in future expenditures not being the most economic, given the projected future requirements of the plant.

4.10 Alternatives

There are no viable alternatives to this study. Due to the age of the plant, Hydro cannot guarantee the reliable operation of Holyrood in the future as a synchronous condensing facility without performing a condition assessment and life extension study of the key balance of plant systems.

5 CONCLUSION

Units 1 and 2 at Holyrood were placed in service 40 years ago and have exceeded the normal life expectancy for such a plant. Following the development of the Lower Churchill project, power will be made available to the Island Interconnected system via a DC transmission system. Thereafter, Holyrood is expected to operate as a synchronous condensing station. To meet this requirement, a condition assessment of the generators and associated BOP systems is necessary and recommendations are needed to determine the prudent expenditures that should occur to ensure that reliable service can continue to be provided.

5.1 Budget Estimate

The budget estimate shown below in Table 1 was prepared based on a recommendation from AMEC Americas Limited, a professional engineering consulting firm that was recently contracted by Hydro to complete Phase 1 of the Holyrood condition assessment and life extension study. The recommendation is located in Appendix B.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	152.3	0.0	0.0	152.3
Consultant	1,282.0	0.0	0.0	1,282.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	12.0	0.0	0.0	12.0
O/H, AFUDC & Escln.	81.1	0.0	0.0	81.1
Contingency	144.6	0.0	0.0	144.6
TOTAL	**1,672.0**	**0.0**	**0.0**	**1,672.0**

5.2 Project Schedule

The anticipated project schedule is shown below in Table 2.

Table 2: Project Milestones

Project Milestone	Date
Initiation	January 2011
Request For Proposals issued to consultants	January 2011
Consulting contract awarded	February 2011
Site investigations and research	August 2011
Draft Report	October 2011
Final Report and Close Out	December 2011

APPENDIX A

EPRI: Overview and Strategy for Boiler Condition Assessments

1

OVERVIEW AND STRATEGY FOR BOILER CONDITION ASSESSMENT

Introduction

The underlying driver for performing component condition assessment is the need to manage component life to achieve plant operating safety, reliability, and economic objectives. Current power industry changes have not altered these objectives but have, in many instances, provided renewed interest in comprehensively performing condition assessments. This is especially true for economic objectives because competitive forces within the industry place increased importance on trimming operating and maintenance costs to their lowest possible level. For fossil-fired power plants, boiler components command a major portion of maintenance activities and produce a majority of operational outages. Therefore, it is essential that the plant personnel have comprehensive information on the key components of the boiler to manage the operation of the unit effectively and to assess the continuing economic viability of that operation. This boiler condition assessment guideline is intended to aid utilities in preparing and maintaining such information for their fossil units.

This guideline is a compilation of information derived largely from the existing library of EPRI-sponsored work on condition assessment of boiler components. To the extent practical, this material is presented in a streamlined format with the intent to quickly focus efforts on the required activities, and corresponding tools available, to perform boiler component condition assessments. This version (Rev. 1a) of the guideline features added discussion of the procedures and tools needed to extend boiler outage intervals.

Condition Assessment Fundamentals

The objective of this guideline is to assist utility personnel in structuring the critical activities required to perform condition assessment of major fossil boiler components. Condition assessment is the primary requirement for managing the useful life of plant components, and it relies on the following three pieces of information:

- The degree of damage currently in the component
- The rate of damage accumulation
- The degree of damage required to cause failure

EPRI research has provided extensive information in each of these categories, and that material is incorporated within this guideline both directly and via reference. A bibliography is provided at the end of this chapter to identify the key resources used in the preparation of this report.

In the chapters that follow, specific processes are identified for acquiring and evaluating these three pieces of data for key boiler components. Note that attention is given to damage prevention options as a subset of the damage accumulation category. Generally, the most cost-effective life management approach is addressing root causes for component damage and eliminating future damage. Much of EPRI's successful program to reduce boiler tube failures (BTF) is based upon this specific approach and is discussed in Chapter 2, "Boiler Tubing."

A key feature of the condition assessment approach recommended by EPRI has been the use of a multi-level structure in which component evaluations become progressively more detailed. This feature is illustrated in Figure 1-1. Specifically, a three-level structure is provided in which the estimated remaining life (RL) is iteratively compared to the desired life (DL). Note that the DL is typically set by the component maintenance interval (e.g., 1 to 5 years) or by an economics planning window (e.g., 5, 10, 15, or more years). The economics window is, in turn, generally set via an asset management approach applied to all operating units for the utility. This asset management activity is outside the scope of this report.

The iterative approach allows utilities to balance the costs of obtaining additional data against the value of that data in a formalized process. Table 1-1 illustrates the increasing levels of sophistication required in progressing through Level I, II, and III assessments. In the chapters that follow, component-specific activities such as inspections are categorized as Level I, II, or III. Note that a Level III assessment would typically be recommended to obtain the most confident estimate of the RL of a component.

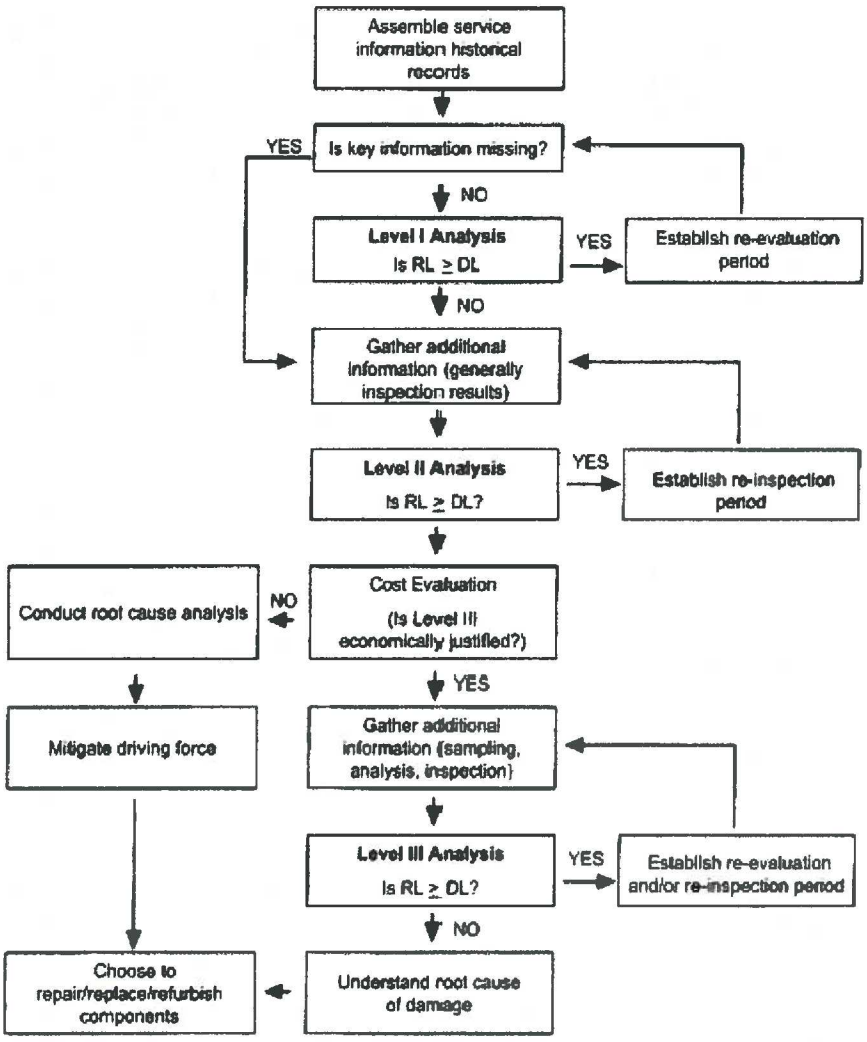

Figure 1-1
Generic Procedures for Mechanical Component Life Assessment

1-3

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Table 1-1

Feature	Level I	Level II	Level III
Failure History	Plant records	Plant records	Plant records
Dimensions	Design or nominal	Measured or nominal	Measured
Condition	Records or nominal	Inspection	Detailed inspection
Temperature and pressure	Design or operational	Operational or measured	Measured
Stresses	Design or operational	Simple calculation	Refined analysis
Material properties	Minimum	Minimum	Actual material
Material samples required?	No	No	Yes
More rigorous assessment →			
More accurate operation data required →			
More accurate estimate of equipment RL →			

1-4

Program Plan

To carry out a condition assessment program successfully, utility personnel must have several key elements in place beyond the technical guidance provided in this and other EPRI reports. These elements have been well-established by the successful EPRI BTF reduction program and are summarized as follows:

- Management statement of support
- Cross-functional teaming (including maintenance, operations, and engineering personnel) in performing the program
- Attention to long-term solutions to root cause problems
- Training
- Documentation of results and periodic review

Although these elements are straightforward in concept, it is essential that they be formally included in the condition assessment program plan. These elements ensure the successful execution of the program objectives and effective use of the results to manage component life.

An end result of utility boiler condition assessment efforts should be a document that fully captures the condition assessment results and provides a clear basis for utility decision making. The document should include the following types of information:

- Date the assessment was performed
- Summary of assessment activities, such as inspections, material tests, and results
- Estimate of component RL and summary of basis
- Damage mitigation/prevention actions, if appropriate
- Follow-on inspections or monitoring actions and their timing, if appropriate
- Recommendations for next assessment, including operating changes/upsets that would prompt a re-assessment

All information should be carefully maintained for easy access and future reference. A computer-based database is strongly recommended. EPRI has developed the Boiler Maintenance Workstation (software), which can be used for this function.

Added Considerations for Extending Outage Intervals

Safely extending major boiler inspection and maintenance outages involves a systematic effort to collect component-specific data and operating history data that reduce "material condition" uncertainty and thereby enable removal of the conservatism prudently employed when using "component/material class" (statistical average) information. In addition, new approaches to unit operation and availability have recognized that cracks can be tolerated in certain locations.

As an analogy, this change in approach would be akin to a change in the life insurance industry from policy pricing based on actuarial tables of life expectancy considering only age and whether on smokes to life expectancy estimates based on a comprehensive physical examination and a review of genetic factors. Although the incentive for such a change isn't generally sufficient in the insurance industry, the premium of assured availability at critical times in competitive power markets may warrant added investment in NDE and other techniques to better estimate remaining life and failure probabilities.

In the context of information presented in this guideline, that means more and new types of Level III analyses. Opportunity areas include:

- **Use of EPRI's Boiler Life Evaluation and Simulation System (BLESS) software to analyze cracks and predict the rate of crack growth.** Although techniques for detecting and measuring cracks are well established, methods to confidently predict a component's remaining life after crack initiation are less developed. Recent and ongoing upgrades to EPRI's BLESS software have simplified and improved prediction of crack initiation and growth rates. In many instances, crack initiation may occur early but propagation is so slow that it poses little or no failure risk.

- **Use of acoustic emissions date to distinguish between active (growing) and non-active (stationary) cracks** (e.g., between cracks introduced during fabrication or by other means prior to service vs. cracks induced due to in-service stresses). Often, the current practice is to remove flaws above a certain size detected during inspections without establishing their growth rates. This can lead to the unnecessary removal of stationary flaws posing no failure risk.

- **Use of accelerated creep and fatigue tests on miniature specimens to gauge remaining life.** Traditionally, remaining life estimates have been based on statistical analyses of material properties. Now date from tests of actual component material can help remove the conservatism inherent in "actuarial" type predictions of material properties.

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- **Quantifying the ability of weld repairs to provide adequate creep strength to safely extend component life.** Preliminary EPRI findings appear promising.

- **Use of "small punch" tests to gauge a thick-walled component's fracture appearance transition temperature** (FATT, the temperature at which a material's failure mode changes from brittle to ductile). Comparison of the original (as-quenched and tempered) FATT with the FATTs of aged samples provides a measure of susceptibility to embrittlement (reduced toughness at elevated temperatures caused by the precipitation of certain elements at grain boundaries). EPRI and others developed the "small punch test" method in the 1980's using miniature specimens as an alternative to a Charpy V-notch test because it required less material to be removed. Initially applied to turbine rotors, the small punch test has now also been successfully applied to turbine disks, nuclear reactor pressure vessels, and thick-walled boiler components. It is primarily used in situations where a hydrotest will be conduced at a temperature below the current FATT.

- Ongoing investigations are **determining the kinetics of the fine-grain and coarse-grain portions of weld heat-affected zones (HAZ) and their role in Type IV cavity formation and growth.** EPRI suspects that current practices with respect to Type IV cracks (often immediate removal) are overly conservative.

Structure of This Guideline

This guideline is organized by major boiler components, including boiler tubing, high-temperature steam headers, high-energy steam piping, economizer headers, steam and lower drums, and attemperators. Each chapter begins with a roadmap of condition assessment activities for the specific component. These roadmaps have been developed to reflect damage mechanisms and degradation time frames as the key drivers to performing specific condition assessment activities. As a general reference, Table 1-2 provides a summary mapping of boiler components and their major in-service damage mechanisms.

For each component, additional information on nondestructive evaluation (NDE) techniques, life assessment calculations, and damage prevention are presented in tabular form as options linked to the overall roadmap. Level I, II, and III designations are provided as appropriate. Again, the intent of this format is to allow users to quickly identify actions that need to be performed within their condition assessment program. More detailed information is available through the referenced EPRI documents.

Table 1-2
Key Boiler Pressure Components and Damage Mechanisms

Component	Creep	Fatigue	Corrosion	Erosion
Waterwall tubing	X	X	X	X
Superheater (SH)/ reheater (RH) tubing	X	X	X	X
Economizer tubing		X	X	X
Superheater headers	X	X	X	
Reheater headers	X	X	X	
Main steam piping	X	X		
Hot reheat piping	X	X		
Cold reheat piping		X	X	X
Economizer inlet header		X	X	
Drums		X	X	
Downcomers		X	X	
Waterwall headers		X	X	
Attemperator	X	X		

1-9

Bibliography of Selected Boiler-Related Reports

Boiler Condition Assessment

Accelerated Stress Rupture Testing Guidelines for Remaining Creep Life Prediction. Electric Power Research Institute: 1997. Report TR-106171.

Condition Assessment Guidelines for Fossil Fuel Power Plant Components. Electric Power Research Institute: 1990. Report GS-6724.

Guidelines for Performing Probabilistic Analysis of Boiler Pressure Parts. Electric Power Research Institute: 2000. Report 1000311.

Guidelines for the Evaluation of Seam-Welded High-Energy Piping. Electric Power Research Institute: 2001. Report 1003978.

Guidelines for the Prevention of Economizer Inlet Header Cracking in Fossil Boilers. Electric Power Research Institute: 1989. Report GS-5949.

Life Assessment of Boiler Pressure Parts. Electric Power Research Institute: 1993. Report TR-103377, Vols. 1-3, 5, and 7.

Boiler Tube Failures

Boiler Tube Failure Metallurgical Guide. Electric Power Research Institute: 1993. Report TR-102433, Vols. 1-2.

Boiler Tube Failure Reduction Program. Electric Power Research Institute: 1991. Report GS-7454.

Boiler Tube Failures: Theory and Practice. Electric Power Research Institute: 1996. Report TR-105261, Vols. 1-3.

Circumferential Cracking on the Waterwall of Supercritical Boiler. Electric Power Research Institute: 1995. Report TR-104442, Vols. 1-2.

Corrosion-Fatigue Boiler Tube Failures in Waterwalls and Economizers. Electric Power Research Institute: 1992, 1996. Report TR-100455, Vols. 1-5.

Corrosion-Fatigue Crack Initiation of Boiler Tubes, Effect of Phosphate in Boiler Water. Electric Power Research Institute: 1997. Report TR-105568.

Guidelines for the Control and Prevention of Fly Ash Erosion in Fossil-Fired Power Plants. Electric Power Research Institute: 1994. Report TR-102432.

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Proceedings: Third International Conference on Boiler Tube Failures in Fossil Plants. Electric Power Research Institute: 1998. Report TR 109938. (See TR-100493 for proceedings of the Second International Conference.)

State-of-Knowledge Assessment for Accelerated Waterwall Corrosion with Low-NO_x Burners. Electric Power Research Institute: 1997. Report TR-107775.

Waterwall Fireside Corrosion Under Low-NO_x Burner Conditions. Electric Power Research Institute. 2001. Report 1001351.

Nondestructive Evaluation

Acoustic Boiler Tube Leak Detection: Utility Experience. Electric Power Research Institute: 1987. Report CS-5136.

Acoustic Emission Monitoring of Cracks in Fossil Fuel Boilers. Electric Power Research Institute: 1987. Report CS-5264.

Acoustic Emission Monitoring of High-Energy Headers. Electric Power Research Institute: 1997. Report TR-107839-V1, Vol. 1.

Acoustic Emission Monitoring of High-Energy Steam Piping. Electric Power Research Institute: 1995. Report TR-105265-V1, Vol. 1.

Assessment of NDE for Pre-Crack Fatigue Damage in Boiler Pressure Components. Electric Power Research Institute: 2000. Report 1000313.

Fossil-Fired Boiler Tube Inspection. Electric Power Research Institute: 1986. Report CS-4633-V1, Vol. 1.

Guidelines for Advanced Ultrasonic Examination of Seam-Welded High-Energy Piping. Electric Power Research Institute: 2000. Report 1000564.

Life Assessment of Boiler Pressure Parts. Electric Power Research Institute: 1993. Report TR-103377-V6, Vol. 6.

NDE Guidelines for Fossil Power Plants. Electric Power Research Institute: 1997. Report TR-108450 and CD-ROM CD-108450.

Nondestructive Inspection Systems for Boiler Tubes. Electric Power Research Institute: 1986. Report CS-4742.

CITATIONS

This on-line EPRIweb product is based on EPRI report TR-111559, prepared by

EPRI
1300 W.T. Harris Blvd.
Charlotte, NC 28262

Author:
R. Tilley

This report describes research sponsored by EPRI. The on-line EPRIweb product is a corporate document that should be cited in the literature in the following manner:

On-line Boiler Condition Assessment Guideline, Rev. 1a, EPRI, Palo Alto, CA: 2002.
Report Number 1004626.

APPENDIX B

AMEC Phase 2 Recommendation

31 May 2010

Mr. Todd Collins, P. Eng.
Mechanical Design Engineer, Engineering Services
Newfoundland and Labrador Hydro, a NALCOR Energy Company
Hydro Place, 500 Columbus Drive
PO Box 12400, St John's, NL, Canada A1B 4K7

Dear Todd,

Holyrood Thermal Generating Station (Holyrood) Condition Assessment & Life Extension Study – Level 2 Cost Information

Per your request, we have compiled a summary of the Level 2 Condition Assessment & Life Extension Study cost requirements for the key Balance of Plant systems required for the operation of Holyrood Thermal Generating Station as a Synchronous Condensing Facility to 2041, taking into account current maintenance, overhaul and inspection plans as should be included in the 2011 budgeting plans.

As per our discussions, we have removed primarily those costs related to the boiler and steam cycle key and focused this current assessment on the inspection/testing costs of strategic electrical systems. This includes those test related to the generators that can be done in 2011 without removing the generator rotor, but that would help the overall evaluation. This is a somewhat different tack from our current overall project assessment where we had deferred costs associated with the generators on the belief that they are able to make it to their next major inspections/overhauls in 2012 (Unit 1), 2014 (Unit 2) and 2016 Unit 3) – although with operational checks and minor tests. The advantage of this approach to earlier limited testing is that it may help better define the scope and costs of the subsequent overhauls.

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Fax: (905) 829-5401
www.amec.com

The overall costs suggested are:

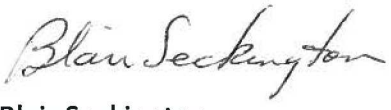
Assets Listing - Holyrood GS
Level 2 Costs - Synch Condesning 2011 **31-May-10**
Rev 3

Generators	$600
Generator Bus Duct & Conn	$50
Steam Turbine Oil System	$10
CW System	$15
Control Cables	$20
Power Cables	$30
Transformers & Aux	$100
Quarry Brook Dam & Fishway	$25
WTP Sand Filter	$15
Oil/Water Separators	$50
Hydrogen Storage and Supply	$15
Carbon Dioxide Storage & Supply	$10
GT Detailed Inspection	$100
GT Options Assess	$75
Contingency	$167
Total Program Cost k$ 2011)	$1,282

The details are in the attached document. I trust that this will meet your budgeting needs prior to our draft report. Obviously there is considerable room for optimization, as the scoping of the tests can vary substantially and the costs

Please advise us on any required changes as soon as possible. Thank you for the opportunity to work on this very interesting project.

Yours truly,



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Holyrood Generating Station Condition Assessment & Life Extension Study

Level 2 Condition Assessment Requirements - Balance of Plant Systems as a Synchronous Condensing Facility to 2041

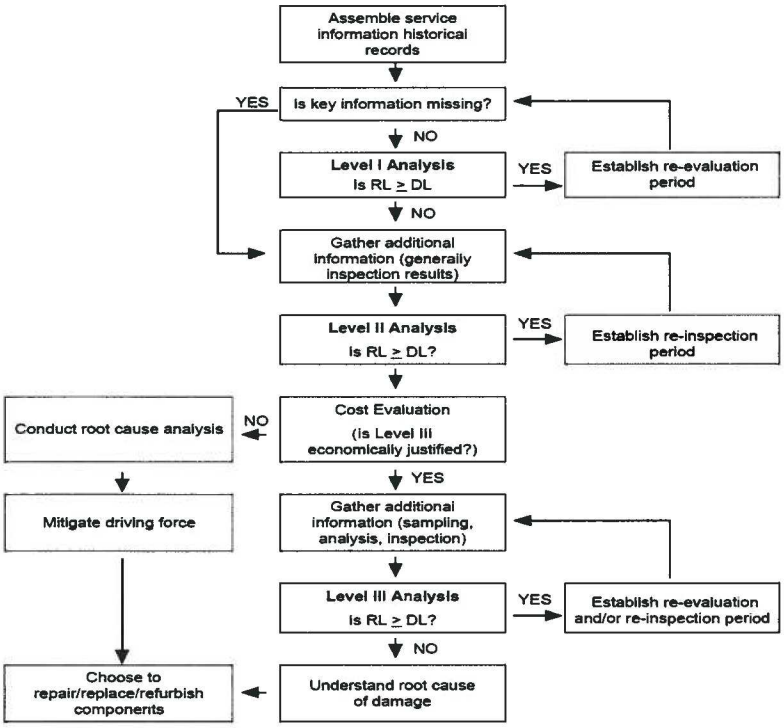
Newfoundland & Labrador Hydro requested a summary of the Level 2 Condition Assessment & Life Extension Study requirements for the key Balance of Plant systems for operation of Holyrood Thermal Generating Station as a Synchronous Condensing Facility to 2041 (taking into account the current overhaul and inspection plans). AMEC was asked to identify those items deemed to be necessary for Synchronous Generation operation that require a "Level 2" condition assessment in 2011. It was specifically to exclude those items associated with the steam generation or steam turbine use. It was to include generator items that could be tested or inspected without taking the generator rotors out.

It is important to require the requirements for a Level 2 assessment.

The EPRI Level 1 approach is:

- only design or overall service parameters are examined
- for conservative considerations, the residual life is compared to the anticipated extended service period (or the interval to the next inspection whichever is less)
- incorporate service and measurement information where practical, available and useful – including:
    - Unit running hours
    - Numbers of starts and stops – hot, warm, cold, trips, ramp rates
    - Unit load records
    - Failure history and analyses reports
    - Maintenance activities
    - Specifics of past component repairs and replacements
    - Materials of construction composition checks
    - Dimensional checks
    - Steam temperature histories
    - Design parameters

The EPRI methodology (for mechanical systems is illustrated below.



The intent in moving from Level 1 to Level 2 is to address those items for which sufficient information was not available on which to make decisions on repair and refurbishment going forward. In the chart below for example, Level 1 allows you to select a number of components to replace, a number to repair or refurbish, but leaves the majority as uncertain.

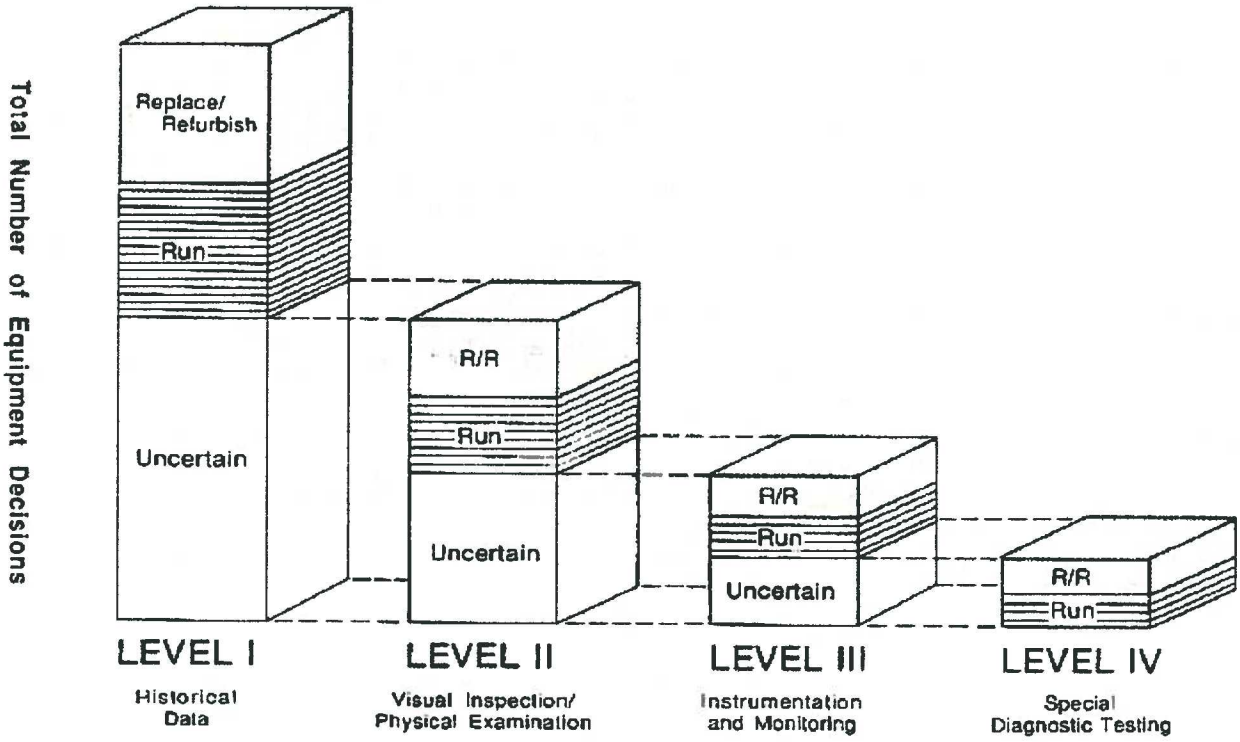


Figure 1-3. Four-Level Electrical Component Life Assessment

Source: Cambrias and Rittenhouse (9)

The goal is to identify those items where the Level 1 assessment was unable to determine the needs going forward and a Level 2 would be needed to provide the necessary further direction. The following Section describes the key items considered necessary for the longer term synchronous generation option to 2041. The intent once again is to compare the residual life to the anticipated extended service period to 2041 **OR** to the interval to the next inspection whichever is less.

1. GENERATORS & AUXILIARIES

The generator & Auxiliaries scope includes:

- Rotor Gen Sip Rngs & Brush
- Stator (Incl Standoff Insulators & PT Cubicle)
- Generator Hydrogen System
  - Seal Oil System (Including AC Seal Oil Pump & DC Seal Oil Pump & AC Seal Oil Vacuum Pump , & Gen CO2 Gas Purge, & Comp Air)
  - Gen Hydrogen Cooling
- Gen Excitation System (Including Exciter, Excitation Transformer, Field Breaker)

AMEC generator expert staff reviewed the three generators and auxiliaries using existing inspection data, staff interviews and discussion, comparative analyses to other units, staff

expertise, and visual inspections of accessible parts. The intent of the Level 1 assessment was to establish whether the equipment could on the whole be reasonably be expected to meet an end of life date for generation service of 2020 and for synchronous condensing operation of 2041, but primarily whether the unit could continue reliably to its next planned overhaul/inspection. The next generator overhauls/inspections are planned for in 2012 (Unit 1), 2014 (Unit 2) and 2016 Unit 3). The timeframes are based on satisfying Holyrood's Insurance Provider's requirement of a detailed inspection every 9 years (minor valves etc every 3 years).

Based on the review of the AMEC expert, it is expected that with suitable operation and maintenance, inspections, and capital re-investment that each generator and its auxiliaries will be able to meet the required service lives, and make it to its next inspection without significant issue.

Although technically no Level 2 generator inspections that would require that the generator rotor be removed are required in 2011, there are a series of activities that could be performed that will further refine the condition of the generator, and assist in scoping out the requirements for the next more costly and complex unit overhauls as well as capital expenses for those overhauls.

An analysis of the issues with Unit 1 is presented as an example of the issues faced by all three units In Appendix A.

The scope of generator inspections and testing that could be done in 2011 on each of the units is presented below. Not all of the testing can be done and the overall scope would as a first stage in the work be optimized.

Inspections:

Inspection – External Components: The following external component items could be inspected:

- Frame footing and bolts – torque for tightness, damage
- Generator foundation – free from cracks other structural damage; footing grouting cracking/spalling
- Seismic supports – alignment check against design, where operation vibration a chronic issue
- Grounding cables – tightness, condition (corrosion, overheating, fraying, cracking), current flow (unexpected)
- Piping & connections – condition, grounding, gasket and o-ring conditions, tightness, oil-free
- Generator end brackets (end doors) – seal damage, cleaning/replacement of seal material, hydrogen leaks (NDE surface penetrant if leaking)

- Bearing Insulation & pedestals – grounding and bearing insulation device condition; bearing and journal pitting, insulation carbon contamination, insulation resistance (>Million ohm range)
- Space heater – loose connections, wire integrity, heating element integrity, resistance testing continuity
- RTD, Thermocouple and Misc devices, Instrument Panel - hydrogen leak test, gaskets/O-ring check, wiring to external device – condition, operational check

Inspection – Stator Internal Components: The following stator internal component items could be inspected with the rotor in:

- Frame & support structure - compression bolts – greasing (oil/dust indicating loose bolts/core/nut lock device vibration), surge ring supports – cracking/looseness; fingerplates – cracked/bent fingers; stator core – looseness, mechanical damage; stator windings – looseness, cracking, greasing
- In event of operational stator vibration, check for frame cracks/fretting (employ NDE if appropriate), inspect and tighten vibration dampening devices as required; core to stator frame interface inspect and NDE as necessary for cracks
- RTD and TC wiring and monitoring devices – visually inspect wiring to and from stator RTD and TC devices as possible – tightly secured. Damaged ones that are accessible may be replaced, others left for major overhaul/rewind
- Winding TC's – inspect and check for function
- Short turn detectors, partial discharge detectors, vibration detection etc. – insect, repair, replace as required and possible.
- Miscellaneous hardware – space heater tightness/integrity; zone ring/gas guide ties and wedging tightness; air/gas baffles stress and fatigue cracking

Inspection – Stator Core:

The following stator core items could be inspected with the Stator Core (Rotor In) to the Extent Possible

- Bore Contamination (to the extent possible)
    - Excessive discoloration (flaking) of paint on casing, frame, bore – overheating
    - Presence of oil/duct – H2 seals issues
    - Excessive iron powder with oil/dust or alone in bore area – loose core or core to keybar vibration impacting
    - Stator bore greasing – fret debris and oil – fretting interlaminar or stator winding wedge loosening
    - Debris identification – source and cause
- Blocked Cooling vent Ducts –"lighted" visual inspection

- Iron Ore Deposits – dusting on bore or radial cooling vents – if significant likely loose laminations or wedges that may require more detailed inspection (loose wedge, loose winding, loose core piece)
- Core Compression plates – inspect both end plates for looseness and condition, as well as keybar and through bolt nuts - caution in retightening
- Core End Flux Screens and Flux Shunts – overheating, insulation resistance and thermal and distortion damage
- Frame to Core Compression Bands – stator casing underbelly inspection ports (maybe) inspect, maybe tighten as required if stator vibration exists and attributable to insufficient compression of core suspension arrangement
- Back of Core Burning – inspect core ends for shorted laminations where they touch frame
- Core end overheating – not usually seen directly during inspection, unless at tooth tops. Check for back of core burning (possible indicator) – test using EL-CID and flux testing with infrared scan. May be visible during stator rewind with winding removed to see effect.

Inspection – Stator Windings: The following stator windings could be inspected with the Stator Core (Rotor In) to the Extent Possible

- End winding blocking and roving – inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits
- Surge rings - inspect condition of blocking, roving, ties – looseness, greasing, dryness, powder, abrasion, cracked painting, missing bits
- Surge ring insulation - inspect (mirrors) integrity of insulation, especially beneath ties
- End winding support structures - inspect (mirrors/other) condition – looseness, loose parts, missing/loose bolts/nuts, cracked supports (solid insulation material), greasing bolts, cracked/loose welding; retighten carefully and if possible; check retightening system condition (if exists)
- Ancillary end-winding support hardware – integrity of water cooled system and O-rings – looseness, cracks, welds, bolts/nut conditions
- Asphalt bleeding – insulation bulging, oozing from stator bars - hand pressure potential weekend area for soft spot
- Tape separation/Girth cracking – inspect for near ends
- Insulation galling/necking beyond slot – inspect for lack of insulation or cracking/separation
- Insulation bulges into Air Ducts – bulging of insulation outside of slot into cooling vent indicate soft spot, tape separation, girth cracks, asphalt migration – further inspect slot are with borescope
- Corona discharge: End windings – white or brownish powder on end bars, dark brown burn marks
- End Wedge Migration Out of Slot – inspection by eye or mirror (may not be applicable – locking mechanism)

Inspection – Phase Bus Connectors and Terminals: The following could be inspected with the Stator Core (Rotor In) to the Extent Possible

- Phase Bus Circumferential Bus Insulation: fretting, greasing, cracking insulation/paint, cracks in connectors/support ties
- Phase Bus Phase Droppers: greasing, cracking insulation
- High Voltage Bushings: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues, Vent clogging (if applicable)
- Stand-off Insulators: Cracks, oil leakage (if applicable), looseness, dirt, tracking residues
- Bushing Well (If Applicable) Insulators & Hydrogen Sealant Condition: sealant condition, gasket condition
- Generator Current Transformers (CT's): visual - cracks, leaking resin, discoloration; infrared camera scan (in operation)

Inspection - Hydrogen Coolers: The following stator windings could be inspected with the Rotor in to the Extent Practical

- Tube clogging: visual inspection and de-scale
- Tube leaks: hydrogen sensors, water inside casing, pressure test
- Tube thinning: eddy current tests

Inspection – Rotor: The following rotor item could be inspected with the Rotor in to the Extent Practical

- Rotor cleanliness: copper dust (dc field coils on turning gear), copper dust in vent holes in winding slot wedges (shorted turns/ground faults) – short turn testing; copper dust in rotor end winding – blocking, insulation; "megger" to check insulation resistance; inspect before and after cleaning
- Retaining Rings: visual inspection, hardness, Non-Destructive Testing (NDT) using eddy current and dye-penetrating techniques; electric pitting/discoloration between rings and adjacent rotor wedges (Check EPRI EL/EM-5117-SR, April 1987)
- Fan Rings/Hubs: Cracks in shrink area – visual if possible, NDE if fans removed; cracks/snugness at fan blade attachment to hub – NDE as appropriate
- Bearings & Journals: journals, babbit materials, oil-baffle labyrinth, oil-seal ring clearance, bearing clearance; used oil condition (including tiny rounded electrical pits); bearing insulation and grounding brush integrity
- End Wedges and Damper Windings: discoloration, electric pitting between wedges and slot; different wedges, wedges and retaining ring
- C-Channel Subslot (if applicable): physical damage - borescope examination through slot under retaining ring may be possible
- Collector Rings: condition, insulation condition, collector thickness/groove depth, spring condition

- Shaft Voltage Discharge Brushes: visual inspection, monitor system (applicable?)
- Rotor Winding main Lead Hydrogen Sealing: Pressure test, visual not practical
- Couplings and Coupling Bolts: chafing, fretting, thread condition
- Bearing insulation: inspect grounding devices, insulation, electric pitting of Babbitt, insulation carbon dust, electrical testing - megger
- Hydrogen Seals: Seals: inspect babbit and steel shell, seal rings, seal housing, wipers, springs/pressure components, gaskets/O-rings, NDE – Liquid Penetrant inspection (LPI) for cracks, Ultrasonics (UT) for babbit bonding to shell, Insulation resistance – megger seal insulation to ground

Inspection – Auxiliaries: The following systems could undergo inspections as part of overall generator program, but specific details to be developed:

- Lube oil system – pre-shutdown detailed system readings, tank condition/cleanliness, piping looseness defects, valve operation, oil coolers condition (possible leak test), filters, switches, gauges, pump bearings, monitoring instrumentation check, purifier/centrifuge check
- Hydrogen Cooling System: general condition and functionality – dryers and control, bulk supply, controls and instruments, desiccant condition
- Seal Oil System: general condition and functionality – coolers condition (possible leak test), filters, reservoirs condition/cleanliness, hydrogen detraining, piping looseness defects, switches, gauges, pump bearings, monitoring instrumentation check
- Stator Cooling Water System: general condition and functionality – demin water tank, pipework, valves, heat exchangers, filters/strainers, pumps, deionizer, hydrogen detraining system, gas release and monitoring system, instrumentation
- Exciters: Electrical and Mechanical systems

Tests:

Test – Stator: The tests to be further evaluated for the Stator with the rotor in could include:

- Though Bolt (If Applicable) Insulation Resistance: Megger (500 V dc)
- Flux Screen Insulation: Megger (500 V dc)
- Stator Cooled Winding Tests
    - Air Pressure Decay: dry, pressurize to op pressure, watch depressure rate, soapy water "snoop" test
    - Tracer gases: helium leak test
    - Vacuum decay (more sensitive than air pressure): leak sensitivity of whole winding
    - Pressure Drop: stator inlet to outlet (offline/online)
- Core and Frame Vibration: vibration transducers (accelerometers) on core and frame inside machine and magnetic transducers on outside (typically on-line; off-line where a known problem)
- Stator Winding Electrical Tests – dry, phase isolation

- AC – more an electrical stress test – conducting properties, loss or power factor characteristics, dielectric properties, mechanical integrity by capacitance characteristics
- DC – cracks, moisture, particle contamination, general degradation
- Series Winding Resistance: ohmic resistance of copper in each phase – shorted windings, bad connections, wrong/open connections
- Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (stator core) – gross insulation issues so that further hi-voltage testing can be carried out safely
- Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture
- Dielectric Absorption during DC voltage Application: measures aging of resin binder in ground wall insulation – time dependent current flow. Affected by voids in insulation.
- DC leakage or Ramped Voltage: leakage current versus applied voltage applied increasingly over time – warns of impending insulation breakdown
- DC Hi Pot: high voltage to winding (each phase separately or all)
- AC Hi Pot: high voltage to winding (each phase separately or all)
- Partial Discharge Off-Line Testing: Capacitive Coupling – whole winding measurement (generally on-line);
- Capacitance Measurement: AC on a phase basis Power Factor of winding compared to as new factory
- Dissipation/Power Factor Testing: bulk quality of ground wall insulation measuring dielectric loss per volume insulation, somewhat void dependent
- Dissipation/Power Factor Tip-Up Testing: measures the void content of insulation, also other ionizing losses (PD or slot discharges). For bad individual bars, a PD test and manual probing is used

Test – Rotor: The tests to be further evaluated for the rotor with the rotor in could include:

- Mechanical Testing
  - Rotor Vibration: typically on-line measurements, detailed testing (using on-line device connections – characterize magnitude, phase relation, frequency spectrum
- Test – Rotor Electrical Testing
  - Rotor Winding Resistance Tests: Megger - ohmic resistance of total copper winding shorter turns, bad connections, wrong/open connections
  - Insulation Resistance: Megger - ohmic resistance between conductors in each phase and ground (rotor forging) – gross insulation issues so that further hi-voltage testing can be carried out safely
  - Polarization Index (PI) – Megger - change in IR in first minutes (IR minute 10/IR minute 1) = function of insulation condition, contamination, moisture
  - DC Hi Pot: high voltage to winding for 1 minute

- AC Hi Pot: high voltage to winding for 1 minute
- Shorted turns Detection
    - General: higher field current input, increased rotor vibration – "OEM on-line "search coil method" is generally available
    - Open Circuit Shorted Turn Detection: open circuit saturation curve compared to design may identify a significant size short
    - Off-Line Testing: winding impedance measurement during acceleration and deceleration
    - Low Voltage DC – Volt Drop Shorted Turn Test:
    - Flux Probe (or Shorted Turns Detector) Test: search coil mounted on stator core in airgap – identified slot short is in, estimated numbers of shorted turns, captures speed dependent shorts
    - Field Winding Ground Detection – Split Voltage Test: locates rotor grounds through field winding
    - Field Winding Ground Detection – Current through Forging Test: locates axial position of the ground – retaining rings on
    - Shaft Voltage and Grounding: consider upgrading grounding system to on-line monitoring by OEM
- Hydrogen Seals: NDE - liquid penetrant inspection (LPI) for cracks and surface damage, and ultrasonic testing (UT) for babbit bonding to seal ring components; Megger seal insulation
- Bearings: NDE - liquid penetrant inspection (LPI) for cracks and surface damage, and ultrasonic testing (UT) for babbit bonding to bearing shell; Megger bearing insulation

Generator Inspection & Test Cost

The specifics of this inspection and testing program will need to be addressed as a first step in the next phase, and the final costs could depend on some of the initial results. For the purposes of cost planning, it is recommended that an allowance of $600,000 be allocated for the generator inspection program.

2. STEAM TURBINE & AUXILIARIES

The steam turbine generator and most of its auxiliary systems are not included in this assessment as they are not required for synchronous condensing operation. There remain however a few subsystems that are required for synchronous condensing operation, including:

- Turbine Oil System (including Turbine Lube Oil System - Lube Oil Tank & Equip, Lube Oil Purification, AC Flushing Oil Pp South, AC Oil Pp North, DC Pump)
- T/Gen Water Cooling (Including Cooling Water Pump North and South)

The Turbine Oil System (including Turbine Lube Oil System - Lube Oil Tank & Equip, Lube Oil Purification, AC Flushing Oil Pp South, AC Oil Pp North, DC Pump) provides for lubrication of the bearings required for the generator. As such these systems need to be assessed.

Generally speaking the pumps and pump motors are part of a regular program of maintenance of motors and pumps by the station. It is expected that they will have no difficulty operating satisfactorily, until their next maintenance inspection. The tanks themselves are not expected to have any issues, but given the lack of information a Level 2 tank thickness inspection is recommended at a total three unit cost of about $10,000. A tank internals inspection is recommended at the next major turbine inspection in 2012.

Steam Turbine Cost

The lube oil tanks themselves are not expected to have any issues, but given the lack of information a Level 2 tank thickness inspection is recommended at a total three unit cost of about $10,000. A tank internals inspection is recommended at the next major turbine inspection in 2012.

3. COOLING WATER SYSTEMS

General Service Cooling Water

The piping, pumps and pump motors that form the General Service Cooling System are part of a regular program of maintenance of motors and pumps by the station. It is expected that they will have no difficulty operating satisfactorily, until their next maintenance inspection. No additional testing is required.

Cooling Water (CW) System

The CW System includes the CW Intake System, Traveling Screens East & West, CW Screen Wash System, CW pump East & West, and the Discharge to Outfall. The CW Intake structure, and CW Discharge to Outfall will be required for future operation. The traveling Screens (either East & West or both), and the associated CW Screen Wash System may be required depending on how the system is developed - i.e. Unit 3 can and typically does use a sump pump drawing from the unit 4 CW pit. It may be capable of meeting the needs of the three synchronous condensing units, or a similar larger system installed.

An inspection is required of the CW pump valves and piping in the Stage 1 Pumphouse to ensure that they are suitable for duty going forward and do not cause issues. A cost of $15,000 for the three units is assumed, although replacement might be an alternative for the future. There was

no record of recent inspections of the Intake and Outfall, although this has been done in the past.

Cooling Water (CW) Inspection & Test Cost

It is recommended that a diver perform a visual inspection of both the intake structure and the outfall structure, as well as walk-downs of the concrete pipe from the pumphouses to the powerhouse and to the outfall. A cost allowance of $15,000 has been allocated.

4. UNIT CONTROLS & CONTROL CABLING

There are age and spares problems with the relaying system. It is recommended a that study be conducted to remove existing control relaying and transducers, re-direct field cabling to the DCS and re-configure the software. Foxboro has digital and analog modules to replace the existing relays and transducers, respectively. All digital and analog functions will then be software items in the DCS. The unit controls will no doubt require replacements and repairs over the future for continued operation to 2041 as synchronous condensers. There is no current requirement for Level 2 testing in 2011, but with a review within the next 5 years.

Control cables have some uncertainty associated with their condition and it is recommended that a representative group of control cables that will be required for synchronous condensing should be tested. Insulation Tests are sufficient for control cables, with cable selected where cables run through good and bad areas in order to average out the condition, etc. The Low Resistance Test measures the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.

Control Cable Inspection & Test Cost

The cost of performing the recommended tests is $20,000 has been allocated.

5. GENERATOR BUS-DUCT AND CONNECTIONS

The Units 1 & 2 generator bus-duct is a 3ph Isolated Phase Bus c/w PT's and Neutral Cubicle, manufactured by ITE and installed in 1969. On Unit 2, Bus-duct connections were modified when T1 power transformer was up-graded. When sprinkler heads were secured to the bus-duct arcing was seen between phases and the sprinklers were removed. A partial maintenance inspection was carried out in May, 2009, using a 5kV Megger and was recorded on a Holyrood PM Inspection Sheet PM0155H1.Only Section 2, of the sheet was completed and indicates good insulation test

readings. However, Section 1 (A-toward generator and B-toward main transformer) was blank.

The Unit 3 generator bus-duct was manufactured by Westinghouse and installed in 1979. No recorded maintenance inspections have been carried out since installation.

Tests should be carried-out, and the Holyrood Bus-Duct PM Inspection sheet extended to also record the low resistance tests, as outlined below, and to show comments on the condition of sectional gaskets, sectional grounding straps and condition of all grounding points. Tests are as follows:

Low Resistance Test.
Measure the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value.

Insulation Resistance Test.
Measure the phase-to-phase and phase-to-ground insulation resistance, which must be at least 100Mohm per 1000 ft. of bus-duct.

Cost

The specifics of the bus duct test program are approximately $50,000 for the three units.

6. TRANSFORMERS & AUXILIARIES

Power Transformers generally have a design life of 20-35 years. In practice, the life can be as much as 60 years with appropriate maintenance. This is illustrated in the following figure from GE on distribution power transformers (applicable to large power transformers).

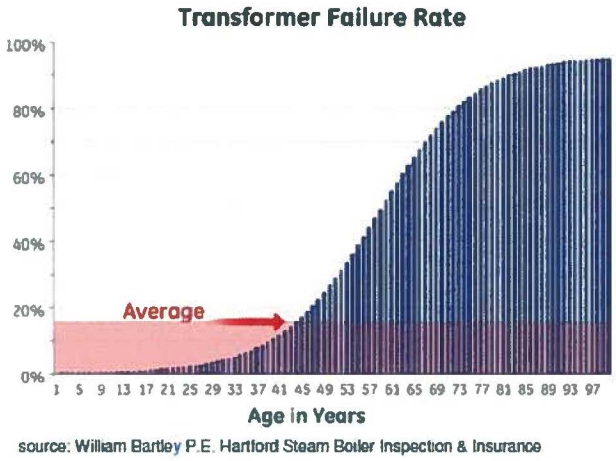
Generically, periodic tests are done after a transformer is installed in its permanent location. The main purpose of this test is to monitor the condition of the unit so that any potential trouble may be spotted early before a failure occurs. Some of these are listed below:

- Turns ratio
- Insulation resistance
- Power factor
- Resistance (winding)
- Oil tests (DGA, moisture, dielectrics, etc.)
- Excitation current test

- Visual inspection

Aging infrastructure reduces reliability

- The average transformers is 40 years old
- Transformer failure means a less reliable, less stable grid





Source: GE Website – CEA Pitch 11-24-2009

Generally NLH carry out transformer PM on a 6 year basis with Oil Analysis annually. At the same time Typical Maintenance Requests are carried out more frequently and on an as required basis. These are identified by Work Orders in the J. D. Edwards program. Some organizations carry out more frequent testing (on the order of 3 years), and given the age of Holyrood's transformers, NLH may wish to consider reducing the timing between testing. It is suggested that a testing program be undertaken in 2011 as part of the base line data for Holyrood Transformers. It is recognized however that there is an existing program, that optimization is possible, and with the numbers of transformer units involved a program over two years or more is more likely.

NLH scheduled maintenance for the transformer equipment is typically as follows:
- 6 year detailed Planned Maintenance.
- 1 year thermography tests
- 4 month visual inspection

2009 Transformer Insulating oil Test Results vs. IEEE Recommendations and Standards are followed:

- IEEE Standards C57.104 – 2008 IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers

- IEEE Standards C57.106 – 2002 IEEE Guide for Acceptance and Maintenance of Insulating Oil in Equipment

Testing provides functional verification of the condition of the transformer. All transformer testing requires an outage. The tests that could be performed on a regularly scheduled basis are: Power factor, Insulation resistance-Dielectric absorption, Turns ratio and Winding resistance. Testing is an important part of a comprehensive program because it uses electricity to verify the operating condition of the transformer.

As an example, for T1 Unit 1's main power output transformer, NLH Transformer Maintenance History Sheets are available from 1979 to 2005 (tests in 2005, 2000, 1992, 1988 and 1983). Currently, "Scheduled Maintenance is due in 2011, or before, and it is recommended that maintenance procedures be carried out as per the relevant Transformer Maintenance History Sheets, to include all requirements as listed, (including those tests not performed in the last inspection) and to enable comparisons to be made from previous history." Previous to the 2005 tests, some of the history raises questions, but with tests being done now we can establish base line data, which will be the same idea for the Gas and Oil analyses.

CHECKS COMPLETED:

- ✓ Check Explosion Vent
- ✓ Check HV & LV Connections
- ✓ Ladder Guards
- ✓ Check Porcelain Insulators for chips or cracks
- ✓ Manually Operate Pumps and/or Fans
- ✓ Check Paint/Rust Condition (Main Tank)
- ✓ Silica Gel Checked
- ___ Silica Gel Replaced
- ✓ Visual Check For Dirty Insulators & Clean if Necess
- ✓ Check Conservator For Water & Drain if Necessary
- ✓ Check Paint/Rust Condition (Radiators)

CHECKS COMPLETED ONLY IF INSTRUCTED:

- _____ Obtain Gas Analysis Sample
- _____ Transformer Ratio Readings (Form III)
- _____ Capacitive Bridge Testing
- _____ Doble Test

The transformers to be addressed include:

o T1 Power Transformer	T2 Power Transformer	T3 Power Transformer
o T4 Power Transformer	T5 Power Transformer	T6 Power Transformer
o T7Power Transformer	T8Power Transformer	T9 Power Transformer
o T10 Power Transformer	UST1 Transformer	UST2 Transformer
o UST3 Transformer	SST-12 Transformer	SST-34 transformer
o RT1 Rectifying Transformer	RT2 Rectifying Transformer	RT3 Rectifying Transformer

Transformer Details

Unit 1, T1 Power Transformer

The present T1 transformer was manufactured by Trafo-Union, Germany and installed at the T1 location in 1978. It was located originally at the T3 location, being installed there in 1979. It is a 105/140/180 MVA, Star-Delta, 230kV:16kV, ONAN/ONAF/OFAF, with tap-changer of +2@4.35%, -

1@4.35%, Yd1, Z1=13.6%, Z0=11.7%.

Doble tests were done in 2000 and 2005, but there is no indication of more recent tests. Typical Maintenance Request Sheets have been provided, but these are incomplete as to whether those requests were carried out. In addition, some maintenance has been completed during years 2000 to 2005, such as fan maintenance, various gauge/relay maintenance, except silica gel replacement in 2007, and pump maintenance, but there is no indication of similar maintenance from 2005 to the present. Silica gel replaced in 2007. Transformer Maintenance History sheets are available from 1979 to 2005.

Two anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher level of moisture presented in the oil which could be the primary cause of the lower than normal dielectric breakdown voltage. Given the important role of the T1 transformer, a brief review was also performed on the moisture levels from previous years test, findings suggested that there has been an unusual and noticeable increase in the moisture level during the past 6 months before the test in 2009. This may be a strong indication that the oil needs to be reconditioned.

Unit 2, T2 Power Transformer

The T2 transformer was manufactured by Federal Pioneer and installed in 1989, and is a 115/152/190 MVA, Star-Delta, 230kV:16kV, ONAN/ONAF/ONAF, with primary tap-changer of +2@4.35%, -1@4.35%, Yd1, Z1=13.7%, Z0=11.75%. This transformer was a replacement for the original T2 transformer that had been installed in 1970. This original 170 MVA T2 transformer is now designated as T4 and is kept as a spare. Doble tests were done in 2002, but there is no indication of more recent tests. In addition, some maintenance has been completed during years 2000 to 2006, including work done on fans. No indication of similar maintenance appears from 2007 to the present. Silica gel replaced in 2002 and 2007.
6 year Planned Maintenance sheets are available for 2009.

Two anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher color number could be an indication of the possible start of contaminations, and the higher power factor at100 degrees Celsius indicates higher power loss when under operation.

Unit 3, T3 Power Transformer

The present T3 transformer was manufactured by General Electric and installed at the T3 location in 1978. It was located originally at the T1 location, being installed there in 1970. It is a 170 MVA, Star-Delta, 230kV:16kV, OFAF, +2@4.35%, -1@4.35%, Yd1, Z1=13.5%. Doble tests were done in 2002, but there is no indication of more recent tests. Typical maintenance has been recorded as

completed during years 2008 and 2009 for various gauge/relay maintenance, pump maintenance and structural work, but no indication of other maintenance prior to 2008. Radiators were replaced in 2003, 2005 and 2008. Silica gel replaced in 2008. Latest Planned Maintenance was in 2002, with no outstanding remarks.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss, and the interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products and it is likely the cause of the high color number.

Transformer T4 (spare)

The present T4 (spare) transformer was manufactured by Canadian General Electric and installed in its current location in 1988. It was located originally at the T2 location, being installed there in 1970. It is a 115/152/190 MVA, Delta-Wye, 230kV:16kV, oil cooled. Doble tests have been done in 2004. Radiators were replaced in 2005. Silica gel replaced in 2008. Planned Maintenance performed in 2004.

Three anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factor at 100 degrees Celsius indicates higher power loss, and also the oil has a higher solubility of polar contaminants and oxidation products which could be the cause of the low dielectric breakdown voltage.

Transformer T5

T5 transformer was manufactured by Westinghouse and installed in 1969. It is a 15/20/25 MVA, Delta-Wye, 230kV:66kV, oil cooled. Doble tests have been done in 2001 and 2009. Maintenance has been recorded completed during years 2000 to 2005 for fan maintenance and various gauge/relay maintenance. Silica gel replaced in 2002. Sanded and painted in 2003. Lightning arrestors replaced and doble tested in 2005. Oil was sampled in 2007. Latest Planned Maintenance was in 2009.

Three anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factor at 100 degrees Celsius indicates higher power loss, and also the oil has a higher solubility of polar contaminants and oxidation products which could be the cause of the low dielectric breakdown voltage.

Transformer T6

T6 transformer was manufactured by Canadian General Electric in 1960. It is a 25/33.3/41.7 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, with primary tap-changer of +4@1.25%, -12@1.25%, Yd, Z1=5.5%. Doble tests have been done in 2002 and 2009. Maintenance has been

recorded completed during years 2007 and 2008 for various gauge/relay maintenance. Lightning arrestor replaced in 2007. Oil was sampled in 2007. Latest Planned Maintenance was in 2007.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The value of carbon monoxide is higher than that of the IEEE standards which suggests greater thermal decomposition of cellulose. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products which could be the cause of the low dielectric breakdown voltage.

Transformer T7

T7 transformer was manufactured by Canadian General Electric pre 1974. It is a 25/33.3/41.7 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, with primary tap-changer of +4@1.25%, -12@1.25%, Yd, Z1=5.5%. Doble tests have been done in 2002. Maintenance has been recorded completed during years 2003, 2007 and 2008 for various gauge/relay and pressure switch maintenance. Silica gel was replaced in 2002, 2006 and 2008. Lightning arrestor replaced in 2007. Lightning counter removed in 2004. Structural work was completed in 2003 and 2008. Oil was sampled in 2007. Latest Planned Maintenance was in 2007.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The value of carbon monoxide is higher than that of the IEEE standards which suggests thermal decomposition of cellulose. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products which could be the cause of the low dielectric breakdown voltage.

Transformer T8

T8 transformer was manufactured by Federal Pioneer in 1989. It is a 75/100/125 MVA, ONAN/ONAF/ONAF, Wye-Wye, 230kV:138kV, oil cooled. Doble tests have been done in 2001. Maintenance has been recorded completed during years 2004 and 2008 for various gauge/relay and fan maintenance. Silica gel was replaced in 2007 and 2008. Structural work was completed in 2008. Oil was sampled in 2007. Latest Planned Maintenance was in 2008.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The value of carbon monoxide is higher than that of the IEEE standards which suggests thermal decomposition of cellulose. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products.

Transformer T9

T9 transformer was manufactured by Federal Pioneer in 1970. It is a 10.5/14 MVA, ONAN/ONAF, Wye-Delta, 13.8kV:4160Y/2400V, resistance grounded, with primary tap-changer of +2@2.5%, -2@2.5%, Dy1, Z1=5.5%. Doble tests have been done in 2001. Maintenance has been recorded completed during years 2000, 2004 and 2006 for various gauge/relay maintenance. Silica gel was replaced in 2002. Oil was sampled and dielectric test performed in 1983. Latest Planned Maintenance was in 2006.

Three anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products.

Transformer T10

T10 transformer was manufactured by Federal Pioneer in 1990. It is a 15/20/25 MVA, ONAN/ONAF/ONAF, Wye-Delta, 230kV:69kV.Doble tests have been done in 2000. Gas relay repaired in 2004. Sanded and painted in 2001. Silica gel was replaced in 2004. Lightning arrestor repaired in 2005. Lightning counter removed in 2004. Oil was sampled in 2007. Latest Planned Maintenance was in 2006.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The value of carbon monoxide is higher than that of the IEEE standards which suggests thermal decomposition of cellulose. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss when under operation, and also the oil has a higher solubility of polar contaminants and oxidation products which could be the cause of the low dielectric breakdown voltage.

Unit 1 Service Power System, UST-1 Transformer

The UST-1 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer, +2@2.5%, -2@2.5%, Dy1. The following maintenance has been recorded completed by the JDE:Doble tested in 2000. Winding temperature gauge repaired in 2000. Silica gel replaced in 2003 and 2008. Planned maintenance performed in 2004.

Two anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factors at 100 degrees Celsius indicate higher power loss, and the interfacial tension of the oil shows a slight lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products.

Unit 2 Service Power System, UST-2 Transformer

The UST-2 transformer was manufactured by Federal Pioneer, installed in 1969 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1. The following maintenance has been recorded completed by the JDE: Doble tested in 2002. Oil level gauge repaired in 2003. Radiators repaired in 2003. Winding temperature relay replaced in 2005. Winding temperature gauge replaced in 2005. Silica gel replaced in 2006. Planned maintenance performed in 2007.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss, and the interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products and it is likely the cause of the higher color number.

Unit 3, Unit Service Power System, UST-3 Transformer

The UST-3 transformer was manufactured by General Electric, installed in 1978 and is 10MVA, Star-Delta, resistance grounded, ONAN, 16kV:4160/2400V, with primary tap -changer +2@2.5%, -2@2.5%, Dy1, Z1-6%. The following maintenance has been recorded completed by the JDE: Doble tested in 2000 and 2006. Structural work in 2001. Silica gel replaced in 2002 and 2008. Gas relay replaced in 2005. Planned maintenance performed in 2006. Oil level gauge replaced in 2007. Radiator replaced in 2007. Control cabinet repaired in 2008.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss, and the interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products and it is likely the cause of the higher color number. Since the interfacial tension is much lower than the IEEE standards, a brief review was also performed on the interfacial tension levels from previous years test, and the findings suggested that it exhibits a steady trend of decrease over the years of service which signals an alert on its possible impact to the performance of the transformer.

Common, Stage 1, Station Service Power. SST-12 Trans.

The SST-12 transformer was manufactured by Federal Pioneer, installed in 1969, and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 69kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6.86%. Completed test sheets for Transformer SST12 Protection, dated, 2006 are available. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material. The following maintenance has been recorded completed by the JDE: 69kV cable repaired in 2002. Doble tested in 2002. Pothead replaced in 2002. Silica gel replaced in 2002. Fan motor replaced in 2003. Structural work done in

2004. Oil level gauge replaced in 2009. Radiators replaced in 2009. Planned maintenance performed in 2009.

Several anomalies were found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The higher power factors at 25 and 100 degrees Celsius indicate higher power loss, and the interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products.

Common, Stage 2, Station Service Power, SST-34 Trans

The SST-34 transformer was manufactured by Westinghouse, installed in 1978 and is a 10.5/14MVA, Star-Delta, resistance grounded, ONAN/ONAF, 16kV:4160/2400V, with primary tap-changer +2@2.5%, -2@2.5%, Dy1, Z1-6%. The following maintenance has been recorded completed by the JDE: Insulator replaced in 1999. Doble tested in 2000 and 2006. Silica gel replaced in 2002 and 2007. Oil temperature gauge replaced in 2004. Planned maintenance performed in 2006. Oil leak in conservator repaired in 2009. Completed test sheets for Transformer SST34 Protection, dated 2007/2008, are available. Results indicate reasonable tolerances.

Only one anomaly was found in the 2009 dissolved gas and oil quality test results for the insulating oil of the transformer. The interfacial tension of the oil shows a lower value than that of the IEEE standards which suggests the oil has a higher solubility of polar contaminants and oxidation products.

Transformer Testing Costs

The scope of the testing required can vary from simple annual oil sample testing to doble testing to a more complete test depending on when and the scope of the last testing. The cost per transformer inspection and testing is approximately can vary from $4,000 to $10,000 per transformer depending on the scope of the testing agreed to by scheduling and budgeting constraints. For estimating purposes, an allowance of about $100,000 is recommended.

7. SWITCHYARD

The following information covers breakers, motorized disconnects and ground switches in the switchyard. Planned maintenance (PM) and corrective action (CA) sheets are available for the Switchyard equipment. Scheduled maintenance for the Switchyard equipment is typically as follows:

- 6 year detailed Planned Maintenance.
- 1 year thermography tests

- 4 month visual inspection.

Thermography and hot spot guidelines have been applied by NLH, dated June 13, 2006, indicating the priority, temperature difference and response times required to carry out 'hot spot' checks. The NLH approach is to identify the problem with the camera, create a work order to repair, then re-shoot the area to verify the repair effectiveness.

230kV Breakers

Planned maintenance has been carried out on a consistent basis in the years indicated. Dependent on various factors, including maintenance, usage, area conditions, etc. the life has been extended to 40 years, being due, in part, to regular planned maintenance and corrective actions. It is expected that this process will be continued, with refurbishments and replacements as needed.

1. Breakers B12L17, B2L42, B1L17 are Brown Boveri, Air Blast type DLF 245 nc2, installed in 1973. The following maintenance has been recorded as completed by the JDE:
   a. B12L17: Pressure reducing valve replaced in 1999. Sanded & painted in 1999 and 2003. Washed in 2004. Leslie valve regulator replaced in 2006. Planned maintenance performed in 2008. Relief valve replaced in 2009. Doble tested in 2009.
   b. B2L42: Sanded & painted in 1999 and 2003. P3 maintenance performed in 2001. Washed in 2004. Doble tested in 2004. Indication repaired in 2005. Capacitor replaced in 2008. Relief valve replaced in 2009. Planned Maintenance performed in 2009.
   c. B1L17: P3 maintenance performed in 2001. Jumpers replaced in 2001. Doble test in 2001. Air leak repaired in 2003. Sanded and painted in 2003. Control valve leak repaired in 2003. Washed in 2004. PLC control installed in 2005. Operation check in 2005. Protection and time tests performed in 2005. Planned maintenance performed in 2006. Trip coil contacts cleaned in 2009.

2. Breakers B2B11, B1B11 are Brown Boveri, Air Blast type DLF 245 nc2, installed in 1974. The following maintenance has been recorded as completed by the JDE:
   a. B2B11: Sand & paint in 1999 and 2003. P3 maintenance in 2001. Doble tested in 2001. Capacitor replaced in 2004. Washed in 2004. Handle replaced in 2005. Indication repair in 2005. RTV coating in 2006. Hinges replaced in 2008. Relief valve replaced in 2009. Planned maintenance performed in 2009.
   b. B1B11: Sand & paint in 1999 and 2003. P3 maintenance in 2001. Doble tested in 2001. Fuse holder replace in 2003. Indication relay replaced in 2004. Washed in 2004. Capacitor replaced in 2005. Pressure reducing valve replaced in 2005. Hinges replaced in 2008. RTV coating in 2006. Planned maintenance performed in 2007. Heat trace replaced in 2008. Relief valve replaced in 2009.

3. Breakers B3L18, B12B15, B3B13, B12L42 are Brown Boveri Air Blast type DLF 245 nc2 and installed in 1978. The following maintenance has been recorded as completed by the JDE:
   a. B3L18: Sand & paint in 1999 and 2003. Indication repaired in 2001. P3 maintenance in 2001. Capacitor replaced in 2001 and 2003. Drain valve replaced in 2003. Washed in 2004. Planned maintenance performed in 1985 and 1991.
   b. B12B15: Sand & paint in 1999 and 2003. Planned maintenance performed in 2001 and 2008. Doble test in 2001. Capacitor replaced in 2001. Washed in 2004. Safety relief valve replaced in 2005.
   c. B3B13: Sand & paint in 1999 and 2003. Planned maintenance performed in 2001 and 2008. Washed in 2004. Capacitor replaced in 2008. Doble test in 2009.
   d. B12L42: Sand & paint in 1999 and 2003. P3 maintenance performed in 2000. Doble test in 2000 and 2009. Washed in 2004. Air leak repaired in 2007. Planned maintenance performed in 2008.

4. Breakers B13B15, B12L18 are Brown Boveri SF6/N2 type ELF 245 n2s, and installed in 1981. The following maintenance has been recorded as completed by the JDE:
   a. B13B15: Sand & paint in 2000 and 2003. P3 maintenance performed in 2001 and 2007. Doble tests in 2001 and 2007. Indications repaired in 2002. New thermostat installed in 2004. Washed in 2004. Fittings and hoses replaced in 2006. Drive mechanism overhaul in 2007. Planned maintenance performed in 2007.
   b. B12L18: Solenoid valve replaced in 1999. P3 Maintenance performed in 2001. Doble test in 2001. Indication repaired in 2003. Sanded and painted in 2003. Washed in 2004. Air leak repaired in 2004. Breaker mechanism overhauled and planned maintenance performed in 2006.

5. Breaker B12T10 is Siemens SF6 type 3AQ1 and installed in 1990. The following maintenance has been recorded as completed by the JDE:
   a. B12T10: P3 Maintenance performed in 2000. Washed in 2004. Contacts replaced in 2006. Hydraulic overhaul in 2007. Planned maintenance performed in 2007.

No Level 2 testing is planned for the 230 kV Switchyard Breaker equipment.

138kV Breakers

Like the 230 kV breakers, planned maintenance has been carried out on a consistent basis. It is expected that this process will be continued, with refurbishments and replacements as needed.

1. Breaker B8L39 is CGE Oil type, KSO-138-5000, and installed in 1978. The following maintenance has been recorded as completed by the JDE:
   b. B8L39: Mounting bracket replaced in 1999. Doble test in 2001. P3 Maintenance in 2001. Revised trip interlock circuit in 2001. Breaker overhaul in 2002 (ref.

WO#241903). Junction box replaced in 2002. Planned maintenance performed in 2005 and 2008. Oil sample taken in 2007.

No Level 2 testing is planned for the 138 kV Switchyard Breaker equipment.

69kV Breakers

Like the 230 kV breakers, planned maintenance has been carried out on a consistent basis. It is expected that this process will be continued, with refurbishments and replacements as needed.

1. Breakers B7L38, B7L2 are CGE Oil type KSO-69-1500 and installed in 1969. The following maintenance has been recorded as completed by the JDE:
   a. B7L38: P3 Maintenance performed in 2001. Oil sample taken in 2007.
   b. B7L2: P3 Maintenance performed in 2001. Oil sample taken in 2007.

2. Breaker B6L3 is CGE Oil type FKP and installed in 1978. The following maintenance has been recorded as completed by the JDE:
   c. B6L3: P3 Maintenance performed in 2000. Doble test in 2000. Oil sample taken in 2007. Gaskets replaced in 2009. Planned maintenance performed in 2009.

3. Breakers B7T5, B6T10 are AEG SF6 typeDT1-72F1 and installed in 1996. The following maintenance has been recorded as completed by the JDE:
   d. B7T5: P3 Maintenance performed in 2000. Sanded and painted in 2001. Cabinet heater installed in 2007. Planned maintenance performed in 2009.
   e. B6T10: P3 Maintenance performed in 2001. Sanded and painted in 2001 and 2007. Moisture heater installed in 2007.

No Level 2 testing is planned for the 69 kV Switchyard Breaker equipment.

230kV and 138 kV Motorized Disconnects

Planned maintenance has been carried out on a consistent basis. It is expected that this process will be continued, with refurbishments and replacements as needed.

c. Motorized disconnects B11T5, B15T6 are 230 kV Raised Vertical Break type Kearney RVB, c/w Kearney KMT operator, vintage 1969-1978. The following maintenance has been recorded as completed by the JDE:

d. Motorized disconnects B8T6, B8T7, B8T8 are 138 kV Raised Vertical Break type Joslyn RF-2, c/w Joslyn JMO operator, vintage 1969-1978. The following maintenance has been recorded as completed by the JDE:

No Level 2 testing is planned for the Switchyard equipment.

8. MOTOR CONTROL CENTERS

Most of the motor control centers have not previously been upgraded and are original equipment, such as in the Stage 1 Pumphouse. Generally speaking, these MCC's have or will exceed their original and reasonable design lives in the scenarios going forward. They do not need to undergo testing, but rather any required for synchronous condensing should be refurbished given their age.

No Level 2 testing or cost is suggested.

9. POWER CABLES

Prior to 1995 planned maintenance was carried out on Power Cables, approximately, every 10 years. Since 1995 no PM has been done and no records have been kept. Visual inspection indicates some contamination of trays in the boiler areas due to asbestos and heavy metal-dust. Modifications, over the last 40 years, has resulted in cables, power and control, being added casually into trays that have been convenient in the routings associated with the new installations.

It is not practical to test all power cables, but there is some risk associated with cables that are 40+ years old, especially those which have been subject to unusual conditions. It is recommended that a representative group of power cables that will be required for synchronous condensing should be tested. Insulation Tests and Low Resistance and IR Tests should be carried out on power cables at the test voltages indicated. The Low Resistance Test measures the resistance of bolted connections using a low-resistance ohmmeter (Ductor). Compare resistance readings between similar bolted connections. There must not be any difference greater than 50% between resistance readings. Check the resistance values are below the manufacturer's recommended maximum value. The Insulation Resistance Test involves applying a test voltage of 5kV for cable used for 4160V, 1000V for cable rated at 600V, and 500V for cable rated at 300V. Record phase-to-phase and phase-to-ground insulation resistance tests, which must be at least 100Mohm per 1000 ft. of cable.

Cleaning of raceways, trays and cables should be done by a crew of specialized hazardous area cleaners before any inspections or tests are carried out. Any new cable installations should be installed on new tray, and in accordance with the applicable Codes.

Power Cable Inspection & Testing Costs

A representative program is assumed for an allowance of about $30,000 is recommended.

10. SWITCHGEAR 4160 & 600 V

The average life of this type of switchgear is 20-30 years, dependent on various factors, including maintenance, usage, area conditions, etc. In this case the life has been extended to 40 years, being due, in part, to regular planned maintenance and corrective action. The last planned maintenance was carried out 2006-2007, meaning the switchgear is now due for planned maintenance procedures.

The Unit 3 Boards UB3 and Station Board SB34, (4160V) were manufactured by FPE and installed in 1980. The 4160V switchgear, utilizes original draw-out ITE type power breakers. Protection, synch, and control relays are original CGE electro-mechanical. All Feeders have Schweitzer 701, Motor Protection Relays, installed in 2009, replacing the original P&B Golds relays. Yearly Planned Maintenance (PM) and Corrective Action (CA) sheets are available for Unit Board UB3 and SB34 breakers.

Most of the 4160V and 600V switchgear, including cubicles and breaker elements do not need to undergo testing, but rather refurbishment given their age - a complete overhaul to an "as new condition" thus extending the life expectancy of the existing switchgear for a further 15-20 years.. With the availability of spare breaker elements, a program can be set up to overhaul each breaker, off site, with essentially no interruption to plant requirements. At the same time, the spare cubicle (UB1-12), can be made available for the new Synchronous Condenser Start Pony Motor requirements. Hence no Level 2 testing is suggested. Rather given their age, the station should be going through an active program of refurbishment. The total refurbishment cost is estimated at $15,000 per 4160V breaker and at $10,000 per 600V breaker. Based on this, for the existing system the program would cost roughly:

4160V Boards.	Bkrs.	Total.
UB1	11	$165k
UB2	11	$165k
UB3	11	$165k
SB12	4	$60k
SB34	5	$75k
Total		$620k

600V Boards.	Bkrs.	Total.
UAB1	7	$70k
UAB2	6	$60k
UAB3	6	$60k
SAB12	14	$140k
SAB34	12	$120k
DB12	4	$40k
Sub-Total		$490k

Total	$1,100k

Given few of the 4160V and only some of the 600 V will be required, the estimated cost for required systems is likely will be on the order of $400k. This is not however a test and inspection cost.

4160 and 600 V Switchgear Inspection & Testing Costs

No inspection or testing of 4160 and 600 V Switchgear testing is assumed required.

11. 4160V MOTORS

Maintenance has been carried out on the 4160V Motors during annual unit outages, in the form of Meggar and Bridge tests, air filter changes and oil sampling and analysis. At the same time, there is on-line bearing and winding temperature monitoring and system alarms based on motor current levels. Outage statistics are available indicating the need for unit de-rating during full operational times, and the impact on system reliability.

The following figures show the graphical presentations of the service life of 4160 V Motors for Units 1, 2 and 3.

BFP – Boiler Feed Pump
CEP – Condensate Extraction Pumps
FDF – Forced Draft Fans
CWP – Cooling Water Pumps

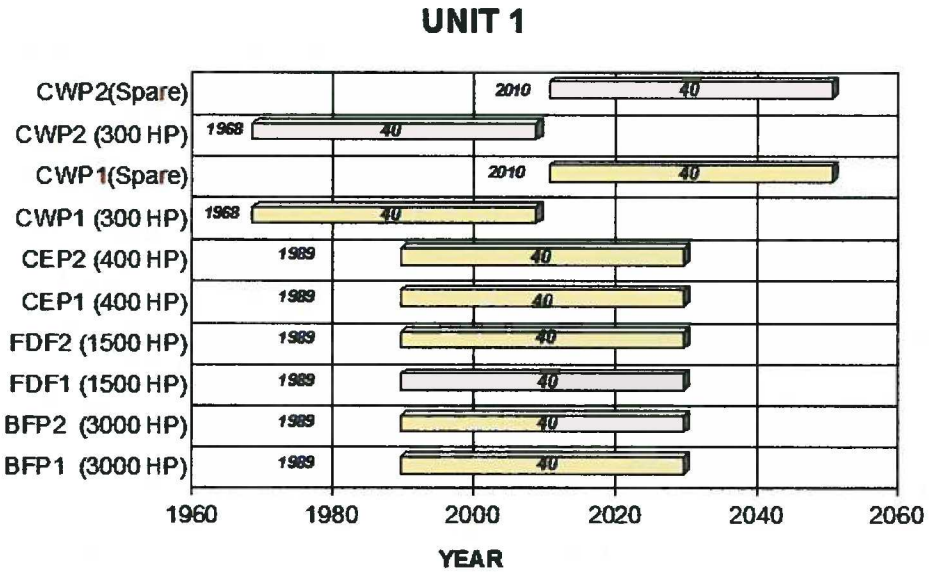


Figure 4.1 Service Life Expectancies of Motors in Unit 1.

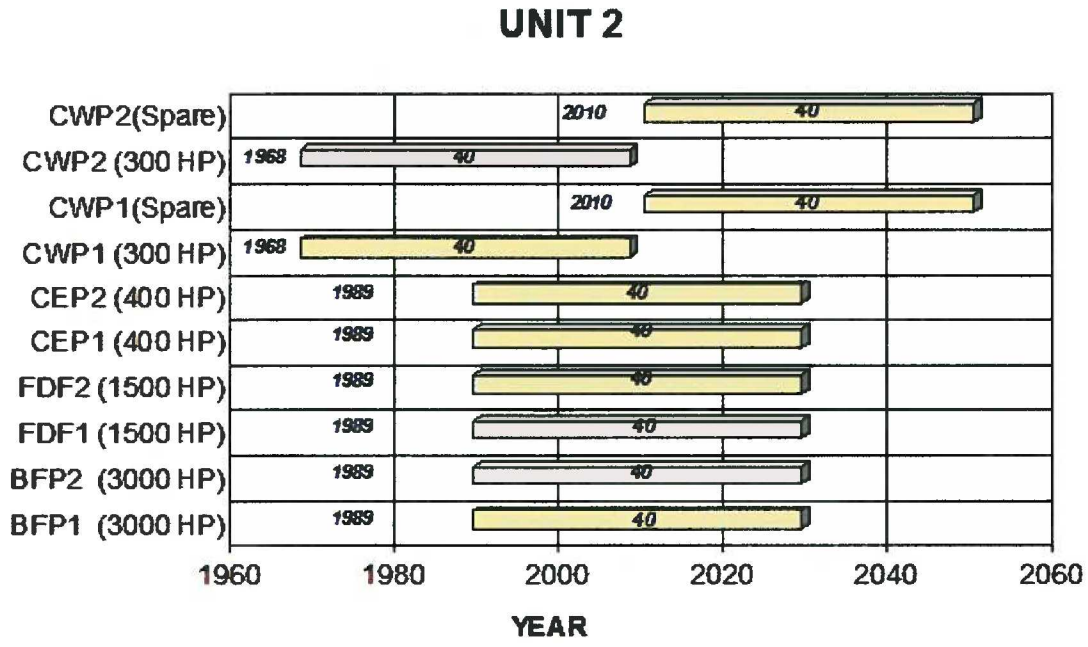
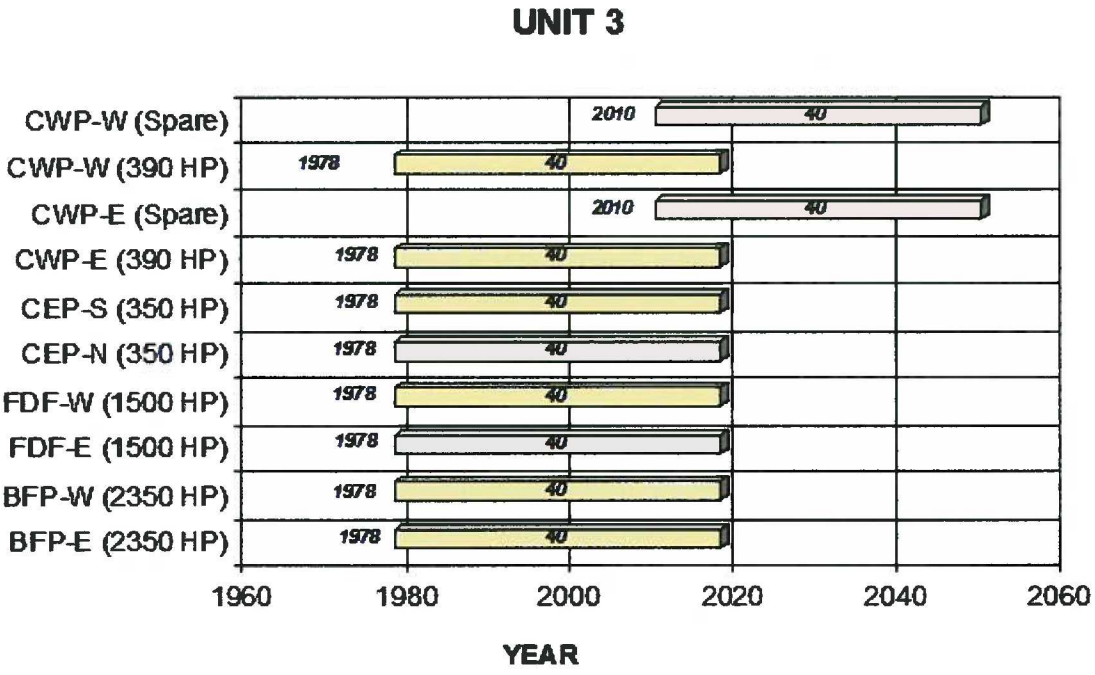


Figure 4.1
Service Life

Expectancies of Motors in Unit 2



Expectancies of Motors in Unit 3

These motors are not required for synchronous condensing operation and hence no Level 2 testing is recommended. The anticipated service life of these motors is expected to be 40 years being dependant on the operating conditions remaining the same, and that the maintenance procedures are properly carried out on a scheduled basis. The anticipated service life of the three motor sets, for Units 1 and 2, (Boiler Feed Pumps, Forced Draft Fans and Condensate Ext. Pumps), replaced in 1989, is expected to be until 2029.

Similarly, based on this anticipated service life, the two U1 and U2 sets (4 motors) of Circulating Water Pumps, have exceeded their life expectancy (1967 – 2007), and consideration should be given to replacing them as soon as possible. (Refer to Unit 1 and Unit 2 Figures).

Based on the 40 year life expectancy all motors associated with Unit 3 will reach their anticipated service life around 2018. As such, one spare circulating water pump motor should be purchased. (Refer to Unit 3 figure).

12. RELAY ROOM PROTECTION & CONTROL

Units 1 & 2 Relay Room Protection & Control

Generator, Transformer, and Auxiliaries P&C Panels, were manufactured by Canadian General Electric, and installed in 1969. The Generator and Transformer Protection Panels utililze GE electro-mechanical relays and blocking switches. In addition they show annunciation and T1/UST1 gas and winding temperature trips and indications. The Unit Protection Auxiliary Panel shows DC buses indications and blocking switches. The Unit Metering Panel shows Generator and Static Exciter WHR's, runtime, flexitests and stator ground fault protection added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs.)

The rear of the panels show the original GE and Brown Boveri Control relays, Agastat timers and transducers. Completed Test Plan Activity sheets for Generator and Transformer Protection, dated, 2005 and 2006 respectively are on file. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material.

The GE electro-mechanical relays appear to been in good condition at the test times indicated. New and refurbished relays are available for the unforeseen future, but new or refurbished relays are expensive. At the same time, the Brown Boveri control relays are obsolete. A modernization study should be conducted to appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying. The scope of the existing Schweitzer SEL 300G should be extended from its present usage of ground fault monitoring, to include all unit protection. At the same time a similar multi-function relay, from a different manufacturer, should be considered for back-up protection. For the control, indication and annunciation functions, an ABB Combiflex system should be considered.

The Station Service Transformers UT1 and UT2 Protection Panels and Gas Turbine Metering and Protection Panels utilize GE electro-mechanical relays and blocking switches. In addition they show annunciation and SST1/SST2 gas and winding temperature trip indications. The Unit 1 Services Protection Panel shows UT1/SST/UT2 MWatts, WHR's, DC buses indications, voltages and blocking switches.

Completed test sheets for the Transformers UT1, UT2 and SST12 Protection, dated, 2006 are available. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material.

The Gas Turbine Metering and Protection Panel includes relaying for differential, WHR, neutral over-current, annunciation and blocking switches. Completed test sheets for Generator GT Protection, Transformer T9 Protection and GT Sync. Check, dated 2008 are available. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material.

No Level 2 testing is planned for the equipment.

Unit 3 Relay Room Protection & Control

The Generator G3 Transformer T3, ST3/ST4 and Auxiliaries P & C were manufactured by Canadian General Electric, and installed in 1979. The Generator G3 and Transformer T3 Protection Panels utilize GE electro-mechanical relays and blocking switches. In addition they show lockouts, annunciation and indications. The Unit Transformer T3 and Unit #3 Protection Panel utilizes GE electro-mechanical relays and blocking switches. In addition they show lockouts, annunciation and indications. The Unit 3 Metering Panel contains G3, T3 UST3 MWH meters and stator ground fault protection added in 2008. (Schweitzer SEL 300G multi-function relay and AREVA MML G01 test plugs. The Transformer ST3/ST4 protection panel utilizes GE electro-mechanical relays and blocking switches. In addition they show lockouts, annunciation and indications.

The rear of the panels show the original ASEA Combiflex relays and Agastat timers. Completed Test Plan Activity sheets for Generator G3 and Transformer T3 Protection, are on file. Results are satisfactory at this time. Relays and cases required cleaning due to ingress of dust and foreign material.

The GE electro-mechanical relays appear to been in good condition at the test times indicated. New and refurbished relays are available for the unforeseen future, but new or refurbished relays are expensive. At the same time, the Brown Boveri control relays are obsolete. A modernization study should be conducted to appraise the cost of refurbishing the old GE electro-magnetic relays against the cost of multi-function relaying. The scope of the existing Schweitzer SEL 300G should be extended from its present usage of ground fault monitoring, to include all unit protection. At

the same time a similar multi-function relay, from a different manufacturer, should be considered for back-up protection. For the control, indication and annunciation functions, an ABB Combiflex system should be considered.

No Level 2 testing is planned for the equipment.

13. COMMON SYSTEMS

Raw Water System - Quarry Brook Dam & Pipeline

The Quarry Brrok Dam and the associated raw water pipeline from the dam to the station are critical to the operation of the station. Holyrood Thermal Generation Station (HTGS) obtains its fresh water for raw water and for domestic water from the pond behind the Quarry Brook Dam.

The raw water supply line extends from Quarry Brook dam to Pumphouse #1. The majority of this 976 m line is 16" asbestos concrete pipe, installed in 1969, except for two sections of the line that have been replaced. These include a 105 m section of pipe in the warehouse yard, which was replaced with 400 mm PVC pipe, installed in 1996. And an 80 m section of pipe around Pumphouse #2, which was replaced with 18" Sclair pipe, installed in 1976. The line is gravity fed with approximately 15 feet of head. There is one valve located at Quarry Brook dam that will shut the flow of water off for the entire line.

The Quarry Brook Dam and Fishway is a rock filled wooden tie based structure. The dam and associated equipment is a critical piece of station equipment that must be sustained as long as the station is manned and functional in any form. It is a single contingency item that could effectively shut down the entire station, if no other contingency plan be established.

Based on interviews, there have been some visual surface inspections, with the last one conducted in 2008. A diving inspection should be conducted of the dam and intake structure, and the any recommended repairs or replacements of dam in part or in whole undertaken.

Dam and Pipeline Inspection & Testing Costs

A Level 2 inspection cost of $25,000 has been allocated for the dam inspection and the pipeline inspection.

Water Treatment Plant Systems

The Water Treatment Plant serves Unit 1, Unit 2 and Unit 3. It contains the various sub-systems identified in table 2. This includes the major equipment elements:

Clarifier System

Sand Filter

Clearwell System

Primary cation and Anion demineralizer Trains - Generally these are in very good condition – replaced in 1992

Mixed Cation/Anion Bed Trains - Generally these are in very good condition – replaced in 1992

Bulk Acid and Caustic Storage Vessels

Demin Water Storage Vessel

Water Treatment Plant Tank Inspection & Testing Costs

A Level 2 inspection of tank thickness assessments of the sand filter vessels in the water treatment plant is warranted, similar to that done for the clarifier in 2009. A cost allowance of $15,000 is assumed.

Waste Water Treatment System

The waste water treatment processes will have to continue to treat the station and site waste water, although admittedly much less once the facility is in Synchronous Condensing mode. The major process steps are relatively new and no testing is required.

Waste Water Treatment Basin Building - The building encloses two WWTP Treatment Basins. They take the full waste water flow from plant and site drains and from boiler blowdowns and cleans. They are concrete basins built on bedrock. They are periodically cleaned and inspected. No major issues have been identified with the basins themselves - some minor cracking of the concrete. The large concrete treatment basin tanks could not be inspected as they were filled with water at the time. They should be inspected and repaired as necessary. Overall the basins themselves are expected to be serviceable until 2040. Some refurbishment of the building structure and siding/roofing is likely required as soon as reasonable.

Oily Water Separator and Piping - The facility has four oily water separator tanks that are expected to remove essentially all the oil from waste water flowing to the Treatment Basin ponds. It was evident from the visible inspection of the treatment basin ponds that this is not always the case. Further it was noted that some staff are concerned that not all of the plant drains are draining properly and may have breaks or blockages. No specific inspection documentation was available that indicated the state of thee lines.

It is recommended that some form of inspection and/or testing program be undertaken to assess the condition of the underground drain lines, and that a detailed condition assessment of the oily water separator/treatment basin oil containment system be undertaken.

Waste Water Treatment Plant Tank & Basin Inspection & Testing Costs

A Level 2 inspection cost allocation of $50,000 for testing of the basin concrete, the basin building structural integrity, for the oily water tank thickness, and for underground drains piping.

14. HYDROGEN AND CARBON DIOXIDE GAS STORAGE & SUPPLY SYSTEMS

Hydrogen and carbon dioxide are currently stored in a gas storage building in pressure tube packs and delivered by underground pipe to the southern exterior of the powerhouse and from there to the units. Consideration is being given to a stand-alone hydrolysis plant to produce hydrogen locally, as there is no local Newfoundland supplier. In the event that this is not undertaken in the 2011 budget, a check of the integrity of the hydrogen system is warranted.

Hydrogen and Carbon Dioxide Storage/Delivery Inspection & Testing Costs

A Level 2 inspection cost allocation of $25,000 for testing and repairs has been made for both the hydrogen and carbon dioxide systems.

15. GAS TURBINE GENERATOR

The black start gas turbine system consists of 7202 Gas Turbine Systems (Including GT Power Turb & G/B, GT Avon Jet Engine, GT Gen, GT E&C, Aux Systems) as well the fuel delivery, air intakes, exhaust stacks, and building. The engine was originally installed in 1066 at another location and at Holyrood in 1986. It has experienced difficulty with the gearbox, with internal corrosion. It runs very little, but has also not had a major overhaul since its initial operation.

An overall detailed inspection of the unit is required. This would look at the current condition of the entire unit using boroscopes and visual inspections on the engine components and power turbine, as well as historic data assessment, plus civil and mechanical assessments of the balance of plant. The result would be an assessment of the costs to refurbish the existing unit (off-site, onsite), or swap the unit with a replacement engine and upgrade auxiliary systems. Alternatively an options study would also examine entirely new system alternatives (GT, diesel) in the light of the future plans for the site..

GT Inspection & Testing and Options Study Costs

A Level 2 inspection cost allocation of $100,000 for initial inspection – likely during 2010. A further Options Study is expected to be required that would likely cost a further testing and repairs has been made for both $75,000.

16. TOTAL LEVEL 2, PHASE 2 COSTS

The total Level 2 inspection Test Program for 2011 related to Synchronous Condensing operation (including generator assessments without rotor extraction) is about $1.28 Million.

Assets Listing - Holyrood GS
Level 2 Costs - Synch Condesning 2011 **31-May-10**
Rev 3

Generators	$600
Generator Bus Duct & Conn	$50
Steam Turbine Oil System	$10
CW System	$15
Control Cables	$20
Power Cables	$30
Transformers & Aux	$100
Quarry Brook Dam & Fishway	$25
WTP Sand Filter	$15
Oil/Water Separators	$50
Hydrogen Storage and Supply	$15
Carbon Dioxide Storage & Supply	$10
GT Detailed Inspection	$100
GT Options Assess	$75
Contingency	$167
Total Program Cost k$ 2011)	$1,282

APPENDIX A (AMEC)

Unit 1 Generator Issues

AMEC Americas Limited 2011 Level 2 Requirements - Holyrood CALE

HOLYROOD G.S UNIT #1.

APPENDIX 4. LIST OF DEFECTS AND SHORTCOMINGS REPORTED, AND RECOMMENDED ACTIONS TO ADDRESS THEM.

Status legend: 1 = done, 2 = in hand, 3 = scheduled for next outage, 4 = scheduled for next major inspection, 5 = unscheduled, 6 = rejected.

R0 – Dated 23 March 2010 by R. Jeffreys.

Defect Found	Action Recommended	Status
A. Operation.		
1. The hydrogen pressure is low, probably due to hydrogen leaks, resulting in extra heating of the generator core and windings.	-Locate and repair the hydrogen leaks. -Increase the hydrogen pressure to 30 psi.	
2. The hydrogen consumption of each generator is not recorded.	Fit a totalizer in the hydrogen supply line, so the daily hydrogen consumption of each generator can be recorded.	
3. The stator winding and core RTD's do not read credible values. They are too low.	Using the GE calibration from the last outage, monitor the most accurate RTD of each phase, and the hottest core RTD, on the DCS display.	
4. The field current is not credible, it is much too low.	-Check the source and calibrate the DCCT, or use the field current value shown on the exciter.	

5. The field winding temperature is not monitored. (During overexcited synchronous condenser operation the field current will be higher, and there is an increased risk of overheating the filed winding insulation).	-Install a mean field winding temperature simulator(if one does not already exist in the static excitation system), or -obtain an algorithm for the mean field winding temperature, based on the field current, cold resistance and the cold gas temperature. Show the mean field winding temperature on the control room display.	
6. The cold gas temperature is low at 30 C, GE usually recommend a minimum of 35 C to avoid algae forming on the windings and the increased risk of brittle fracture in the rotor forging.	Ask GE to confirm the rotor forging is water-quenched, not air-quenched. Increase the cold gas temperature setting to 35 C, especially if the forging is air-quenched.	
7. There is no on-line monitoring for shorted field turns (this is the most common indication the rotor needs to be re-wound).	-Install a flux probe in the stator bore at the next major outage, when the rotor is out of the stator core.	
8 The partial discharge monitoring is not working. The GE test report shows the stator windings are in very poor condition, so the partial discharge levels in operation should be monitored carefully, to minimize the risk of a winding failure – see also item 2 above)	Contact IRIS service dept, to obtain advice on how to get it working. Record the values every 3 months and watch for an increase of >20 % in the readings of the highest 3 sensors. Bring forward the planned outage if necessary.	
9. The shaft voltage and the shaft ground current are not monitored or checked in operation. A harmful current could flow through the bearing or hydrogen seal. (the risk of damage increases when the starting package is added at the collector end, for synchronous condenser operation).	Upgrade the shaft grounding brushes with a constant-tension spring brush box, and replace the other with a copper braid, to clean the shaft. Fit a shaft voltage monitoring brush at the outer end of the shaft, so the shaft voltage can be checked safely in operation, or Install a Sohre grounding brush and shaft current and	

	voltage monitoring system.	
10. During the two month summer outage and the major inspection outages, moisture collects on the stator and rotor windings. Corrosion of the collector distributor bolts was found on units 1 and 2 at the last outage. It greatly affects the Megger and DC hipot test results.	When the generator is out of service and de-gassed, blow warm dry instrument air through the generator. When the rotor is out, install heaters in the stator ends, and a tarp over the ends to keep it warm and reduce dust ingress. Consider fitting pad heaters to the lower outer surface of the stator ends, with a switch to turn the heat on when the unit is off-line. The rotor should be kept in a clean conditions "tent" and air heaters installed to keep the windings warm and dry.	
11. Four of the stator (winding) slot temperatures are monitored on the "turbine generator" screen, but the stator core temperature is not monitored in operation. During high over-excited load the centre of the stator becomes the hottest, but during under-excited operation the core end temperatures are the highest. This is particularly important during synchronous condenser operation.	Use three of the lines for the hottest winding temperature in each phase, and label them phase A, phase B and phase C. Use the fourth line to monitor the hottest stator core-end temperature. Add a fifth line to show the hottest core temperature at the centre of the stator.	
12. The hot gas temperatures are not recorded, so it is not possible to check the temperature rise across each cooler, i.e. whether the hydrogen coolers are balanced. Sometimes a cooler leak occurs, or a plug of the vent pipe after return to service, that should be detected.	Every month check the temperature rise across each cooler, to ensure they are balanced, and no gas lock, plugged vent, or cooler leak has occurred, which will unbalance the temperatures across the generator, and result in undesirable overheating.	

B. Stator		
1. There is oil leaking into the stator, reducing the effectiveness of the winding support. Oil and grease has been found on the end-windings at each past inspection, and on other similar GE generators. A leak in the horizontal joint of the seal assembly was found at the last outage and a temporary repair was made –is it still effective 7 years later?	-Keep the differential seal oil/hydrogen differential pressure constant and between 4 and 6 psi (27 – 40 kPa). Check the oil level in the de-training tank is not high, and the flow in the seal oil drain lines is not excessive or foaming, which increases the risk of oil backing up and leaking into the generator Monitor the partial discharge activity every 3 months for signs of increased partial discharge activity. If the end-winding partial discharge activity exceeds 30 mV on any of the phases, plan an early intervention for repair of the stator end-winding looseness. Check the liquid leak detector for oil deposits. Check the hydrogen consumption and seal oil consumption for leakage.	
2. The stator core appears to be in satisfactory condition, but the GE El-Cid test report is incomplete. (It is important to confirm the condition of the core is sound, before ordering a replacement stator winding for installation in 2012, see next item).	Plan for an El-cid test and a high flux test of the stator core, during the next major inspection. Check the stepped end packets, and record the highest defect values in each slot. Repeat the measurements in the highest three slots and note the positions, for boroscope inspection. Take infra-red photos of the core and note the hot spots. (areas greater than 3 C above the surrounding areas).	
3. The GE tests showed the right phase of the stator winding was in	-At the next major inspection, repeat the 10 KV Megger	

very weak condition in 2003. A rewind was recommended. An update on the winding condition should be obtained at the 2012 inspection (preferably from a second source). The tests should only be done on the winding after it has been carefully cleaned and re-tightened, and is known to be clean and dry.	test, and the DC hipot test at 34 KV. (Check whether the poor insulation condition was due to the high moisture, or to the insulation deteriorating during the re-wedging – this is useful information for unit 3). -Also test the bushings and the PT's, and carry out ratio tests on the CT's. -Decide whether the windings will last until 2015, or whether they should be replaced during the 2012 outage. -Draft a specification now, for the manufacture, test and installation of a replacement winding, together with new RTD's, and bushing and terminal plate flange seals. Also include options for new bushings and CT's, in case they are necessary. This will reduce the outage time, if a winding failure should occur during the next two years. -At the next major inspection, have the OEM (or potential rewind Contractors) take the stator slot and winding dimensions. -Consider taking advance delivery of the winding and store it at the plant until needed. (make sure the new winding will fit either unit1 or unit 2, or identify why this is not possible).	
4. The end-winding support structure is not able to withstand the operating and system stresses. It loosens and allows the insulation to	-Ask the OEM for an improved end-winding support system to be supplied with the new stator winding.	

erode and form grease. An improved end-winding support system is required.	(modern techniques are available to allow the supports to slide when hot, rather than develop internal stress that loosens them. -Have the effectiveness of the new winding installation checked with the "bump" test, and additional support provided where it is found necessary	
5. Top ripple springs were installed to increase the time between re-wedging the stator slots. Check that the top ripple springs are still holding the slot parts of the windings firmly in place, and no loosening of the wedges/windings has occurred.	Carry out a wedge tap survey, to check for loose wedges, (and find out whether unit 2 is likely to require re-wedging at it s next major outage). Visually inspect the core teeth for signs of fretting dust or "grease".	
6. Further information is desirable regarding the deterioration of the stator winding in operation, and the possible need for more frequent maintenance.	Take Doble test measurements every 2 years, during the summer outage (it is necessary to disconnect the neutral bar – make sure it is replaced carefully, and check the joint resistance with a low resistance meter ("ductor")	
7. A hydrogen seal leak was found at the bushings and at the terminal plate seals. It was sealed temporarily from the inside with RTV. GE recommended the area be checked annually for leaks, but it is not known if this was done.	Replace the bushing seals and the terminal plate seals. This is a difficult and expensive repair that is best done during a stator rewind. RTV sealing of the inside is satisfactory for a short time, but the deteriorated seal usually leaks elsewhere. GE uses viscaseal and a dam to identify a leak, but Hitachi repairs the leak with "titeseal" which is better.	
C. Rotor.		

1. The retaining rings and the rotor forging, and slot wedges do not appear to have been NDE checked for defects since they were installed in 1997. (Defects have been found in other similar rotors after less than 30 years operation).	Remove the retaining rings and the slot wedges. Carry out a detailed visual and NDE inspection for defects and fatigue cracks developing, in the dovetails, wedge ends, rotor bore, retaining rings, etc. Remove any crack-like defects. Check the shrink fit areas for fretting, and contact of end-wedges with the retaining rings.	
2. The condition of the end-windings is not known, and some deformation of the turns in the coil stacks is expected, especially at the series connections between longer coils and at the lead connections to the winding. The packing blocks are expected to be fretted and dust will have collected under the retaining ring insulation that should be removed.	Check the end-windings for fretting, fatigue cracks in the top turns under the retaining rings, any distortion or cracking of the flexible connections.	
3. The turn insulation may be damaged, or the packing blocks broken, fretted or displaced, and the ends of the slot cells may be abraided, overheated, or crushed by the retaining rings.	Check the insulation blocks and re-place or re-tighten as necessary. (note the dust found probably contains asbestos).	
4. The ventilation system of the rotor slots uses sub-slots and radial ventilation ducts. It is prone to axial elongation (creep of the copper and restriction of the ventilation holes.	Check the radial holes near the ends of the rotor body for restrictions, and record the restrictions, for future (the rotor should be re-wound when the restriction exceeds 25 % of the hole area).heck the sub-slots for oil, dirt and accumulated debris. Vacuum/blow out as much of the dirt as possible.	
5. The turbine generator shaft line has been realigned at each major inspection. The adjustment seems to be too much to be due to	Trend the bearing vibration levels over time, and record the changes. Try to relate them to the MVAR load, as well	

bearing wear, and it appears that the foundation is settling over time.	as the MW load. If the vibration level is high put the readings on a polar plot (Bode) and compromise balance it with marked weights. Re-align and re-balance the rotor after the shaft line has been corrected, at the major inspection.	
6. There is no record of the generator bearings being re-metalled, but GE recommended sending out the generator bearings for refurbishment at the next major overhaul. Other rotors have found uneven wear, poor babbit bond, and electrical damage. The #5 bearing insulation was found defective.	Re-furbish both generator bearings. NDE the bearing babbitt for good bond with the shell. Check the surface for even wear, Check the insulation resistance of #5 bearing and hydrogen seal, and inspect visually. Replace if defective. Replace oil deflectors.	
7. GE recommended that spare bearing thermocouples be held in stock in case the installed thermocouples fail in service.	The bearing thermocouples are old, and in dubious condition. New thermocouples should be installed at the next major outage.	
8. A week was spent working on the hydrogen seals, and numerous problems were encountered. The hydrogen seal clearances on the hydrogen side were reduced to the low end of the clearance, in an attempt to prevent oil leaking into the generator. An oil leak from the horizontal joint of the hydrogen seal was found at the CE and repaired temporarily with epoxy	Replace the insulation plates of the CE seals. Check the tite-seal groove at the upper and lower CE end-shield for leaks. Air-test the generator for leaks, and fix them properly at the next major inspection. A new hydrogen seal assembly should be considered for the CE end.	
D. Auxiliaries.		

1. Several problems were found with the float trap of the middle de-training tank of the seal oil system. The valve disc had hardened, the level control was incorrect, and the valve was installed backwards.	Replace the seals, and viton disk, and gaskets, and check the operating level in the tank at both 30 and 45 psi hydrogen pressures. GE recommend the seal oil supply piping be flushed annually, to prevent dirt in the emergency by-pass line entering the system.	
2. The seal oil vacuum pump is a high maintenance item. It has a rotary valve that needs to be replaced at each inspection.	Purchase a spare rotary seal and install it at the next major inspection. Carry out preventive maintenance on the pump	
3. The hydrogen coolers were leak tested and found satisfactory, but GE recommended the gaskets be replaced at each major inspection.	Replace the gaskets and seals, and leak test at every major inspection. Check cold parts for green slime (operating temp too low!)	
4. The ABB static excitation system is reported to be operating satisfactorily. However, the controls and protective relays are prone to calibration drift, and malfunctions. The field flashing can maloperate	Check the operation of the excitation system controls, limiters and protection relays. Check the field breaker contacts and operation. Check the thyristors and heat sinks, and snubbers, for signs of overheating,	
5. The liquid leak detector valve had incorrect flanges and gaskets and is prone to failure.	Check the operation of the liquid leak detector relay, and service the parts.	
6. Hydrogen dryer. The replacement hydrogen dryer is of small capacity and will require frequent regeneration. Oil from the leaking hydrogen seals reduces its effectiveness. A pipe blockage can burn out the heater.	Carry out preventive maintenance on the hydrogen dryer, replace the desiccant, check the regeneration operation, check for hydrogen leaks, especially at the purity meter and sampling valves.	

7. The excitation system is expected to have a V/f limiter to protect the generator against over-fluxing, -the risk of generator damage is highest during initial energization on AVR control.	Connect the V/f element of the multi-functional generator protection relay to trip the excitation when off-line, if over-fluxing occurs..	
8. The hydrogen pressure is automatically controlled by a valve, but this generator operates at low pressure. Is the valve not in service or is it broken? Keeping the pressure constant reduces the risk of oil ingress into the generator.	Service the hydrogen pressure control valve. Locate and repair hydrogen leaks ASAP.	

APPENDIX B (AMEC)
Transformer T1 Inspection Sheet

AMEC Americas Limited 2011 Level 2 Requirements - Holyrood CALE

3.2 2.8 09 June 2005

FORM II — TRANSFORMER MAINTENANCE HISTORY 5975

System ID: T1 Station: HRD Serial No.: 303 236
Manufacturer: ITE/ED-UNION Type: STEP UP. YΔ M.V.A: 105
Test Date: June 9/05 Test Completed By: WD/GH J.D.E. W/O #: 472670

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

WEATHER CONDITIONS: dry: ✓ rain: ____ humidity: 60 ambient temperature: 15
DIELECTRIC OIL TEST ASTM D-1816 (kV): Conservator: 34kV MAIN TANK 33kV

WINDING TEMP RELAY: (Check if Applicable)					
First Stage Fans:	Found	65	°C	Left	65
Second Stage Fans: Yes ___ N/A ___	Found	75	°C	Left	75
Alarm:	Found	105	°C	Left	105
Trip:	Found	120	°C	Left	120

LIQUID TEMP RELAY: (Check if Applicable)					
Alarm:	Found	90	°C	Left	90
Trip: Yes ___ N/A ___	Found	105	°C	Left	105

FAULT PRESSURE RELAY: (GAS DETECTOR)				
Alarm:	Found	O.K	(cc)	Left
Trip;	Found	O K	(kpa)	Left

CONSERVATOR TANK: (Function Test Low level Alarm) OK ✓

RESISTANCE CHECKS: (including Wiring to Terminal Boards) 500 Volt Test
Test & record in Mega Ohms or N/A

		Line 1-line 2	Line 1/2 - GND
Winding Temp Relay:	Alarm	infinity	infinity
	Trip	infinity	infinity
Liquid Temp Relay:	Alarm	BAD	READING
	Trip	NEEDS	REPLACING
Fault Pressure Relay:	Alarm	infinity	infinity
	Trip	infinity	infinity
Conservator O/L Gauge:	Alarm	infinity	infinity

** Caution: Confirm all Primary Protection Circuits are open before Closing Links.

CHECK OIL LEVELS (Normal, High, Low)					Conservator Tank	N
HV BUSHINGS:	H1	N	H2	N	H3	N

OPERATING AMPERAGE: (N/A If not Applicable)		
1 st STAGE FANS	2 nd STAGE FANS 3A	CABINET HEATER
OIL CIRCULATING PUMPS:	1 st STAGE 5.3 / 2 nd STAGE	

ALL FANS WORKING
ALL OIL CIRC. PUMPS APP 5 AMPS

Sheet 1

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FORM [illegible] TRANSFORMER MAINTENANCE HISTORY 09 June 2005

System ID: T1 Station: HRD Serial No.: 302236
Manufacturer: _____ Type: _____ M.V.A: _____
Test Date: June 9/05 Test Completed By: WD/GH J.D.E. W/O #: 479670

GROUND CONTINUITY: (Micro-Ohms)		NEUTRAL BUSHING:	
HV. ARRESTORS:	H1	H2	H3
ALL gr. connection cleaned. new Pentrox			
OFF LOAD TAP CHANGER:			
Tap Position: (Located on the HV Windings)	Found C	Left C	
Off load Tap Changer (Confirm Mechanical Center): DONE			
Transformer Winding Resistance: Form IV: ____ Attached			

DIELECTRIC ABSORBTION (5 KV):			
H-LG	1 Min. 3 GΩ Mega Ω	10 Min. 4.6 Mega Ω	Index.
L-HG	1 Min. 1.29 G Mega Ω	10 Min. 2.28 Mega Ω	Index.
HL-G	1 Min. 1.10 G Mega Ω	10 Min. 1.47 Mega Ω	Index.

CORE GROUND: (500 Volt test)	Externally Connected Yes ____ No ____
RESISTOR: (Ohms)	CORE GROUND: (Mega Ohms)

CHECKS COMPLETED:

- ✓ Check Explosion Vent
- ✓ Check HV & LV Connections
- ✓ Ladder Guards
- ✓ Check Porcelain Insulators for chips or cracks
- ✓ Manually Operate Pumps and/or Fans
- ✓ Check Paint/Rust Condition (Main Tank)
- ✓ Silica Gel Checked
- ___ Silica Gel Replaced
- ✓ Visual Check For Dirty Insulators & Clean if Necess
- ✓ Check Conservator For Water & Drain if Necessary
- ✓ Check Paint/Rust Condition (Radiators)

CHECKS COMPLETED ONLY IF INSTRUCTED:

- _____ Obtain Gas Analysis Sample
- _____ Transformer Ratio Readings (Form III)
- _____ Capacitive Bridge Testing
- _____ Doble Test

COMMENTS:

A Ø High small chip
B Ø low chiped & leaking bad. -
oil temp gauge meggars not good.
quatrol has identification pin missing
Needs cap on oil drain valve from bottom of tank.

Sheet 2

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FORM IV – TRANSFORMER WINDING RESISTANCE

System ID: T1 Sution: HRD6S Serial No: _____ Manufacture: TRAFO - UNION
Type: OLTC ___ TC ___ High voltage _____ Low Voltage _____ Tester Serial No: 303236
Test Date: June 9/05 Test Completed By: _____ J.D.E. W/O #: 472670

VECTORS: HV: Y LV: Δ TERT: 09 June 2005

NOTE: Y Complete Winding Resistance Test on Tap Position Found.
Y Complete Winding Resistance Test on Maximum Tap Position Raise.
Y Complete Winding Resistance Test on Maximum Tap Position Lower.
Y Confirm Mechanical Center (Off Load Tap Changers).
Y Complete Winding Resistance Test on Tap Position Left.

TAP CHANGER LOCATION: HV C LV _____

TAP POSITION C	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTA DELTA x
Found	A	500 MA	200M	102	.09	
Found	B	500MA	20 M	104	.09	
Found	C	500 MA	20 M	101	.08	
Max. Raise	A	500 MA	20 M	100.7	.05	
Max. Raise	B	500 MA	20 M	101	.05	
Max. Raise	C	500 MA	20 M	104	.05	
Max. Lower	A	500 MA	20M	104	.05	
Max. Lower	B	500 MA	20M	104	.05	
Max. Lower	C	500 MA	20M	104		
Left	A	"	"	103	.05	
Left	B	"	"	105.9	.09	
Left	C	"	"	105.9	.08	
Non Tap Winding	A-B	"	"	107.4	.12	
Non Tap Winding	A-C	"	"	107.4	.12	
Non Tap Winding	B-C	"	"	107.4	.11	
Tertiary Winding						
Tertiary Winding						
Tertiary Winding						

Note: Observe Indicator Light & Record OHMS or MILLI-OHMS

REMARKS:

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APPENDIX C

Major Upgrades Listing

Newfoundland and Labrador Hydro
Holyrood Thermal Generating Station
Major Upgrades List

	Major Upgrade	**Year**
1)	Uprate Generation Units 1 and 2 (150 MW to 175 MW)	1989
2)	Major Turbine/Generator Disassembly, Overhaul and Repair (each Generation Unit)	every 9 yrs
3)	Turbine/Generator Valves Disassembly, Inspection and Repair (each Generation Unit)	every 3 yrs
4)	Boilers Internal Cleaning, Inspection and Minor Repairs	annually
5)	Construct New Water Treatment Plant	1992
6)	Construct New Wastewater Treatment Plant	1994
7)	Replace Unit 1 Boiler Stack Liner	2000
8)	Replace Unit 2 Boiler Stack Liner	2001
9)	Upgrade Unit 1 and 2 Exciter	2002
10)	Upgrade Unit 1 and 2 Governor Controls	2003
11)	Replace Uninterrupted Power System	2000
12)	Replace Boilers Breeching	1990
13)	Upgrade Units 1, 2, and 3 Controls System	2002-2003

14) Install Warm Air Make-up System
1992

15) Construct New Security Building
2004

16) Plant Asbestos Removal Program (3 year project)
2003-2006

17) Replace Boiler No. 2 Superheater
2007

18) Replace Boiler No. 1 Superheater
2008

19) Replace Roof and Upgrade Siding
1990-2000

20) Replace Boiler No. 2 Partial Water Wall
2006

21) Install Boiler Soot Blower
1995

22) Upgrade Boiler Air Pre-heater Steam Heat Exchanger
1990

23) Install Continuous Emissions Monitoring System (shared)
2003

24) Construct five Ambient Air Monitoring Stations
1993

25) Replace Heating, Ventilation & Air Conditioning Units
2002-2005

26) Install Copper Ion Injection System
2007

27) Replace Unit 2 Boiler Stop Valve
2008

28) Unit 2 – HP Heater No.5 Replacement
2009

29) Tank Farm Drainage Improvements
2009

30) Unit 3 – Steam Seal Regulator Replacement
2009

31) Unit 1 – Emergency Hydrogen Venting 2009

32) Unit 2 – Installation of Cold Reheat Drain Pots
2009

Notes: 1) Major items are identified but list is not complete.
2) Years noted are approximate.

APPENDIX D

Maintenance History

Thermal Generation
Actual Expenditures By Work Plan

Sum of Budget	Fiscal Year				
Work Plan	**2005**	**2006**	**2007**	**2008**	**2009**
Corrective	$ 3,344,736	$ 3,837,285	$ 5,815,665	$ 6,335,586	$5,238,767
Non Maintenance	$ 6,973,007	$ 8,035,277	$10,404,864	$11,260,723	$10,701,868
Operating Projects	$ 2,489,513	$ 1,417,478	$ 337,546	$ 498,145	$595,677
Preventive	$ 6,103,725	$ 3,892,175	$ 6,421,115	$ 4,349,042	$4,645,410
Grand Total	$18,910,980	$17,182,214	$22,979,190	$22,443,496	$21,181,721

APPENDIX E

Outage Statistics

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY **YEAR:** 2005
UNIT: 1

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Mar 14-18	92.73		97.8996	153	7.12		"OFD" State 12[1] Air Heater fouling FP in alarm
Mar 18-20	0.00	36.5999			0.00		"MO" State 24[2] Air Heater wash (Hydroblast South Condenser tubes)
Mar 20-21	84.85		29.5800	140	4.48		"OFD" State 12 Marv Control limits to 140 mw
Mar 21	100.00	0.6000			0.00		"FO" State 21[3] reset Megavars
April 8-9	72.73	11.5500		120	0.00		"OFD" State 12 (Hydroblast North Condenser tubes)
Apr 17	100.00	10.7000			0.00		"MO" State 24 Pre- Annual outage Air Heater wash
Apr 25-Oct 18	0.00	4119.0500			0.00		"PO" State 25[4]
Oct 17	100.00	1.7834			0.00		"FO" State 21 (3) tuning Feul Oil control valve
Oct 17-18	57.58		18.7000	95	7.93		"OFD" State 12 tuning Feul Oil Control valve
Dec 17-19	0.00	79.0666			0.00		Air Heater Wash & minor maintenance
Dec 29	100.00	6.8500			0.00		"MO" State 24 @ 1059-1750 (Secondary Superheater safety valve maintenance & minor maintenance)

[1] Operating under a Forced Derating: the generating unit is spinning and/or synchronized with the system but not capable of carrying its Maximum Continuous Rating (MCR) due to a forced derating being in effect.

[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Planned Outage State: the generating unit has a planned outage which requires that it be removed from service.

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY YEAR: 2006 UNIT: 1 Page 1

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Feb 21-28	95.76		160.7833	158	6.82		"OFD" [1] @ 2100 hrs (Lowered throttle pressure due to Secondary Superheater safety valve feathering)
Feb 28-Mar 15	92.73		361.2200	153	26.27		"OFD" Feb 28 @ 1347 Air Heater differential & Furnace Pressure in alarm
Mar 15	82.42		51.8833	136	9.12		"OFD" Mar 15 @ 1500 to 136 mw Air Heater differential & Furnace Pressure in alarm
Mar 17-19	0.00	38.866000			0.00		"MO" State 24 [3] (Air Heater wash & minor maintenance)
Mar 19-Apr 4	96.97		383.2500	160	11.61		"OFD" [4] to 160 mw (Secondary Superheater safety valve passing)
Apr 4-19	96.36		366.7166	159	13.34		Safety valve & condenser pressure
Apr 19-28	94.55		224.1333	156	12.23		Condenser pressure
Apr 28-May 2	94.55		77.6000	156	4.23		"ABNO-FD" [5] to 156 mw Energy Control Center requirement
May 2-4	94.55		58.0500	156	3.17		"OFD" [6] Condenser pressure high
May 4-8	94.55		87.4833	156	4.77		"ABNO-FD" Condenser pressure high
May 8	100.00	6.066600			0.00		"FO" [7] @ 0756 hrs
May 8	94.55		3.2500	156	0.18		"OFD-FD" [8] "@ 1400 hrs (condenser pressure)
May 8-18	94.55		229.0667	156	12.49		"ABNO-FD" @ 1715 hrs (condenser pressure)
May 18-19	0.00	29.230000			0.00		"FO" State 21 (4) East Intercept valve servo control
May 19-Jun 2	94.55		342.0999	156	18.66		"OFD-FD" @ 1214 hrs on May 19 (condenser pressure)
Jun 2-5	94.55		86.3800	156	4.71		"ABNO-FD" @ 1820 hrs (condenser pressure)
Jun 5-8	94.55		66.0200	156	3.60		"OFD-FD" @ 2003 hrs (condenser pressure)
Jun 8-12	94.55		86.9300	156	4.74		"ABNO-FD" @ 1404 hrs (condenser pressure)
Jun 12-13	0.00	16.000000			0.00		"MO" State 24 @ 1900 (Air Heater wash)
Jun 13	94.55		8.1333	156	0.44		"ABNO" @ 1100 hrs (refire boiler for Air Heater wash steam)
Jun 13-14	0.00	26.630000			0.00		"MO" @ 1908 hrs (Air Heater wash)
Jun 14-19	96.97		124.8900	160	3.78		"ABNO- FD" @ 1540 hrs
Aug 16-18	0.00	54.250000			0.00		"PO" [9] Aug 16 @ 1301 hrs (Station Service DCS upgrade)
Sept 24-25	0.00	20.166600			0.00		"FO" @ 22 00 hrs fuel oil pressure control
Sept 25-29	0.00	90.832600			0.00		"FO" @ 1820 Sept 25 Mark V control problems
Oct 9-Nov 29	0.00	1212.080000			0.00		Planned outage pre-outage Air Heater wash permit
Nov 29	6.06		1.8200	10	1.71		"OSD" [10] to 10 mw Mark V testing
Nov 29	30.30		2.6000	50	1.81		"OSD" to 50 mw Mark V testing
Nov 29	100.00	2.900000			0.00		"FO" Over Speed test
Nov 29	45.45		6.6833	75	3.65		"OFD" BFPW recirc valve drive failure
Nov 29-30	3.03		2.2500	5	2.18		Mark V testing
Nov 30-Dec 2	45.45		57.8330	75	31.55		"OFD" BFPW recirc vlv drive failure
Dec 2-3	0.00	37.016000			0.00		"MO" BFPW recirc valve drive repair and other maintenance

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

ANNUAL SUMMARY CONTINUED YEAR: 2006 Page 2

UNIT: 1

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Dec 11-12	0.00	25.526600			0.00		"FO" State 21 (1) @ 1956hrs (Mark V failure)
Dec 12-13	30.30		22.7333	50	15.84		"OFD" State 12 @ 2128 hrs Mark V problems
Dec 13	100.00	3.466600			0.00		"MO" State 24 @ 2012-2340 hrs (Servo replacement)
Dec 14	100.00	0.483337			0.00		"FO" State 21 Remove T/G starter coil
Dec 14	100.00	0.916667			0.00		"FO" State 21 Replace T/G starter coil
Dec 16-18	0.00	45.999000			0.00		"FO" State 21 (3) Air Heater bearing housing cracked
Dec 29-Jan 2	84.85		100.5000	140	15.23		"OFD" State 12 to 140 mw (Air Heating drive motor in alarm)

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[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Planned Outage State: the generating unit has a planned outage which requires that it be removed from service

[5] Available But Not Operating - Forced Derating: the generating unit can deliver only part of its MCR due to a forced derating but is not being operated to supply system load

[6] Forced Derating: a reduction (below MCR) of generating unit capacity in excess of 2% of its MCR resulting from a component failure or other condition which requires that the generating unit be derated at once or as soon as possible up to and including the very next weekend.

[7] Operating under a Scheduled Derating: the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY YEAR: 2007
UNIT: 1

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Jan 1-2	84.85		41.0000	140	6.21		"OFD"[1] brought forward from 2006
Jan 12	100.00	5.50000			0.00		"MO"[2] State 24 Feedwater vent line repair
Jan 13	0.00	13.61670			0.00		"MO" State 24 fans dorsel fin cracks repair
Jan 26-27	0.00	15.04990			0.00		"FO"[3] State 21 (Main Servo erratic)
Feb 6-7	84.85		18.2166	140	2.76		"OFD" to 140 mw (opacity problems on load test)
Feb 8	100.00	1.33300			0.00		"FO" State 21 (Damper problems)
Feb 9	100.00	4.28330			0.00		"FO" State 21 (Servo filter change)
Feb 13-22	81.82		207.5000	135	37.73		"OFD" (Air Heater fouling) Air Heater wash required)
22-Feb	64.24		58.5330	106	20.93		"OFD" (Air Heater fouling) Air Heater wash required) load test to 106 @ 0930
Feb 24-26	0.00	33.19960			0.00		"MO" Air Heater wash & minor maintenance
Mar 3-22	0.00	441.95000			0.00		"FO" State 21 (1) West Forced Draft (WFD) fan failure @ 2330 hs on March 3
22-Mar	24.24		7.3330	40	5.56		"OFD" State 12 One Forced Draft (FD) fan to 40 mw
Mar 22-23	100.00	10.04990			0.00		"FO" state 21 (install blank in crossover duct to WFD fan)
Mar 23-Apr 17	33.33		608.6600	55	405.77		"OFD" State 12 One FD fan to 55 mw
Apr 17	100.00	1.08330			0.00		"FO" State 21 (1) (atomizing steam control valve closed)
Apr 17-24	33.33		167.4200	55	111.61		"OFD" State 12 One FD fan to 55 mw
Apr 24-26	31.52		48.0000	52	32.87		"OFD" State 12 One FD fan to 52 mw
Apr 26-27	27.27		27.5333	45	20.02		"OFD" State 12 One FD fan to 45 mw
Apr 27-28	0.00	18.01666			0.00		"MO" State 24 Air Heater wash
Apr 28-May 9	33.33		264.4500	55	176.30		"OFD" State 12 One FD fan to 55 mw @ 0933 hrs
May 9	0.00	13.20000			0.00		"MO" State 24 (intercept valve repair)
May 9-Jun 5	33.33		632.2000	55	421.47		"OFD" State 12 One FD fan to 55 mw @ 2312 hrs
Jun 5-6	30.30		24.0000	50	16.73		"OFD" State 12 One FD fan to 50 mw @ 0800 hrs
Jun 6-7	28.48		24.0000	47	17.16		"OFD" State 12 One FD fan to 47 mw @ 0800 hrs
Jun 7-11	27.27		100.8660	45	73.36		"OFD" State 12 One FD fan to 45 mw @ 0800 hrs
Jun 11	100.00	10.93330			0.00		"MO" State 24 repair cracked duct
Jun 11-13	33.33		35.8000	55	23.87		"OFD" State 12 One FD fan to 55 mw @ 2348 hrs
Jun 13-19	29.70		146.6200	49	103.08		"OFD" State 12 One FD fan to 49 @ 1100 hrs fan duct vibrating
Jun 19	100.00	7.78334			0.00		"FO" (1) State 21 Switching Station service Under Frequency Load Shedding (UFLS)
Jun 19-28	29.70		213.5600	49	150.14		"OFD" State 12 One FD fan to 49 @ 2124 hrs fan duct vibrating
Jun 28-Aug 11	0.00	1061.03000			0.00		Planned Outage @ 1858 hrs (Annual)
Aug 12-25	0.00	297.10000			0.00		Planned Outage @ 1300 hrs (Acid Wash)
Aug 31-7	0.00	169.75000			0.00		Forced Outage SV vent stack replacement
Sept 7-10	0.00	84.48330			0.00		Forced Outage @ 0145 hrs (oil leak in Left Hand (LH) intercept)

ANNUAL SUMMARY cont'd YEAR: 2007
UNIT: 1

Page 2

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Oct 1-2	0.00	26.58000			0.00		*Forced Outage @ 0800 hrs (Boiler Water Chemistry TSS high)*
Oct 2-5	72.73		78.2500	120	21.34		*"OSD"[4] @ 1035 hrs (EVT Safety valves not done)*
6-Oct	100.00	9.78337			0.00		*Forced Outage @ 0932 (Hydraulic Leak)*
Oct 10-11	0.00	14.16630			0.00		*Forced Outage @ 1055 (Hydraulic Leak & Servo erratic)*
Oct 18-21	0.00	87.53000			0.00		*Forced Outage (2) Secondary Superheater tube leak)*
Nov 18-20	72.73		52.4660	120	14.31		*"OPD" East CW pump motor failure swapped motor with unit 2*
Nov 26-27	0.00	12.08320			0.00		*Forced Outage @ 1229 hrs cause unknown but problem caused unit to trip on drum level*
Dec 2	100.00	2.40000			0.00		*Forced Outage @ 2112 (Fault on line 203) external*
Dec 28	100.00	1.30000			0.00		*Forced Outage @ 1436-1554 North A/C Oil pump*

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[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Operating under a Scheduled Derating" the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY YEAR: 2008 Page 1
UNIT: 1

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Jan 3-4	0.00	14.5332			0.00		MO preventative maint on insulator anchor
5-Jan	90.91		14	150	1.27		OFD Attemperator spray block valve repair
Jan 17-20	90.91		72.8333	150	6.62		OFD A/H fouling Furnace Pressure in alarm
20-Jan	42.42		6.5033	70	3.74		OFD SSH tube failure
Jan 20-24	0.00	87.96			0.00		"FO" State 21 (3) @ 1720 hrs (SSH tube failure)
24-Jan	100.00	0.6			0.00		FO State 21 burners
Jan 26-Feb 5	0.00	221.7			0.00		FO State 21 @ 2230 SSH tube failure
5-Feb	42.42		10.817	70	6.23		OFD (low load isolator)
Feb 6-9	0.00	87.1166			0.00		FO State 21 @ 2230 SSH tube failure
Feb 9-March 7	0.00	638.666			0.00		FO State 21 @ HRH safety valve @ 1600 hrs
March 7-10	0.00	80.333			0.00		OFD to 140 mw (Evt HRH safety valve)
March 26-April	0.00	143.016			0.00		FO State 21 @ 2233 SSH tube failure
May 10-15	0.00	118			0.00		FO Turning gear motor failure & Air Heater wash
June 2-4	42.42		53	70	30.52		OSD to 70 mw acid wash Unit 3 no interruptions steady load at 70 mw
July 7-14	0.00	165.1334			0.00		Planned Outage Steam Generator@ 1052 hrs July 7, 2008
July 14-Sept 2	0.00	1208			0.00		Planned outage SH tube replacement @ 0800 hrs July 14
Sep2-Oct 24	0.00	1248.41			0.00		Planned Outage Steam Generator @ 1600 hrs Sept 2
28-Oct	42.42		0.26	70	0.15		OSD to 70 mw EVT Safety valves
28-Oct	100.00	1.76			0.00		FO @ 0704 exiter trip
Oct 28-29	42.42		30.44	70	17.53		OSD @ 0850 hrs EVT safety valves
Oct 29-31	54.55		55.500	90	40.91		OFD (Cooling Water Pump W will not start)
Nov 1-5	72.73		106.08	120	28.93		OFD (Condenser fouling to 120 mw
Nov 5-6	72.73		43.17	120	11.77		ABNO State 15 @ 2205 hrs (condenser fouling)
Nov 7-8	0.00	24.91			0.00		MO State 24 @ 1715 hrs (Condenser cleaning)
Nov 27-Dec 4	95.76		194.5	158	8.25		OFD to 158 mw bled stem valve stuck 4 & 5 heaters out of service
Dec 4-6	84.85		19	140	2.88		"OFD " State 12 to 140 mw WFD fan duct vibration
Dec 6-8	0.00	52	24	143.33333	24.00		MO Bled steam actuator No. 5 heater and Main stop valve strainer
Dec 9-10	90.91		24	150	2.18		OFD State 12 @ 1829 hrs West Boiler Feed pump oil change
Dec 17-24	0.00	176.933			0.00		"FO" State 21 (3) @ 0145 hrs FD fan East failure
Dec 26-27	84.85		35	140	5.30		WFD fan vibration
Dec 27-31	90.91		104	150	9.45		WFD fan vibration

Outage Statistics

ANNUAL SUMMARY **YEAR: 2009**
UNIT: 1

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATE		ADJ HOURS	Total Outage CEA	REASONS FOR OUTAGES/DERATINGS
			HRS	MW			
Jan 1-16	90.91		168	150	33.45	33.45	*WFD fan vibration brought forward*
Jan 18-Feb 25	94.55		972.02	150	53.07	53.07	*WFD fan duct vibration to 156 mm @ 0800 hrs*
Feb 25-26	0.00	21.31			0.00	21.31	*FD (3) N2 cooler vent line broken*
Feb 28-Mar 28	94.55		668.5	150	18.35	18.35	*CFD WFD fan duct vibration to 156 mm @ 1824 hrs*
Mar 28-30	94.55		99.3	150	5.42	5.42	*AEND - FD @ 1244 hrs (ECC requirement)*
Mar 30-April 4	0.00	116.9			0.00	116.90	*FD Stale 21 (exciter problem)*
4-Apr	94.55		9.82	150	0.54	0.54	*D - FD @ 1254 hrs (ECC requirement)*
April 4-7	94.55		58.18	150	3.06	3.06	*AEND-FD @ 2343 hrs (ECC requirement/Stack testing issues)*
April 7-8	0.00	23.58			0.00	23.58	*FD Stale 21 (4) @ 0700 hrs (accumulator vent line leak)*
April 8-23	94.55		373.7033	150	20.36	20.36	*CFD WFD fan duct vibration to 156 mm @ 0835 hrs*
April 23-27	94.55		81.37	150	4.44	4.44	*AEND-FD @ 2027 hrs (ECC requirement)*
April 27-May 5	94.55		205.033	150	11.18	11.18	*D - FD @ 0530 hrs (ECC requirement)*
May 5-July 24	0.00	1925.32			0.00	1925.32	*Planned Outage @ 1841 hrs May 5*
July 25-Aug 29	0.00	835.25			0.00	835.25	*FEPO @ July 25 @ 0000 hrs (Nozzle Block failure)*
4-Oct	100.00	0.85			0.00	0.85	*FD Stale 21 high drum level!*
4-Oct	100.00	0.44			0.00	0.44	*FD Perform O/S trip*
Oct 4-7	60.61		61.05	100	11.93	11.93	*DSD EVT safety valves pending*
Oct 11-13	0.00	104.9			0.00	104.90	*FD @ 1436 hrs (steam leak and No. 1 bearing wire causing vibration spikes)*
Oct 21-23	0.00	14.17			0.00	14.17	*FD @ 1647 hrs #2 Bearing smoking due to oil leak from around the RTD focal area*
Oct 30-31	42.42		17.67	70	10.17	10.17	*DFD @ 2120 hrs (superheat spray block valve broken)*
1-Nov	48.48		9.5	80	4.83	4.83	*DFD @ 1130-2100 hrs BFPT Motor IB bearing hi alarm*
4-Nov	51.52		28.04	85	14.08	14.08	*DFD @ 1532 hrs EWP motor alignment*
8-Nov	42.42		10.000	70	5.76	5.76	*Nov 8 CFD @ 0300 hrs-1700 hrs (attemperation spray block valve broken)*
11-Nov	42.42		5.75	70	3.31	3.31	*Nov 11 CFD West spray stand valve broken*
4-Dec	100.00	6.58			0.00	6.58	*FD (1) trip (condenser backwash)*
Dec 20-23	0.00	60.28			0.00	60.28	*IAD Stale 24 Fan bearing IB west) BFPT Check valve cover)*

Outage Statistics

ANNUAL SUMMARY **YEAR:** 2005 **Page 1**
UNIT: 2

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Jan 12	81.82		6.6500	135	1.21		"OSD"[4] State 13 Repair East Superheat spray control valve
Jan 14	51.52		3.6500	85	1.77		"OPD"[1] State 12 Replace both boiler feed pumps motor air filter
Feb 3-4	89.70		33.9500	148	3.50		"OPD" State 12 (Air Heater fouling furnace pressure in Alarm)
Feb 4-6	0.00	35.61660			0.00		"MO"[2] State 24 (Air Heater wash & Superheat spray by pass valvse)
Feb 17	27.27		1.5500	45	1.13		"OSD" State 13 (Repair atomizing control valve)
Feb 22-27	0.00	111.54993			0.00		"FO"[3] State 21 (3) Boiler tube leak in vicinty of other SSH failures
Apr 13-17	0.00	83.86660			0.00		"FO" State 21 (4) Boiler tube leak (waterwall) in 3 places
Apr 18 - 21	0.00	71.71666			0.00		"FO" State 21 (3) Economizer tube leak
Apr 25-30	0.00	113.65000			0.00		"FO" State 21 Boiler tube leak SSH in vicinty of other failures
May 13	72.73		2.2500	120	0.61		"OSD" State 13 (South Side Condenser Inspection)
Jun 30-Sept 27	0.00	2390.60000			0.00		"PO"[5] State 25 @ 0845 hrs June 20
Sept 27-28	18.18		2.1166	30	1.73		"OSD" State 13 (Turbo Generator (TG) balancing)
Sept 28-30	0.00	50.53330			0.00		"PO" State 25 @ 0148 hrs (TG balancing cont'd)
Sept 30	27.27		3.3670	45	2.45		"OSD" State 13 (TG balancing ongoing)
Sept 30-Oct 2	0.00	49.18330			0.00		"PO" State 25 @ 0742 hrs
Oct 2	27.27		7.2332	45	5.26		"OSD" (Q/S test)
Oct 2	100.00	1.86670			0.00		"PO" (Q/S test)
Oct 2	0.00	13.25000		70	0.00		"OSD" (EVT Safety valves)
Oct 3-4	83.03		39.5000	137	6.70		"OSD" Deaerator (DA) Bled steam check valve problem
Oct 4-5	83.03		31.0000	137	5.26		"OPD" (fuel oil control valves tuning)
Oct 5-6	24.24		9.1666	40	6.94		"OPD" (separate Station Service from Unit 3)
Oct 6	83.03		2.3330	137	0.40		"OPD" Fuel oil Control valves tuning)
Oct 6-7	78.79		31.0000	130	6.58		"OPD" (Atomizing steam control valve limits)
Oct 7-12	83.03		135.5000	137	22.99		"OPD" (Fuel oil control valves requires tuning beyond this load)
Oct 14-21	95.76		165.2166	158	7.01		"OPD" State 12 (No. 5 hp heater failure)
Nov 18-19	0.00	19.85000			0.00		"FO" State 21 (3) A/H wash (forced)
Dec 15-18	95.76		47.2500	158	2.00		"OPD" State 12 (Nos. 4 & 5 heaters out of service) suspect tube failure
Dec 18-20	70.30		45.6166	116	13.55		"OPD" State 12 (A/H diff & Furnace pressure in alarm)
Dec 20-22	0.00	49.71660			0.00		"MO" State 24 (A/H wash & minor maint)

[1] Operating under a Forced Derating: the generating unit is spinning and/or synchronized with the system but not capable of carrying its Maximum Continuous Rating (MCR) due to a forced derating being in effect.

[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Operating under a Scheduled Derating" the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

[5] Planned Outage State: the generating unit has a planned outage which requires that it be removed from service.

Outage Statistics

ANNUAL SUMMARY **YEAR: 2006**
UNIT: 2

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Jan 6-25	0.00	467.5499			0.00		"FO"[3] 21 (1) Boiler tube failure (Waterwall East 3rd floor)
	100.00				0.00		Many blisters found. Door opened in tube
Jan 25-Mar 14	0.00	1132.8332			0.00		"FO" 21 (1) Boiler tube failure (Waterwall East 3rd floor)
	100.00				0.00		External Conditions awaiting DOL approval Code 99999 other @ 2105 hrs Jan 25
Mar 14	30.30		2.0833	50	1.45		"OFD"[1] to 50 mw limited capacity & pressure due to waterwall tube failure
Mar 14	100.00	7.0833			0.00		"FO" state 21 due to Mark V problems
Mar 14-31	30.30		413.4200	50	288.14		"OFD" to 50 mw limited capacity & pressure due to waterwall tube failure @ 1005 hrs
Mar 31-Oct 1	0.00	4423.5833			0.00		"PO"[3] State 25 @ 1425 hrs March 31- Oct 1
Oct 1-4	60.61		64.9200	100	25.57		"ABMO SD"[6] @ 2200 hrs
Oct 4-7	60.61		69.3000	100	27.30		"OSD"[4] EVT safety valves
Oct 7-9	0.00	40.4000			0.00		"FO" State 21 HP heater flange leak repair
Oct 9-13	66.67		103.5200	110	34.51		"OFD" State 12 Drum level controls tested to 150 mw
Nov 21-24	0.00	61.7330			0.00		"FO" State 21 (2) East Forced Draft Fan (EFDF) high vibration
Nov 28-30	30.30		49.2500	50	34.33		"OFD" State 12 Fuel oil meter problems
Nov 30	6.06	2.2500	2.2500	10	2.11		"OSD" State 13 @ 1315 hrs, FO @ 1530 hrs exiter fault
Nov 30-Dec 2	0.00	37.1333			0.00		"FO" State 21 Exiter fault (mass flow meter replaced)
Dec 12-14	78.79		54.2000	130	11.50		"OFD" State 12 Air Heater fouling
Dec 14-16	0.00	34.7833			0.00		"MO"[3] State 24 Air Heater wash

[1] Operating under a Forced Derating: the generating unit is spinning and/or synchronized with the system but not capable of carrying its Maximum Continuous Rating (MCR) due to a forced derating being in effect.

[3] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[5] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Operating under a Scheduled Derating" the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

[6] Planned Outage State: the generating unit has a planned outage which requires that it be removed from service.

[9] Available But Not Operating - Scheduled Derating State: the generating unit can deliver only part of its MCR due to a scheduled derating but it is not being operated to supply system load

Outage Statistics

ANNUAL SUMMARY **YEAR:** 2007
UNIT: 2

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Jan 5-7	0.00	40.6000			0.00		Air Heater bearing oil change
Jan 11	100.00	3.8166			0.00		Uninteruptable Power Supply (UPS) transfer
Feb 21-Mar 1	88.48		194.61600	146	22.41		"OFD"[1] Air Heater fouling
Mar 1-2	100.00				0.00		Air Heater wash & minor maintenance
Mar 30-Apr 2	0.00	74.5200			0.00		"FO" [3] (30) Isolation to repair No. 5 hp heater)
May 8-16	96.97		193.00000	160	5.85		"OFD" to 160 @ 0900 hrs inlet vane and Air Heater fouling
May 16-17	92.12		22.00000	152	1.73		"OFD" to 152 @1000 hrs inlet vane and Air Heater fouling
Jun 13-19	95.15		141.00000	157	6.84		"OFD" to 157 @1200 Air Heater fouling & Furnace pressure in alarm
Jun 19-22	86.06		81.41666	142	11.35		"OFD" to 142 @ 0900 Air Heater fouling & Furnace pressure in alarm
Jun 22-24	0.00	40.7999			0.00		"MO"[2] Air Heater wash & minor maintenance
Jul 5	18.18		1.00000	30	0.82		"OFD" to 30 mw UPS 3 & 4 tie in
Jul 28-Aug 3	0.00	156.0830			0.00		Total Plant Outage @ 1930 hrs (Planned Outage) Common Mode Outage
Aug 3-20	0.00	410.6600			0.00		"FEPO"[5] @ 1635 hrs (Staff shortage)
Aug 20-Nov 3	0.00	1804.7500			0.00		Planned Outage @ 1915 hrs
Nov 4-Dec 14	0.00	965.2660			0.00		"FEPO" @ 0000 hrs Nov 4 (Nozzle block failure & Rotor Repair)
Dec 14-19	0.00	124.0334			0.00		"FEPO" main stop valve
Dec 19	30.30		5.46660	50	3.81		"OSD"[4] @ 1112-1640
Dec 19	100.00	2.5333			0.00		"FO" @ 1640-1912
Dec 19	7.27		0.30000	12	0.28		"OSD" @ 1912-1930
Dec 19	100.00	1.2500			0.00		"FO" @ 1930-2045
Dec 19-20	39.39		18.75000	65	11.36		"OSD" @ 2045-Dec 20 @ 1530
Dec 20-21	72.73		105.00000	120	28.64		"OFD" @ 1530 hrs 1 cooling water pump to 120 mw
Dec 21-31	81.82		297.00000	135	54.00		"OFD" @ 1244 hrs 1 cooling water pump to 135 mw

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[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Operating under a Scheduled Derating" the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

[5] Forced Extension of a Planned Outage State: the generating unit has an outage resulting from a condition discovered during a planned outage which has forced the extension of the planned outage.

Outage Statistics

ANNUAL SUMMARY YEAR: 2008
UNIT: 2

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Dec 21-Jan 2	0.00	43.9666			0.00		Brought forward OFD to 135 mw 1 cw pump
Jan 4-5	100.00	7.3			0.00		MO Preventative main on insulator anchor
March 20-21	100.00	10.75			0.00		MO A/H wash while off as per Ecc requirement
April 4-10	0.00	144.43			0.00		FO State 21 Turning gear chain broken 30 min after coming off for ECC
June 2-July 25	0.00	1279.2			0.00		PO @ 1323 hrs June 2
Aug 11-24	0.00	305.3667			0.00		TPO Tansformer outage (T2)
24-Aug	100.00	2.3833			0.00		MO State 24 (Isolation requirement to shut down entire compressed air system)
Oct 6-7	27.27		18.74	45	13.63		OFD @ 1852 hrs to 45 mw
7-Oct	100.00	4.2			0.00		FO (2) Turbine O/S testing
Oct 7-8	0.00	21.200		60	0.00		OSD EVT safety valves to 60 mw
24-Oct	100.00	1.83			0.00		Generator fire system
Oct 24-25	0.00	26.57			0.00		FO @ 0232 hrs Heating set blowdown leak
Dec 10-18	0.00	186.53			0.00		MO State 24 @ 2126 hrs (MSV Strainer removal)

Outage Statistics

ANNUAL SUMMARY **YEAR: 2009**
UNIT: 2

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATE HRS	DERATE MW	ADJ HOURS	Total Outage CEA	REASONS FOR OUTAGES/DERATINGS
Jan 17-Mar 31	100.00				0.00	0.00	No. 5 hp heater failure (all heaters out of service) Selected components
31-Mar	100.00	0.6			0.00	0.60	PO State 21 (1) Unit 1 GS lockout operated in error
July 16-Sept 4	0.00	1208.33			0.00	1208.33	PO State 25 @ 1540 hrs Annual outage
Sept 4-Oct 18	0.00	1074.08			0.00	1074.08	PO State 25 @ 0000 hrs (No. 5 hp heater installation)
Oct 27-29	60.61		61.75	100	24.13	24.13	DSD @ 0215 hrs EVT safety valve
8-Nov	100.00	1.8			0.00	1.80	PO (1) @ 1941 hrs (Main feedwater control valve leakage was found)
Nov 8-7	24.14		26.05	40	19.73	19.73	DSD to 40 mw @ 2117 hrs (load restricted due to problem not solved)
Nov 18-Dec 4	81.82		383.5	115	68.73	68.73	DSD to 115 mw @/H motor drives in alarm high amps seals rubbing at 115)
Dec 4-15	72.73		347.5	120	67.50	67.50	DSD to 120 mw @/H motor drives in alarm high amps seals rubbing at 115)
Dec 15-Jan 2	80.00		441.1	132	88.21	88.21	DSD to 132 mw @/H motor drives in alarm high amps seals rubbing at 115)

Outage Statistics

ANNUAL SUMMARY YEAR: 2005
UNIT: 3

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Mar 10-28	90.00		434.00	135	43.40		Cooling Water Pump West (CWPW)Motor failure @ 1200 hrs
Mar 28-31	94.00		72.30	141	4.34		Cooling Water Pump West motor failure to 141 mw on load test after amertapp operation
Apr 1	100.00	6.500			0.00		"MO"[1] State 24 Start Up desuperheater repair
Apr 3-4	53.33		21.92	80	10.23		"ABNO FD"[2] to 80 mw BFPW recirc v repair
Apr 4	94.00		5.42	141	0.32		Cooling Water Pump West motor failure
Apr 4-5	53.33		1.25	80	0.58		BFPW Recirc v not open
Apr 4-5	53.33		15.23	80.0	7.11		BFPW recirc v not open
Apr 5-19	94.00		335.75	141.0	20.14		"OFD"[1] CWPW motor failure
Apr 19-May 2	87.33		317.68	131.0	40.24		"OFD" CWPW motor failure & Main Steam Temperature (MST) high
May 2-6	87.33		85.87	131.0	10.88		"ABNO FD" State 15 @ 1845 hrs CWPW Motor failure
May 6-8	0.00	45.333			0.00		"MO" State 24 to Synchronous Condenser conversion
May 8-9	87.33		37.30	131.0	4.72		"ABNO FD" CWPW Motor failure
May 9-28	87.33		474.55	131.0	60.11		"ABNO FD" (Sync Condenser Operation) CWPW Motor failure 131 mw
Jun 22-27	0.00	125.550			0.00		"MO" State 24 from SC conversion
Jun 28-29	88.67		20.50	133.0	2.32		"OFD" State 12 MST & FD fan amps maxed
Jun 29-Jul 5	90.00		143.50	135.0	14.35		"OFD" State 12 MST & FD fan amps maxed to 135 mw
Jul 5-8	91.33		74.30	137.0	6.44		"OFD" State 12 MST & FD fan amps maxed to 137 mw @ 1200 hrs
Jul 8-9	0.00	13.483			0.00		"FO" State 21 (3) WFDF Vibration & balancing)
Jul 9	91.33		207.52	137.0	17.98		"OFD" State 12 @ 0347 hrs (MST & FD fan amps high)
Jul 14-19	90.00		117.95	135.0	11.80		"OFD" State 12 @1700 hrs (MST & FD fan amps high) to 135 mw
Jul 19-20	0.00	14.350			0.00		"FO"[2] State 21 (3) WDPF of the hiway @ 1457 hrs
Jul 20	17.33		3.65	26.0	3.02		"OFD" State 12 Low load valve problems due to computer
Jul 20-21	0.00	25.750			0.00		"FO" State 21 (1) trip on drum level @ 0857
Jul 21	4.00		0.63	6.0	0.61		"OFD" to 6 mw no breaker indication
Jul 21	100.00	2.967			0.00		"FO" State 21 (1) no inication breaker position
Jul 21-28	90.00		155.45	135.0	15.55		"OFD" State 12 @ 1418 hrs (MST & FD fan amps high)
Jul 28-29	90.00		44.35	135.0	4.44		"ABNO"[6] State 15 @ 0145 ECC requirement
Jul 29-Aug 7	83.33		241.90	125.0	40.32		"OFD" State 12 @ 2206 hrs (CW inlet temp over design)
Aug 7	48.67		3.25	73.0	1.67		"OFD" State 12 @ 1400 hrs West Boiler Feed Pump (WBFP) blowout
Aug 7-13	83.33		149.75	125.0	24.96		"OFD" State 12 @ 1715 hrs CW inlet temp high
Aug 13-14	48.67		2.82	73.0	1.45		"OFD" @ 2300 packing blew out in recirc valve
Aug 14-15	83.33		24.95	125.0	4.16		"OFD" State 12 @ 0149 hrs CW inlet temp high
Aug 15-16	0.00	26.517			0.00		"FO" State 21 (1) FDFE. Cw fitting broken
Aug 16-30	83.33		341.14	125.0	56.86		"ABNO" State 15 @ 0145 ECC requirement cw in temp
Aug 30-Sept 1	83.33		48.67	125.0	8.11		"OFD-FD" State 12 @ 1026 hrs MST
Sept 1	53.33		8.92	80.0	4.16		"OFD" to 80 mw WBFP recirc valve limit switch

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

ANNUAL SUMMARY YEAR: 2005 Page 2
UNIT: 3

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
Sept 1-2	83.33		14.98	125.0	2.50		"OFD" State 12 (FD fan amps & MST)
Sept 2	83.33		3.12	125.0	0.52		"ABNO-FD" State 15 (MST)
Sept 2-4	83.33		44.70	125.0	7.45		"ABNO-FD" State 15 (MST)
Sept 4	0.00	32.600					"FO" State 21 (3) FDFW OB contaminated with water
Sept 5-6	83.33		11.58	125.0	1.93		"OFD" State 15 (CWT)
Sept 6-7	83.33		35.50	125.0	5.92		"OFD" State 15 (CWT)
Sept 7-10	73.33		64.37	110.0	17.16		"OFD" State 15 (CWT)
Sept 10	100.00	0.750			0.00		"FO" State 21 (1) (East Fuel pump tripped)
Sept 10-22	73.33		280.13	110.0	74.70		"OFD" State 12 (FD fan amps & MST))
Sept 22-Oct 4	73.33		308.35	110.0	82.23		"OFD" State 12 (CW inlet temperature above design)
Oct 4-Dec 9	0.00	1577.750			0.00		Planned outage State 25 @ 2321 hrs Oct 4-Dec 9 @ 1706 hrs
Dec 9-12	43.33		71.23	65.0	40.37		"OSD" State 13 to 65 mw @ 1706 hrs
Dec 12-14	0.00	33.800			0.00		"FO" State 21 (3) B3T3 arcing (external Conditions)
Dec 14-15	0.00	15.767			0.00		"FO" Statye 21 (1) Unit trip due to CWPE DV closed (Operator Error) when switched to remote
Dec 15	43.33		18.32	65.0	10.38		"OSD" State 13 @ 0049 hrs DCS commissioning
Dec 15-16	83.33		21.07	125.0	3.51		"OSD" State 13 @1908 hrs to 125 mw (DCS commissioning)

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[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Operating under a Scheduled Derating" the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

[5] Available But Not Operating - Forced Derating: the generating unit can deliver only part of its MCR due to a forced derating but is not being operated to supply system load

[6] Available But Not Operating: the generating unit can carry its MCR but is not being operated to supply system load.

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY YEAR: 2006
UNIT: 3

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS *External Conditions in red*
Jan 4	53.33		16.50	80	7.70		*Boiler Feed Pump West Motor relay*
Mar 21-26	0.00	127.6560			0.00		*"MO"[3] State 24 @ 1554 hrs (A/H Wash & minor maint) ERT an issue therefore delaying the wash*
Mar 26-28	33.33		34.85	50	23.23		*"OFD"[1] State 12 (Low load valve)*
Mar 30	24.67		2.85	37	2.15		*"OFD" @ 0943-1234 (data collection for Boiler water level controls)*
Apr 19-20	95.33		31.95	143	1.49		*"OFD" fan amps in alarm*
May 25-Jun 6	0.00	293.4061			0.00		*"MO" State 24 @ 1153 hrs. (Convert to SC mode)*
Aug 21-Oct 23	0.00	453.2960			0.00		*"PO"[4] State 25 @ 1253 hrs (DCS upgrade) and continue into its annal planned outage*
Oct 19-24	0.00	112.3833			0.00		*SC to Gen mode conversion @ 1126 hrs Oct 21*
Oct 27-28	0.00	20.2333			0.00		*Forced Outage DCS problems*
Oct 29-30	73.33		51.78	110	13.81		*"OFD" to 110 mw EVT safety valves*
Nov 16-17	0.00	28.3999			0.00		*"FO"[2] State 21 (2) Heavy guns tripped at 35 mw while testing*
Dec 12-14	93.33		56.88	140	3.79		*"OFD" State 12 @ 1600 hrs (Air Heater fouling)*
Dec 15	100.00	0.7000			0.00		*"FO" State 21 loss of fuel oil pressure when switching pumps*
Dec 15-23	93.33		269.82	140	17.99		*"OFD" State 12 @ 0135 hrs (Air Heater fouling)*
Dec 23-24	100.00	2.2666			0.00		*"FO" State 21 (1) Boiler drum level controls tripped both feed pumps*
Dec 24-31	93.33		191.22	140	12.75		*"OFD" State 12 @ 0047 hrs (Air Heater fouling)*

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[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Planned Outage State: the generating unit has a planned outage which requires that it be removed from service

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY YEAR: 2007
UNIT: 3

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS *(external conditions in red)*
Jan 1-8	93.33		186.33	140.0	12.42	12.42	"OFD"[1] State 12 @ 0047 hrs (Air Heater fouling) Brought forward
Jan 8-10	0.00	43.6			0.00	43.55	"MO"[2] Air Heater wash
Jan 10	100.00	0.52			0.00	0.52	"FO"[3] Reverse power
Jan 23	53.33		10.57	80.0	4.93	4.93	"OSD"[4] Attemperator repair
Mar 20-22	95.33		49.00	143.0	2.29	61.42	"OFD" @ 1100 hrs (WFDF amps in alarm @ 143 mw
Mar 22-29	98.67		211.72	145.0	7.06	7.06	"OFD" to 145 mw (Air Heater fouling)
Mar 29-30	98.67		7.63	145.0	0.25	0.25	"ABNO-FD"[5] to 145 mw
Mar 30-Apr 3	94.67		105.65	142.0	5.63	5.63	"OFD" to 142 mw (A/H fouling)
Apr 3-Apr 4	96.67		29.15	145.0	0.97	0.97	"OFD" to 145 mw (A/H fouling) @ 1200 hrs load test
Apr 4-Jul 21	0.00	2610.1			0.00	2610.07	Planned Annual Major Outage @ 1709 hrs
Jul 21-22	30.00		12.78	45.0	8.95	8.95	"OSD" to 45 mw (burner problems)
Jul 22-25	0.00	80.6			0.00	80.62	Forced Outage No. 4 bearing oil leak
Jul 25-26	43.33		13.22	65.0	7.49	7.49	OSD to 65 mw Safety Valves not EVTeed
Jul 26-27	43.33		19.40	65.0	10.99	10.99	Forced Outage (NE observation Port blowout)
Jul 27-28	93.33		8.32	140.0	0.55	0.55	"OSD" to 140 mw (safety valves evteed)
Jul 28-Aug 3	0.00	160.3			0.00	160.27	Total Plant outage (Planned Outage)
Aug 3-Aug 7	0.00	80.7			0.00		"ABNO-FD" @ 1635 hrs (1 cooling water pump E)
Aug 7-9	86.67		148.33	130.0	19.78		"OFD" to 130 mw @ 0117 hrs (1 cooling water pump E)
Aug 11-29	0.00	435.8			0.00		"MO" State 24 @ 0955 hrs (throttle valve repair)
Sept 1-9	0.00	192.600			0.00		"MO" State 24 @ 1348 hrs (Sync condenser Conversion)
Sept 15-16	0.00	33.3			0.00		"FO" State 21 3 (vibration problems) loose pins and realignment
Oct 8-9	0.00	14.6			0.00		"FO" @ 2237 hrs (burner & Vibration problems)
Oct 9	0.00	13.2			0.00		"FO" @ 2237 hrs (Hydraulic leak & Servo erratic)
Oct 12-13	0.00	33.62			0.00		"FO" @ 1228 hrs (trip on high drum level)
Oct 18-22	95.33		98.00	143.0	4.57		"OFD" @ 1100 hrs (fan amps in alarm)
Nov 1-15	80.00		347.55	120.0	69.51		"OFD" @ 0908 hrs (CWPE motor oil leak) motor removed and sent to St. Johns for repair
Dec 2-3	100.00	4.15			0.00		Forced Outage State 21 (1) @ 2112 hrs (203 line fault) External

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[2] Maintenance Outage State: the generating unit has a maintenance outage which requires that it be removed from service.

[3] Forced Outage State: the generating unit has a forced outage which requires that it be removed from service.

[4] Operating under a Scheduled Derating" the generating unit is spinning and/or synchronized with the system but not capable of carrying its MCR due to a scheduled derating being in effect.

[5] Available But Not Operating - Forced Derating: the generating unit can deliver only part of its MCR due to a forced derating but is not being operated to supply system load.

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY YEAR: 2008
UNIT: 3

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	TOTAL OUTAGE CEA	REASONS FOR OUTAGES/DERATINGS (external conditions in red)
1-Jan	0.00	21.2			0.00	21.17	FO (1) (External) insulator anchor on B phase failed & shorted
Jan 7-11	46.67		98.40	70	52.48	52.48	OFD W Boiler Feed pump flange leak
18-Jan	46.67		10.60	70	5.65	5.65	OFD (Flue Gas Leak)
Jan 18-19	0.00	31.40			0.00	31.40	FO @1136 hrs suspect furnace leak (smoulder in windbox)
Jan 19-20	0.00	27.10			0.00	110.70	FO @ 1900 hrs (external conditions staff shortage) unable to start
Feb 14-15	0.00	27.0			0.00	26.98	FO @ 1644 hrs (Generator Trip)
April 11-26	0.00	356.4			0.00	356.38	PO State 25 (Sync condenser conversion)
April 26-May	0.00	272.4166			0.00	272.42	PO State 25 (Sync condenser conversion permit terminated @ 0850 hrs) (Steam Generate
May 7-June 1	0.00	884.080			0.00	884.08	PO State 25 Sync condenser on at 1715 hrs (Steam Generator)
July 24-31	0.00	178.5			0.00	178.45	Sync condenser off due to whitbourne crew tripping from switchyard shearv pin broken
Aug 13-22	0.00	221.3			0.00	221.33	TPO (water treatment plant clarifier outage)
Aug 23-24	0.00	27.1			0.00	27.08	MO (compressed air system isolation requirement)
Aug 24-31	0.00	178.5			0.00	178.45	SC tripped due to switchyard work (external) and then starting failure
Nov 16-23	0.00	164.6			0.00	164.58	PO Convert to Generation mode
30-Nov	26.67		9.4	40.0	6.87	6.87	OSD to 40 mw perform o/s test
30-Nov	100.00	2.8			0.00	2.75	FO @ 2116 hrs o/s test
Dec 1-2	0.00	45.6			0.00	45.55	OSD to 60 mw to EVT safety valves
9-Dec	83.33		15.5	125.0	2.58		OFD to 125 mw burners and air flow problems

2011 Holyrood Condition Assessment and Life Extension Study Appendix E

Outage Statistics

ANNUAL SUMMARY **YEAR: 2009**
UNIT: 3

DATE	PERCENT LOAD	OUTAGE DURATION HOURS	DERATED HRS	DERATED MW	ADJ HOURS	Total Outage CEA	REASONS FOR OUTAGES/DERATINGS
Jan 21-22	66.67		25.00	100	8.33	8.33	OFD to 100 mw Burner yoke broken
Feb 9-10	100.00	7.3833			0.00	7.38	FO State 21 (1) Unit trip OCS configuring by FOMBORO
April 8-June 29	0.00	1969.70			0.00	1969.70	Planned Outage State 25 @ 1420 hrs (convert to Sync Condenser mode) ABBO June 29 @ 1665 hrs
April 12-16	0.00	100.00			0.00	100.00	Convert to SC mode
April 21-23	0.00	52.18			0.00	52.18	Realignment of coupling
April 23-24	100.00				0.00	0.00	Preparing for start up
April 24-25	100.00				0.00	0.00	Sync to system high vibration
April 25-27	0.00	60.0500			0.00	60.05	Off at 0347 hrs April 25 (Preparing permit for investigation)
April 27-28	0.00	29.900			0.00	29.90	Permit time Sync condenser issued at 1558 hrs April 27 terminated at 2142 hrs april 28
May 3-4	0.00	34.7			0.00	34.70	Permit time Sync condenser issued at 1053 hrs May 3 terminated at May 4 @ 2130 hrs
July 21-Aug 1	0.00	292.0			0.00	292.00	"MO" SC re-alignment high vibration
Sept 9-Oct 29	0.00	1204.9			0.00	1204.92	Planned Outage (Steam seal regulator)
Nov 1-5	0.00	99.9			0.00	99.90	FO SC off due to 8373 damage in wind conditions on Nov1 @ 0911 hrs
Nov 9-24	0.00	348.9			0.00	348.90	PO on Nov 9 @ 2023 hrs Conversion to Gen mode Permit time Nov 9-24
Nov 22-24	0.00	35.450			0.00	35.45	FO (4) Boiler tube leak on Nov 22 @ 2150 hrs WW West 7 th floor while on SC permit
Nov 24-26	0.00	51.2			0.00	51.22	FO (4) Boiler tube leak ww West 7 th floor vestibule starting when SC permit terminated @ 0917 hrs on the 24 th
Nov 26-Dec 3	0.00	177.5			0.00	177.50	FO (4) Boiler tube leak ww West 7 th floor vestibule @ 1230 Nov 26 SPT passed SSR commissioning

APPENDIX F

Maintenance Service Agreements

HTGS Condition Assessment and Life Extension-Appendix F

Newfoundland and Labrador Hydro
Holyrood Thermal Generating Station
Service Contracts

	Service Contract	Company
1)	Boiler Maintenance	Alstom Power
2)	Turbine Maintenance	General Electric
3)	Non- Destructive Testing	Team Industrial
4)	Motor Repairs	Electromechanical
5)	Inverter Service	Powerwright
6)	Vacuum and Pressure Washing	Crosbie Industrial
7)	Safety Valve Repairs	New Valve Services
8)	Elevator Service	Thyssen Dover
9)	Heating, Ventilation and Air Conditioning Service	Johnson Controls
10)	Digital Control System Service	Foxoboro
11)	Cranes and Hoists Service	Atlantic Cranes
12)	Tanker and Boom Service	Shirickden
13)	Controlled Waste Landfill Maintenance	Hubert Murphy Ltd
14)	Fire System Service	Simplex Grinnell
15)	Stack Testing	Air Testing Services
16)	Laboratory Equipment Service	HACH
17)	Lube Oil Analysis	Wear Check
18)	Asbestos Abatement	Donalco Atlantic
19)	Air Sampling and Testing	Enviroteck
20)	Waste Water Consulting and Unit Inspection	GE Betz
21)	Lab Analysis and Waste Water Treatment	Jacques Whitford Ltd
22)	Performance Monitoring	General Physics Ltd
23)	Thermal Insulation	Parker Kaefer

A REPORT TO

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OVERHAUL GAS TURBINE

Holyrood Thermal Generating Station

April 2010

newfoundland labrador hydro
a nalcor energy company

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APPENDIX A A1

1 INTRODUCTION

The Holyrood Thermal Generating Station (Holyrood) has been producing power for Newfoundland and Labrador Hydro (Hydro) for nearly 40 years. Holyrood produces approximately one-third of Hydro's total Island Interconnected System generating capacity.

Holyrood uses some of the power it generates to operate its own equipment. This quantity of power is known as station service power. If Holyrood's generators are shut down, station service power is supplied from the Island Interconnected System (grid) through two dedicated supplies via the Holyrood switchyard. When power from the transmission grid is not available, station service power is provided by Holyrood's gas turbine plant. This gas turbine plant, shown in Figure 1, is located adjacent to the Holyrood thermal plant.



Figure 1: Holyrood Gas Turbine Plant

If Holyrood's generators are off-line during an Avalon Peninsula transmission outage, Holyrood must undergo a black start in order to begin restoring power initially to the plant

and eventually to the grid. A black start is defined as starting the plant in the absence of power from the grid. The equipment that must be started during a black start includes the boiler feedwater pumps, forced-draft combustion blowers that supply combustion air to the plant boilers, and fuel pumps. Holyrood's gas turbine plant provides power to the main plant for a black start. After a successful black start, power from the gas turbine plant is no longer required as the station service power is supplied from the plant's own generators.

In addition to supplying power to Holyrood during a black start, the gas turbine plant is also used to supply power to the Island Interconnected System during peak load and emergency periods. Holyrood's gas turbine plant is rated at a capacity of 13 MW.

2 PROJECT DESCRIPTION

This project is required to overhaul the gas turbine engine at the Holyrood gas turbine plant. The engine, shown in Figure 2, is a Rolls-Royce Avon 1533-70L model. It was last overhauled in 1991.



Figure 2: Holyrood's Gas Turbine Engine

The scope of work for the gas turbine overhaul is based on the latest boroscope inspection performed on the engine in 2008 and other inspections performed in 2009. During a boroscope inspection, a tiny camera is inserted inside the gas turbine through one of the fuel nozzle ports. The images viewed by the camera show up on an external video screen. However, a boroscope inspection is unable to identify all necessary refurbishment work. Therefore, the engine will be disassembled under this project so that a detailed inspection of internal components may be performed. The final scope of work will be developed after the completion of the detailed inspection report. This is the typical approach taken with gas turbine overhaul work.

A contractor specializing in gas turbine overhauls will perform the engine repair work. The engine will be removed from its berth at Holyrood and shipped to the vendor's overhaul facility. The vendor will be required to have access to a Rolls-Royce Avon test cell that will be used to monitor the engine during performance verification at the completion of the repair work. Removal and reinstallation of the engine will be performed by the vendor, with

assistance as required from Holyrood personnel.

The gas turbine plant at Holyrood will be out of service for approximately five months to complete the work under this project.

3 EXISTING SYSTEM

The Holyrood gas turbine plant consists of a Rolls-Royce Avon 1533-70L aero-derivative engine coupled to an Associated Electrical Industries (AEI) AP.1 power turbine that drives an AEI electrical generator. Total generating capacity is 13 MW. The engine was last overhauled in 1991.

The latest internal inspection of the inside of the engine (see Appendix A) was completed in June 2008. The recommendations from the inspection report included replacing the combustion cans and performing fuel system repairs. This work was completed in 2009. Also, the 2008 inspection report identified corrosion and protective coating loss on internal components. In October 2009, three broken discharge nozzle brackets were noted during maintenance work on the unit (see Figure 3).



Figure 3: Cracked Discharge Nozzle Bracket

3.1 Age of Equipment or System

The Rolls-Royce Avon gas turbine engine, AEI power turbine, and AEI generator was purchased by Newfoundland and Labrador Hydro in 1966. The equipment was initially installed at the Hardwoods Terminal Station near the west end of St. John's where it was used for emergency purposes and during peak load conditions. The set was relocated to its existing location during the initial construction of the Holyrood plant. Since that time, it has served as Holyrood's black start power source and has generated power during peak load and in emergencies.

3.2 Major Work and/or Upgrades

Table 1 shows the upgrades that have occurred since installation:

Table 1: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2009	Repairs	Combustion cans replaced, fuel pumps replaced, RTC replaced
2007	Repairs	IGV Ram exchanged, burners cleaned, plenum fixed, bleed valve duct repaired, IGV brushes repaired and replaced, oil leak on power turbine repaired
2004	Starter motor changed	
1991	Overhaul	Rehabilitate Gas Turbine but fuel pump and RTC not overhauled
1985	Overhaul	Rehabilitate Gas Turbine

3.3 Anticipated Useful Life

The useful life of the gas turbine is 25 years however this overhaul is expected to extend the life of this asset for an additional 15 years.

3.4 Maintenance History

The five-year maintenance history for Holyrood's Rolls-Royce Avon gas turbine engine is shown in Table 2.

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2009	0.0	179.3	179.3
2008	8.4	0.0	8.4
2007	26.9	40.4	67.3
2006	0.0	0.0	0.0
2005	7.0	0.0	7.0

3.5 Outage Statistics

The table below lists the 2005 to 2009 average capability factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for the Holyrood Gas Turbine compared to all Hydro's gas turbine units and the latest CEA average (2003 to 2007).

Table 3: Outage Statistics

Five Year Average 2005-2009

Unit	All Causes		
	Capability[1] Factor (%)	UFOP[2] (%)	Failure[3] Rate
Holyrood Gas Turbine	88.37	15.34	803.76
All Hydro Gas Turbine Units	82.56	13.36	41.82
CEA (2003-2007)	92.36	4.95	25.74

3.6 Industry Experience

Industry experience has not been considered since this is an engine overhaul to address deficiencies reported during inspections of the gas turbine engine.

3.7 Maintenance or Support Arrangements

Holyrood's gas turbine engine is maintained by companies specializing in repairs to the Rolls-Royce Avon gas turbine engine.

3.8 Vendor Recommendations

An Original Equipment Manufacturer (OEM) certified repair shop has been contacted for advice on repairing the gas turbine engine. The vendor recommended that detailed inspections of internal components must be performed in order to finalize the scope of

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

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

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

work required for the engine overhaul. This involves shipping the unit to a repair facility where the engine would undergo a disassembly and detailed inspection.

3.9 Availability of Replacement Parts

Replacement parts are available for the gas turbine engine.

3.10 Safety Performance

There are no safety performance issues relating to this project.

3.11 Environmental Performance

There are no environmental performance issues related to this project.

3.12 Operating Regime

The Holyrood gas turbine plant is mainly used to supply station service power during a black start of the main Holyrood plant. The gas turbine plant is also in continuous standby mode to supply 13 MW of power to the Island Interconnected System. This normally occurs during peak load periods as well as during an unscheduled outage at other generating facilities. Each week, the Holyrood gas turbine plant undergoes a 15 minute operational test to verify its availability for its black start function.

4 JUSTIFICATION

The Holyrood gas turbine plant is critical to the Island Interconnected System. Its main function is to supply power to Holyrood during a black start. A black start of Holyrood is required when the grid is down because of an emergency outage caused by other generation sources. If the gas turbine plant failed to supply power to Holyrood during a black start, Holyrood would not be able to start until power was restored to the grid by alternate generation sources. This would cause an unnecessary delay in restoring full power to the grid. For this reason, the gas turbine plant needs to be reliable.

Overhauls to gas turbine engines are required throughout their operating life to maintain operational reliability. The last overhaul completed on Holyrood's gas turbine took place in 1991. Inspections have indicated the presence of internal corrosion and coating loss to internal components of Holyrood's gas turbine. These issues can only be addressed through an engine overhaul. If these issues are not addressed, more damage will occur that will lead to a more costly overhaul in the future.

4.1 Net Present Value

A net present value calculation is not required as there is no viable alternative to repairing the gas turbine engine.

4.2 Levelized Cost of Energy

The levelized cost of energy is not a factor in this project.

4.3 Cost Benefit Analysis

A cost benefit analysis has not been performed, as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

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

4.5 Historical Information

As this is not a recurring project, no relevant historical information is available.

4.6 Forecast Customer Growth

This project is not required to accommodate customer growth.

4.7 Energy Efficiency Benefits

There are no energy efficiency benefits to be gained from this project.

4.8 Losses during Construction

There will be no losses during construction, as the work will be performed during a planned outage.

4.9 Status Quo

Maintaining the status quo is not acceptable. If internal corrosion and coating loss are not repaired, the unit will continue to degrade further resulting in more costly repairs.

4.10 Alternatives

There are no viable alternatives to repairing the gas turbine engine.

5 CONCLUSION

Holyrood's gas turbine plant supplies power to the Holyrood Thermal Generating Station during a black start condition. It is critical to the successful operation of Holyrood. As well, the gas turbine plant is used to supply power to the Island Interconnected System during peak load conditions and emergency periods.

Corrosion and coating loss on internal components were found during the last boroscope inspection of the engine. Also, broken nozzle discharge brackets, discovered during maintenance work in 2009 need to be replaced. While disassembly and further detailed inspections of the engine are required to finalize the scope of work for this project, it is evident from internal inspections that the gas turbine engine requires an overhaul.

This engine has been in service since 1966. An overhaul is required to maintain continued operational reliability of the Holyrood gas turbine plant.

5.1 Budget Estimate

This budget estimate is based on information provided by Rolls-Wood for an overhaul to a typical Avon unit with an operating regime similar to the one at Holyrood. The budget estimate is shown in Table 4.

Table 4: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	50.0	0.0	0.0	50.0
Labour	157.6	0.0	0.0	157.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	811.4	0.0	0.0	811.4
Other Direct Costs	25.0	0.0	0.0	25.0
O/H, AFUDC & Escln.	142.9	0.0	0.0	142.9
Contingency	104.4	0.0	0.0	104.4
TOTAL	**1,291.4**	**0.0**	**0.0**	**1,291.4**

5.2 Project Schedule

The anticipated project schedule is shown in Table 5.

Table 5: Project Schedule

Activity	Milestone
Project Initiation	January 2011
Tender Repair Work	February 2011
Ship Engine to Repair Facility	April 2011
Repair Period	August 2011
Install Unit at Holyrood	September 2011
Project Closeout	December 2011

APPENDIX A

Borescope Inspection of Avon 37029
1533 70L

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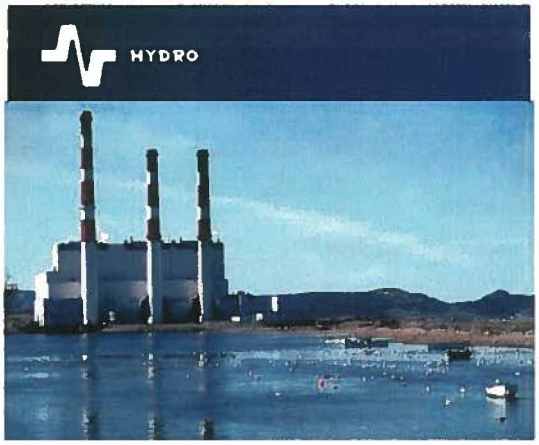
Inspection Report To



Borescope inspection of Avon 37029 1533 70L

Proposal Number: Alba 1633

Date: June 10 2008

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Note:

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Introduction

After successful repairs and assistance in 2008 Alba Power were asked to return to complete inspection works on the unit at Holyrood.

The unit has completed 26 Hours and 54 starts since the last inspection in May 2007.

The inspection was completed 10 June 1008 after site induction.

Alba Power would like to take this opportunity to thank the client and staff at Holyrood generating site for the assistance and approach to Alba Power, this was greatly appreciated an we look forward to assisting you in the future.

If you do have any questions or queries please do not hesitate to contact us, your contact for this proposal is as follows:

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1 Avon Repair and Borescope Inspection



On Site Personnel- Mr Campbell Archibald and Mr Martin Andrews

Date of inspection – 10 June 2008

1.1 Inspection Review

On arrival at site an induction of site-specific requirements was completed with Mr Ted Smith. This was followed by a toolbox review at the workstation.

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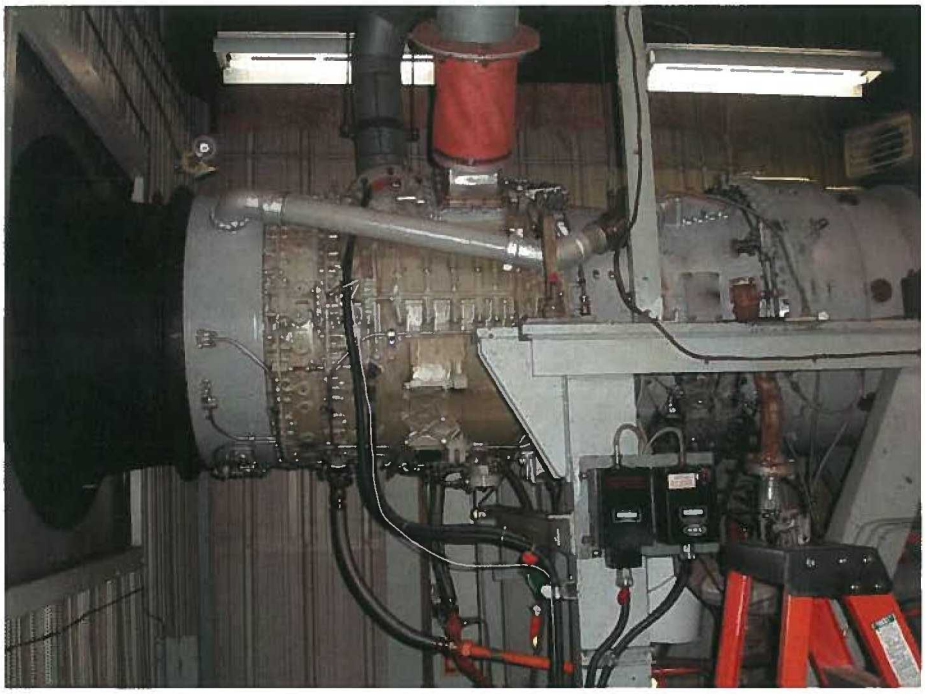
1.2 Workscope Review

The following are details of the workscope completed at site;

1.2.1 Tuesday 10 June 2008

- Plenum inspection
- Compressor inspection
- Burner removal (Where possible)
- Combustion area inspection
- Turbine area inspection
- Package inspection

1.2.2 Unit images



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2 Borescope Results

As detailed within our workscope above the unit was borescoped throughout and within this report we will detail the sections accordingly.

All images will be provided separately on a CD for client files.

2.1 Package Plenum

On entering the plenum it was noted that a large amount of water had gathered under the intake, this will have a significant impact on the units condition, corrosion and potential for FOD ingress. In addition 2 large holes where noted in the sidewall as well as a large amount of rust particles on the floor. All of these will have a risk of ingress attached.



Water in plenum **Hole in side wall**



Rust particles Corrosion on intake

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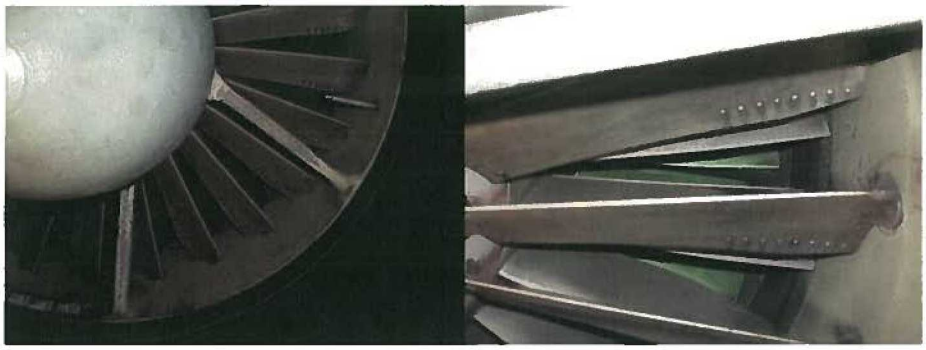
2.2 Compressor Section

It was noted that the Front bearing housing, Inlet Guide Vanes and Compressor have significant corrosion and coating loss. This has now increased greatly from last year's inspection with the addition of salt ingress and the Front Bearing housing pitting (As shown in above section)



Corrosion pitting on Front Bearing housing struts and outer casing



IGV Inner journals FBH Wear

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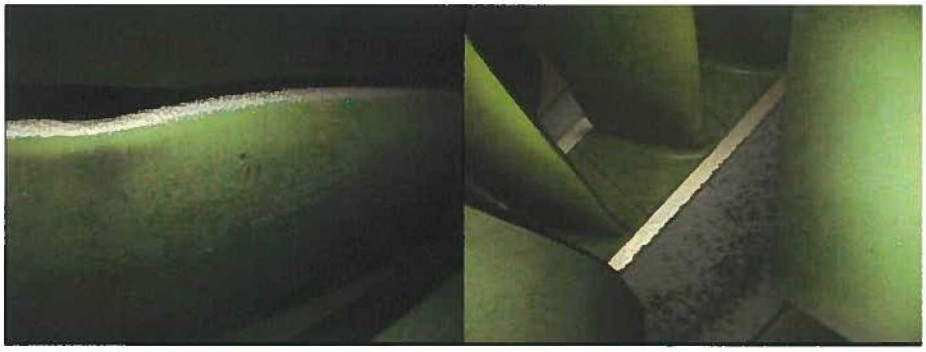
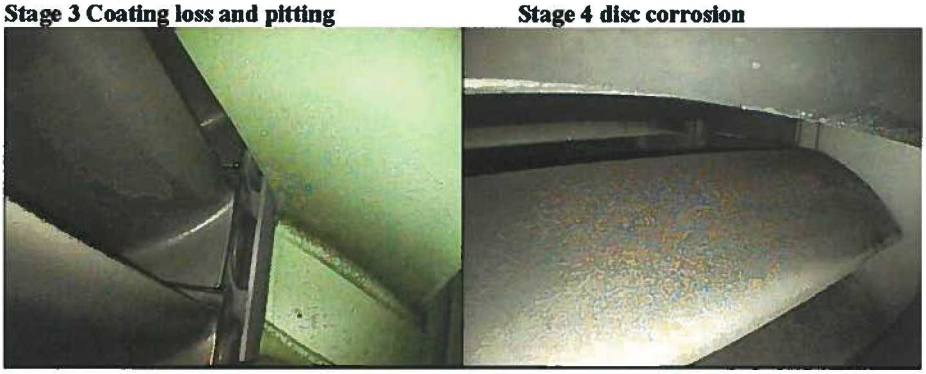
Coating loss and pitting stage 1



Stage 3 Coating loss and pitting

Stage 4 disc corrosion



Stage 5 Salt ingress

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Stage 5 Disc Corrosion



Stage 4 casing and blade condition



Stage 15 OGV Corrosion



COC Corrosion

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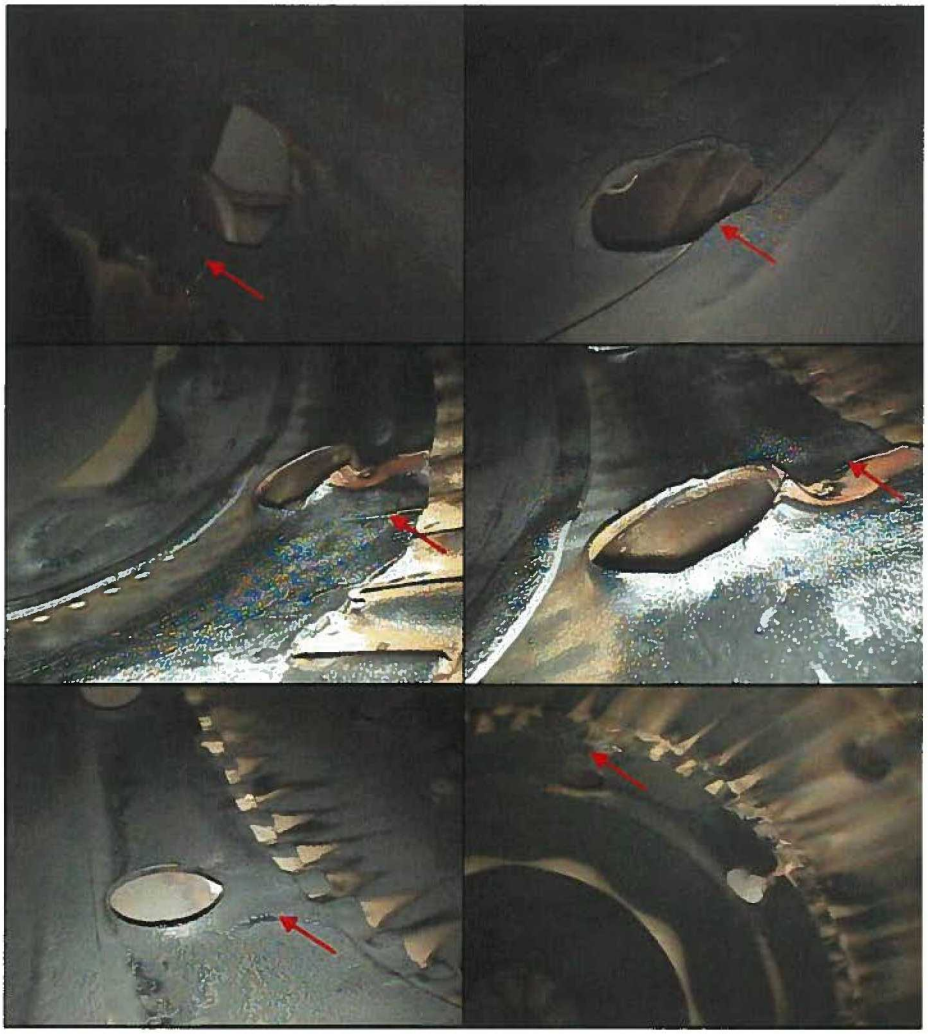
2.3 Combustion Section

In 2007 the unit showed extreme wear of the Combustion cans with cracks and loss of coating. The unit has operated 26 Hours and 54 Starts since that time which has increased the level of cracking. It may only be a matter of time before this material is released and impacts the turbine.

Access could only be gained through burners 1 and 2 due to rusting bolting in other areas, all borescope ports where removed to gain minimal access in the combustion area.



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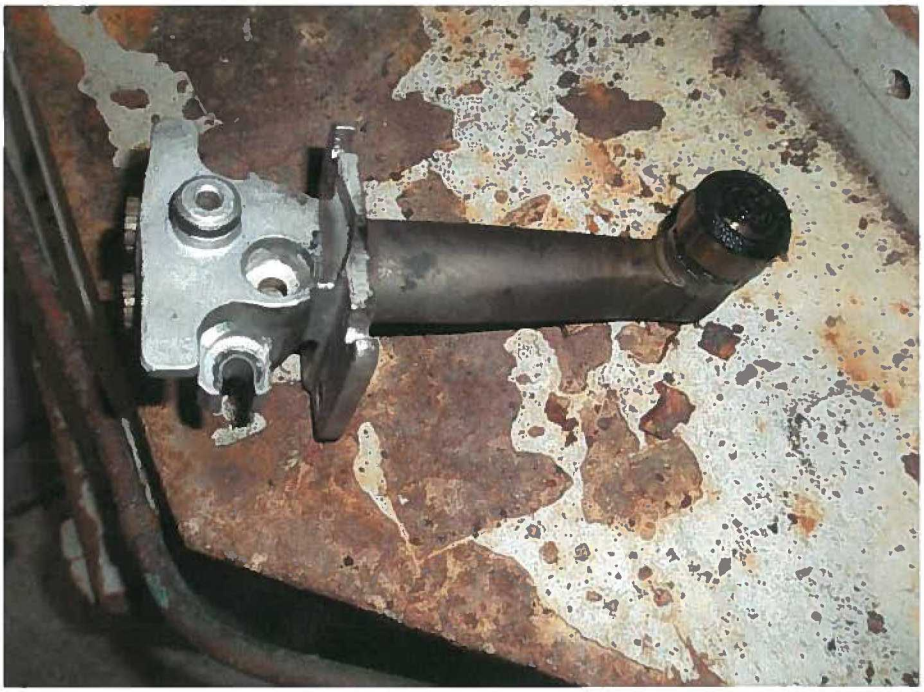

Burner No1 after removal

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2.4 Turbine Section

Access was gained in this area through the 2 available burners as well as the thermocouples at positions 3 and 4. It will become more difficult to inspect the unit with specific clarity due to the age and condition whilst trying to return to service quickly.

The turbine section showed minor impact damage from either combustion can material or corrosion flakes from the intake. Coating loss was evident throughout with some minor pitting.



HP Nozzle Guide Vane



HP Turbine Blade inner platform



HP Blade leading edge pitting



HP Blade outer platform

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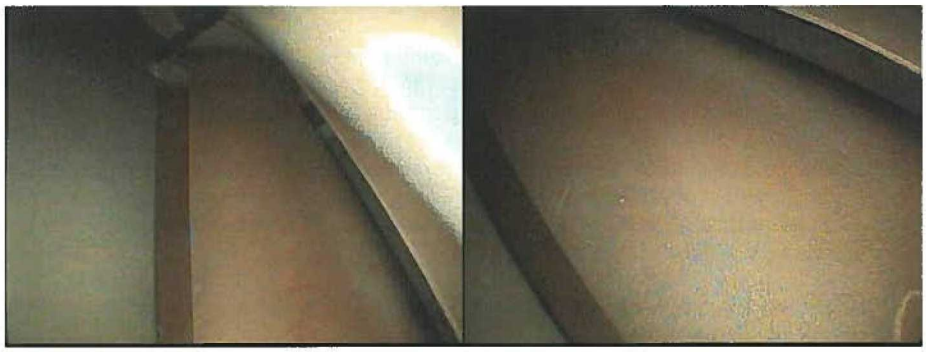
LP Turbine Blades

LP Turbine blade damage and FOD material flakes



IP Blade and NGV

IP Blade



LP Blade coating deterioration

IP Blade outer platform

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3 Conclusions / Recommendations

After the last inspection it was highly recommended that as a minimum the Combustion cans be replaced. Whilst we understand due to budgetary and operational requirements this has not happened it must now be placed as a high priority to ensure the continuous availability of this unit.

The unit showed greater salt ingress and corrosion this year, this would be attributed to the poor condition of the intake plenum, water ingress and flaking corrosion particles. This should be addressed prior to any further running.

The unit shows signs of burner leaking, it was highlighted last year that the drains tank fills continuously and the unit has some start issues. These where and continue to be attributed to the failing of the seals in the Fuel control unit, this should be addressed to improve start reliability while reducing poor burn in the combustion area and reducing leaks back through the drains system.

The unit would ideally be returned to our facility for repair / overhaul due to the coating loss, pitting, corrosion etc. If the unit continues to run in its current condition then overhaul and replacement prices will increase while the parent material decreases in reparability.

In the immediate future the combustion cans should be changed, if a part is ingested into the turbine the unit could suffer a catastrophic failure which would not only damage and increase the Avon overhaul / replacement price, but would do considerable damage to the Power Turbine as well as be a large safety risk.

Alba Power remains flexible as always and look forward to preparing options suited to your site-specific requirements.

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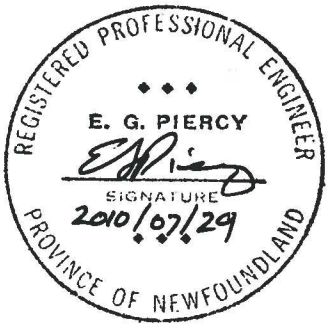	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

UPGRADE BURNT DAM ACCESS ROAD
PHASE 2

Bay d'Espoir

April 2010

newfoundland labrador hydro
a nalcor energy company

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APPENDIX A 1

1 INTRODUCTION

The Bay d'Espoir Development includes three hydroelectric generating stations, six reservoir systems, and associated dykes, dams, canals and hydraulic structures. The headwaters of the Bay d'Espoir Development begin at Victoria Lake at an approximate elevation of 320 meters. The water travels through the Granite Canal Hydroelectric Generating Station (Granite Canal), Upper Salmon Hydroelectric Generating Station and finally through the Bay d'Espoir Hydroelectric Generating Station (Bay d'Espoir) where it discharges at sea level. Additional water is collected, stored and diverted from a number of drainage areas between Victoria Lake and Long Pond which is the forebay for Bay d'Espoir.

The hydraulic structures within the Bay d'Espoir Development are the four intake structures of the Bay d'Espoir Hydroelectric Generating Station, the Ebbegunbaeg Control Structure, the Salmon River Spillway Structure, the Victoria Control Structure and the Burnt Dam Spillway Structure (Burnt Damn).

The Burnt Dam Access Road is a 48 kilometer gravel road that starts at Granite Canal and ends at Burnt Dam (see Appendix A). Hydro employs two personnel at the Burnt Dam site on a continual basis. The road is used by Hydro personnel for access to fishery release structures, to perform maintenance and to receive fuel deliveries, which are made four to six times per year. The road is also used by the public.

2 PROJECT DESCRIPTION

This project is Phase 2 of an upgrade started in 2007. This project will complete the upgrading of the existing access road to Burnt Dam. The project consists of excavating the ditches along the sides of the road, supplying and installing thirty-five new road culverts and supplying, spreading and compacting 50,000 tons of road topping over the 48 kilometers of road surface.

3 EXISTING SYSTEM

The existing access road was constructed in the late 1960s as part of the original Bay d'Espoir Development. The road is maintained by Hydro personnel using standard road grading and maintenance techniques. Over the past forty years the road topping has deteriorated to the point where the original sub-grade material is exposed.

This has led to large rocks being exposed in the middle of the driving surface. Some of these rocks have been removed as annual maintenance which is essentially removing the base of the road. Also the surface is very rough to drive over which is tough on both vehicles and Hydro personnel and takes an average of 2.5 hours to travel the 48 kilometers.

Hydro received approval in Board Order No. P.U. 35 (2006) to upgrade the Burnt Dam access road in 2007. The project involved clearing brush along the road, excavating ditches and replacing culverts to improve drainage, and supplying and placing granular backfill. This was performed as Phase 1 of the upgrading of the Burnt Dam access road. No road topping was performed under the 2007 project. Figures 1 to 3 are some pictures that show the condition of the existing road. Drainage problems consist of deteriorated culverts which do not allow water to flow through them as well as ditches that are filled with debris. As a result, water flows over the road and causes erosion of the road.



Figure 1: Burnt Dam Access Road



Figure 2: Burnt Dam Access Road



Figure 3: Burnt Dam Access Road

3.1 Age of Equipment or System

The existing access road was constructed in the late 1960s and is now over forty years old. An upgrade was performed in 2007.

3.2 Major Work and/or Upgrades

The only major work performed on the Burnt Dam access road was in 2007 at a cost of $288,500. Table 1 provides a listing of the major components of the work.

Table 1: Major Upgrades

Activity	Quantity	Unit	Cost ($000)
Mob and Demob	1	Lump Sum	7.5
Clearing	2	Hectares	7.5
Excavator Rental (ditching)	300	Hours	65.0
Supply 600 mm culverts	104	Each	50.0
Install 600 mm culverts	104	Each	44.7
Supply 900 mm culverts	10	Each	7.3
Install 900 mm culverts	10	Each	4.8
Granular Backfill	160	Truck Loads	21.5
Road Topping	10	Truck Loads	3.7
		Sub –Total	212.0
Labor	1	Lump Sum	48.1
Travel	1	Lump Sum	10.0
Corporate Overheads	1	Lump Sum	16.3
AFUDC	1	Lump Sum	2.1
		Sub -Total	76.5
		Total	288.5

3.3 Anticipated Useful life

The anticipated useful life of the access road is 50 years.

3.4 Maintenance History

The five year maintenance history is shown in Table 2.

Table 2: Five Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($ 000)
2009	0.0	0.0	0.0
2008	0.0	0.0	0.0
2007	0.0	0.0	0.0
2006	0.0	44.0	44.0
2005	0.0	16.0	16.0

3.5 Outage Statistics

There are no outage statistics related to the access road at Burnt Dam.

3.6 Industry Experience

Industry practice is to maintain roads in a safe and passable condition.

3.7 Maintenance or Support Arrangements

This access road is maintained by Hydro Operations personnel.

3.8 Vendor Recommendations

No vendor recommendations have been sought for this project.

3.9 Availability of Replacement Parts

Since this is an access road availability of replacement parts do not apply.

3.10 Safety Performance

There are no safety issues associated with this project.

3.11 Environmental Performance

The Burnt Dam access road is required for personnel to travel between sites to perform environmental duties on fish habitat structures. Also, the condition of the road creates a risk of fuel spillage from trucks delivering fuel to the Burnt Dam structure.

3.12 Operating Regime

The road is required all year round for access to the Burnt Dam Spillway.

4 JUSTIFICATION

This project is justified on the need to upgrade deteriorated infrastructure. The Burnt Dam access road requires road topping which could not be done until all the drainage problems were rectified. Most of the drainage work was completed in 2007. Phase 2 will complete the drainage improvements and improve the road surface which will reduce the travel time between Burnt Dam and Granite Canal sites. Burnt Dam personnel have to travel the road to perform operational and environmental duties. Since the Granite Canal Development was commissioned in 2003, there has been an increased need for personnel stationed at the Burnt Dam site to travel to Granite Canal for water management activities. Prior to Granite Canal coming on line, personnel would only be required to travel the road four to six times per year. However, as personnel at the Burnt Dam site are responsible to respond to any alarms at Granite Canal, the road is required for increased usage. There have been incidences where Burnt Dam personnel have had to travel to Granite five times in a six day period. It takes approximately two and a half hours for a one-way trip.

Also, fuel suppliers have expressed major concerns about traveling this road to deliver fuel. The fuel deliveries take up to five hours and the fuel delivery drivers stay in Burnt Dam overnight because of this. Further deterioration of this road could result in the refusal of fuel deliveries by suppliers.

4.1 Net Present Value

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

4.2 Levelized Cost of Energy

The levilized cost of energy is not applicable for this project.

4.3 Cost Benefit Analysis

A cost benefit analysis was not completed as there are no quantifiable benefits.

4.4 Legislative or Regulatory Requirements

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

4.5 Historical Information

In 2007, Hydro upgraded the Upper Salmon Access Road by supplying and compacting 60,000 tons of road topping over the 48 kilometer long road. The cost of that project was $573,000. The current project has a larger scope including ditching and culvert installation.

4.6 Forecast Customer Growth

There is no customer growth associated with this project.

4.7 Energy Efficiency Benefits

There are no energy benefits from this project.

4.8 Losses during Construction

There will be no losses during construction.

4.9 Status Quo

The status quo will see this road deteriorating every year. If this access road is not

upgraded it will become unusable and required fuel delivery and maintenance will not be possible.

4.10 Alternatives

There are no viable alternatives to this project.

5 CONCLUSION

This Burnt Dam access road is a vital access to the Burnt Dam Spillway and Granite Canal. It is used by Hydro personnel all year round for access to fishery release structures, for maintenance work and fuel deliveries. If this road is not upgraded it will have a negative impact on these activities.

5.1 Budget Estimate

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

Table 2: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	21.0	0.0	0.0	21.0
Labour	43.0	0.0	0.0	43.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	752.0	0.0	0.0	752.0
Other Direct Costs	18.0	0.0	0.0	18.0
O/H, AFUDC & Escln.	81.0	0.0	0.0	81.0
Contingency	83.4	0.0	0.0	83.4
TOTAL	**998.4**	**0.0**	**0.0**	**998.4**

5.2 Project Schedule

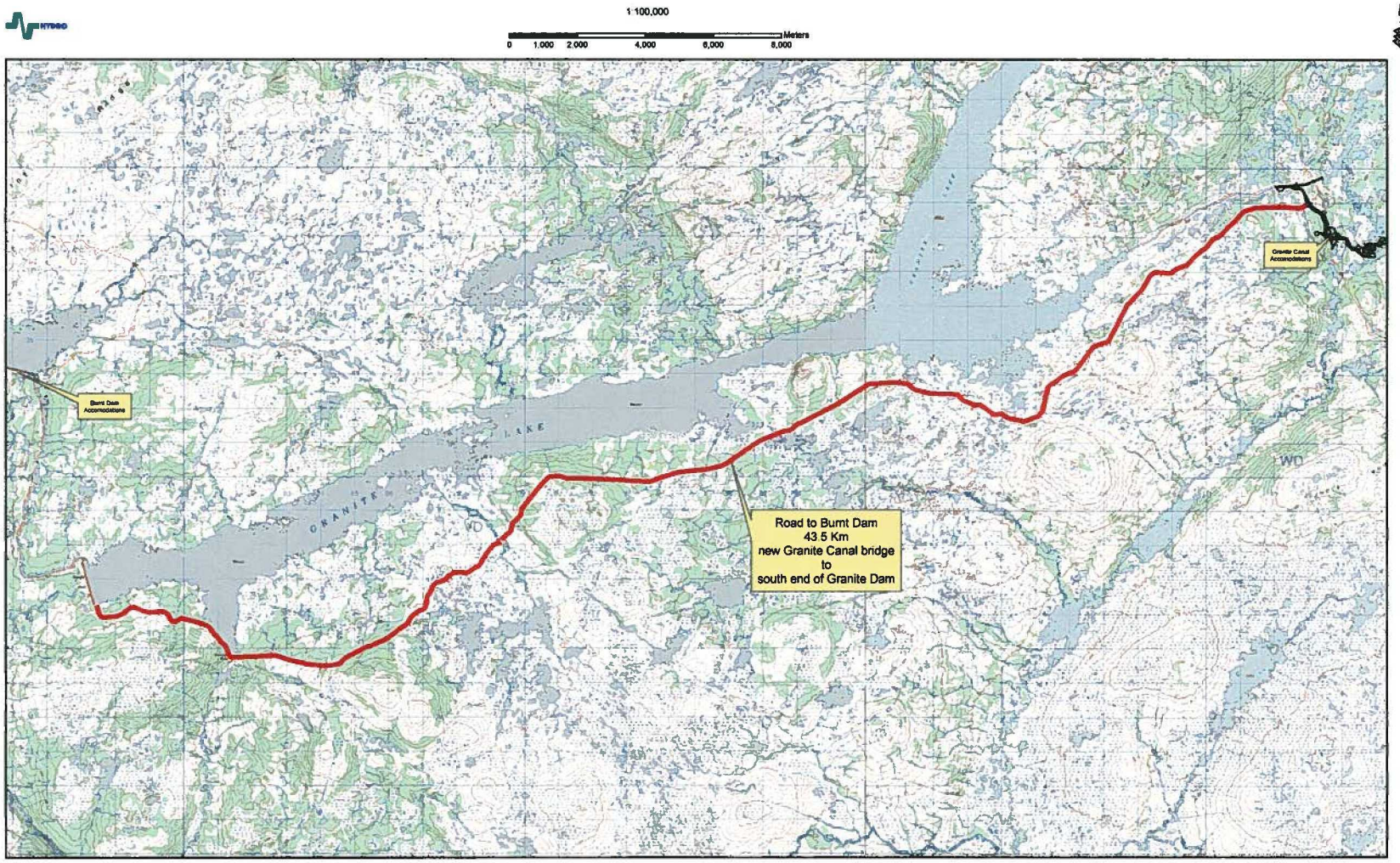
Table 4 provides the anticipated project schedule.

Table 4: Project Schedule

Activity	Milestone
Prepare Tender Documents	March 2011
Invite Tenders	April 2011
Award Tender	May 2011
Complete Construction	September 2011
Closeout Project	November 2011

APPENDIX A

Burnt Dam Access Road Map



Burnt Dam Road

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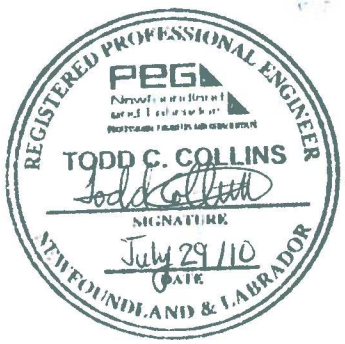	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning

HOLYROOD UNIT 3 SYNCHRONOUS CONDENSER UPGRADE

Holyrood Thermal Generating Station

June 2010

newfoundland labrador hydro
a nalcor energy company

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APPENDIX A A1

APPENDIX B B1

APPENDIX C C1

1 INTRODUCTION

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



Figure 1: Holyrood Thermal Generating Station

The three main components of each generating unit are the boiler, turbine, and generator. In addition to being operated as a generator of electrical power and energy, the Unit 3 generator at Holyrood has the capability of operating as a synchronous condenser. Each year Holyrood Unit 3 is converted to operate as a synchronous condenser during the off-peak generation period which typically occurs between April and November. A synchronous

condenser is a specialized synchronous motor whose purpose is not to produce mechanical power, but to adjust electrical conditions on an interconnected power grid system. Synchronous condenser's provide voltage control in the form of MVAR injection/absorption to/from the system when power is transmitted over long distances on an interconnected power grid system. In the case of Holyrood Unit 3, the synchronous condenser consists of a relatively small induction motor that is coupled to a gearbox (or speed increaser) which, in turn, is mechanically connected to the generator via a clutch system. During operation of Unit 3 as a synchronous condenser, the generator assembly is de-coupled from the turbine.

The 230 kV transmission system east of Bay d'Espoir can be characterized as a heavily loaded system and consequently experiences significant voltage drop during peak load conditions. As a result, this portion of the system requires voltage support in the form of MVAR injection in order to bring system voltages up to minimum acceptable levels. The Holyrood Thermal Generating Station, the Hardwoods Gas Turbine operating as a synchronous condenser and shunt capacitor banks at Long Harbour, Hardwoods and Oxen Pond Terminal Stations provide the MVAR injection into the 230 kV system to counteract the voltage drop. During the April to November time frame there is sufficient hydroelectric capacity on the Island Interconnected system to supply the system load. Subsequently, the generating units at Holyrood are not required and the plant is shut down. Therefore, with all generating resources located off the Avalon Peninsula, voltage control on the 230 kV transmission system east of Bay d'Espoir is of concern during the April to November period. Operation of Holyrood Unit 3 in synchronous condenser mode ensures acceptable voltage levels on the Avalon Peninsula during both normal operation and under line out contingencies.

2 PROJECT DESCRIPTION

This project is required to perform modifications to the Holyrood Unit 3 to reduce vibration levels during synchronous condenser operation. With the existing extension shaft in place connecting the generator output shaft to the synchronous condenser SSS clutch assembly, vibrations of the generator rotor are much higher than desired during the synchronous condenser operation. The existing extension shaft will be replaced with a new extension shaft complete with a journal bearing, thrust bearing and coupling assemblies. The journal bearing will control the radial vibrations of the extension shaft and generator rotor. The existing extension shaft extends approximately five feet beyond the axial center of the generator outboard bearing and this length is too long without a journal bearing near the end of the shaft to control radial vibrations. The thrust bearing will control the axial thrust vibrations from the generator rotor that are experienced during synchronous condenser operation. A modification to the existing Unit 3 jacking oil system will also be necessary to provide lifting oil to both the thrust and journal bearings in order to minimize the additional torsional resistance during synchronous condenser start-up.

The project will also reduce the time required to convert Unit 3 from generation to synchronous condenser mode. It currently takes approximately 16 days for Holyrood to convert Unit 3 to a synchronous condenser. The existing conversion process involves the installation and mechanical alignment of an extension shaft between the generator output shaft and the fluid drive SSS clutch. However, following completion of the project, the extension shaft will remain in place and only the thrust bearing pads will require removal when converting Unit 3 to synchronous condenser mode. The conversion time will then be reduced to approximately three to five days.

3 EXISTING SYSTEM

Unit 3 is converted from a generator to synchronous condenser mode during the off- peak generation period for Holyrood which typically begins during April of the operating season. Unit 3 then operates as a synchronous condenser until the unit is required again for generation, which typically begins in mid November. During the off-peak period, the power supply for the Island Interconnected System is typically provided by hydroelectric generating facilities such Bay d'Espoir, Hinds Lake, and Cat Arm that are located in central and western Newfoundland. As a result, power used on the Avalon Peninsula during the off-peak period has to be transmitted over long distances resulting in unacceptably low voltage levels on the Avalon Peninsula. During this period, the operation of Unit 3 as a synchronous condenser is necessary to provide voltage support to the eastern portion of the Island Interconnected Transmission System.

The existing components for Unit 3 synchronous condenser mode of operation is illustrated below in Figures 2 and 3. The main components of the synchronous condenser are the pony motor, gearbox (or speed increaser), hydraulic oil pump assembly, SSS clutch, and extension shaft. During the conversion of Unit 3 from generation to synchronous condenser mode, the extension shaft that connects the generator to the steam turbine is removed. An extension shaft is then installed between the generator output shaft and the SSS clutch, which, in turn, connects the generator to the synchronous condenser drive assembly.

During start-up, the pony motor, gearbox, hydraulic actuator, and SSS clutch are used to accelerate the generator up to synchronous speed. The pony motor is a 1,500 Horsepower (HP) 1,800 revolutions per minute (RPM), three phase induction motor that is connected to the input shaft of the gearbox. The ratio of the gearbox is 1 to 2.167 which can increase the speed of the output shaft up to approximately 3,900 RPM. The speed of the gearbox output shaft is controlled on the principle of shearing an oil film to transmit speed and torque. The output shaft contains a disc pack assembly that contains both a drive disc and a friction disc

that are separated by an oil film. Under rotation the drive disc shears the oil film and transmits torque to the friction disc which then causes rotation of the friction disc. The torque transmitted from the drive disc to the friction disc is a function of the variable clamping force applied to the disc pack assembly. The higher the clamping force applied to the disc pack assembly, the faster the output shaft speed. The variable clamping force is controlled by a hydraulic actuator through varying the hydraulic pressure. During start-up, the operator must slowly apply the hydraulic pressure to the disc pack in order to avoid over heating the hydraulic fluid. The couple between the drive disc and friction disc allows a variable gearbox output shaft speed up to 100 percent of the input shaft speed. In addition, the operator also applies a DC field voltage to the generator rotor.

As soon as the generator reaches synchronous speed, the operator then closes the breaker that connects Unit 3 generator to the Island Interconnected Transmission System. Simultaneously, the SSS clutch disengages the pony motor and gearbox drive assembly from the generator and the pony motor shuts down. At this point, Unit 3 generator operates as a synchronous condenser and the voltage support (MVAR generated or absorbed by the machine) afforded by varying the DC field voltage applied to the generator rotor.

During synchronous condenser operation, the generator rotor moves axially and vibrates excessively, damaging the SSS clutch. Also, radial vibrations of the generator rotor at the outboard bearing are much higher than desired. The existing extension shaft extends approximately five feet beyond the axial center of the generator outboard bearing. This unsupported length is too long and causes excessive radial vibrations at the SSS clutch.

Excessive vibration levels on Unit 3 in synchronous condenser mode of operation have become an issue since the original installation in 1985. The specification indicating the limitations of bearing vibrations is located in Appendix A. This specification was provided by Hitachi, the steam turbine/generator original equipment manufacturer (OEM). According to Hitachi, the maximum generator bearing vibration should not exceed 1.2 mil (30.5 micron)

during normal operation and the generator should be immediately shut down if the vibration levels exceed 2.0 mil (50.8 micron). Occasionally, excessive vibration levels have necessitated taking the synchronous condenser off line and performing mechanical alignment checks and corrections on the drive assembly in order to enable the plant to operate the synchronous condenser with slightly reduced vibration levels. A trend of the generator bearing vibrations taken during the forced outage that occurred on Unit 3 in synchronous condenser mode in April of 2009 (as indicated in Table 2 – Outage Statistics of Section 3.5 of this report) is also included in Appendix A. The vibration levels on this trend are measured in microns. During this period, the generator bearing vibration levels reached 175 microns which is more than three times higher than the absolute maximum level of 50.8 microns that requires an immediate shut down. Installation of the existing extension shaft between the generator and the SSS clutch during the changeover from generation to synchronous condenser mode and any alignment corrections that have followed have normally been completed by plant maintenance crews. However, it has been necessary in the past to hire vibration experts to perform mechanical vibration analysis and make recommendations to plant maintenance crews to reduce vibration levels. The success rate of using vibration experts to troubleshoot the synchronous condenser vibration issue has been very marginal.



Figure 2: Unit 3 Synchronous Condenser Components



Figure 3: Unit 3 Synchronous Condenser Components

3.1 Age of Equipment or System

Unit 3 was commissioned in 1979. The existing oil fired boiler and steam turbine are 31 years old. However, the components for Unit 3 to operate in synchronous condenser mode were installed and commissioned in 1985 and are 25 years old.

3.2 Major Work and/or Upgrades

There has been no major work or upgrade performed on the Unit 3 synchronous condenser components since it was commissioned in 1985.

3.3 Anticipated Useful life

The anticipated useful life of Unit 3 has been forecasted to extend to the year 2020, absent

an infeed from Lower Churchill. However, following the infeed, it is anticipated that Holyrood will operate as a synchronous condenser plant, providing voltage support for the Island Interconnected Transmission System. Hence, upgrades to the components of Unit 3 synchronous condenser will be necessary to extend its reliable useful life into the future, particularly following the infeed from the Lower Churchill.

3.4 Maintenance History

Synchronous condenser maintenance is a component of the annual maintenance strategy for Unit 3. Hydro uses the plant maintenance personnel to perform preventative maintenance inspections and corrective maintenance on components of the Unit 3 synchronous condenser. The five year maintenance history for the synchronous condenser is located below in Table 1. The majority of maintenance performed on the synchronous condenser has involved alignment checks and re-alignment of the pony motor drive assembly in order to reduce vibration levels caused by misalignment. In addition, frequent maintenance has been required on the SSS clutch assembly due to deterioration caused by axial thrusting of the generator rotor during synchronous condenser operation. With reference to Table 1 below, there has been a significant increase in maintenance cost during the past two years due to the additional maintenance required to reduce vibration levels during forced outages on the components of Unit 3 synchronous condenser.

Table 1: Five Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total ($000)
2009	108	65	174
2008	21	110	131
2007	34	13	47
2006	28	1	29
2005	21	0	21

3.5 Outage Statistics

During the past three years, there have been forced outages on Unit 3 operating in a synchronous mode due to excessive vibration which has required corrective maintenance necessary to reduce vibration levels. A summary of the forced outages is included below in Table 2.

Table 2: Outage Statistics

Date	Duration (hours)	Reason For Outage
April 2009	384	High vibration on synchronous condenser – mechanical re-alignment
July 2009	288	High vibration on synchronous condenser - mechanical realignment
July 2008	176	Broke shear pin on coupling
September 2007	33	High vibration on synchronous condenser - mechanical realignment

3.6 Industry Experience

Excessive vibration and component deterioration is very common in rotating machinery. Rotating components must be equipped with both radial and thrust bearing assemblies in order to support the radial and axial loads that occur during operation. Failure to support these loads will result in excessive vibration and forced outages. In many cases, excessive vibration and component deterioration in rotating machinery is the result of poor bearing design. Many companies now specialize in providing professional engineering services and manufacture products that are generally related to reducing vibration levels and component deterioration in rotating machinery.

TRI Transmission & Bearing Corp (TRI) is a recognized company in the utilities industry that specializes in the design and manufacturer of products that are installed on existing mechanical systems which incorporate a fluid drive design similar to the components of

Unit 3 synchronous condenser. TRI currently holds a patent for the design and manufacturer of "Align-A Pad Journal Bearings and Equalizing Thrust Bearings" that have been installed on rotating machinery with a variable speed fluid drive by various companies in the utilities industry in order to reduce excessive vibration and component deterioration. A list of companies that currently have "Align-A Pad Journal Bearings and Equalizing Thrust Bearings" in service is included in Appendix B.

3.7 Maintenance or Support Arrangements

Hydro uses internal plant resources to perform annual maintenance on the components of Unit 3 synchronous condenser. However, in recent years, Hydro has hired vibration specialists to assist internal plant resources in trouble shooting the vibration issues on the synchronous condenser with very limited success.

3.8 Vendor Recommendations

Hydro recently had a preliminary evaluation of the components of Unit 3 synchronous condenser completed by TRI, a company that specializes in the design and manufacturer of products that are installed on existing mechanical systems which incorporate a fluid drive design in order to reduce vibration levels. Following the evaluation, TRI submitted a preliminary proposal to Hydro outlining design problems associated with the existing synchronous condenser fluid drive assembly and modifications that are necessary to reduce vibration levels. According to TRI, the existing extension shaft between the SSS clutch and generator output shaft currently extends approximately five feet beyond the axial center of the generator outboard bearing and this length is too long without a journal bearing near the end of the shaft to control radial vibrations. In addition, the thrust bearing in the existing SSS clutch does not have sufficient capacity to support the axial thrusting of the generator rotor during synchronous condenser operation. This explains the frequent

deterioration of the thrust bearing in the SSS clutch. TRI has proposed to reduce the synchronous condenser vibration levels by installing a new extension shaft between the generator output shaft and SSS clutch complete with thrust bearing and journal bearing assemblies. In addition, a modification to the existing Unit 3 jacking oil system will be necessary to provide lifting oil to both the thrust and journal bearings in order to minimize the additional torsional resistance during synchronous condenser start-up. TRI has also indicated that the new extension shaft assembly will remain in place following the installation and only the thrust bearing pads will require removal when converting Unit 3 to synchronous condenser mode, thereby reducing the conversion time. The proposal is located in Appendix C.

3.9 Availability of Replacement Parts

Availability of spare parts for the existing components of Unit 3 synchronous condenser has not been an issue.

3.10 Safety Performance

There are no safety issues related to this project.

3.11 Environmental Performance

There are no environmental violations with Unit 3 operating in a synchronous condenser mode. However, a forced outage on the synchronous condenser during the off-peak period may require Hydro to operate a generating unit at Holyrood in order to meet the requirements of the Island Interconnected System. This would increase the overall emissions produced by Holyrood.

3.12 Operating Regime

Holyrood operates in a seasonal regime. The full plant capacity is needed to meet the winter electrical requirements on the Island Interconnected System. However, Unit 3 operates as a synchronous condenser during the off-peak period in order to provide voltage support for the eastern portion of the Island Interconnected Transmission System.

4 JUSTIFICATION

The Unit 3 at Holyrood operates in a synchronous condenser mode during the off-peak period typically between April and November each year in order to provide voltage support for the eastern portion of the Island Interconnected Transmission System. The current design of the extension shaft assembly between the generator rotor output shaft and SSS clutch does not have the capability of supporting the axial and radial vibrations experienced by the rotor during synchronous condenser operations. The project will improve the reliability of Unit 3 operating in a synchronous condenser mode by reducing the vibration levels during operation.

The proposed modifications to the Unit 3 synchronous condenser will permit a very quick changeover time, which is the time to convert Unit 3 from generation to synchronous condenser mode. Under the existing configuration, an extension shaft must be installed to connect the generator output shaft to the fluid drive SSS clutch during the changeover. The changeover is typically completed in mid April and takes approximately 16 days with the existing extension shaft design. At this time, Hydro must operate an additional generating unit at Holyrood at a relatively low load (typically 70 MW) in order to meet the voltage support requirements of the Island Interconnected Transmission System. However, the proposed extension shaft complete with journal and thrust bearing assemblies will remain in place during both generation and synchronous condenser modes of operation. The only modification required during the changeover would be the removal of the pads from the thrust bearing assembly. This will reduce the changeover time to three to five days and will decrease the overall cost of meeting the requirements of the Island Interconnected Transmission System. The reduced changeover time will increase the overall thermal efficiency at Holyrood. The efficiency gain is associated with not having to operate a unit at a relatively low (inefficient) load setting during the 11 day reduction in the normal changeover period in April. Thermal energy is still required to supplement hydroelectric energy generated during this period but it can be generated more efficiently at higher loads

outside the changeover period, thereby reducing the overall fuel consumption at Holyrood.

4.1 Net Present Value

A Net Present Value (NPV) calculation was completed on two alternatives over a study period of ten years. The two alternatives are:

Alternative 1 – Modify components of Unit 3 synchronous condenser. Using Nalcor Energy/NLH Thermal Fuel Oil Price Forecast the NPV of Alternative 1 has a benefit of $3,154,587 with a payback of less than one year.

Alternative 2 – Status Quo. The NPV of Alternative 2 is a cost of $553,682.

4.2 Levelized Cost of Energy

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

4.3 Cost Benefit Analysis

A cost benefit analysis was completed on the two alternatives noted below. The study period for the cost benefit analysis was ten years.

<u>Alternative 1 - Modify Components of Unit 3 Synchronous Condenser to Reduce Vibrations Using Nalcor Energy/NLH Thermal Fuel Oil Price Forecast:</u>

Alternative 1 is to complete the proposed modifications to the Unit 3 synchronous condenser in order to reduce vibration levels and the time to convert Unit 3 from generation to synchronous condenser mode. Upon completion of Alternative 1, it is anticipated that the time to convert Unit 3 from generation to synchronous condenser

mode will be three to five days as compared to 16 days with the existing extension shaft design. Using five days as the changeover time, the annual operating and maintenance (O&M) cost was calculated at $7,150 per year using Hydro's standard estimating rates for internal unionized labor. This estimate also includes an allowance for annual preventative maintenance inspections.

There is a saving associated with the reduced time required to convert Unit 3 from generation to synchronous condenser mode due to an increase in the overall thermal efficiency at Holyrood. During the conversion period, Hydro must operate an additional generating unit at Holyrood at a relatively low load (typically 70 MW) in order to meet the requirements of the Island Interconnected Transmission System. The efficiency gain is associated with not having to operate a unit at a relatively low (inefficient) load setting during the 11 day reduction in the normal changeover period in April. Thermal energy is still required to supplement hydroelectric energy generated during this period but it can be generated more efficiently at higher loads outside the changeover period, thereby reducing the overall fuel consumption at Holyrood. The annual fuel savings for Alternative 1 was calculated using the Nalcor Energy/NLH Thermal Fuel Oil Price Forecast.

Using the annual Operating and Maintenance cost of $7,150 and the annual fuel savings, the Cumulative Present Worth (CPW) for Alternative 1 is a benefit at $3,154,587 with a payback of less than one year.

Alternative 2 – Status Quo:

This alternative is to operate Unit 3 as a synchronous condenser without performing any modifications to the extension shaft between the generator output shaft and SSS clutch. Using the maintenance history available for Unit 3 operating as a synchronous condenser, the average annual operating and maintenance cost for this alternative would be $80,000 per year to perform preventative maintenance inspections and corrective maintenance repairs. The annual operating and maintenance cost also includes the cost associated with

converting Unit 3 from generation to synchronous condenser mode and visa versa. Using the operating and maintenance cost indicated above, the CPW for Alternative 2 is a cost of $553,682.

Alternative 1 is the lowest cost option using the Nalcor Energy/NLH Thermal Fuel Oil Price Forecast to calculate the savings as compared to the status quo alternative.

The results of the cost benefit analysis are shown in Table 3.

Table 3: Cost Benefit Analysis

Holyrood - Modify Unit 3 Synchnonous Condenser **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2020**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Modify Unit 3 Sync. Condenser Status Quo	(3,154,587) 553,682	0 3,708,268

4.4 Legislative or Regulatory Requirements

There are no current legislative or regulatory requirements to modify Unit 3 for synchronous condenser mode to reduce vibration levels.

4.5 Historical Information

There have been no capital expenditures in past years on the components of Unit 3 synchronous condenser.

4.6 Forecast Customer Growth

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

4.7 Energy Efficiency Benefits

It is anticipated that completion of the project will reduce the time required to convert Unit 3 from generation to synchronous condenser mode by 11 days. The reduced changeover time will increase the overall thermal efficiency, thereby reducing the fuel consumed by Holyrood. The CPW of the project is a benefit at $3,154,587.

4.8 Losses during Construction

There are no associated losses during the construction of this project as it will be scheduled during the regular period when Unit 3 is converted from generation to synchronous condenser mode.

4.9 Status Quo

Status quo is not an acceptable alternative. Delays to completing this project could result in a forced outage on Unit 3 operating in a synchronous condenser mode due to excessive vibration levels. Depending on the load requirements of the Island Interconnected Transmission System typically from the beginning of October to mid November, a forced outage on the synchronous condenser would necessitate Hydro to operate a generating unit at Holyrood at minimum load of approximately 70 MW. This may increase the overall cost of meeting the requirements of the Island Interconnected System, in the event that Hydro is spilling water required for hydroelectric generation during the forced outage period. In addition, as mentioned previously, the time to convert Unit 3 from synchronous condenser to generation mode with the status quo option is 16 days as compared to five

days with the proposed project. The reduced changeover time will increase the efficiency of Holyrood, thereby reducing the cost of meeting the energy requirements of the Island Interconnected System.

4.10 Alternatives

Two alternatives were considered.

Alternative 1 – Modify components of Unit 3 synchronous condenser to reduce vibration levels

Alternative 2 – Status Quo

5 CONCLUSION

This project is required for modifications to the components of Unit 3 synchronous condenser to reduce vibration levels. During synchronous condenser operation with the existing extension shaft in place that connects the generator output shaft to the synchronous condenser SSS clutch assembly, vibrations of the generator rotor are much higher than desired. The existing extension shaft will be replaced with a new extension shaft complete with journal and thrust bearing assemblies. The journal bearing will control the radial vibrations of the extension shaft and generator rotor. The thrust bearing will control the axial thrust vibrations from the generator rotor that are experienced during synchronous condenser operation. The proposed modifications will increase the reliability of Unit 3 synchronous condenser mode of operation.

The project will also reduce the time required to convert Unit 3 from generation to synchronous condenser mode. It currently takes approximately 16 days for Holyrood to convert Unit 3 to a synchronous condenser with the existing extension shaft design. However, following completion of the project, the new extension shaft will remain in place and only the thrust bearing pads will require removal when converting Unit 3 to a synchronous condenser. It is anticipated that it will take five days to complete the conversion following the proposed modifications, reducing the conversion time by 11 days. The reduced changeover time will increase the efficiency of Holyrood, thereby reducing the cost of meeting the energy requirements of the Island Interconnected System.

5.1 Budget Estimate

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

Table 4: Budget Estimate

Project Cost:*($ x1,000)*	2011	2012	Beyond	Total
Material Supply	298.4	0.0	0.0	298.4
Labour	50.0	128.0	0.0	178.0
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	131.4	0.0	131.4
Other Direct Costs	1.5	1.5	0.0	3.0
O/H, AFUDC & Escln.	33.6	73.5	0.0	107.1
Contingency	0.0	71.1	0.0	71.1
TOTAL	**483.5**	**405.5**	**0.0**	**889.0**

5.2 Project Schedule

The anticipated project schedule is shown in Table 5.

Table 5: Project Milestones

Activity	Milestone
Project Kick-off Meeting	January 2011
Complete Design Transmittal	February 2011
Develop & Issue RFP for Professional Engineering Services	March 2011
Develop Design & Build Contract	May 2011
Issue Tender & Award Contract	June 2011
Procurement of Materials	October 2011
Develop Installation Contract	November 2011
Issue Tender & Award Contract	December 2011
Installation	April 2012
Commissioning	May 2012
Project Final Documentation and Closeout	November 2012

APPENDIX A

Vibration Data

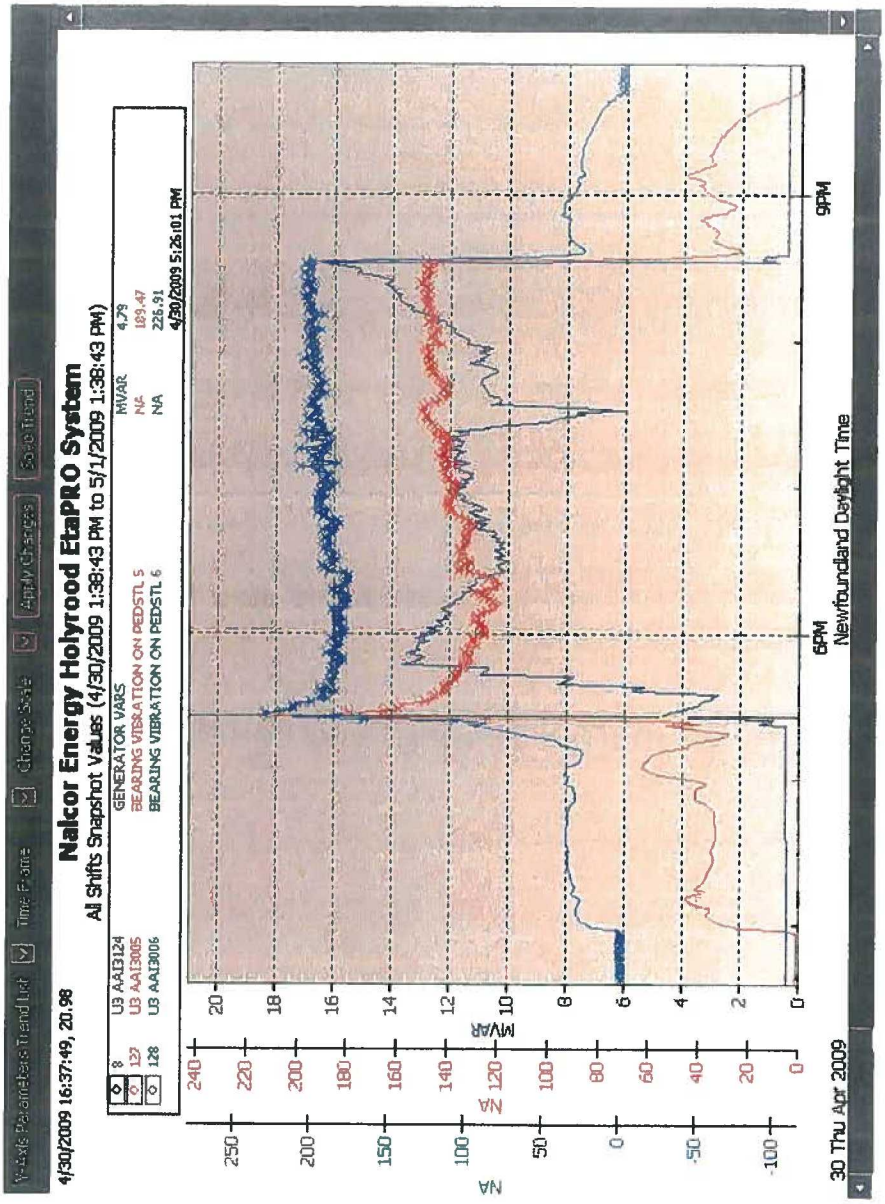
Limitations of Steam Turbine Operation (5/6)

< : less than
> : more than

Limitation items			Limitations	Turbine alarms	Turbine trips	Remarks
BEARING VIBRATION	Normal operation	acceptable	< 1.2 mil	1.5 mil.	-	cap vibration (peak to peak)
		rebalancing	1.2 ~ 1.5 mil			
		short time operation	< 2.0 mil			
		immediately stop	> 2.0 mil			
	at critical speeds	immediately stop	> 2.0 mil			
ECCE-NTRI-CITY	Turbine shaft eccentricity		< normal x 1.1	-	-	at turning speed only
DIFFEREN-TIAL EXPANSION	Shell/Rotor differential expansion (Rotor-long means a condition of larger rotor expansion compared to shell expansion. Rotor-short means a condition of larger shell expansion compared to rotor expansion.)		HIP +316.5 mil -194.1 mil	+316.5 mil -194.1 mil	-	+ : rotor-long - : rotor-short
			LP +87.8 mil -2.23 mil	+87.8 mil -2.23 mil		Do not trip in. Orange band
BEARING	Thrust bearing	metal wear	-	-	> 30 mil	P.SW contacts close (17.1 PSIG)
		metal temperature	160 ~ 175°F	185°F(85°C)	-	
		drain temperature	140 ~ 160°F	167°F(75°C)	-	
	Journal bearing	metal temperature	160 ~ 175°F	-	-	
		drain temperature	140 ~ 160°F	167°F(75°C)	-	

EtaPRO HOLYROOD ETAPRO SYSTEM on HOM2 Historical Trend

APRIL 30,2009



APPENDIX B

Align-A Pad Journal Bearings and Equalizing Thrust Bearings

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
PPL	Brunner Island	1 - HP	1	10	6	Alstom-W	325
	Brunner Island	1 - HP	2	10	6	Alstom-W	
PPL	Brunner Island	1 - IP	1	10	6	Siemens-W	
	Brunner Island	1 - IP	2	11	6	Siemens-W	
PPL	Brunner Island	2 - HP	1	10	6	Alstom-W	325
	Brunner Island	2 - HP	2	10	6	Alstom-W	
PPL	Brunner Island	2 - IP	1	10	6	Siemens-W	
	Brunner Island	2 - IP	2	10	6	Siemens-W	
PPL	Brunner Island	3	1	12	6	Alstom-GE	800
	Brunner Island	3	2	14	6	Alstom-GE	
PPL	Brunner Island	3	3	14	6	GE	
	Brunner Island	3	4	17	6	GE	
PPL	Brunner Island	3-A BFPT	1	6	5	GE	
	Brunner Island	3-A BFPT	2	10	6	GE	
PPL	Brunner Island	3-B BFPT	1	6	5	GE	
	Brunner Island	3-B BFPT	2	10	6	GE	
PPL	Montour	1	1	12	6	Alstom-GE	800
	Montour	1	2	14	6	Alstom-GE	
PPL	Montour	1	5	18	6	GE	
	Montour	1	6	19	6	GE	
	Montour	1	7	19	6	GE	
	Montour	1	8	20	6	GE	
PPL	Montour	2	1	12	6	Alstom-GE	800
	Montour	2	2	14	6	Alstom-GE	
MidAmerica	Louisa	1	1	11	6	Alstom-W	750
	Louisa	1	2	13	6	Alstom-W	
Progress - CP&L	Sutton	3	1	12	6	W	400
	Sutton	3	2	14	6	W	
	Sutton	3	9	9	6	W	
Progress - CP&L	Lee	3	1	10	6	W	275
	Lee	3	2	10	6	W	
Progress - CP&L	Mayo	1	1	12	6	W	750
	Mayo	1	2	14	6	W	
Progress - FPC	Crystal River	1	Inp-Outbd	11	6	TRI	400
	CR 1 Mtr Driven	1	Input-Inbd	11	6	TRI	
	BFP Fluid Drive	1	(4) Thr Brgs	11	8	TRI	

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
Ameren-UE	Labadie	1	Stdy Rest	5.5	5	TRI Extn Shaft	630
	Labadie	1	1	12	6	Alstom-W	
	Labadie	1	2	14	6	Alstom-W	
	Labadie	1	3	14	6	Alstom-W	
Ameren-UE	Labadie	2	Stdy Rest	5.5	5	TRI Extn Shaft	630
	Labadie	2	1	12	6	Alstom-W	
	Labadie	2	2	14	6	Alstom-W	
	Labadie	2	3	14	6	W	
Ameren-UE	Labadie	3	1	16	6	Alstom-GE	650
	Labadie	3	2	17	6	Alstom-GE	
Ameren-UE	Labadie	4	1	16	6	Alstom-GE	650
	Labadie	4	2	17	6	Alstom-GE	
Ameren-UE	Rush Island	1	Stdy Rest	5.5	5	TRI Extn Shaft	640
	Rush Island	1	1	12	6	Alstom-W	
	Rush Island	1	2	14	6	Alstom-W	
	Rush Island	1	3	14	6	W	
Ameren-UE	Rush Island	2	Stdy Rest	5.5	5	TRI Extn Shaft	640
	Rush Island	2	1	12	6	Alstom-W	
	Rush Island	2	2	14	6	Alstom-W	
	Rush Island	2	3	14	6	W	
Ameren-UE	Meramec	4	1	10	6	W	275
	Meramec	4	2	10	6	W	
Ameren-CIPS	Meredosia	2	1	6	5	GE	100
Ameren-UE	Sioux	1	(4) Thr Brgs	14		TRI	
	Sioux	2	(4) Thr Brgs	14		TRI	
TVA	Kingston	6	1	10	6	GE	200
	Kingston	6	2	12	6	GE	
	Kingston	6	3	12	6	GE	
TVA	Kingston	8	1	10	6	GE	200
	Kingston	8	2	12	6	GE	
	Kingston	8	3	12	6	GE	
TVA	J Sevier	1	1	10	6	GE	200
	J Sevier	1	2	12	6	GE	
TVA	J Sevier	2	1	10	6	GE	200
	J Sevier	2	2	12	6	GE	
TVA	J Sevier	3	1	10	6	GE	200
	J Sevier	3	2	12	6	GE	

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
TVA	J Sevier	4	1	10	6	GE	200
	J Sevier	4	2	12	6	GE	
TVA	Gallatin	1	1	11	6	W	250
	Gallatin	1	2	10	6	W	
TVA	Widows Creek	5	1	8	6	GE	125
TVA	Widows Creek	6	1	8	6	GE	125
Duke Energy	Belews Creek	2	1	11	6	Alstom-W	1250
	Belews Creek	2	2	14	6	Alstom-W	
	Belews Creek	2	3	14	6	Alstom-W	
	Belews Creek	2	4	17	6	Alstom-W	
First Energy	Bay Shore	4	1	10	6	W	275
	Bay Shore	4	2	12	6	W	
First Energy	Sammis	5	Stdy Rest	5.125	5	W	375
	Sammis	5	1	11	6	W	
	Sammis	5	2	13	6	W	
Con Edison	East River	5	LPT B-1	17	5	GE	150
Con Edison	East River	6	LPT B-1	17	5	GE	150
Con Edison	East River	7	A-1	8	6	W	225
	East River	7	A-2	8	6	W	
	East River	7	A-3	8	6	W	
	East River	7	A-4	12	6	W	
Con Edison	Hudson Ave	10	1	9	6	W	60
	Hudson Ave	10	2	10	6	W	
Con Edison	Waterside	8	1	9	6	W	60
	Waterside	8	2	10	6	W	
Con Edison	Waterside	9	1	9	6	W	60
	Waterside	9	2	10	6	W	
Keyspan/Con Ed	Ravenswood	1	A-1	8	6	GE	400
	Ravenswood	1	A-2	12	6	GE	
	Ravenswood	1	A-3	12	6	GE	
	Ravenswood	1	A-4	14	6	GE	
	Ravenswood	1	A-7	8.5	5	GE	
	Rav Fluid Drive	1	Inp-Outbd	13	6	TRI	
	Rav Fluid Drive	1	Inp-Inbd	13	6	TRI	
	Rav Fluid Drive	1	Outp-Inbd	7	6	TRI	
	Rav Fluid Drive	1	Outp-Outbd	7	6	TRI	
	Rav Fluid Drive	1	(4) Thr Brgs	14"		TRI	

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
Keyspan/Con Ed	Ravenswood	2	A-1	8	6	GE	400
	Ravenswood	2	A-2	12	6	GE	
	Ravenswood	2	A-3	12	6	GE	
	Ravenswood	2	A-4	14	6	GE	
	Ravenswood	2	A-7	8.5	5	GE	
	Rav Fluid Drive	2	Inp-Outbd	13	6	TRI	
	Rav Fluid Drive	2	Inp-Inbd	13	6	TRI	
	Rav Fluid Drive	2	Outp-Inbd	7	6	TRI	
	Rav Fluid Drive	2	Outp-Outbd	7	6	TRI	
	Rav Fluid Drive	2	(4) Thr Brgs	14"		TRI	
Keyspan/Con Ed	Ravenswood	3	A-1	8	6	Allis-Chalmers	1000
	Ravenswood	3	A-2	17	6	Allis-Chalmers	
	Ravenswood	3	A-3	17	6	Allis-Chalmers	
	Ravenswood	3	A-4	19	6	Allis-Chalmers	
	Ravenswood	3	A-7	10	5	Allis-Chalmers	
	Rav Fluid Drive	3 - North	Inp-Outbd	13	6	TRI	
	Rav Fluid Drive	3 - North	Inp-Inbd	9	6	TRI	
	Rav Fluid Drive	3 - North	Outp-Inbd	7.5	5	TRI	
	Rav Fluid Drive	3 - North	Outp-Outbd	7.5	6	TRI	
	Rav Fluid Drive	3 - North	(4) Thr Brgs	14"		TRI	
	Rav Fluid Drive	3 - South	Inp-Outbd	13	6	TRI	
	Rav Fluid Drive	3 - South	Inp-Inbd	9	6	TRI	
	Rav Fluid Drive	3 - South	Outp-Inbd	7.5	5	TRI	
	Rav Fluid Drive	3 - South	Outp-Outbd	7.5	6	TRI	
	Rav Fluid Drive	3 - South	(4) Thr Brgs	14"		TRI	
US Power Gen	Astoria	3	A-1	8	6	GE	400
was Con Ed	Astoria	3	A-2	12	6	GE	
	Astoria	3	A-3	12	6	GE	
	Astoria	3	A-4	14	6	GE	
	Astoria	3	A-7	8.5	5	GE	
	Astoria - Fluid Drive	3	Inp-Outbd	13	6	TRI	
	Astoria - Fluid Drive	3	Inp-Inbd	13	6	TRI	
	Astoria - Fluid Drive	3	Outp-Inbd	7	6	TRI	
	Astoria - Fluid Drive	3	Outp-Outbd	7	6	TRI	
	Astoria - Fluid Drive	3	(4) Thr Brgs	14"		TRI	
US Power Gen	Astoria	4	A-1	8	6	Allis-Chalmers	400
was Con Ed	Astoria	4	A-2	12	6	Allis-Chalmers	
	Astoria	4	A-3	12	6	Allis-Chalmers	
	Astoria	4	A-4	14	6	Allis-Chalmers	
	Astoria	4	A-7	8.5	5	Allis-Chalmers	
	Astoria - Fluid Drive	4	Inp-Outbd	13	6	TRI	
	Astoria - Fluid Drive	4	Inp-Inbd	13	6	TRI	
	Astoria - Fluid Drive	4	Outp-Inbd	7	6	TRI	
	Astoria - Fluid Drive	4	Outp-Outbd	7	6	TRI	
	Astoria - Fluid Drive	4	(4) Thr Brgs	14"		TRI	

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
US Power Gen	Astoria	5	A-1	8	6	Allis-Chalmers	400
was Con Ed	Astoria	5	A-2	12	6	Allis-Chalmers	
	Astoria	5	A-3	12	6	Allis-Chalmers	
	Astoria	5	A-4	14	6	Allis-Chalmers	
	Astoria	5	A-7	8.5	5	Allis-Chalmers	
	Astoria - Fluid Drive	5	Inp-Outbd	13	6	TRI	
	Astoria - Fluid Drive	5	Inp-Inbd	13	6	TRI	
	Astoria - Fluid Drive	5	Outp-Inbd	7	6	TRI	
	Astoria - Fluid Drive	5	Outp-Outbd	7	6	TRI	
	Astoria - Fluid Drive	5	(4) Thr Brgs	14"		TRI	
NRG / Con Ed	Arthur Kill	2	A-1	8	6	GE	400
	Arthur Kill	2	A-2	12	6	GE	
	Arthur Kill	2	A-3	12	6	GE	
	Arthur Kill	2	A-4	14	6	GE	
	Arthur Kill	2	A-7	8.5	5	GE	
	Arthur Kill - Fluid Drive	2	Inp-Outbd	13	6	TRI	
	Arthur Kill - Fluid Drive	2	Inp-Inbd	13	6	TRI	
	Arthur Kill - Fluid Drive	2	Outp-Inbd	7	6	TRI	
	Arthur Kill - Fluid Drive	2	Outp-Outbd	7	6	TRI	
	Arthur Kill - Fluid Drive	2	(4) Thr Brgs	14"		TRI	
RRI Energy	Conemaugh - FI Drive	1	(4) Thr Brgs	14"		TRI	
	Conemaugh - FI Drive	2	(4) Thr Brgs	14"		TRI	
RRI Energy	Keystone - FI Drive	1	(4) Thr Brgs	14"		TRI	
	Keystone - FI Drive	2	(4) Thr Brgs	14"		TRI	
PSE&G	Sewaren	2	1	10	6	GE	100
PSE&G	Sewaren	3	1	10	6	GE	100
Mirant/PG&E	Contra Costa	2	1	10	6	GE	100
Mirant/PG&E	Contra Costa	6 - HP	Stdy Rest	4.5	5	W	330
		6 - IP	Stdy Rest	4.5	5	W	
Mirant/PG&E	Contra Costa	7 - HP	Stdy Rest	4.5	5	W	330
		7 - IP	Stdy Rest	4.5	5	W	
JCP&L	Gilbert	8	1	8	6	GE	175
NYSE&G	Sync Condenser	7	Extn Shaft	10	6	GE	
Westar/ KG&E	Gordon Evans - FI Drv	2	Inp-Outbd	13	6	TRI	400
	Gordon Evans - FI Drv	2	Inp-Inbd	13	6	TRI	
	Gordon Evans - FI Drv	2	Outp-Inbd	7	6	TRI	
	Gordon Evans - FI Drv	2	Outp-Outbd	7	6	TRI	

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
	Gordon Evans - Fl Drv	2	(4) Thr Brgs	14"		TRI	
NU - PSNH	Newington	1	1	12	6	W	350
NU - PSNH	Merrimack GS	2	Stdy Rest	5.125	5	W	340
	Merrimack GS	2	1	12	6	W	
	Merrimack GS	2	2	14	6	W	
	Merrimack GS	2	3	13	5	W	
	Merrimack GS	2	4	13	5	W	
	Merrimack GS	2	5	13	5	W	
	Merrimack GS	2	6	14	5	W	
	Merrimack GS - Fl Drv	2	(4) Thr Brgs	13"		TRI	
Exelon/ Boston Ed	New Boston - Turb	1	Stdy Rest	4.5	5	W	400
	New Boston - Fl Drv	1	Inp-Outbd	13	6	TRI	
	New Boston - Fl Drv	1	Inp-Inbd	13	6	TRI	
	New Boston - Fl Drv	1	Outp-Inbd	7	6	TRI	
	New Boston - Fl Drv	1	Outp-Outbd	7	6	TRI	
	New Boston - Fl Drv	1	(4) Thr Brgs	13"		TRI	
Exelon/ Texas Util	Handley - Turb	3	Stdy Rest	4.5	5	W	405
	Handley - Fl Drv	3	Inp-Outbd	13	6	TRI	
	Handley - Fl Drv	3	Inp-Inbd	13	6	TRI	
	Handley - Fl Drv	3	Outp-Inbd	7	6	TRI	
	Handley - Fl Drv	3	Outp-Outbd	7	6	TRI	
	Handley - Fl Drv	3	(4) Thr Brgs	13"		TRI	
Intl Paper/Champior	Cantonment	1	2	8	6	W	40
Intl Paper/ Champio	Weldwood	2	1	5.125	5	GE	30
	Alberta, Canada	2	2	10	6	GE	
		2	3	10	5	GE	
		2	4	10	5	GE	
Blue Ridge Papers	Canton, NC	5	1	5	5	GE	20
Newark Bay CC	Steam Turb	1	2	11	6	Mitsubishi	250
Kentucky Utilities	EW Brown	3-A BFP T	1	4	5	W	400
	EW Brown	3-A BFP T	2	5	5	W	
Kentucky Utilities	EW Brown	3-B BFP T	1	4	5	W	
	EW Brown	3-B BFP T	2	5	5	W	
Xcel Energy	AS King	1	1	12	6	Alstom/W	700
	AS King	1	2	14	6	Alstom/W	
Oklahoma G&E	Muskogee	6	1	12	6	Alstom/W	580
	Muskogee	6	2	14	6	Alstom/W	
Oklahoma G&E	Muskogee	4	1	12	6	Alstom/W	580

List of Users of TRI Align-A-Pad ® Journal Bearings and Fully Equalizing Thrust Bearings							
Utility	Plant	Unit Number	Bearing Number	Diameter (inches)	Number of Pads	Equipment Manufacturer	MW Served
	Muskogee	4	2	14	6	Alstom/W	
Enpower	Oildale Energy	1	Extn Shaft	11	6	GE LM 6000	50
Whitecourt Power	Whitecourt, Canada	1	2	10	6	GE	38
Being Manufactured							
Minnesota P&L	C. Boswell 4	4	1	12	6	Alstom/W	600
		4	2	14	6	Alstom/W	
Dominion	Mt. Storm	1	1	10	6	Alstom/W	585
	Mt. Storm	1	2	12	6	Alstom/W	
Dominion	Mt. Storm	2	1	10	6	Alstom/W	585
	Mt. Storm	2	2	12	6	Alstom/W	
Total Number of TRI Align-A-Pad Journal Bearings in Service = 220							
Total Number of TRI Fully Equalizing Tilting Pad Thrust Bearings in Service = 83							
Total Megawatts Served = 25,033							

APPENDIX C

TRI Proposal 2009-77-01

Transmission & Bearing Corp.
A Division of Turbo Research, Inc.

Mr. Christian Thangasamy, P.Eng.
Holyrood Thermal Generating Station
Newfoundland and Labrador Hydro

December 21, 2009
Page 1 / 5

Subject: **Extension Shaft and Combined Journal Brg and Thrust Brg Assy For Holyrood Unit 3 Sync Condenser Start-up Package - -- Permits Fast "Quick-change" Time -- TRI Proposal 2009-77-01**

Dear Mr. Thangasamy:

It was a pleasure visiting you and your associates earlier this month. During my visit, we discussed many existing issues that you are having with the present arrangement, and from those discussions, we developed certain project objectives. We also reviewed a preliminarylayout sketch of the subject extension shaft, journal and thrust bearings, and flexible coupling. TRI had developed that sketch in the morning using information obtained and measured on site.

1. Technical Issues to be Resolved in this Project:

The core issue to be addressed by this project is this: In the present arrangement, the rotor moves axially excessively and vibrates axially excessively, damaging the SSS clutch in the process. When TRI's proposed extension shaft and bearing assembly is installed, this issue will disappear.

Two other critical issues, identified below, that TRI was not aware of prior to my visit came to light during our meeting. Consequently, two objectives were established for this project to resolve these issues:

1. TRI learned that during SC operation with the current extension shaft (stub shaft) in place, the vibrations of the generator rotor, particularly the vibrations of the rotor at the outboard bearing are higher than desired. Consequently, an objective for the project is to design the new TRI proposed extension shaft and bearing arrangement to control these rotor vibrations so as to reduce them to acceptable levels.

2. Another objective is to design the new TRI proposed extension shaft and bearing arrangement **to permit very a quick change-over time**, which is the time to go from generation mode operation to sync condenser mode operation, or the other way around.

The solution to issue number 1 is to include a journal bearing in the arrangement, as TRI has proposed in the preliminary proposal. The reason for including a TRI Align-A-Pad journal bearing with a 5-pad arrangement and an 8.5" journal diameter is to provide a sufficiently heavy-duty bearing that is **capable of controlling the radial vibrations of the extension shaft AND the generator rotor.** This extension shaft extends approximately 5 feet long beyond the axial center of the outboard generator bearing. This overhang length is too long without a journal bearing near the end of the shaft to control radial vibrations.

Engineering Services and Products for Large Rotating Machinery
P.O. Box 454 212 Welsh Pool Rd
Lionville, PA 19353-0454
Tel:610-363-8570 Fax:610-524-6326
E-mail: mel.giberson@turboresearch.com
www.turboresearch.com

As a result of establishing the objective for resolving issue number 2, TRI has spent considerable time to redesign the entire arrangement to meet this "Quick-change" objective so that it has the following features:

2. Description of Proposed Equipment:

The proposed arrangement includes a heavy duty combined journal bearing and thrust bearing arrangement that includes:

- Heavy Duty Outer Housing.
- Outer Housing Mounts onto the existing soleplate that supports the Brush Gear without blocking the air flow.
- New Extension Shaft and New Insulated Coupling Bolts.
- Tilting pad journal bearing, 8.5" journal, 5-pad design.
- Thrust Bearing Housing that attaches to the side of the journal bearing housing.
- Double Sided Thrust Bearing, tilting pad, 10" OD, steel pads, central pivots.
- Shimplates for setting rotor position and axial float.
- New coupling to the SSS shaft.
- Instrumentation:
  - x-y proximity probes
  - TCs in each bearing 1- JB, 2 in each TB

The thrust bearing arrangement designed for this package provides at least 11,000 lbs of thrust force capability at 3600 rpm, about 10 times that specified in your inquiry. The thrust force capability decreases to about 5000 lbs at 100 rpm. TRI is concerned that the axial force level provided by the generator OEM may be too low. Further, if there is any seismic activity, the axial forces will be considerably higher than the specified force level of 500 kg (1100 lbf).

It is critical that there be a journal bearing adjacent to the thrust bearing. The journal bearing stabilizes and controls the radial vibrations that are experienced by the thrust bearing and the flexible coupling. The journal bearing that we would use here is the same as that which we have used for the extension shaft of the 185 MW, 3600 rpm Generators at Ravenswood Units 1 and 2. These Extension Shaft Bearings have been in service at Ravenswood with very satisfactory results since the late 1980s. TransCanada Pipeline now owns this station, located in NYC.

The new flexible coupling will be lubricated with heavy oil and will be better sealed with O-rings than the past couplings, so there should be no leakage, or perhaps very minimal oil leakage. Nevertheless, it is appropriate to check the oil level during every changeover. (Rotate so that the coupling oil filling ports in the flanges are at 45 degrees, and inspect/fill/drain them, as appropriate.)

TRI has developed a Layout Drawing for this Arrangement.

There is a reason for the lift oil pumping and distribution system. The generator tries to go downhill toward the turbine. Hence, when the rotor stops, and when the rotor contracts, it loads the governor side thrust bearing. Furthermore, the extension shaft will be lifted to load the new journal bearing. When trying to start with these additional resistive torques, more resistance is provided to the starting equipment. Lift oil for the bottom pads of the journal bearing and for both thrust bearings minimizes the additional torsional resistance during starting.

Please note that the lagging (outer sheet metal) covering of the end of the brush gear housing (aka "dog house") will need to be cut and adjusted when the new pedestal and coupling is in place.

Piping stubs (Sch. 80) are provided for connecting lube oil supply and lube oil drain lines.

3. Description of the Quick-change Feature:

This entire bearing and extension shaft arrangement has been designed with the desired "Quick-change" capability.

With the double thrust bearings removed from the thrust bearing housing, **the extension shaft can travel freely a distance of 1.25 inches toward the SSS clutch.** This 1.25" distance should be more than sufficient to disassemble/assemble the LP Turbine to Generator Coupling that contains the turning gear. With the double thrust bearing installed, the axial float will be limited to approximately 0.010 inches end to end.

This changeover is accomplished with the Flex Coupling to the SSS Clutch fully assembled.

If appropriate, an axial stop feature can be included that will limit the axial float to a lower value that will protect the generator from internal damage.

To remove the double thrust bearing for generation operation, perform these steps:
- All permits have been obtained and the lube oil is off.
- Remove the shaft seals at the SSS end (gen end) of the housing.
- Remove the half-cover (SSS end) of the Upper Outer Housing with upper shaft seal attached, exposing the thrust bearing housing.
- Remove all of the lift oil flex hoses to the thrust pads (shoes).
- Remove the thermocouples (have bayonet fittings on outside of thrust bearing housing)
- Remove the upper half of the thrust bearing housing.
- Remove both of the thrust bearings and shimplates.

- Install a block for the lift oil lines.
- The lube oil does not need to be addressed, as it can continue to flow out the drain pipe and orifice.
- Close it up in reverse order. Clean the joints and use new sealant (Permatex 2).
- Turn on lube oil.
- Turn in permits.

Nothing needs to be done to the coupling between the Extension shaft and the SSS clutch. It remains fully assembled.

To install the thrust bearings when going to Sync Cond operation, there will be steps required first to install the governor end thrust bearing, move the shaft against the governor end thrust bearing, and install the generator end (SSS end) thrust bearing and shimplate. Then complete the remainder of the assembly in reverse order from that given above.

4. Pricing for the new Extension Shaft and Bearing Assembly:

The attached Spreadsheet, identified as 2009-71-02, shows how the pricing for the assembly is developed from the prices for the various components.

This Spreadsheet includes items that were not considered in the preliminary pricing. One is modification of the SSS clutch output shaft. This is very valuable because it provides the opportunity for the "Quick-change" feature, as described above.

An estimate of limited monies to provide new rolling element bearings and seals for the SSS output shaft is included in this pricing schedule. If the incoming inspection suggests that other refurbishment work should be done on the SSS clutch, TRI will so notify NLH.

The housing, bearing, shaft, and coupling arrangement that provides for a large axial float and splitting of the cover of the outer housing is of necessity more complex than the original design, and hence, takes more effort to manufacture.

Certain monies are allocated for associated services that are usually involved in such projects, including Technical Direction for installation. TRI's rate for Technical Direction for installation for this job would be US$260. per hour. Expenses and OT are handled as indicated in the currently published TRI Rate and Policy Schedule, attached. These are shown separately, as occasionally these are handled separately from the hardware items. However, NLH may wish to include them as a fixed price portion of the project.

5. Shipment:

5.1. Schedule:

TRI anticipates that this equipment could be made and shipped for installation beginning around April 15, 2010. This is approximately a 14 week lead-time, which is relatively short for a complex piece of equipment for which the detail manufacturing drawings must also be produced.

Consequently, an early approval and release for manufacturing is requested.

5.2. Terms of Shipment:

FOB: Lionville: (TRI will load the crates onto the means of conveyance selected by NLH at no additional cost.)

6. Progress Payments:

TRI requests progress payments according to certain milestones, usually five in number. These would be negotiated at time of order placement. Suggestions for the milestones include these:

- when materials have been ordered,
- when rough machining has started,
- when finish machining has started,
- when assembly has started, and
- when the assembly has been shipped.

7. Invoicing:

TRI would issue invoices according to the progress payments negotiated. TRI prefers to transmit invoices by email, and it is believed that NLH receives invoices by email.

8. Terms of Payment:

TRI prefers that payment be made by Electronic Fund Transfer methods. This provides superb tracking ability and almost always provides shorter transfer time.

TRI offers a discount for early payment, with details to be negotiated at time of order placement.

Please contact me with questions that you may have.

Thank you
Sincerely yours,
TRI Transmission & Bearing Corp.

Mel Giberson
Melbourne F. Giberson, Ph.D.,P.E.
President

		Holyrood Sync Cond 3				
		Extension Shaft and				
	Combined Journal and Thrust Bearing Assembly					
	TRI Document 2009-77-02 - December 21, 2009					

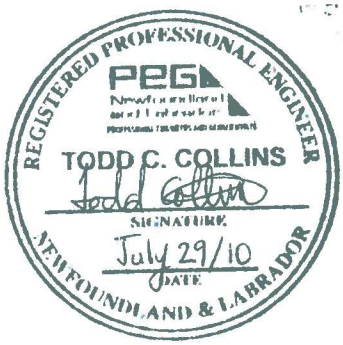
Item		
1	Pedestal Housing	$ 82,445
20	Oil Seals and Baffle Plate, Gov End	$ 16,337
30	Oil Seals and Baffle Plate, Gen End	$ 10,528
50	Hold-down Bolts and Washers	$ 5,220
100	Extension Shaft Assembly, Insulated Cplg and Ins Cplg Bolts	$ 34,414
131	Flexible Coupling, Fast's, Size 3 modified, and Fit onto Shaft Ends	$ 10,220
150	Modify SSS Cplg Shaft (Disass, Insp, Mod, & Reassemble)	$ 8,980
200	Journal Bearing, 8.5" Dia, 5 pad	$ 67,148
250	Thrust Bearing Housing and Floating Seals	$ 15,746
270	Thrust Bearings, 10", Gov End & Gen End and Shim Plates, with Lift Oil	$ 28,056
400	Lift Oil Pump, Filter, and Pressure Relief Valve	$ 7,200
500	Proximity Vibration and Rotor Position Probes	$ 6,000
	Total Price of Above - Without Contingency	$ 292,294

Note:	All Stationary and rotating components will be assembled together with the SSS Clutch at TRI before being disassembled for shipping to site.	No Added Charge

	Additional Individually Chargeable Items	
600	Heavy Wooden Shipping Crates	$ 2,450
700	Packing for Shipment	$ 3,840
800	Technical Direction for Installation - 5 days on site	$ 19,440

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

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

UPGRADE GENERATING UNIT 1 FORCED DRAFT FAN DUCTWORK

Holyrood Thermal Generating Station

February 2010

newfoundland labrador hydro
a nalcor energy company

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APPENDIX A A1

APPENDIX B B1

1 INTRODUCTION

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



Figure 1: Holyrood Thermal Generating Station

The three main components of each generating unit are the boiler, turbine, and generator. The boiler servicing Unit 1 is equipped with two forced draft (FD) fans which are commonly referred to as the east and west FD fans. A FD fan is a system that provides combustion air to the boiler during operation. The fan consist of a rotating assembly, commonly referred to as an impellor, that is positioned inside a steel casing which contains both air intake and

discharge zones. The impellor is driven by a 1,500 horsepower electric motor. Each FD fan also contains air intake and discharge ductwork which is connected to the fan casing air intake and discharge zones respectively. During operation, the intake ductwork conveys ambient air to the FD fan from both inside and outside the plant. After passing through the FD fan, the discharge ductwork then conveys the air to the boiler furnace where it is mixed with the boiler fuel oil for combustion. The Unit 1 FD fan arrangement is illustrated below in Figure 2.

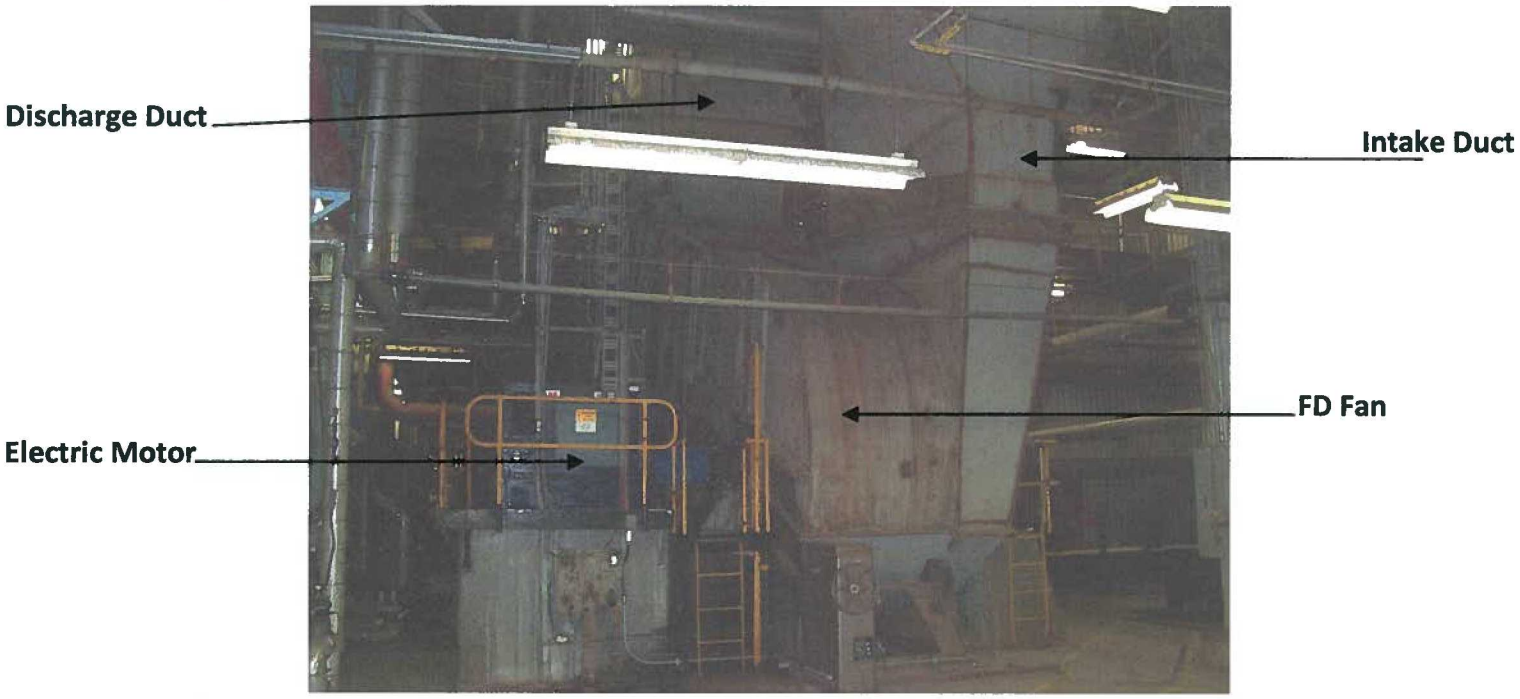

Figure 2: Holyrood Unit 1 West FD Fan

2 PROJECT DESCRIPTION

This project is required to perform modifications to the ductwork on the east and west FD fans servicing generating Unit 1 to reduce fan vibration levels and eliminate ductwork cracking. A Computational Fluid Dynamics (CFD) analysis will be completed on the fans while they are in operation in order to model the air flow characteristics inside the intake and discharge ductwork. CFD analysis is a computer modeling technique commonly used in industry to model fluid flows and analyze problems in mechanical systems by simulating the interaction of fluid flows with equipment surfaces. Based on the results of the CFD analysis, custom fabricated equipment will be installed inside the FD fan intake and discharge ductwork. These modifications will reduce flow induced vibrations and ductwork cracking. It is also anticipated that the modifications will reduce the overall pressure drop across the air handling system thereby reducing the fan power consumption. Due to safety concerns associated with performing modifications to the FD fan ductwork during the regular annual boiler outage maintenance work in the same congested work area, this project will be sole sourced to Alstom Power, the boiler service contractor because of their overall experience and familiarity with Holyrood.

3 EXISTING SYSTEM

The existing Unit 1 west FD fan system is illustrated in Figure 2. The east and west FD fan systems servicing the Unit 1 boiler are identical. During operation, the geometry of the existing FD fan ductwork causes air flow turbulence which creates vibrations on both the intake and discharge ductwork. The vibrations result in ductwork cracks which are normally repaired by Alstom Power during the annual Unit 1 outage. However, extensive ductwork cracking has the potential to cause an unscheduled outage in order to make repairs. An unscheduled unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System. This represents approximately 11 percent of Hydro's Island Interconnected System's capacity. Typical Unit 1 internal ductwork cracking and previous repairs are illustrated in Figure 3.

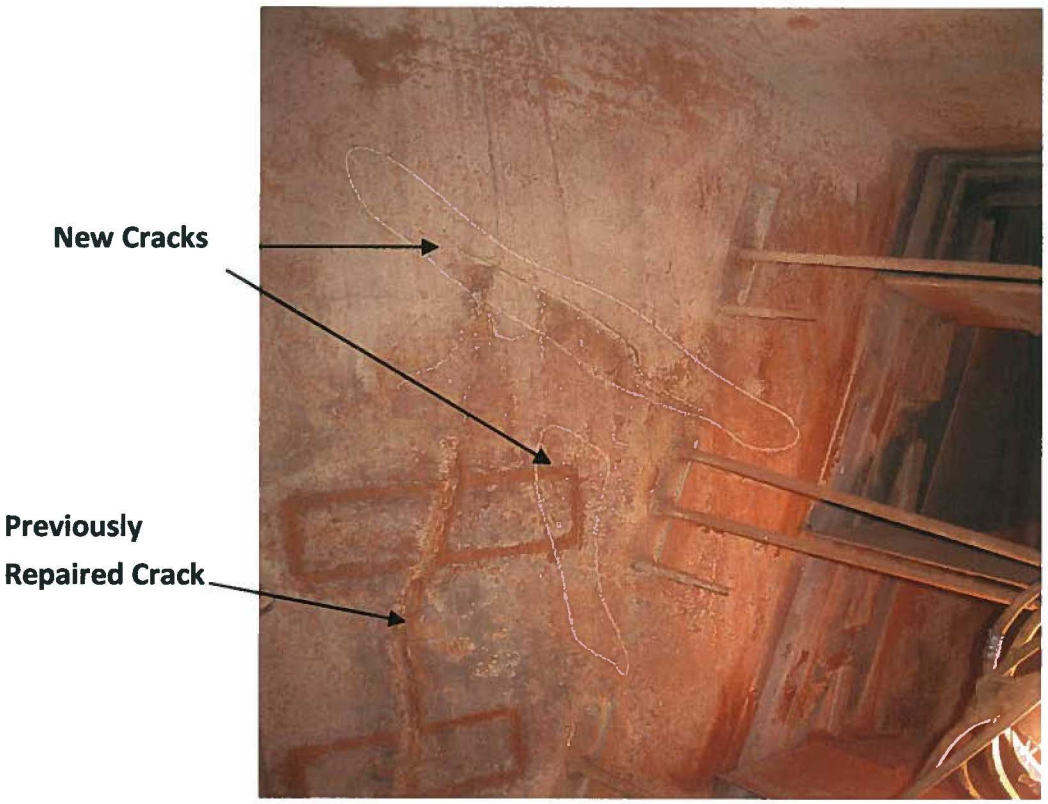

Figure 3: Unit 1 FD Internal Ductwork Cracking

3.1 Age of Equipment or System

The existing oil fired boiler and FD fans are 39 years old.

3.2 Major Work and/or Upgrades

Unit 1 was originally commissioned in 1971 to produce 150 MW and was up-rated to produce 170 MW in 1988. During the upgrade it was necessary to increase the capacity of the FD fans in order to increase the volumetric flow rate of combustion air to the boiler. A higher volume of combustion air was necessary to increase the boiler maximum steam flow rate required to produce the additional 20 MW. The capacity of the FD fans was increased by adding tips to the existing fan impellor blades.

3.3 Anticipated Useful life

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

3.4 Maintenance History

FD fan maintenance is a component of the annual maintenance strategy for Unit 1. During the annual shutdown Hydro uses a boiler service contractor, Alstom Power, to perform preventative maintenance inspections and corrective maintenance repairs on the FD fans and ductwork system. The cost of maintenance for the FD fans is a component of the total maintenance cost for the whole unit. The five-year maintenance history for the Unit 1 FD fans is shown below in Table 1.

Table 1: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2009	2.0	24.0	26.0
2008	1.0	6.0	7.0
2007	1.0	6.0	7.0
2006	0.0	0.0	0.0
2005	0.0	0.0	0.0

3.5 Outage Statistics

In December of 2008, there was a forced outage on Unit 1 with a one-week duration due to a failure of the intake guide vanes on the east FD fan. The intake guide vanes are stationary blades that are welded to the intake ductwork and they function to reduce the air flow turbulence prior to entering the fan. The failure of the guide vanes was attributed to high vibration levels caused by air flow turbulence on both the intake and discharge ductwork as a result of the ductwork geometry.

In addition, following the repairs completed on the intake guide vanes in December of 2008 during the forced outage, Unit 1 was de-rated to produce a maximum of 157 MW for the entire operating season that ended in May of 2009 as a result of high vibration levels on the FD fan intake and discharge ductwork caused by air flow turbulence. To address the issue, turning vanes or stationary blades were installed by Alstom Power inside the FD fan ductwork during the 2009 annual Unit 1 outage as a temporary measure to reduce the air flow turbulence and vibration levels in order for Unit 1 to operate at full capacity. This temporary measure did not address the overall deterioration of the ductwork.

3.6 Industry Experience

Flow induced vibration caused by air flow turbulence due to ductwork geometry is common in FD fan systems. The industry trend is to utilize CFD analysis techniques and perform duct work modifications to reduce air flow turbulence as opposed to replacing the existing ductwork to correct geometry design problems. Many companies now specialize in providing solutions to reduce flow induced vibrations in fan duct work systems and overall fan pressure loss through the use of CFD analysis techniques.

The application of CFD techniques and modifications to FD fan ductwork was completed in February of 2004 at New Brunswick Power's 1,050 MW coal fired power plant located at Colson Cove. M&I Power Technology (M&I), a company that specializes in the application of CFD techniques to modify ductwork in order to reduce flow induced turbulence and overall fan pressure loss, was contracted by New Brunswick Power to perform modifications to the FD fan ductwork servicing one of the 350 MW coal fired units at the Colson Cove generating facility. Appendix A provides the background for the project.

3.7 Maintenance or Support Arrangements

Hydro currently has a service contract with Alstom Power to perform boiler maintenance during the annual scheduled outage. The FD fan maintenance is completed under the boiler service contract.

3.8 Vendor Recommendations

In December of 2009, Hydro had a preliminary CFD analysis completed on the Unit 1 FD fans intake and discharge ductwork systems by M&I to reduce pressure loss and flow induced vibrations in plant air flow systems. The analysis indicated that the air inside the ductwork

does not flow through at a uniform velocity. This results in high fan entry loss and poor fan blade loading. In addition, the analysis also indicated that the fans are operating at a high flow rate (165 Kg/s per fan) resulting in very high velocity magnitude in the range of 84.5 to 96.6 m/s which creates flow induced vibration. The report from M&I recommends that Hydro perform a more comprehensive CFD analysis on the FD fan systems and install aerodynamic diffusers and long turning vanes inside the ductwork to reduce both flow induced vibrations and fan pressure loss. The report outlining the findings of the analysis is included in Appendix B.

3.9 Availability of Replacement Parts

Spare parts are available for the existing Unit 1 FD fan system.

3.10 Safety Performance

There are no safety code violations with the current operation of the Unit 1 FD fans.

3.11 Environmental Performance

There are no environmental code violations with the operation of the existing Unit 1 FD fans.

3.12 Operating Regime

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

4 JUSTIFICATION

The FD fans servicing Unit 1 at Holyrood have an ongoing problem with flow induced vibration on the fan intake and discharge ductwork systems. During operation, the geometry of the existing FD fan ductwork causes air flow turbulence which creates vibrations on both the intake and discharge ductwork. The vibrations cause cracks to develop in the ductwork. The cracks are normally repaired during the annual Unit 1 outage. However, the development of cracks on an on-going basis threatens the integrity of the ductwork infrastructure and reduces the reliability of Unit 1.

In December of 2008, there was a forced outage on Unit 1 due to a failure of the intake guide vanes on the East FD fan. Failure of the intake guide vanes was due to high vibration levels caused by air flow turbulence on both the intake and discharge ductwork. In addition, high vibrations levels resulted in a de-rating of Unit 1 during the 2009 operating season. To address the issue, turning vanes were installed inside the fan ductwork during the 2009 annual Unit 1 outage as a temporary measure to reduce air flow turbulence and vibration levels.

Failure of the FD fan ductwork can result in an unplanned Unit 1 outage of three to four weeks duration. An unscheduled unit outage during the peak winter load demand would result in a loss of 170 MW of power generation to the Island Interconnected System which represents approximately 11 percent of the Island Interconnected System's capacity.

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

4.1 Net Present Value

A Net Present Value (NPV) calculation was not done, however, a cost benefit analysis was completed on two alternatives over a study period of ten years. See Cost Benefit Analysis Section 4.3 for details.

4.2 Levelized Cost of Energy

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

4.3 Cost Benefit Analysis

A cost benefit analysis was completed on two alternatives. The study period for the cost benefit analysis was 10 years.

Alternative 1 - Upgrade Unit 1 FD Fan Ductwork based on Fuel Cost Savings:

This alternative is to complete the proposed modifications to Unit 1 FD fans in order to reduce ductwork vibrations caused by flow induced turbulence and air handling system overall pressure loss. Upon completion of Alternative 1, the annual operating and maintenance (O&M) cost was estimated at $1,000 per year which would cover FD fan preventative maintenance inspections. It is anticipated that there would not be any unscheduled FD fan failures or corrective maintenance to repair ductwork cracks after completing the proposed modifications to the FD fan ductwork. The preliminary CFD analysis report completed by M&I Technology (Appendix B) indicated that the energy savings associated with each FD fan will be 16 percent after completing the proposed modifications to the ductwork. The savings for Alternative 1 were calculated using the January 2010 Nalcor Energy/NLH Thermal Fuel Oil Price Forecast for No.6, 0.7 percent sulphur fuel with a PUB approved conversion factor of 630 kWh/bbl. Using an average Unit 1 load of 80 MW and 4,520 operating hours as in 2009, the Cumulative Present Worth (CPW) for Alternative 1 is a benefit of $489,706 with a payback of six years.

A sensitivity analysis was performed on Alternative 1 using a Levelized Unit Energy Cost (LUEC). The PUB approved LUEC rate at $0.09 per kilowatt hour was used to calculate the

project saving. Using an average Unit 1 load of 80 MW and 4,520 operating hours, the CPW cost is $182,008.

Alternative 2 – Status Quo:

This alternative is to operate the FD fans under the current operating conditions without performing any modification to the ductwork. Using the maintenance history available for the Unit 1 FD fans, the annual O&M cost for this alternative is expected to be $7,000 per year to perform preventative maintenance inspections and corrective maintenance repairs. Also, based on the history of forced outages with an occurrence in 2008 and repair cost at approximately $330,000, it was assumed that an identical forced outage would occur again in 2018. Using the O&M cost indicated above, the CPW cost for Alternative 2 is $242,526.

The analysis indicates that Alternative 1 is the lower cost option. Table 2 shows the results of the cost benefit analysis.

Table 2: Cost Benefit Analysis

HRD Unit 1 FD Fan Ductwork Modifications **Alternative Comparison** ***Cumulative Net Present Value*** ***To The Year*** **2020**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
HRD Unit 1 FD fan Ductwork Modifications @ Fuel Cost	(489,706)	0
Status Quo	242,526	732,232

4.4 Legislative or Regulatory Requirements

There are no legislative or regulatory requirements to complete the proposed modification to the FD fan ductwork to reduce vibration levels and fan pressure loss.

4.5 Historical Information

There is no applicable historical information.

4.6 Forecast Customer Growth

Customer load growth is not affected by this project.

4.7 Energy Efficiency Benefits

It is anticipated that completion of the proposed project will reduce the energy consumed by the Unit 1 FD fans by 16 percent.

4.8 Losses during Construction

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

4.9 Status Quo

Status quo is not an acceptable alternative. A cost benefit analysis has shown that upgrading the FD fan ductwork will present a savings to Hydro. Also, an unscheduled failure during the peak winter load demand could result in a loss of 170 MW of power which represents approximately 11 percent of the Island Interconnected System's capacity.

4.10 Alternatives

Two alternatives were considered as discussed in the Cost Benefit Analysis Section 4.3.

5 CONCLUSION

Modifications to the Unit 1 existing FD fan ductwork systems is required to reduce flow induced vibrations caused by air flow turbulence due to the existing ductwork geometry. The modifications will also reduce the overall fan pressure drop, thereby reducing the fan power consumption by 16 percent. Using an average Unit 1 load of 80 MW and 4,250 operating hours as in 2009, a cost benefit analysis indicates that completing the proposed project is the preferred option as compared to the status quo alternative.

Failure to perform the modifications to the Unit 1 FD fan ductwork systems increases the likelihood of unscheduled downtime on the turbine and increases the risk of being unable to meet customer demands during the peak winter load requirement.

5.1 Budget Estimate

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

Table 3: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	20.0	0.0	0.0	20.0
Labour	68.3	0.0	0.0	68.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	619.1	0.0	0.0	619.1
Other Direct Costs	2.0	0.0	0.0	2.0
O/H, AFUDC & Escln.	62.8	0.0	0.0	62.8
Contingency	70.9	0.0	0.0	70.9
TOTAL	**843.0**	**0.0**	**0.0**	**843.0**

5.2 Project Schedule

The anticipated project schedule is shown in Table 4.

Table 4: Project Milestones

Activity	Milestone
Project Kick-off Meeting	January 2011
Complete Design Transmittal	February 2011
Develop Supply & Installation Contract	February 2011
Issue Tender & Award Contract	March 2011
Installation	July 2011
Commissioning	October 2011
Project Final Documentation and Closeout	December 2011

APPENDIX A

Project Background:

M&I Technology's Solution for FD fan Inlet Duct Silencing System For New Brunswick Power's Colson Cove 1,050 MW Power Plant

M&I Power Tech.

PROJECT BACKGROUND

M&I's Solution for F.D. Fan Inlet Duct Silencing System
For
New Brunswick Power's Colson Cove 1,050 MW Power Plant, Canada

N.B Power sought a solution that would reduce noise emanating from the I.D Fan. The conventional splitter type silencer solution occupies lot of space and it was not possible to accommodate it in the available space. Additionally, the pressure drop of the conventional silencer was very high to the tune of 36 mm WC and this pressure drop was resulting in overloading of the F.D Fans. Even an increase of 12 mm W.C would have adversely affected Fan performance, which in turn would have affected generation capacity.

Babcock & Wilcox, Canada which was contracted for this part of the project, approached M&I to employ its "Aero-Acoustic" technology and develop a solution that would solve this apparently conflicting requirement.

M&I's approach integrates flow streamlining with noise attenuation. The flow across the ducting system and fan was analyzed and the effect of turbulence, flow separation, vortices, etc was determined. M&I then developed a diffusion system that streamlined flow across the inlet ducting and ensured that the flow into the Fan is uniform. This 3-dimensional diffusion system that M&I designed also acts as a silencer and absorbs noise. Additionally, the duct is lined with acoustic insulation, which contributes to noise attenuation. A streamlined flow across the duct without turbulence would reduce the flow induced vibration and this also brings down noise generation.

You would note M&I have not employed the conventional splitter type silencer and this brings down the pressure drop. Also, by streamlining the flow across the duct, it is possible to convert unproductive velocity pressure to useful static pressure. In this case M&I was able to reduce pressure drop by 26 mm W.C. as compared to conventional splitter silencer. The noise level that was guaranteed was 84 dBA at 1 m. 1 dB lower than conventional silencer.

Please refer enclosed CFD analysis and Drawing carried out at bid stage for the customer. We are glad to inform you that M&I met contractual performance guarantees as demonstrated in our CFD results. Please also refer enclosed reference letter from B&W, Canada confirming superiority of M&I's aero-acoustic technology over conventional design.

Babcock & Wilcox Canada Ltd.
a McDermott company

581 Coronation Boulevard
Cambridge, Ontario
Canada N1R 5V3
Tel: (519) 621-2130
Fax: (519) 622-3664

February 13, 2004

To Whomsoever It May Concern

This is to advise that Babcock & Wilcox Canada contracted with M&I Air Systems Engineering, Mississauga, Canada for the design, engineering and supply of an Aerodynamic inlet silencer ducting system. The system will be installed on 6 nos. Forced Draft (F.D.) Fans at the 3 x 350 MW Coleson Cove Power Station (Owned and Operated by New Brunswick Power, Canada). B&W opted for the M&I design as it offered a noise attenuation solution at a very low pressure drop across the ducting system, compared to a conventional splitter type silencer solution. Performance guarantees were provided by M&I.

B&W has recently installed two systems for one of the 350 MW units (Unit # 3). B&W is satisfied with design, engineering and workmanship of the silencer units. Moreover, M&I's modular construction enabled B&W to easily retrofit the FD inlet ducting in spite of the space constraints of the existing station. Unit #3 is operating at full capacity load of 350 MW, and has met the contractual performance criteria.

Yours truly,

Babcock & Wilcox Canada

R.J. Johnston
Project Manager

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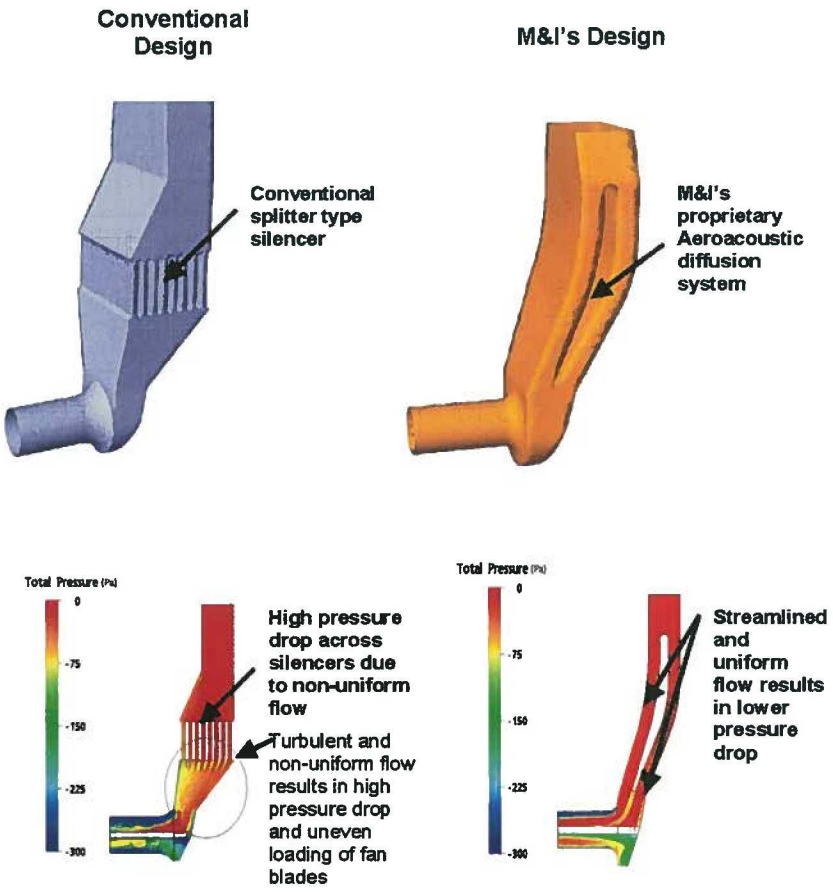
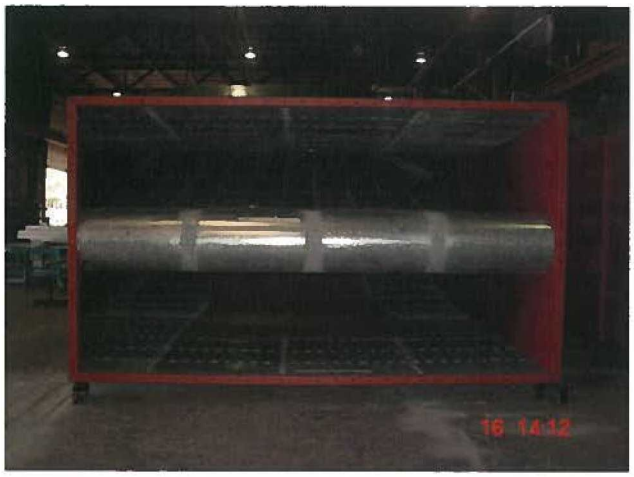
M&I Power Tech.



Pressure drop savings in M&I design: 1" W.G

M&I Power Tech.





Babcock & Wilcox A/c New Brunswick Power
Colson Cove Project (1,050 MW)
FD Fan Aerodynamic Inlet Silencer Duct

M&I Power Tech.

Client: Heyden Power Station, E-ON, Germany

Responsibility:
Design, CFD Analysis, Engineering, Manufacturing, Supply and Supervision of Installation.

Project Background:

Heyden Power Station (An E-ON Company) awarded contract to M&I for CFD Analysis, Design, Engineering, Manufacturing, Supply and Supervision of 2 nos 950 MW units. Objective of working with M&I was to reduce draft loss of 3.5 mbar before ESP and total Draft loss reduction of 10 mbar from Economizer outlet to FD Fan discharge. Above draft saving was very important, since Heyden PS is envisaging use of different grades of Coal in place of Brown Coal. This has resulted in to 10-12% higher volumetric flow in the draft system. Heyden PS had two fold problems to tackle above situation.

1) Suitability of Existing ESP Duct and Structure
2) Static Pressure Margins of ID fan

Bigger ID fan could have solved second problem but first problem was still unresolved. Except M&I solution there were no other feasible alternatives to address first issue.

M&I is offering Aero-acoustic solution for following areas of power plant:

1) SCR Inlet System (Between Ammonia Injection and SCR Catalyst)
2) Air Pre Heater Inlet System
3) ESP Inlet System
4) ESP Inlet Transition
5) Fan Suction Box
6) ID Fan Discharge Duct
7) FGD Inlet System

By leveraging Aero-acoustic technology, M&I is proposing pressure drop reduction in the plant draft system to Heyden PS. Savings are in the tune of 10 mbar to 12 mbar.

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M&I Power Tech.

SUMMARY OF SAVINGS OFFERED BY M&I:

	Description	Current Pr. Drop (mbar)	M&I design (mbar)	Pressure drop saving in (mbar)	++ Appx Increase in net Weight (Kgs)
1	SCR Inlet System	3.43	1.04	2.39	60 tons
2	Air Pre Heater Inlet System	1	0.6	0.4	10 tons
3	ESP Inlet System	3.55	2.05	1.5	
4	ESP Transition	2.95	2.45	0.5	10 tons
5	ID Fan suction box	1.5	0.75	0.75	4 tons
6	ID Fan Discharge System	10.5	5.5	5.0	18 tons
7	FGD Inlet	3.28	2.28	1.0	19 tons

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e·on | Kraftwerke

E.ON Kraftwerke GmbH, Postfach 11 40, D-32459 Petershagen

M & I AIR SYSTEMS ENGINEERING
M & I POWER TECHNOLOGY, INC.
Mr. Dipti Kr. Datta
2140 Meadowpine Blvd.
Mississauga, ON
Canada L5N 6H6

E.ON Kraftwerke GmbH
Kraftwerksgruppe
Mittelweser
Plant manager
Kraftwerkssiedlung
D-32469 Petershagen
www.eon-kraftwerke.com

Matthias Elden
T 49-05702-29-32 21
F 49-05702-29-34 61
matthias.elden@eon-energie.com

Our reference T/Eid-Fr

Petershagen, 2006-03-07

Optimization of Flue Gas Ducts and Fans, including Auxiliary Environmental Equipment

This is to advise that E.ON Kraftwerke GmbH, Tresckowstraße 5, 30457 Hannover, Germany contracted with M&I Power Technology, Inc., Mississauga, Canada for Design, Engineering, Manufacture and Supply of aerodynamic diffusers for our 915 MW Heyden Power Station at Petershagen to reduce the plant draft loss across the following systems:

1) SCR Inlet system
2) ESP Inlet duct and transition
3) ID fan suction box
4) ID fan discharge system
5) FGD inlet system

Above plant draft loss reduction was necessary to accommodate burning of coal with less caloric value. This means more flue gas transportation to produce the same MW. Further it was also necessary to keep same or low suction pressure upstream of ESP, to avoid reconstruction of the ESP casing.

We are pleased to mention here that M&I fulfilled all our expectations and contractual guarantees through an efficient diffusion system. Further M&I solution avoided installation of new ID fans. The following tangible benefits were achieved through M&I technology:

1) Reduction of 2.2 MW ID fan Power Consumption
2) 11 mbar saving in the pressure drop

Chairman of the Supervisory Board:
Bernhard Fischer

Managing Directors:
Dr. Ingo Luge
(Chairman)
Manfred Peters
Dr. Erich Schmitz
Gerhard Seibel
Carsten Stäblein

Registered Office Hanover
Hanover District Court
HRB 58691

1 / 2

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e·on | Kraftwerke

M&I executed this job in time without any delay even in a narrow steel market through efficient project management and offered very good co-operation during installation of the above system.

Due to this excellent result, E-ON would recommend this technology being applied not only to other existing operating plants, but also in case of adding FGD or SCR and forthcoming new plants of their own where most advanced technology will be part of the design group to consider in order to reduce costs and raise performance. As such, M&I technology would be placed on our list of priority.

The technology itself has other salient benefits such as noise and vibration solution without utilizing large conventional silencers, since the technology addresses noise at the source.

For additional information please feel free to contact the undersigned. We wish M&I many more years of success in the future business.

Yours sincerely,

E.ON Kraftwerke GmbH

i.V. i.V.

2 / 2

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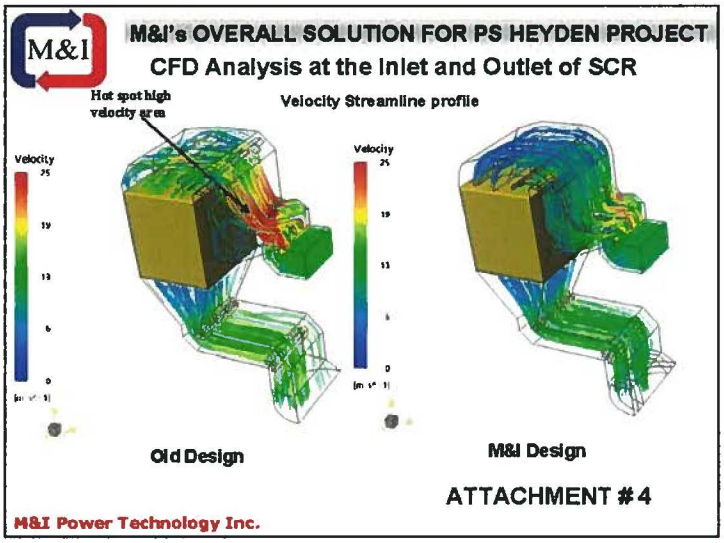
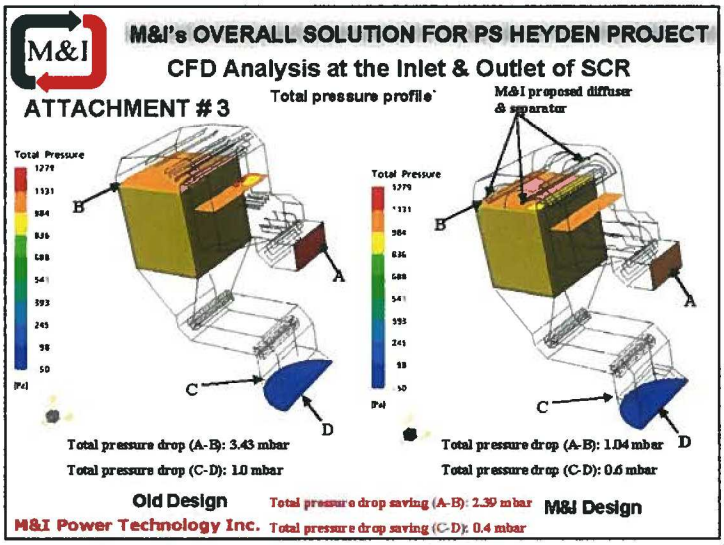
E-ON – Heyden Power Station 950 MW Each
SCR inlet, ESP inlet, ID Fan Suction box inlet, and discharge
(Under Implementation)





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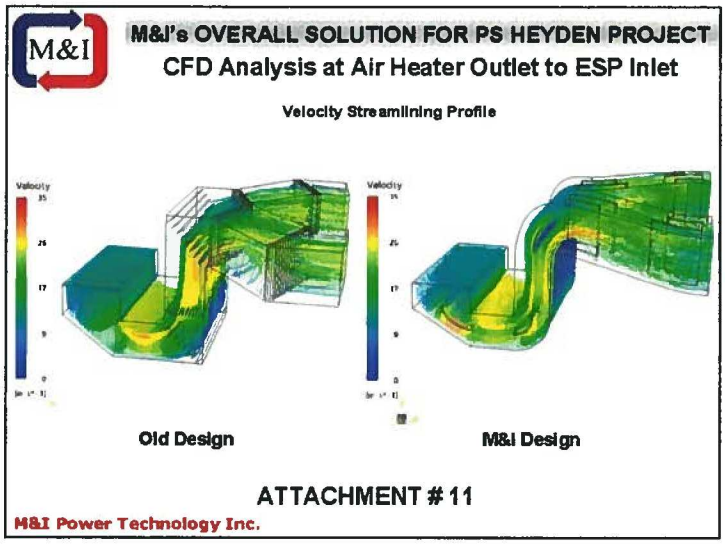
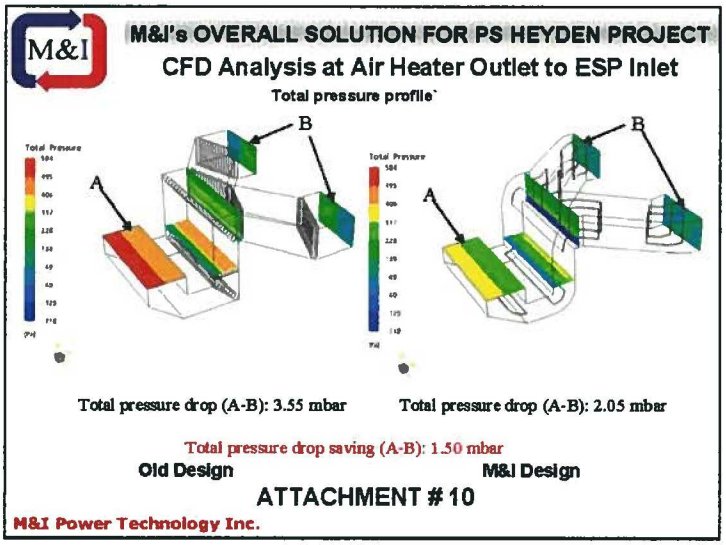

M&I
M&I's OVERALL SOLUTION FOR PS HEYDEN PROJECT
CFD Analysis at Air Heater Outlet to ESP Inlet
Velocity Streamlining Profile
Old Design
M&I Design
ATTACHMENT # 11
M&I Power Technology Inc.


M&I
M&I's OVERALL SOLUTION FOR PS HEYDEN PROJECT
CFD Analysis at Air Heater Outlet to ESP Inlet
Total pressure profile`
A
B
Total pressure drop (A-B): 3.55 mbar
Total pressure drop (A-B): 2.05 mbar
Total pressure drop saving (A-B): 1.50 mbar
Old Design
M&I Design
ATTACHMENT # 10
M&I Power Technology Inc.

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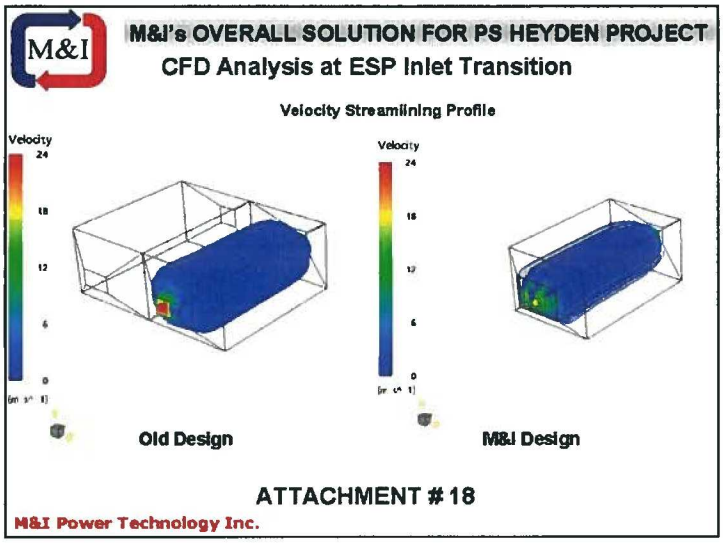
M&I
M&I's OVERALL SOLUTION FOR PS HEYDEN PROJECT
CFD Analysis at ESP Inlet Transition
Velocity Streamlining Profile
Velocity
Old Design
M&I Design
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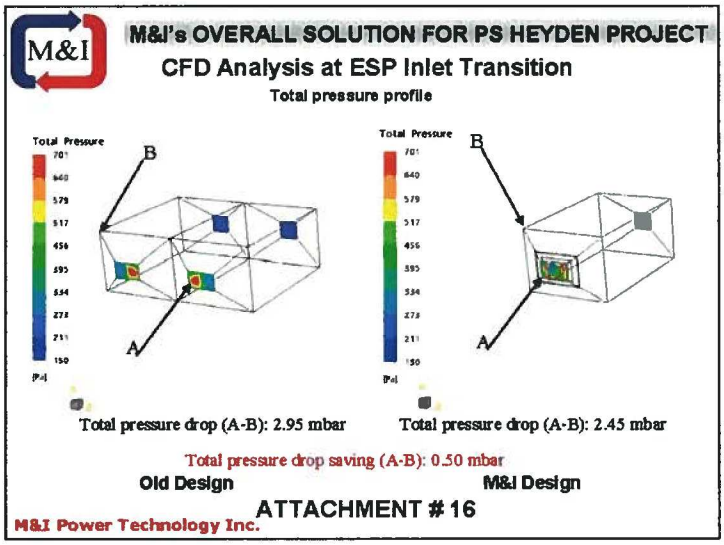
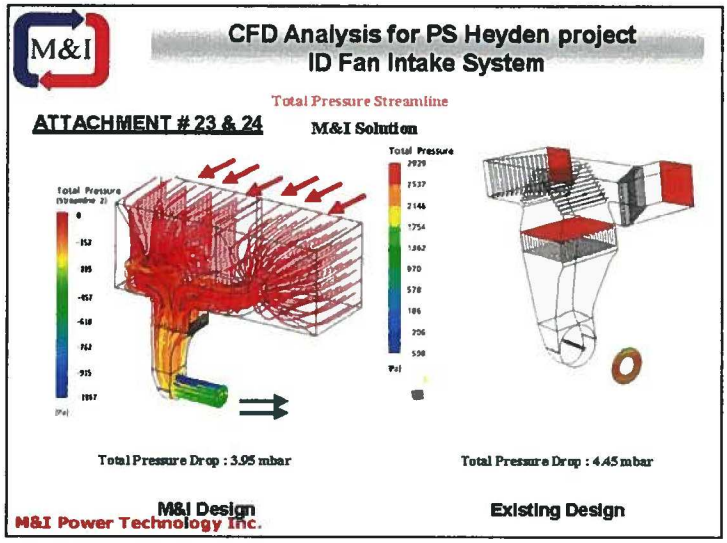
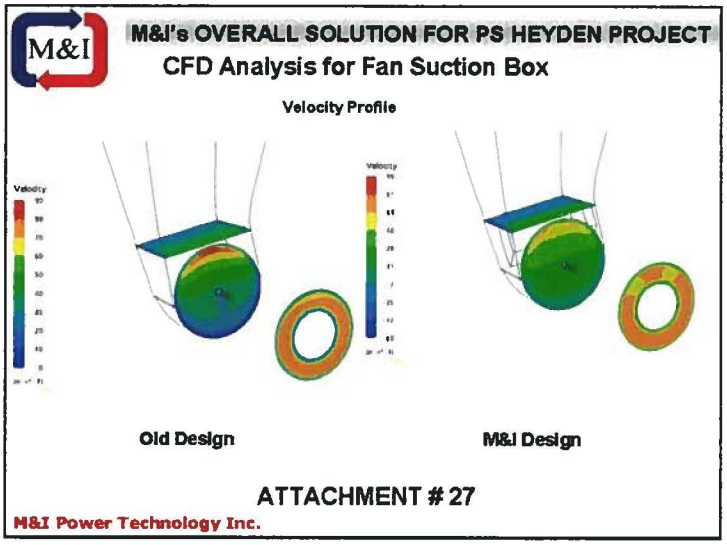
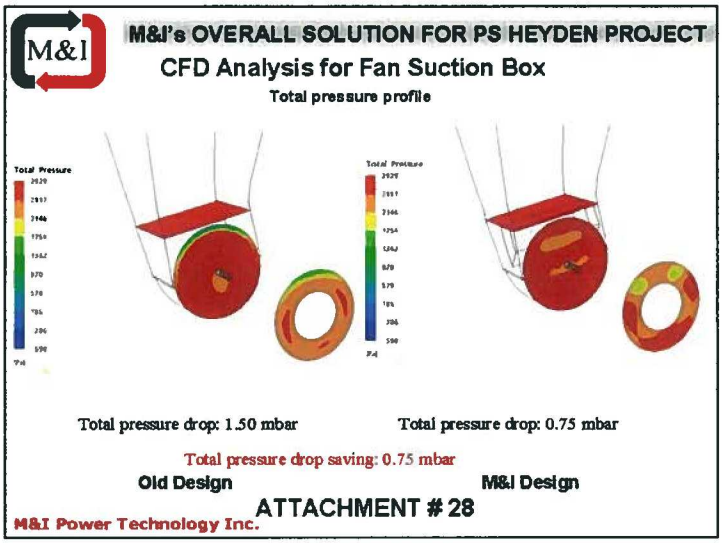
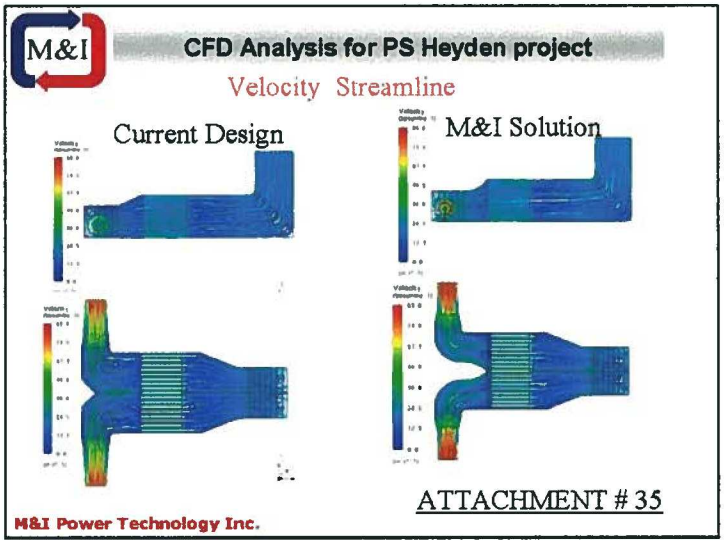
M&I Power Technology Inc.


M&I
M&I's OVERALL SOLUTION FOR PS HEYDEN PROJECT
CFD Analysis at ESP Inlet Transition
Total pressure profile
Total Pressure
B
A
Total pressure drop (A-B): 2.95 mbar
Total pressure drop (A-B): 2.45 mbar
Total pressure drop saving (A-B): 0.50 mbar
Old Design
M&I Design
ATTACHMENT # 16
M&I Power Technology Inc.


CFD Analysis for PS Heyden project
ID Fan Intake System
Total Pressure Streamline
ATTACHMENT # 23 & 24
M&I Solution
Total Pressure Drop : 3.95 mbar
Total Pressure Drop : 4.45 mbar
M&I Design
Existing Design
M&I Power Technology Inc.


M&I's OVERALL SOLUTION FOR PS HEYDEN PROJECT
CFD Analysis for Fan Suction Box
Velocity Profile
Old Design
M&I Design
ATTACHMENT # 27
M&I Power Technology Inc.


M&I
M&I's OVERALL SOLUTION FOR PS HEYDEN PROJECT
CFD Analysis for Fan Suction Box
Total pressure profile
Total pressure drop: 1.50 mbar
Total pressure drop: 0.75 mbar
Total pressure drop saving: 0.75 mbar
Old Design
M&I Design
ATTACHMENT # 28
M&I Power Technology Inc.


M&I
CFD Analysis for PS Heyden project
Velocity Streamline
Current Design
M&I Solution
ATTACHMENT # 35
M&I Power Technology Inc.

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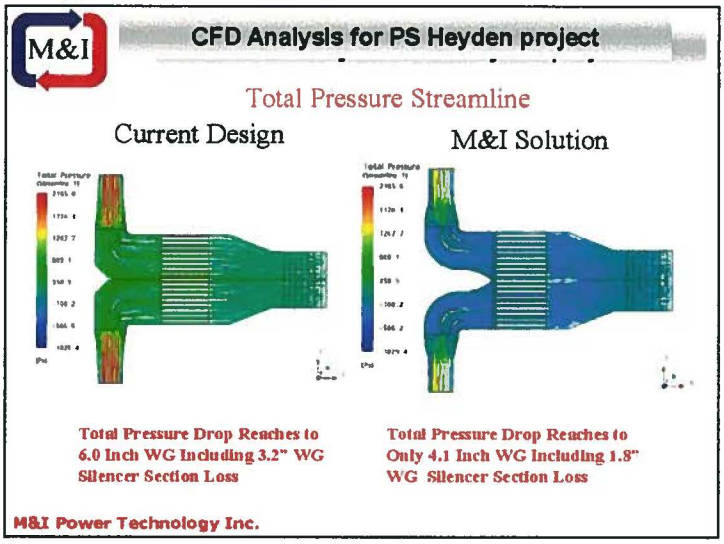
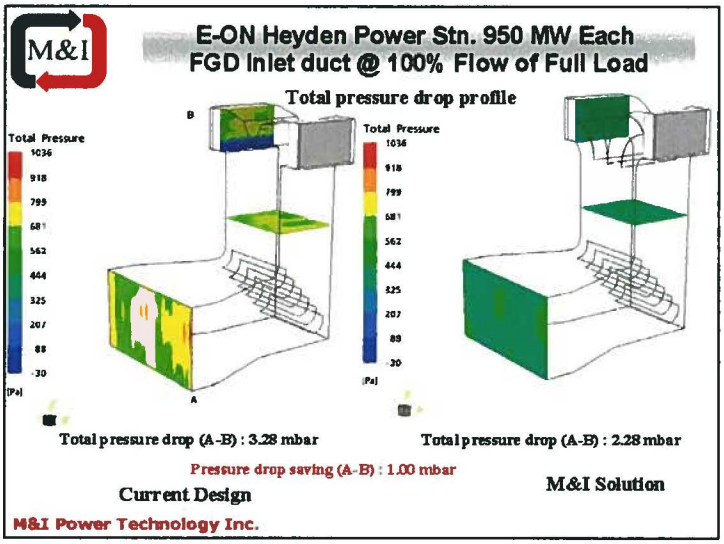

M&I
CFD Analysis for PS Heyden project
Total Pressure Streamline
Current Design
M&I Solution
Total Pressure Drop Reaches to 6.0 Inch WG Including 3.2" WG Silencer Section Loss
Total Pressure Drop Reaches to Only 4.1 Inch WG Including 1.8" WG Silencer Section Loss
M&I Power Technology Inc.


M&I
E-ON Heyden Power Stn. 950 MW Each
FGD Inlet duct @ 100% Flow of Full Load
Total pressure drop profile
Total Pressure
1036
918
799
681
562
444
325
207
88
-30
[Pa]
B
A
Total pressure drop (A-B) : 3.28 mbar
Total pressure drop (A-B) : 2.28 mbar
Pressure drop saving (A-B) : 1.00 mbar
Current Design
M&I Solution
M&I Power Technology Inc.

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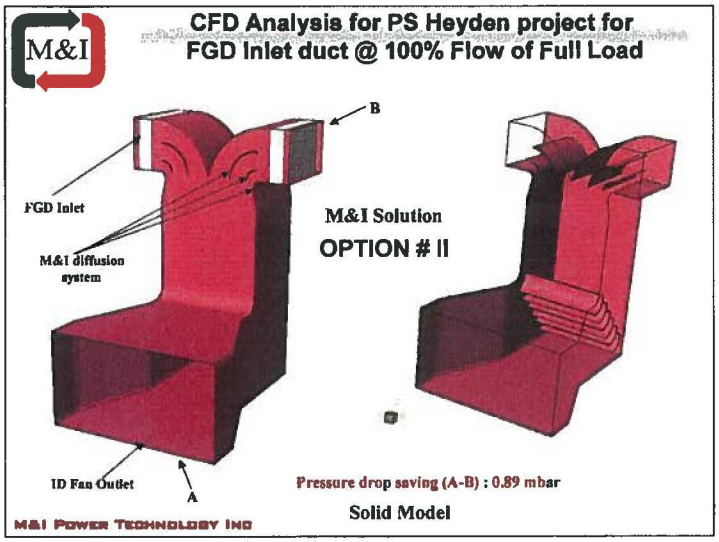
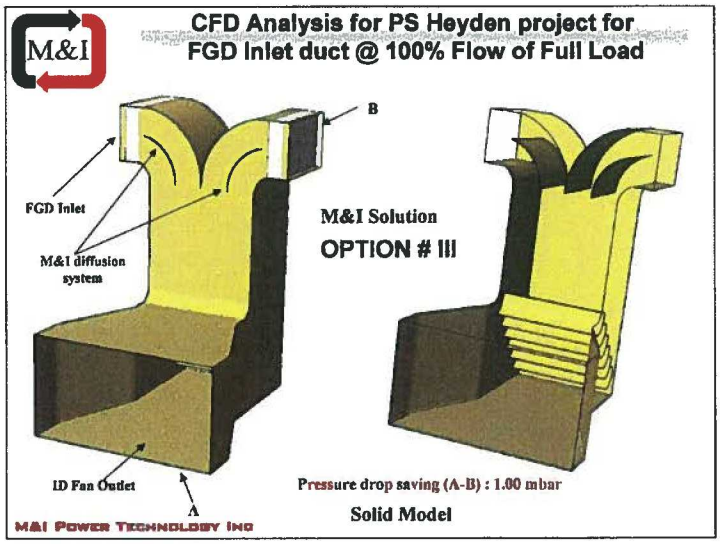
E-ON – Heyden Power Station 950 MW Each
SCR Inlet Modification Different Option offered by M&I





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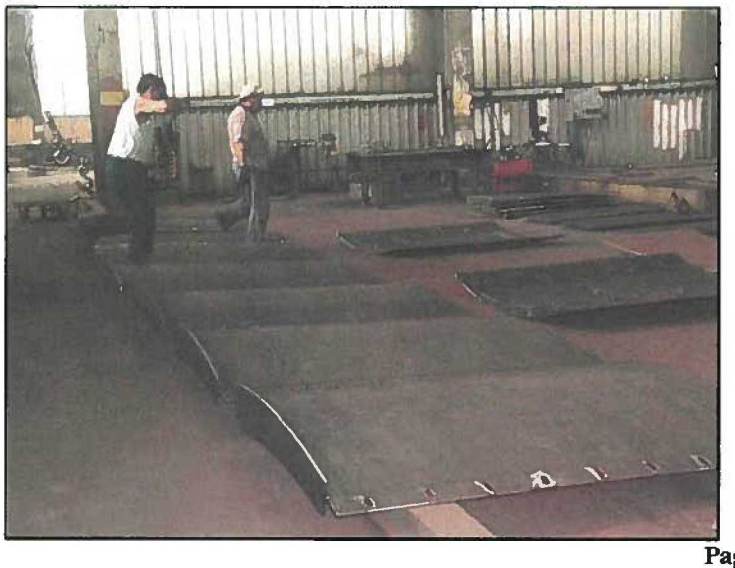
Client: Heyden Power Station, E-ON, Germany.

M&I is offering Aero-acoustic solution for SCR Inlet, Air Pre Heater System, ESP Inlet, ESP Inlet Transition, Fan Suction Box, and ID Fan Discharge Duct





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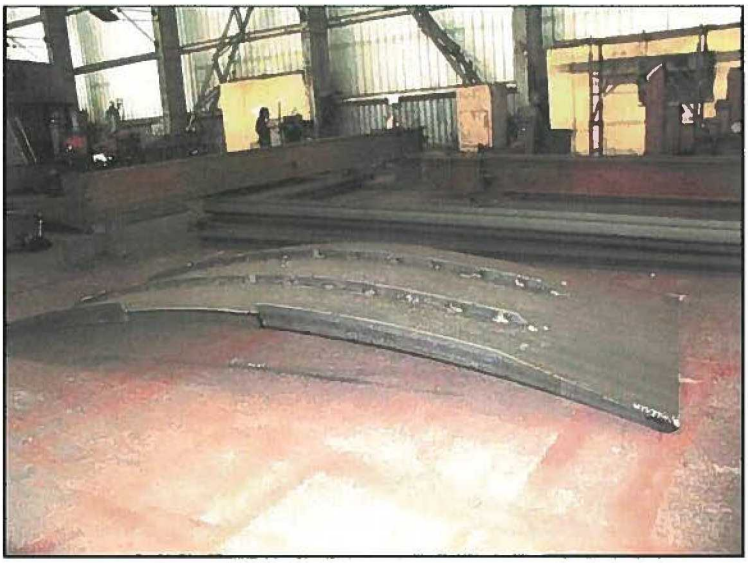

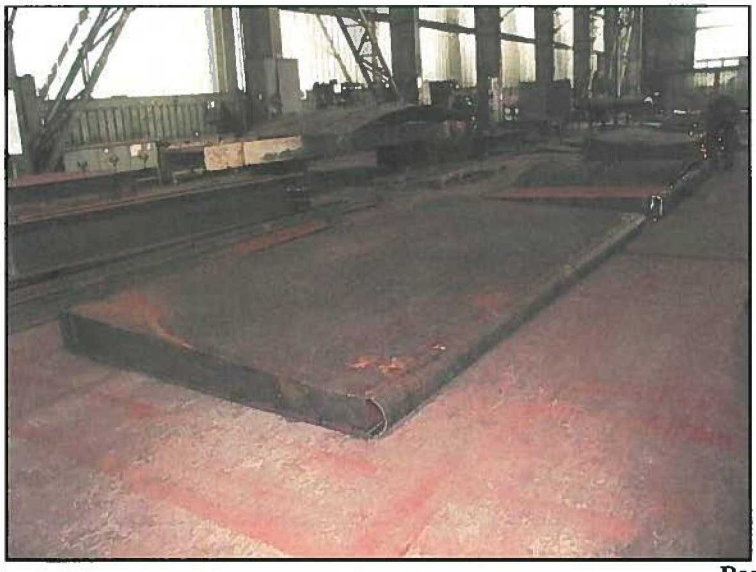

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APPENDIX B

Commercial Proposal For:

FD Fan Inlet & Discharge Ductwork Modifications To Eliminate Flow Induced Vibration And Capacity Bottleneck At the Holyrood Thermal Generating Station

Quotation #: P09-001



Techno-Commercial Proposal

For

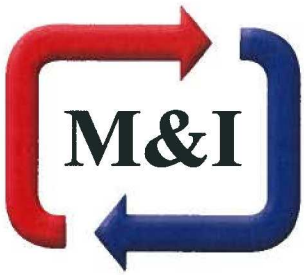
FD Fan Inlet & Discharge Modifications to eliminate flow induced vibrations and capacity bottleneck

At

Holyrood Generating Station

Submitted to:

NEWFOUNDLAND AND LABRADOR HYDRO
ST. JOHN'S, NEWFOUNDLAND



M&I Power Technology, Inc.
2145 Meadowpine Blvd. Mississauga,
Ontario, Canada, L5N 6R8

02/12/2009

February 12,2009

Newfoundland and Labrador Hydro
Holyrood Generating Station
Duff's Road, Holyrood
NL A0A 2RD

SUB: Quotation for CFD analysis & Modification to FD fan Inlet & Discharge Duct.

Dear Sirs,

At the outset I would like to thank you for the courtesy extended to our engineer Vladimir Eline. We also appreciate the opportunity to provide you with the proposal for the modifications of FD fan inlet and discharge duct to eliminate flow induced vibration problem and debottlenecking of fan capacity limitation. In view of long business relations with your esteemed organization, we had no hesitation in carrying out preliminary CFD analysis worth $ 10,000 free of cost to evaluate flow condition inside the FD fan inlet and discharge duct responsible for vibration and turbulence. Refer "Synopsis" segment of the proposal showing CFD results of the existing duct.

Attached is our techno-commercial proposal & general arrangement drawing showing proposed modification areas. We have diligently worked on the proposal based on the information collected by our engineer. Most of our modifications are at the strategic locations where maximum benefits exist in the above draft system. We propose modules to be retrofitted at those locations only. We are also envisaging some outside duct modifications, which can be easily carried out at site..

M&I 's aerodynamic diffusers offer reduction in the vibration and FD fan performance improvement by virtue of reduction in pressure drop in inlet and discharge duct. Estimated savings are enumerated below for review:

- **Expected Pressure drop Reduction/ Savings in FD fan Inlet Duct: 1.5" W.G.**
- **Expected Pressure drop Reduction/ Savings in FD fan Outlet Duct: 2.0" W.G**
- **Minimal flow induced vibrations in the ducts.**

M&I Power Technology Inc.
2145 Meadowvale Blvd. Mississauga, ON L5N 6R8 Canada
Ph +1 (416) 637-0305/0300 Fax +1(416) 623-5496

* All Concepts and Designs outlined in this document remain the property of M&I Power Technology and shall not be used for any purpose other than to evaluate the application of the company's technology for the addressee's project

At this time we are open to help us to work to gather with you on this project.

We now look forward to hear from you to proceed further in the matter. In case you need further clarification, please feel free to contact me.

Thanking you and assuring you of our best services at all times.

Best regards,

Pradeep Gaur, P.Eng.
President
M&I Power Technology Inc.

M&I Power Technology Inc.
2145 Meadowvine Blvd, Mississauga, ON L5N 6R8 Canada
Ph +1 (416) 637-0305/0300 Fax +1(416) 623-5496

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CONTENTS

Section 1 : **Introduction to M&I /Company profile**

Section 2 : **Synopsis**

Section 3 : **Scope of Work**

Section 4 : **Limit of Supply & Exclusion**

Section 5 : **Design Basis**

Section 6 : **Performance Parameters & Guarantees**

Section 7 : **Price Schedule**

Section 8 : **Drawing**

M&I Power Technology Inc.
2145 Meadowine Blvd. Mississauga, ON L5N 6R8 Canada
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Section 1

COMPANY PROFILE

M&I Power Technology Inc.,
2145 Meadowvale Blvd. Mississauga, ON L5N 6R8 Canada
Ph +1 (416) 637-0305/0300 Fax +1(416) 623-5496

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M&I Power Technology, Inc.
Corporate Profile

Incorporated in 1981, M&I and it's various divisions, is an applied R&D oriented company. The company's origin was in niche technologies serving primarily the HVAC Industry. M&I's core competence is in Aero-acoustic Principles, which offers reduction of horsepower, noise and vibration.

M&I developed numerous products in the air movement field, especially vane axial and centrifugal fan systems, and has been able to improve the overall system efficiency, utilizing flow field technology. Many other associated products were developed in the air moving technology, which can be found on our website: www.miair.com.

M&I has grown steadily and profitably over the last 20 years and is represented throughout the United States, Europe and Canada through an established network of manufacturer's representatives. M&I group operates its HVAC business through M&I Heat Transfer Products Ltd. and flow solutions for power and process industries (i.e. boilers, HRSG, Gas Turbine, Steel, Pellet, Cement, Aluminum, etc.) through M&I Power Technology Inc. M&I Power offers expertise in the areas of flow control, draft loss reduction, furnace combustion performance analysis & optimization and efficiency improvement of rotating & stationary equipments used in Power, Cement, Steel, Pellet & other Process industries. Our website: www.mipowertechnology.com.

The engineering, manufacturing and procurement aspects of the Company are well-proven, yet flexible to meet the specific demands on a project-by-project basis. For example, engineering is done in-house or sub-contracted as needed to meet schedules and remain competitive. Alliances and relationships are formed with industrial experts, scientists, and engineers from reputed consulting firms and universities to add new approaches. Procurement is done both locally or internationally, as the Project dictates. Manufacturing is similarly flexible with core/ critical components being manufactured in North America and other scope competitively sub-contracted, but always under M&I Project control.

Leadership innovation and technology (with the latest advances in Computational Fluid Dynamics and 3-D engineering modeling and analysis) to solve customer problems and offer effective solutions is what drives M&I and separates it from it's competition. M&I's various products are thus a secondary means to affect and satisfy this goal. M&I has been awarded 30 Patents in aero-acoustics with an additional 9 pending.

M&I's corporate goals and culture go beyond the best engineering tools and technology. The real capital of M&I is the talented personnel, which has been developed in a conducive environment, leading to excellence. M&I's goal/ objective goes far beyond the traditional shipment of components and accepting warranty obligations to taking complete functional and design responsibility of all the systems that M&I manufactures and puts to beneficial use.



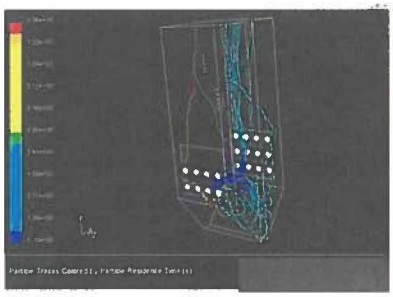
M&I Corporate Office in Mississauga, Canada



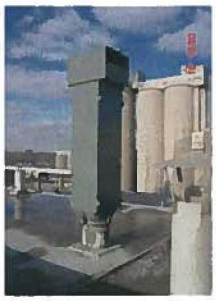
M&I's Exhaust Stack Installation at TransCanada Pipelines site



M&I's FD Fan Inlet Ducting for B&W, Coleson Cove, NB



M&I's 3D Modeling for Furnace Combustion Process



M&I's Baghouse Fan Exhaust Silencer for St. Lawrence Cement, Canada



M&I's Air Intake/ Silencer Ducting for FR 7EA G.T.

Section 2

SYNOPSIS

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SYNOPSIS

M&I has carefully analyzed FD fan inlet duct and discharge duct between fan outlet and Steam coil air heater (SCAH) to identify potential reasons for flow induced vibration and fan capacity curtailment. Based on site visit by M&I Engineer and the information collected / received from plant, M&I carried out a preliminary CFD analysis to map flow behavior inside the upstream and downstream duct of the FD fan. Based on the results of CFD findings, M&I is submitting a proposal for modification of the above segment using their state of the art aerodynamic diffusers to achieve lower pressure loss and elimination of flow stratification and turbulence. To develop an efficient manufactured solution, M&I needs to carryout an advanced CFD analysis. This activity will only be carried out after placement of the order. However preliminary analysis gave us good indication of problems in the system.

It is quite evident from the CFD pictures attached below that there are very high velocity hot spots in the certain portion of the duct combined with local flow separation in the certain areas of the duct causing flow recirculation. Drastic change in velocity distribution across duct cross section resulting in high fan entry loss and poor fan blade loading. Moreover fan is operating at very high flow rate (165 kg/sec/fan) resulting in very high velocity magnitude creating flow induced vibrations. It is very important to eradicate those high velocity hotspots through aerodynamic diffusions by bring dynamic pressure values close to area average velocities from mass average velocities. Further pressure regains needs to be achieved at fan discharge to minimize unproductive velocity pressure responsible for high backpressure and loss across steam coil air heater.

M&I 's proposal comprises of internal modifications and some external modifications to the one side of inlet and discharge duct.:

M&I would propose state of the art aerodynamics diffusion system and long turning vanes to eliminate flow abnormalities like local flow separation, turbulence and eddy's. Utmost care is given to understand flow behavior and insertion of suitable shape diffusers to achieve proper flow diffusion.

Please refer attached schematic drawing #P09-001-001 showing indicative areas (final modifications to be confirmed by detailed CFD analysis) of modifications proposed by M&I(suitable diffusers will be designed & developed to retrofit at those locations) to achieve lower draft loss and pressure drop savings. Indicative pressure drop savings to be achieved by M&I modifications are given below:

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RESULTS AT A GLANCE:

Expected Pressure drop Reduction/ Savings in FD fan Inlet Duct: **1.5" W.G.**

Expected Pressure drop Reduction/ Savings in FD fan Outlet Duct: **2.0" W.G**

Above reduction in pressure drop will give appx. **15-16%** reduction in fan horse power (if fan efficiency does not change at lower static pressure) or **8-10 kg/sec/fan (5%)** more air.

Lower flow induced vibrations: Flow stratification causes flow induced vibration. M&I's aerodynamic diffusers will streamline flow inside the duct and at fan inlet and at SCAH inlet. ..

We also confirm high quality of manufacturing and stringent quality / inspection norms. Every aspect like transient loads, combination loads, are considered in the design criteria of the system. Our manufacturing process confirms to CSA/ equvt. standards.

Efficiency, quietness and reliability is a standard for M&I products. Our approach to the total solution to air and plant draft systems and knowledge sharing culture are the strengths of our organization.

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Proposal: Holyrood Generating station FD fan duct modifications
Client: Newfoundland & Labrador Hydro, NL
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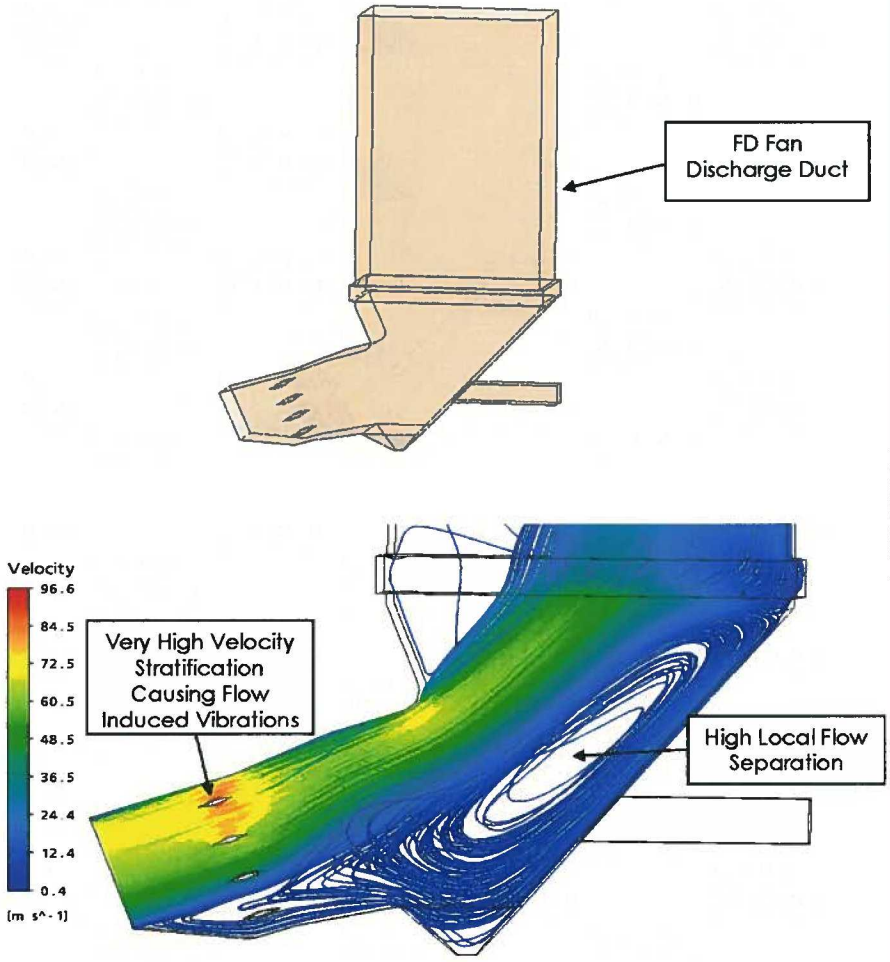
CFD RESULTS OF EXISTING DUCT:



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Proposal: Holyrood Generating station FD fan duct modifications
Client: Newfoundland & Labrador Hydro, NL
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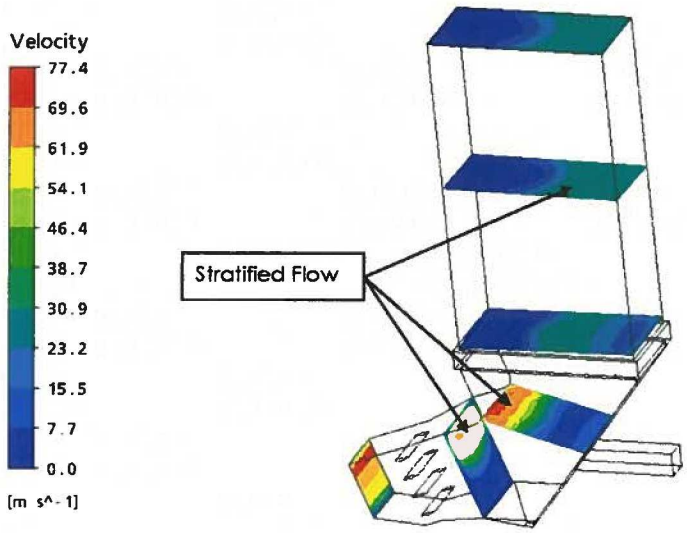

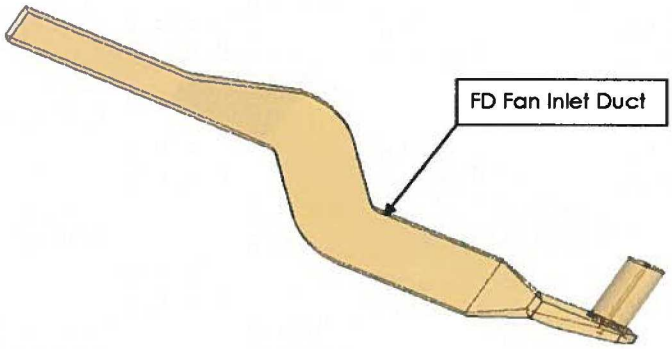

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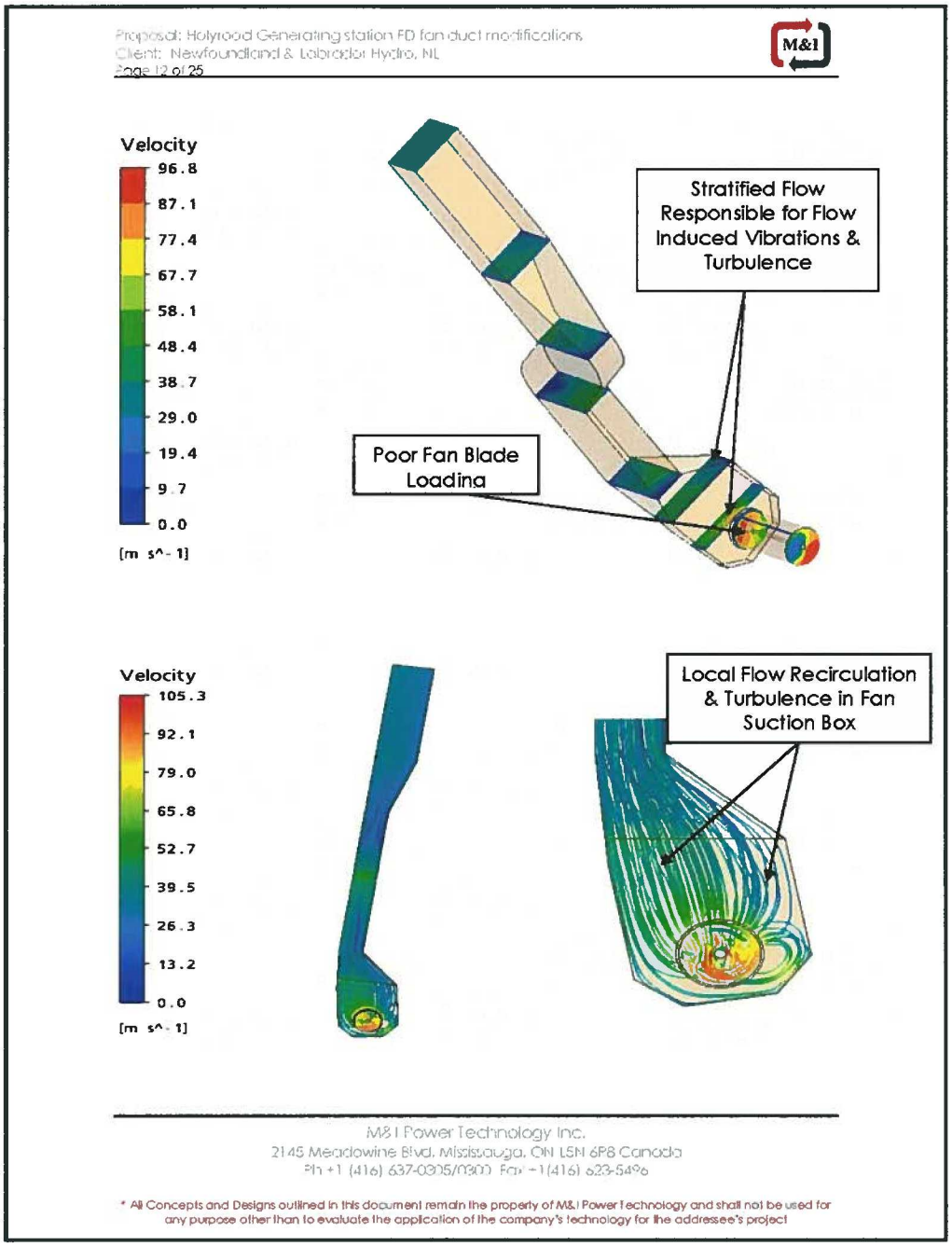
Proposal: Holyrood Generating station FD fan duct modifications
Client: Newfoundland & Labrador Hydro, NL
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M&I
Velocity
96.8
87.1
77.4
67.7
58.1
48.4
38.7
29.0
19.4
9.7
0.0
[m s^-1]
Stratified Flow Responsible for Flow Induced Vibrations & Turbulence
Poor Fan Blade Loading
Velocity
105.3
92.1
79.0
65.8
52.7
39.5
26.3
13.2
0.0
[m s^-1]
Local Flow Recirculation & Turbulence in Fan Suction Box
M&I Power Technology Inc.
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Section 3

SCOPE OF WORK

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SCOPE OF WORK

CFD Analysis, Design, Engineering and Supply of carbon steel internal diffusers (same as existing duct material)

M&I will supply diffusers & long turning vanes (internals) to be integrated inside the FD fan inlet & discharge duct. At couple of places there will be local outside duct modification, which is feasible to carry out under present circumstances. M&I will fabricate complete internal diffusers/vanes (as shown in the **Dwg # P09-001-001**) and partial external modifications. Broad scope includes

- 3/16" / ¼" thick carbon steel (same material as the existing duct) Single / double walled diffusers..and outside duct wall.
- New expansion joint near fan suction box
- Associated Frames and hardware to hold internal diffusers
- Diffusers and external wall modification is 100% seal welded. .
- Required hardware including bolts, nuts, washers and gaskets (wherever necessary) at interfacing point.
- Stiffeners, wherever applicable
- Inspection during manufacturing stage as per M&I standard practice.

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Section 4

LIMIT OF SUPPLY AND EXCLUSION

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LIMIT OF SUPPLY:

- ***Internal & some external modifications to existing duct an extent to meet pressure drop saving values as mentioned in the above scope of work.***

EXCLUSION:

- Foundation, anchor bolts, nuts, washers and leveling hardware.
- Unloading, forwarding, and storage of equipment at job site.
- Dismantling, Installation, start-up, testing, commissioning, utilities and consumables.
- Insulation if any
- Structural support, ladder, grating.
- Plant and equipment lighting.
- Lighting arrestors and grounding system, Fire protection and detection system.
- Site leveling and grading.
- Control and Power cables, Supply of AC or DC power.
- Dampers.
- Third party inspection.
- Emission probes.
- Any statutory clearance.
- Any item not specifically mentioned in our scope

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Section 5

DESIGN BASIS

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DESIGN BASIS:

Design pressure:

- FD fan Downstream duct : - 10 /+ 30 " WG
- Design air temperature : 40 deg C

Operational Condition at Rated load:

- Air Temperature at FD inlet: : 30 deg C
- T Air Flow from one FD fan : 165 kg/sec
- Duct/diffuser Corrosion allowance : 1/16"
- Maximum Velocity inside the duct : 4000 FPM

SITE DATA:

Site location	: Holyrood Generating Station, NL
Site Elevation	:
Ambient temp	
Maximum	: Not Available
Minimum	: Not Available
Design Relative Humidity	: Not Available
Design Ambient Pressure	: 14.03 psia
Max. Rainfall Intensity	: Not Available
Max. Wind Velocity	: Not Available
Seismic Zone Factor	: Low intensity – assumed
Ground Snow Load/Exp. Coeff.	: Not Available

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Design Philosophy:

While designing internal diffusers, long turning vanes and fan discharge diffuser duct , following design considerations were considered

Loads are considered as force applied to support structure'

- For primary load calculations, all loads are considered separately
- Duct internals are designed for transient air heater upset condition

Internal diffusers, turning vanes provided at various locations inside the FD fan duct will be thoroughly checked for structural integrity as well as retained adequately with duct walls.

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Section 6

PERFORMANCE PARAMETERS

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PERFORMANCE PARAMETERS & GUARENTEES:

Performance Guarantees:

Expected flow improvement in air flow: each side **8-10 Kg/sec**

Expected Pressure drop Reduction/ Savings: **3.5" W.G.**

Tolerance:

- Pressure drop: +/- 2.5%

Basis:

Air Temperature at A/H outlet:	30 Deg C
Total Air Flow / fan :	165 kg/sec

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Section 7

PRICE SCHEDULE

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PRICE SCHEDULE:

1) **CFD analysis for developing solution: C$ 25,000**

2) **Design, engineer, manufacture & supply**
Of internal diffusers , expansion joint, ; C$295,000 for 2 fans
External one side duct wall for FD
Fan inlet & discharge duct as per enclosed
scope of supply and dwg # P09-001-001

Price Basis:

- Price includes transportation of diffusers to Holyrood site.
- Does not include dismantling, installation and commissioning
- Includes supervision of diffuser installation
- Above price is in Canadian funds

VALIDITY:

Our quotation is firm and valid for 60 days from the date of the submission.

TERMS OF PAYMENT:

25% as advance along with Purchase Order

25% payment against submission of revised CFD analysis, design and drawings.

40% against dispatch of complete system net 15 days

10% on successful completion of Erection and commissioning

DELIVERY:

To be mutually agreed upon to meet project schedule.

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Section 8

Drawings

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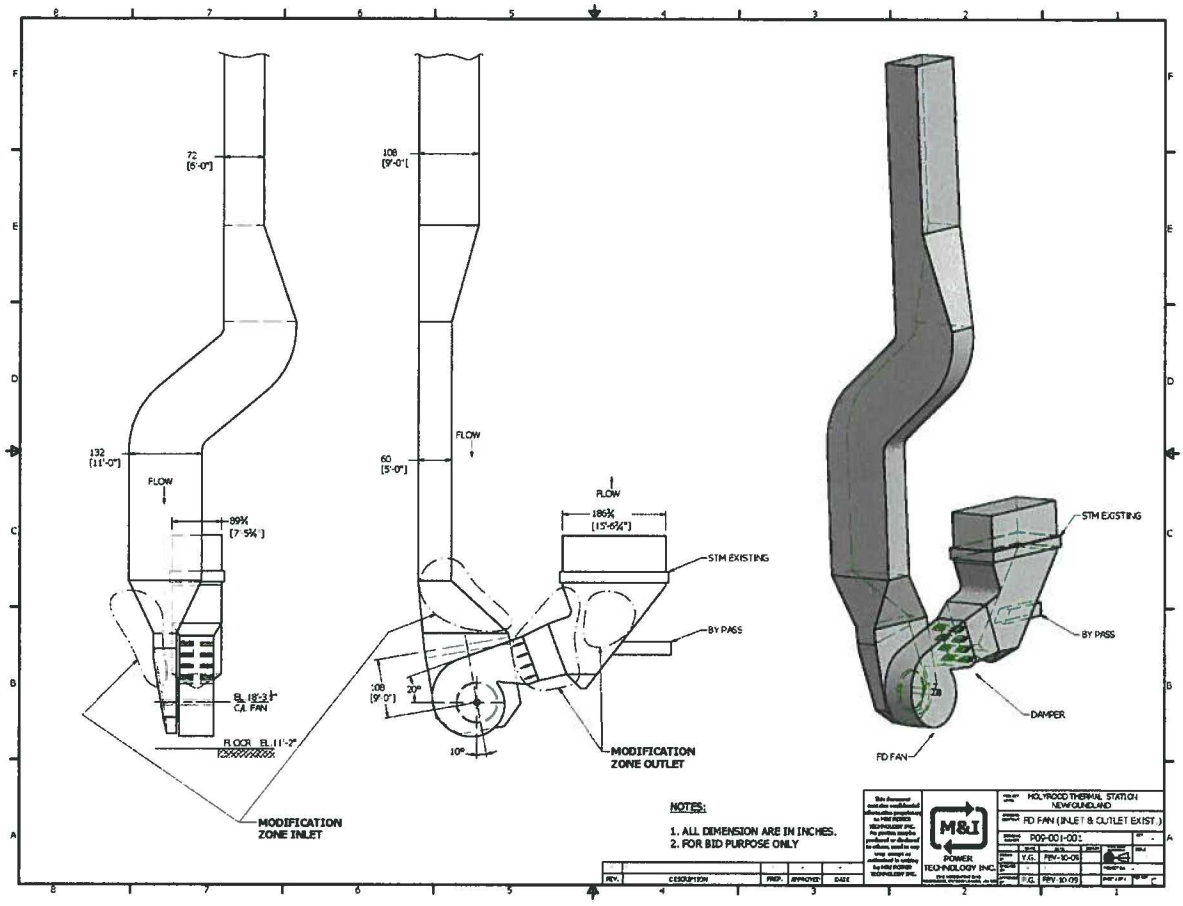
72
[6'-0"]
132
[11'-0"]
FLOW
89¾
[7'-5¾"]
EL 18'-3"
C.L FAN
FLOOR EL 11'-2"
MODIFICATION
ZONE INLET
108
[9'-0"]
60
[5'-0"]
FLOW
108
[9'-0"]
20°
10°
FLOW
186¾
[15'-6¾"]
STM EXISTING
BY PASS
MODIFICATION
ZONE OUTLET
STM EXISTING
BY PASS
DAMPER
FD FAN
NOTES:
1. ALL DIMENSION ARE IN INCHES.
2. FOR BID PURPOSE ONLY
M&I
POWER
TECHNOLOGY INC.
HOLYROOD THERMAL STATION
NEWFOUNDLAND
FD FAN (INLET & OUTLET EXIST.)
P09-001-001
REV. 10-08
REV. 10-09

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

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

REPLACE UNIT 3 RELAY PANELS

Holyrood Thermal Generating Station

April 2010

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

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



Figure 1: Holyrood Thermal Generating Station

The electrical interlock controls for Unit 3 are composed of 167 electromechanical relays that are installed in one large three compartment enclosure commonly referred to as the Unit 3 Relay Panels. The hardwired controls contained within these panels allow either the

manual or automatic operation of all motors, drives and valves installed on Unit 3. As a result of several modifications that were made to these circuits since they were installed in 1978, the panels that contain these relays have become overcrowded to the point where the panel doors can no longer be closed. The condition of these panels is considered by the plant as being a significant safety hazard and a potential point of failure that could result in an outage on Unit 3.

2 PROJECT DESCRIPTION

The project is required to replace the existing hardwired relay logic infrastructure contained in the three relay panels on Unit 3 with a distributed control system (DCS) that will allow more dependability and better operator control functionality. The installation will be completed by removing the existing field wiring that terminates inside the existing relay panels. A new junction box will be installed to house the cabling required for the existing DCS control to remain functional. A new electrical enclosure containing all the required DCS hardware will be installed at the existing location and the field wiring will be re-terminated inside the new DCS control panels. The existing hardwired relay logic will be converted to a software based operating logic that will allow the system to function as it currently does. This new DCS hardware will be an expansion to the existing Foxboro DCS control system and will offer all the benefits of having a single reliable control system operating the entire plant. This will result in an ergonomically acceptable enclosure layout that will be more reliable and safer to maintain.

3 EXISTING SYSTEM

The existing Unit 3 Relay Panels consist of a three section panel or electrical enclosure that is located inside the Stage Two Relay Room in Holyrood (see Figure 2). This panel makes up the control logic section of the plant interlock system and controls the operation of most motors, valves and drives associated with generating Unit 3.

The purpose of this panel is to house the relays, pneumatic timers, current transducers and terminal blocks that interface the Holyrood Central Control Room controls to the field mounted equipment that monitors and controls the generating unit. It also houses various relays that provide the existing automated systems with remote feedback indication. It serves as an interface panel for equipment that was incorporated into the Foxboro DCS in 2004.

The Unit 3 Relay Panels have become a major safety and operational concern as these panels are overloaded and crowded. The problem of overcrowding has escalated to the point where the enclosure equipment doors can no longer be closed. Figures 3, 4 and 5 are pictures showing the amount of wiring contained in each of the three sections of this panel. Figure 6 shows how each of the enclosure doors are prevented from closing by the excess wiring contained inside each enclosure. A custom made plexiglass cover was installed in 2005 to prevent personnel working in the area from accidentally contacting energized electrical sources (see Figure 7). This plexiglass cover also prevents anyone from trying to close the doors on this cabinet which could possibly result in a wire being pulled out of a terminal block resulting in a unit outage.

The physical condition of the terminal blocks inside these panels have deteriorated and are no longer acceptable. These compression type terminal blocks have become brittle and

have the tendency to crack whenever maintenance crews tighten them. In some cases, the bases of several of these blocks have cracked leaving these terminal blocks no longer connected to the mounting rail that is used to support them inside the cabinet (see Figure 8). As a result, several terminal blocks that contain energized conductors are often left hanging inside the panel risking exposure to anyone working on the control system.



Figure 2: Unit 3 Relay Panels

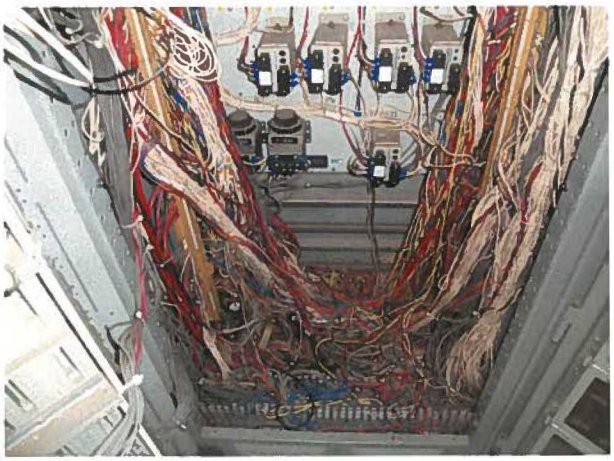

Figure 3: Unit 3 Relay Panels – Compartment 1 of 3

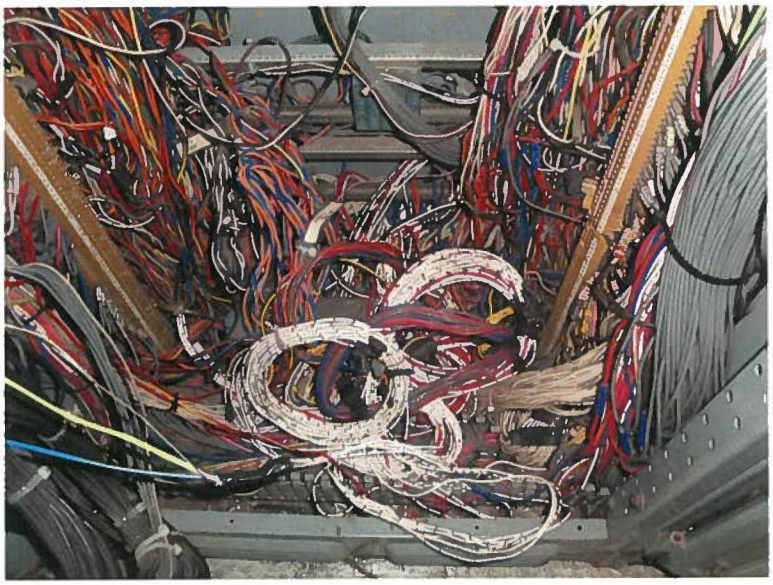

Figure 4: Unit 3 Relay Panels – Compartment 2 of 3

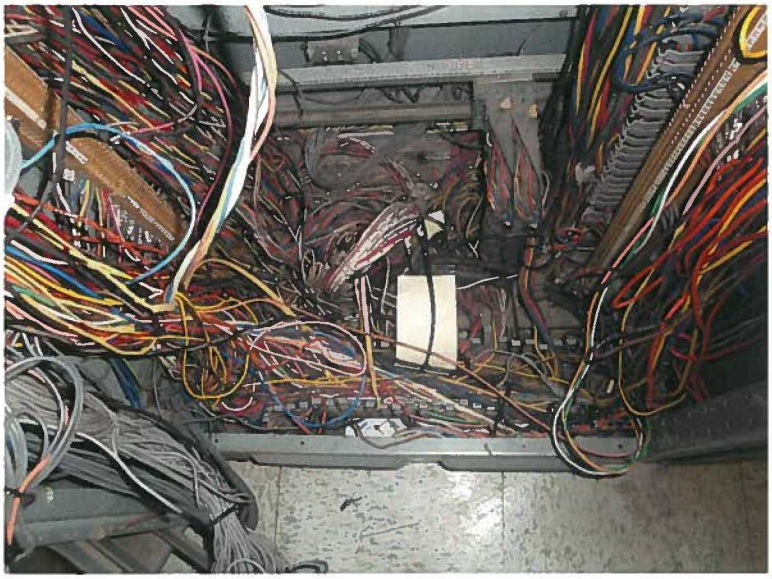

Figure 5: Unit 3 Relay Panels – Compartment 3 of 3



Figure 6: Unit 3 Relay Panels – showing doors prevented from closing



Figure 7: Unit 3 Relay Panels – showing temporary plexiglass cover

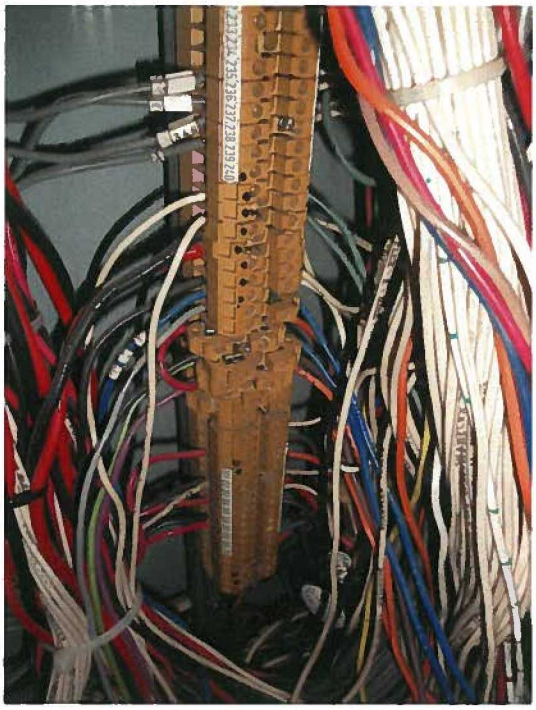

Figure 8: Unit 3 Relay Panels – showing poor condition of terminal blocks

3.1 Age of Equipment or System

The Unit 3 Relay Panels were installed in 1978 and commissioned in the spring of 1979 when Stage Two came on line.

3.2 Major Work and/or Upgrades

There have been no major upgrades to the existing Unit 3 Relay Panels since they were installed in 1978. There have been, however, additions to this panel over the years that have caused overcrowding to the point that the enclosure doors will no longer close. These additions include the installation of several motor current transducers in 1993 when the original Unit 3 control system was converted to a Westinghouse DCS. There have also been other minor operating logic changes and alarm installations since 1993.

In addition, in 2004, the plant changed the Westinghouse DCS into a Foxboro DCS platform. At that time, several relays were removed from this panel and placed in the DCS logic. As a result of this upgrade, new cables had to be installed and terminated in these cabinets making the cabinets overcrowded and untidy.

3.3 Anticipated Useful life

The Unit 3 Relay Panels is composed mainly of terminal blocks, electromechanical relays and timers that have an estimated life span of 25 years.

3.4 Maintenance History

Hydro does not separately track maintenance costs for the relay panels. Maintenance costs for the Unit 3 Relay Panels are included in the costs of other electrical systems.

3.5 Outage Statistics

There have been no outages directly related to the Unit 3 Relay Panels. However, as this panel serves as one of the main interface panels to the existing DCS and the plant equipment, due to the current condition of the panel and the overcrowding of wires, the panel is considered by Hydro to be a major risk that could lead to an outage on Unit 3.

3.6 Industry Experience

The industry standard is that every electrical enclosure should be designed and sized to allow for safe access and easy troubleshooting of individual electrical components to enable performance, reliability, and maintainability of any electrical system.

Utilities are upgrading the older relay based electrical control systems to programmable or distributed logic control systems. These newer systems offer fault tolerant designs that can remain operational despite a single point fault failure. In addition, they have a smaller footprint design, provide easier maintenance and allows for future logic changes without having to make wiring changes.

3.7 Maintenance or Support Arrangements

The Unit 3 Relay Panels are maintained by Hydro. In the event of a failure, there are currently no maintenance or support arrangements in place to provide assistance on the existing control system. However, after this upgrade, the existing service agreement with Invensys Systems (Foxboro) will cover the new control system for continued operational support. Hydro personnel will have unlimited access to the Foxboro system support program, remote system support, and ten hours of on site support per year as well as

reduced training cost benefits.

3.8 Vendor Recommendations

Invensys Systems, the manufacturer of the existing plant wide DCS control system, recommends replacing the Unit 3 Relay Panels by moving the hardwired logic into the existing plant DCS platform.

3.9 Availability of Replacement Parts

Replacement parts are readily available for the existing Unit 3 Relay Panels.

3.10 Safety Performance

The Unit 3 Relay Panels are considered by Hydro as being a significant safety hazard. The sub standard condition of these panels resulted in the submittal of a safe workplace observation program (SWOP) condition. The results of the investigation into this condition revealed that the panels contain sub-standard or poor wiring that present shock hazards to personnel working inside these panels. It also revealed that the amount of wiring located inside these panels will impede or delay future maintenance.

Rule number 2-118 of the Canadian Electrical Code states that "Electrical equipment shall be installed as to ensure that after installation there is ready access to nameplates and access to parts requiring maintenance". Rule number 12-3034 (2)(a)(ii) of the Canadian Electrical Code states that enclosures identified shall be only permitted to be used as junction boxes "where wiring is being added to an enclosure forming part of an existing

installation and the conductors, splices and taps do not fill the wiring space at any cross section to more than 75 percent of the cross sectional area of the space". Rule 11.2.1.1 of the National Fire Protection Association (NFPA) 79 Electrical Standard for Industrial Machinery states that "All items of control equipment shall be placed and oriented so that they can be identified without moving them or the wiring." Rule 11.2.1.2 of this same code states that terminal blocks shall be mounted to provide unobstructed access to the terminals and their conductors. As a result of these deficiencies, it is evident that the condition of the Unit 3 Relay Panels does not meet Canadian Electrical Code or other electrical standards and is thus a potential safety hazard to anyone working inside these enclosures.

In addition to the code deficiencies outlined above, the physical condition of the terminal blocks located inside the panels have deteriorated and are no longer acceptable. These compression type terminal blocks have become brittle and have the tendency to crack whenever maintenance crews tighten them. In some cases the bases of several of these blocks have cracked leaving these terminal blocks no longer connected to the mounting rail that is used to support them inside the cabinet. As a result, terminal blocks that contain energized conductors are often found floating inside the panel risking exposure to workers.

The plant standard for Electrical Equipment Enclosures (standard MSTD-059) states that enclosures shall be National Electrical Manufacturers Association (NEMA) 12 rated or greater when installed in any area of the plant not exposed to damp or corrosive environments. NEMA 12 is a standard from the National Electrical Manufacturers Association, which defines enclosures with protection against dirt, dust, splashes by non-corrosive liquids, and salt spray. The panels do not meet this requirement, since the doors of the enclosures will no longer close. As a result, air borne dust, fibers or splashing water is free to enter these enclosures. In addition, since the doors of these enclosures no longer

close, if an electrical fire was to occur inside these panels, it would spread to the surrounding areas with the possibility of causing significant equipment damage and personnel injury or death. Although the plexiglass barrier does provide some additional protection, it is a temporary installation that does not meet Hydro standards.

3.11 Environmental Performance

There are no environmental issues associated with the existing relay panels.

3.12 Operating Regime

Unit 3 has the capability to operate in generation or synchronous condense modes. This unit operates predominately in the generation mode in the winter and in synchronous condense mode for summer months to provide voltage support to the Island Interconnected System.

The controls in the Unit 3 Relay Panels are vital to the operation of the generating unit whether it is in generation or synchronous condense mode. In addition, there are relays and wiring contained in this panel that monitor and control auxiliary functions of the turbine that are required even when the generating unit is not in service. The relay panels are essential to the daily operation of the plant whether or not Unit 3 is operating.

4 JUSTIFICATION

This project is justified on the need to replace sub-standard equipment and eliminate safety hazards. Unit 3 Relay Panels are overcrowded with wiring which prevents the doors from being able to close. There is a risk of an electrical fire occurring inside the panels that could spread to the surrounding areas of the plant leading to significant equipment damage and potential personnel injury or death.

There are several direct violations of the Canadian Electrical Code and other applicable standards pertaining to the condition of these panels. In addition, the plant maintenance personnel have identified the panels as an area of significant safety concern and expressed direct concerns about working inside these panels.

As a result of the age of these panels and the amount of wiring contained inside them, the terminal blocks that are used to terminate energized conductors inside the panel have become very brittle. This has lead to them cracking in the areas that hold the conductors and on the bases that hold the block to the mounting rail inside the panel. As a result, energized terminal blocks are hanging inside the panel. In addition, maintenance crews have also found non terminated energized conductors inside this enclosure.

Also, by integrating the relay controls into the existing DCS system, the future availability of Unit 3 will be improved. The Foxboro DCS control system offers a fault tolerant design and a redundant communication network that will continue to operate despite a single point failure. The proposed upgrade will also allow easier system troubleshooting after a failure and offers the advantage of being able to make future changes in software as opposed to

having to make physical wiring changes.

4.1 Net Present Value

A net present value analysis was not performed considering two alternatives. Please see section 4.3 'Cost Benefit Analysis' for details.

4.2 Levelized Cost of Energy

A levelized cost of energy analysis is not applicable since no new generation sources are being evaluated.

4.3 Cost Benefit Analysis

The following two viable alternatives were evaluated in a cost benefit analysis:

- Alternative 1: Replacement with DCS System. Replace the existing relay panels and relay logic with a new panel equipped with a DCS controlled system (total proposed capital cost of $830,700);
- Alternative 2: Replacement with Electromechanical Relays. Replace the existing relay panels and relay logic with a new relay panel equipped with electromechanical relays (total proposed capital cost of $676,500).

These two alternatives were evaluated using a cost benefit analysis. The analysis included the following assumptions:

- The study period for the cost benefit analysis is 25 years, (2012 to 2037).
- Electromechanical relays have an anticipated useful life of 25 years.
- The DCS option has an anticipated useful life of 15 years and carries an additional cost of $75,000 in year 2027 to replace any obsolete hardware after the 15 years.

- To assure that both alternatives are compared equally, it is assumed that 1/3 of the value remaining in the DCS system hardware to be installed in 2027 can be recovered at the end of 25 years (2037) since it has an anticipated lifespan of 15 years and has only been in service for ten years.
- $3,500 per annum is allowed for engineering to investigate electrical faults in the electromechanical relay alternative since there would be no single common plant wide control system equipped with Sequence of Events monitoring.
- $4,100 per annum after year ten is allowed for maintenance work in the electromechanical relay alternative.
- An extra $50,000 every ten years is allowed for completing wiring changes inside the electromechanical relay panels for major upgrades that require significant rewiring as opposed to simple logic changes required if the DCS alternative was installed.
- Electromechanical relays do not offer internal diagnostics that quickly indicate the source of a failure. In the event of an outage of unit 3 prior to 2020, as a result of an electromechanical relay failure, requiring the gas turbines to be dispatched for 15 hours would cause the cost benefit analysis to be in a virtual break even position. Using the average required gas turbine energy values for this period (637 MWh) it was determined that the incremental cost of fuel for gas turbine operation over the No. 6 Heavy oil which is burned in Holyrood, will result in an additional cost of $93,668 in the electromechanical relay option.

Using these assumptions, the results of the cost benefit analysis showed that the Electromechanical Relay Alternative is slightly more expensive over the 25 year anticipated useful life of the project. Figure 9 shows the results.

HRD relay panels Alternative Comparison *Cumulative Net Present Value* *To The Year* 2037		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
DCS Alternative	776,237	0
Electromechanical Relay Alternative	778,032	1,795

Figure 9: Cost Benefit Analysis 1 Summary Table

4.4 Legislative or Regulatory Requirements

As stated in rule 478(1) of the Newfoundland and Labrador Occupational Health and Safety Regulations 2009 "an electrical installation, equipment, apparatus and appliance shall conform to the requirements of the Canadian Electrical Code as adopted in the Electrical Regulations under the Public Safety Act". As a result of the existing Canadian Electrical Code deficiencies outlined in the safety performance section of this report, Hydro has decided that this installation should be brought up to standard.

4.5 Historical Information

There is no historical information associated with this proposal as there have been no similar replacements of the existing control systems.

4.6 Forecast Customer Growth

Forecast customer growth has no impact on this project.

4.7 Energy Efficiency Benefits

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

4.8 Losses during Construction

There will be no anticipated energy losses while upgrading the existing control systems. The electrical controls in the panels will be integrated into the Foxboro DCS during the planned annual outage.

4.9 Status Quo

The status quo relay based control system is not an acceptable alternative. Due to safety concerns with the existing system, the age and condition of the equipment, the relay panels need to be replaced.

4.10 Alternatives

When evaluating this project, Hydro has considered the following two alternatives:

- Replacement of the existing relay panels and relay logic with a new panel equipped with a DCS controlled system (total proposed capital cost of $830.7K);

- Replacement of the existing relay panels and relay logic with a new panel equipped with electromechanical relays (total proposed capital cost of $676,500).

  Despite the fact that the upfront capital cost of the DCS alternative is more than the electromechanical relay alternative, in the event of a single electromechanical relay failure that results in Unit 3 becoming unavailable, the DCS alternative becomes the more cost effective option. As a result of this fact and the following benefits gained with going with the DCS alternative, Hydro has decided to proceed with the DCS alternative:

- **Overall safer system since maintenance and troubleshooting can be completed from the safety of the control room** – The DCS system allows maintenance crews to observe the status of input and outputs from an engineering workstation located inside the control room. However, in the electromechanical relay alternative, maintenance crews would have to work inside energized electrical panels when trying to perform maintenance and troubleshoot problems.

- **More dependable system as solid state relays contain no moving parts** – DCS outputs operate using an electronic switch or transistor which contains no moving parts. As a result, fewer faults will occur on the DCS system which will result in more dependable operation of the Unit 3 generator;

- **Easier troubleshooting capabilities since there is less wiring and electrical components to fail** – In the event that an electromechanical relay was to fail, several hours or possibly days would be spent trying to determine the source of the problem. This will lead to extended system unavailability or possibly a Unit 3 outage. The DCS alternative offers built in internal diagnostics, that will alert operators of a problem immediately;

- **Built in fault tolerance that can accept some single point control system failures** – Since the DCS option contains redundant processors and communications, the

system will continue to operate despite a failure on any of these critical components;

- **Smaller equipment footprint that frees up valuable plant real estate** – When replacing the existing system with electromechanical relays, a much larger panel would be required to house all the relays and wiring than what would be required if the DCS alternative was used. Currently, there is very little extra room inside the Stage 2 relay room for a larger enclosure;

- **Easier future upgrade capabilities that will not involve wiring changes for simple logic changes** – The DCS alternative will allow technicians to make simple logic changes by re-configuring software as opposed to spending hours or days re-wiring relays. In addition, it will allow more complicated logic processes to be installed in the event that any future plant upgrades take place. The electromechanical relay option only supports discrete relay logic and does not offer any advanced control capabilities such as analog inputs, analog outputs, closed loop control, accurate timing functions and counting functions;

- **Reduced commissioning time required to fix errors as small logic changes are made much easier in software than in hardwired systems** – If during commissioning, any logic changes are required, the DCS alternative will allow these changes to be made without having to change any of the wiring or equipment inside the panel. However, if changes are required when using the electromechanical relay alternative, this could result in hours or days of re-wiring and if the change is significant enough, there may not be any extra space inside the panel to add extra relays;

- **Better automation capabilities and much faster control processing speeds available in DCS controlled system** – The DCS alternative will allow engineering to program alarms and other automation logic into the system that will inform

operators when something has gone wrong in the process. It will also operate at much faster speeds than relay logic allowing the process to respond to changes much faster than they currently do;

- **Common plant wide control system that allows operators to analyze faults and historically trend and display any information required** – The existing DCS is equipped with sequence of events recording capabilities and historical trending of all inputs and outputs. These features will allow operators and engineering to quickly analyze faults and disturbances by knowing exactly what events occurred at the time of a fault.

- **DCS system allows for remote monitoring and control of systems via HMI computers or operator workstations** – The DCS alternative will allow the operators inside the control room to see the entire process on one Human Machine Interface (HMI) computer screen. This system will allow automatic alarming capabilities and will reduce the amounts of lights, switches and pushbuttons currently installed inside the control room. It will therefore streamline the operation of the process and will reduce the chances of operator error. In addition, it will allow future control room modernization to take place without having to replace any of these systems.

5 CONCLUSION

The Unit 3 Relay Panels must be upgraded to ensure the safety of Hydro's maintenance crews and the overall operational reliability of the Holyrood plant. The existing hardwired control panels are over 30 years old and are overcrowded with wiring to the point that the doors of this panel will no longer close. These panels are in direct violation of several Canadian Electrical Code rules and pose significant safety hazards to anyone working inside these panels.

Hydro is proposing that the existing panels be replaced and the hardwired controls be integrated into the existing plant wide Foxboro DCS control system.

5.1 Budget Estimate

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	23.0	10.0	0.0	33.0
Labour	107.2	157.5	0.0	264.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	112.5	210.4	0.0	322.9
Other Direct Costs	0.6	13.5	0.0	14.1
O/H, AFUDC & Escln.	33.8	98.7	0.0	132.5
Contingency	0.0	63.5	0.0	63.5
TOTAL	**277.1**	**553.6**	**0.0**	**830.7**

5.2 Project Schedule

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Milestone
Project Initiation	January 2011
Review existing drawings and develop I/O list	March 2011
Develop contract for Foxboro and issue Purchase Order	June 2011
Finalize Engineering Drawings and Design	September 2011
Develop DCS Programming	November 2011
Develop Electrical Installation Contract	February 2012
Complete Factory Acceptance Testing	April 2012
Complete Installation and Commissioning	July 2012
In Service	September 2012
Project Completion and Close Out	December 2012