newfoundland labrador hydro
a nalcor energy company

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July 31, 2015

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 – 2016 Capital Budget Application

Please find enclosed twelve copies, plus the original, of Hydro's 2016 Capital Budget Application, in three volumes, filed in accordance with the Provisional Capital Budget Application Guidelines issued by the board in October of 2007 and in accordance with the guidelines and conditions for capital budget proposals as outlined by the Board in Order No. P.U. 7(2002-2003).

Under this Application, Hydro is seeking approval of $183.7 million in capital expenditures. Hydro will seek approval of its 2014 Rate Base as part of its General Rate Application.

.../2

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

Tracey L. Pennell
Legal Counsel

cc: Mr. Peter Alteen,
Newfoundland Power

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

Mr. Dean Porter
Poole Althouse

Mr. Paul Coxworthy
Stewart McKelvey Stirling Scales

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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 2016 capital budget pursuant to s.41(1) of the Act; (2) its 2016 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 2016 pursuant to s.41 (5) of the Act.

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 2016 Capital Budget in the amount of approximately $183.7 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 Hydro's proposed 2016 Capital Budget with multi-year projects listed separately and 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.

4. Section C to this Application is a list of the proposed 2016 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.

5. Section D to this Application is a list of the proposed 2016 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.

6. Section E to this Application is a list of the proposed 2016 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.

7. Section F to this Application summarizes Hydro's proposed 2016 capital projects by definitions, by classification and by materiality as required by the Capital Budget Application Guidelines.

8. Section G contains no new leases proposed for 2016 in excess of $5,000 per year.

9. Section H to this Application is a Schedule of Hydro's Capital Expenditures for the period 2011 to 2020.

10. Section I to this Application is a report on the status of the 2015 capital expenditures including those approved by Order No. P.U. 50(2014), projects under $50,000 not included in these Orders, and the 2014 capital expenditures carried forward to 2015.

11. Section J 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).

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

13. The proposed capital expenditures for 2016 as set out in this Application are required to allow Hydro to continue to provide to its customers service and facilities 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 2016 to be approximately $300,000. The information contained in the 2016 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, Telephone: (709) 737-1277, or Tracey L. Pennell, Legal Counsel, Telephone: (709) 778-6671, P.O. Box 12400, St. John's, Newfoundland and Labrador, A1B 4K7, Fax: (709) 737-1782.

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

    (1) Approving Hydro's 2016 Capital Budget as set out in Section A hereto, pursuant to section 41 (1) of the Act;

    (2) Approving 2016 Capital Purchases and Construction Projects in excess of $50,000 as set out in Sections C, D, and E hereto, and its leases as set in Section F, pursuant to section 41 (3) of the Act; and

(3) Approving the proposed estimated contributions in aid of construction as set out in paragraph 12 hereof for 2016 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.

DATED at St. John's, Newfoundland, this 31st day of July 2015.

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey L. Pennell,
Legal Counsel

Newfoundland and Labrador Hydro,
500 Columbus Drive, P.O. Box 12400
St. John's, Newfoundland, A1B 4K7
Telephone: (709) 778-6671
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 2016 capital budget pursuant to s.41(1) of the Act; (2) its 2016 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 2016 pursuant to s.41 (5) of the Act.

AFFIDAVIT

I, Robert J. Henderson, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice-President, 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 31st day of July 2015, before me:)

Barrister – Newfoundland and Labrador

Robert J. Henderson

A Report to the

Board of Commissioners of Public Utilities

2016 Capital Projects Overview

newfoundland labrador hydro
a nalcor energy company

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1 INTRODUCTION

Hydro is required to provide reliable service to its customers, through the provisions of the Hydro Corporation Act, 2007, 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 maintain, refurbish, renew, and expand 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 framed in the context of the following key drivers: the interconnection between Labrador and the Island via the HVdc link, the interconnection with Nova Scotia system via the Maritime link, the startup of a nickel processing facility, and continued load growth on the Avalon Peninsula. This Overview will discuss the projects proposed for 2016. Discussion of the five year plan is contained in the section entitled "2016-2020 Capital Plan".

2 2016 PLAN CONSIDERATIONS

Maintaining Hydro's systems in reliable operating condition is accomplished through a combination of planned maintenance, rehabilitation of existing assets, and replacement of assets which have reached the end of their useful lives. Replacement of assets may result in lower life cycle costs or improved operational characteristics. Assets may be also replaced, as required, for load growth or reliability criteria violations.

The majority of Hydro's installed assets, like the hydroelectric installation at Bay d'Espoir, the Holyrood Thermal Generating Station, and much of Hydro's transmission and distribution systems are more than 40 years old. In addition, many other generation assets, such as the Stephenville Gas Turbine, the Hardwoods Gas Turbine and the Hinds Lake Generating Station are more than 30 years old.

The sustaining capital proposals, focused on maintaining current assets, contained in this application and in previous applications, appropriately consider both the age and condition of Hydro's existing assets in determining whether to renew or replace them. The number of these sustaining capital proposals can be expected to increase with the continuous assessment of the condition of the aging assets. In other cases, the introduction of newer, more efficient technologies justifies the replacement of 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, allowing operators to focus on maximizing efficiency and equipment monitoring. This Application contains proposals which seek to improve the safety of Hydro's workplaces and to implement automation or improvements in the control of equipment that enable the safe and efficient operation of assets.

In the development of a capital proposal, consideration is given to:

- System performance and reliability criteria;
- Long term asset management strategy;
- Load growth and system planning criteria;
- Maintenance history;
- Condition assessment;
- Performance assessment;
- Legislative requirements;

- Cost efficiencies;
- Operating experience;
- Changing operating conditions;
- 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
- Technical assessment based, where an evaluation of reliability, performance, condition, costs and other factors results in a capital proposal.

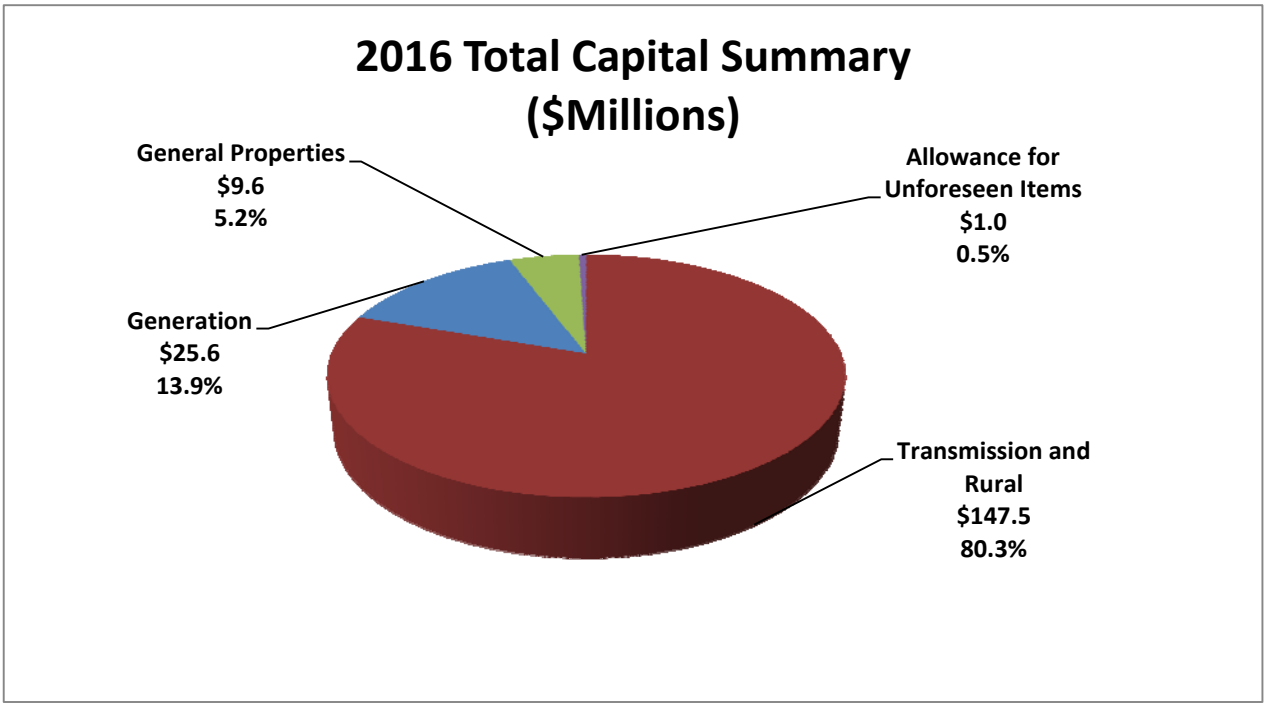
3 2016 CAPITAL BUDGET

This Application contains a capital plan in which the primary consideration is least cost and reliable generation, transmission and distribution of electricity while maintaining and enhancing safety and environmental performance.

This 2016 capital budget application contains 86 new projects. These new projects, such as a five year project to replace circuit breakers, plus previously approved projects, such as the construction of a new 230 kV transmission line between Bay d'Espoir to Western Avalon Terminal Stations, require expenditures totaling $184 million in 2016. All projects address both the need to sustain the existing asset base and to grow the asset base in response to growing customer demand.

Chart 1 shows the 2016 Capital Budget Summary by major category. The categories, other than the Allowance for Unforeseen Items, which represents 0.5% of the 2016 budget, are discussed further in the Overview.

Chart 1: 2016 Capital Budget – Summary



3.1 GENERATION

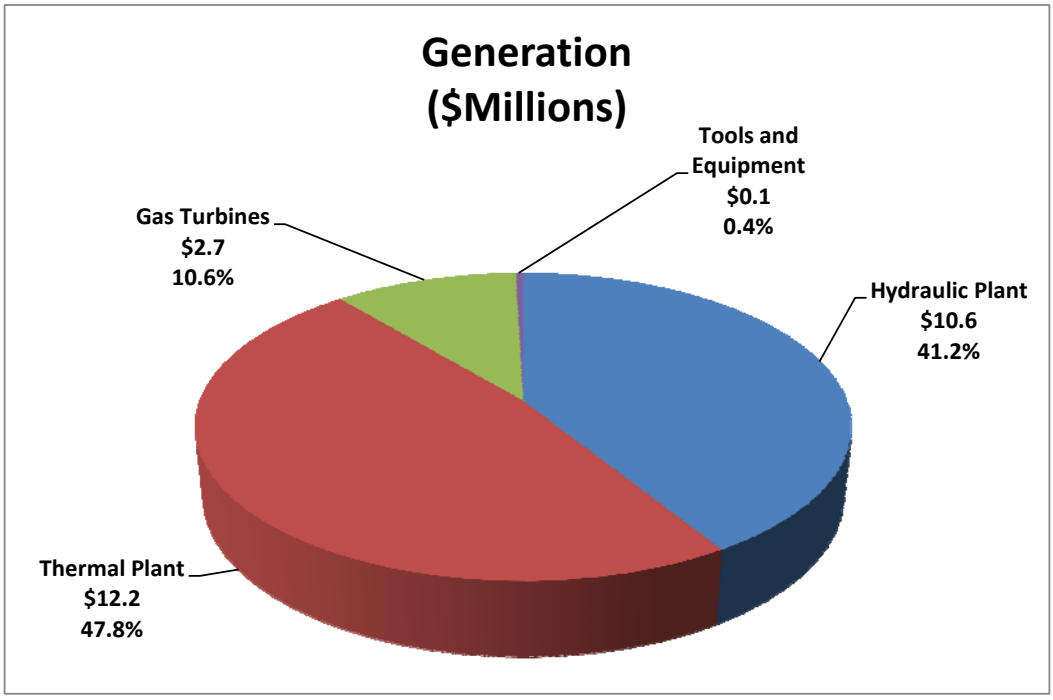
On the Island Interconnected System, power and energy are provided by Hydro through a mix of hydroelectric and fossil-fired generation, supplemented by power purchases. This energy production, along

with the transmission system, is managed by the Energy Control Centre to ensure economic and reliable dispatch of available resources.

The Generation category expenditures of $25.6 million account for 13.9% of overall expenditures for 2016.

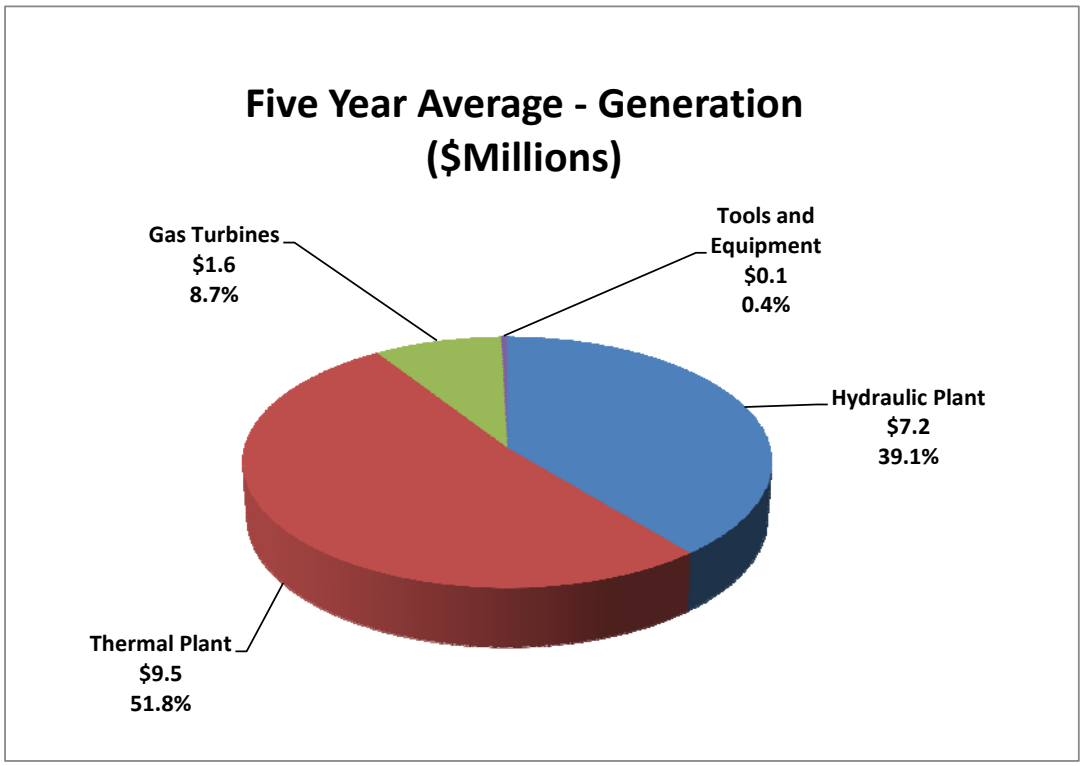
The division of the 2016 Capital Budget for Generation among Hydraulic Plant, Thermal Plant, Gas Turbines and Tools and Equipment expenditures is shown in Chart 2.

Chart 2: 2016 Capital Budget – Generation



The five-year (2010 to 2014) average capital expenditures for generation are shown in Chart 3.

Chart 3: Five-Year Average Capital Expenditures - Generation (2010-2014)



For 2016, Thermal Plant projects represent 47.8% of the Island Interconnected generation capital budget, compared with an average of 51.8% over the past five years. Thermal plant projects continue to require major capital expenditures as the majority of the equipment and systems have reached the final phase of their life cycle and have undergone life extension in some cases. Expenditures are required to ensure that these important generating assets can continue to operate reliably until retired and replaced. Projects at Hydraulic Plants represent 41.2% of the 2016 capital budget for generation, compared with an average of 39.1% over the past five years. Expenditures for Gas Turbines and Tools and Equipment represent 10.6% and 0.4%, respectively, of the total budgeted generation expenditures for 2016, compared with five year average expenditures of 8.7% and 0.4%, respectively. The increase in gas turbine expenditures is primarily a result of the need to refurbish aging assets.

3.1.1 Hydraulic Plant

Hydro's major hydraulic generating plants range from 12 to 48 years of age. Capital expenditures are required to ensure reliability and to maximize the useful operating lives of these assets, many of the components of which have reached or are nearing the end of their expected service lives in the older plants.

Examples of projects to be completed at the hydraulic plants include a proposal for work on the surge tank 2 at Bay d'Espoir and an overhaul of two turbine generators, also at Bay d'Espoir.

3.1.2 Thermal Plant

The three units of the Holyrood Thermal Generating Station have now reached or exceeded their generally expected service life of 30 years. Continued condition assessment and selective life extension will permit them to operate reliably until the Labrador Island Link is in service and providing power to the Island Interconnected customers. Holyrood remains critical to the reliable supply of power to the Island Interconnected System until that time and will be required to supply electricity in the short to medium term.

The long term operational plan for this facility has been developed in the context of the development of Muskrat Falls with a high voltage direct current transmission link to the Island. Holyrood will remain a critically important facility during construction and commissioning. Following completion of Muskrat Falls and the Labrador Island Transmission Link, the Holyrood plant will continue to be an essential component of the Island Interconnected System. Initially, the plant will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the HVdc link between Labrador and Newfoundland. After this period, thermal assets will be decommissioned and the facility will be partially converted to a synchronous condensing configuration.

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 life until it reaches maturity and is then operated as a peaking or standby facility in its final years, operating at a very low capacity factor, often less than 10%. The Holyrood thermal plant has passed the age at which other utilities have performed condition assessment and life extension studies, similar to Hydro's approach, and have either retired their facilities or have initiated major life extension projects. However, until the Muskrat Falls Generating Plant is completed and power is brought to the Island Interconnected System via an HVdc link, the Holyrood plant must continue to operate at or near its historical levels with annual capacity factor in the range of 35 to 45% and at higher levels through the winter period when availability is critical to meet peak demand. As nickel processing plant at Long Harbour increases operation, demand on Holyrood will increase. This is in addition to general growth due to the favourable economy of the province which drives growth in the residential and commercial sectors. The Holyrood capital projects contained in this application are necessary to refurbish and renew assets which are at the

end of their useful lives, and which must be replaced to maintain reliability through to the completion of the Muskrat Falls development.

Please see the Holyrood Overview section for further discussion pertaining to the 2016 Holyrood projects.

3.1.3 Gas Turbines

Hydro's gas turbine plants at Stephenville and Hardwoods are more than thirty years old. The generally accepted life expectancy for gas turbine plants is between twenty-five and thirty years. Further complicating the age of the facilities, is the manufacturer of the power turbines, one of the key components at the Stephenville and Hardwoods plants, is no longer in business, therefore eliminating the availability of factory technical support and spare parts. Also, the gas generators (jet engines) utilized at the Stephenville and Hardwoods plants are no longer manufactured thereby diminishing the supply of spare parts and the availability of technical support to repair the facilities.

Based on the changes noted above, during 2007, Hydro engaged a consultant to perform a condition assessment of the Hardwoods and Stephenville gas turbines. The consultant's findings and recommendations were used to prepare plans for refurbishment of these facilities to ensure that they continue to operate reliably and that their useful service lives can be extended as long as can be financially justified. The refurbishment of the Hardwoods Gas Turbine is now completed and the refurbishment of the Stephenville Gas Turbine is scheduled to be completed in 2016. Along with the new 123.5 MW combustion turbine, Hydro's older gas turbine facilities will continue to play an important role within Hydro's integrated generation plan until their expected retirement in 2025 and 2028 for Hardwoods and Stephenville, respectively.

3.2 TRANSMISSION AND RURAL OPERATIONS

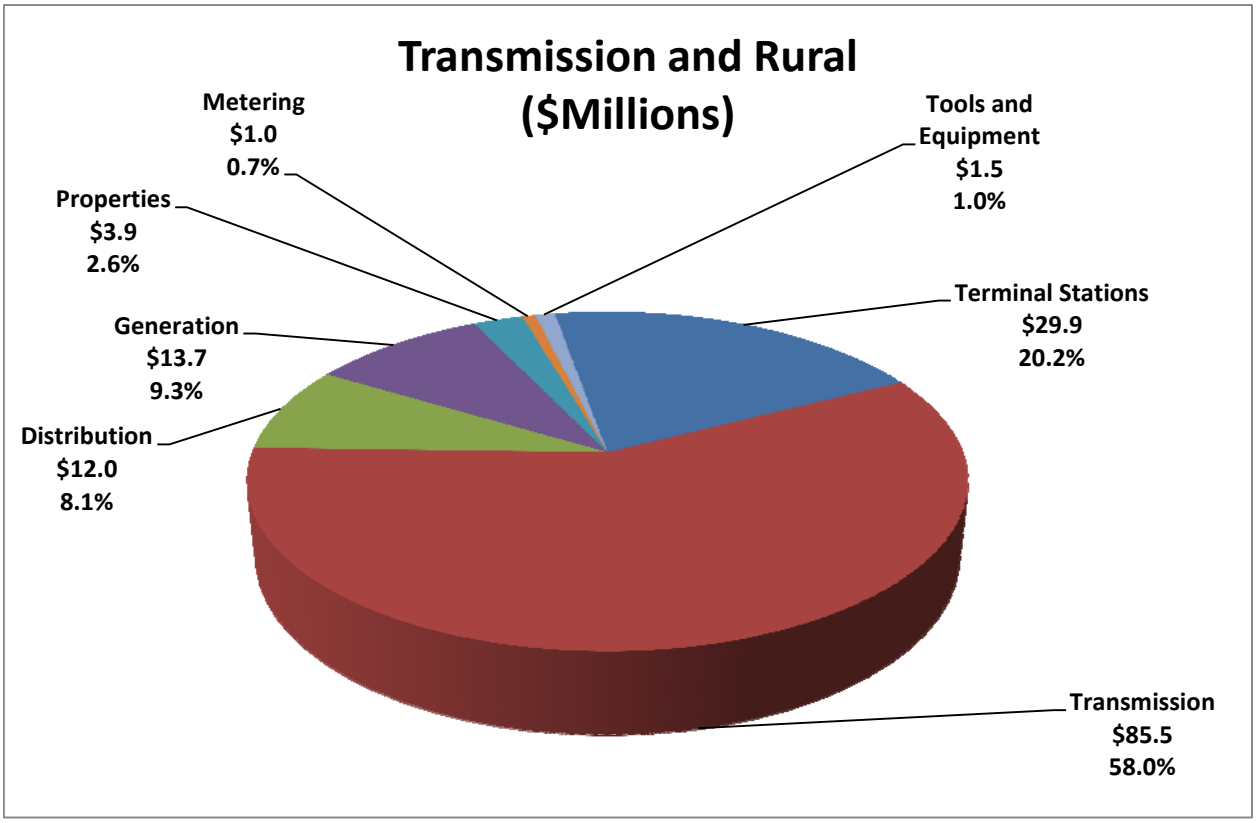
Hydro owns and operates diesel and gas turbine generation with 32.1 MW of net capacity on the Labrador Interconnected system; 14.7 MW of diesel generation on the Island Interconnected system; and diesel generation assets with 33.7 MW of net capacity in 21 isolated rural systems. On the Island Interconnected system, Hydro owns and operates 3,473 kilometers of transmission lines and more than 50 high voltage terminal stations operating at voltages of 230, 138 and 69/66 kV. On the Labrador Interconnected system, Hydro owns and operates 269 kilometers of 138 kV transmission line and the associated terminal stations interconnecting Happy Valley/Goose Bay to Churchill Falls. As of January 1, 2015, Hydro took over operating responsibility for the Wabush Terminal Station and the two 230 kV transmission lines that were previously

owned by TWINCo. In addition, Hydro owns and operates approximately 3,400 kilometers of distribution lines, principally in rural Newfoundland and Labrador.

Hydro's Transmission and Rural Operations assets are replaced based on age and condition, and require ongoing capital expenditures to maintain reliable service, to comply with environmental regulations, and to ensure the safety of employees, contractors, and the general public. As well, capital expenditures to provide service extensions are significant in many areas, particularly on the Labrador Interconnected system, the highest customer growth areas in Hydro's distribution system.

The Transmission and Rural Operations category expenditures account for 80.3% of overall expenditures for 2016 and total $147.5 million.

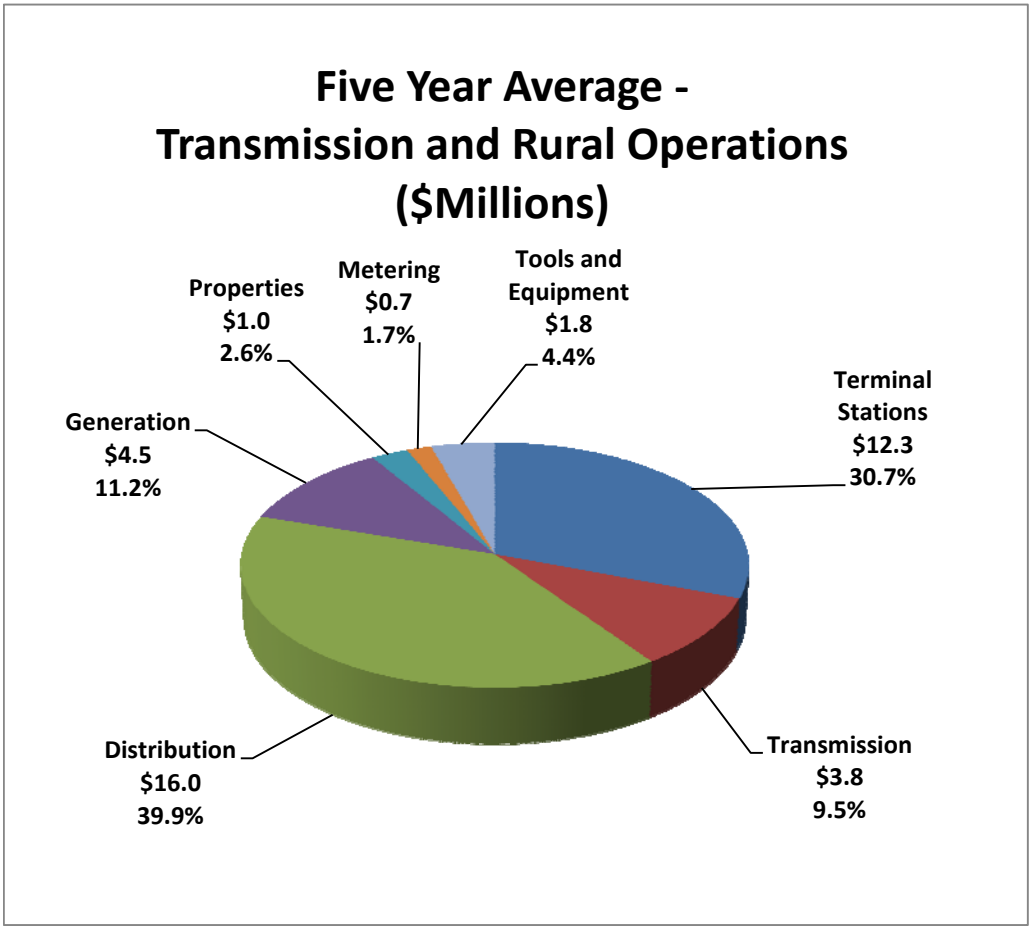
Chart 4: 2016 Capital Budget - Transmission and Rural Operations



The division of the 2016 Capital Budget for Transmission and Rural Operations is shown in Chart 4. Chart 5 provides the five year average expenditures in the Transmission and Rural Operations category. The increase in expenditure related to transmission in 2016, over the five year average expenditure, is mainly

attributable to the already approved transmission line between Western Avalon and Bay d'Espoir Terminal Stations of which $75 million is allocated in the 2016 Capital Budget. The increase in rural generation, over the five year average expenditures, is primarily attributable to the proposed installation of fire protection systems at Nain and Cartwright and the replacement of gensets at Cartwright and Charlottetown. The increase in expenditure at terminal stations, over the five-year average, is largely attributable to the accelerated breaker replacement program.

Chart 5: Five-Year Average Capital Expenditures – Transmission and Rural Operations (2010-2014)



3.2.1 Terminal Stations and Transmission

Many of Hydro's transmission lines and terminal stations were constructed in the 1960s with expected useful lives in the range of 40 years. Annual reconstruction and general upgrades are needed to ensure that Hydro can continue to provide customers with reliable electrical service. Within the 2016 submission, projects are proposed for the continued upgrade of power transformers and circuit breakers, as well as the replacement of surge arrestors, instrument transformers and disconnect switches. The transmission line

projects proposed include the transmission corridor upgrade between Soldier's Pond and Hardwoods, the continuation of the wood pole line management program and the upgrade of tower foundations.

3.2.2 Distribution and Rural Generation

The 21 remote electrical systems along the coasts of Labrador and the Island are primarily served by diesel generation. Providing service to customers in these communities requires that the fuel storage, diesel generating units, facilities, and distribution systems all be kept in safe, reliable and environmentally responsible working order. This application includes projects specifically directed towards safely meeting load growth requirements, including the additions for load growth in isolated generation stations and the installation of fire protections systems in diesel plants. In addition, engine overhauls and replacements will be completed in various diesel plants.

Hydro also provides service to residential and general service customers on the Island and Labrador Interconnected Systems. 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 customers. These projects include the upgrade of the distribution systems in various locations. This Application also includes projects to provide service extensions to new customers throughout Hydro's service area.

3.3 GENERAL PROPERTIES

The General Properties classification expenditures account for 5.2% of overall expenditures for 2016 and total $9.6 million.

The General Properties classification 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 vehicle replacements and telecommunications system replacements which are all necessary for the provision of reliable and cost effective service to customers.

Charts 6 and 7 show the breakdown of the General Properties Capital Budget for 2016 and the previous five year average, respectively.

Chart 6: 2015 Capital Budget - General Properties

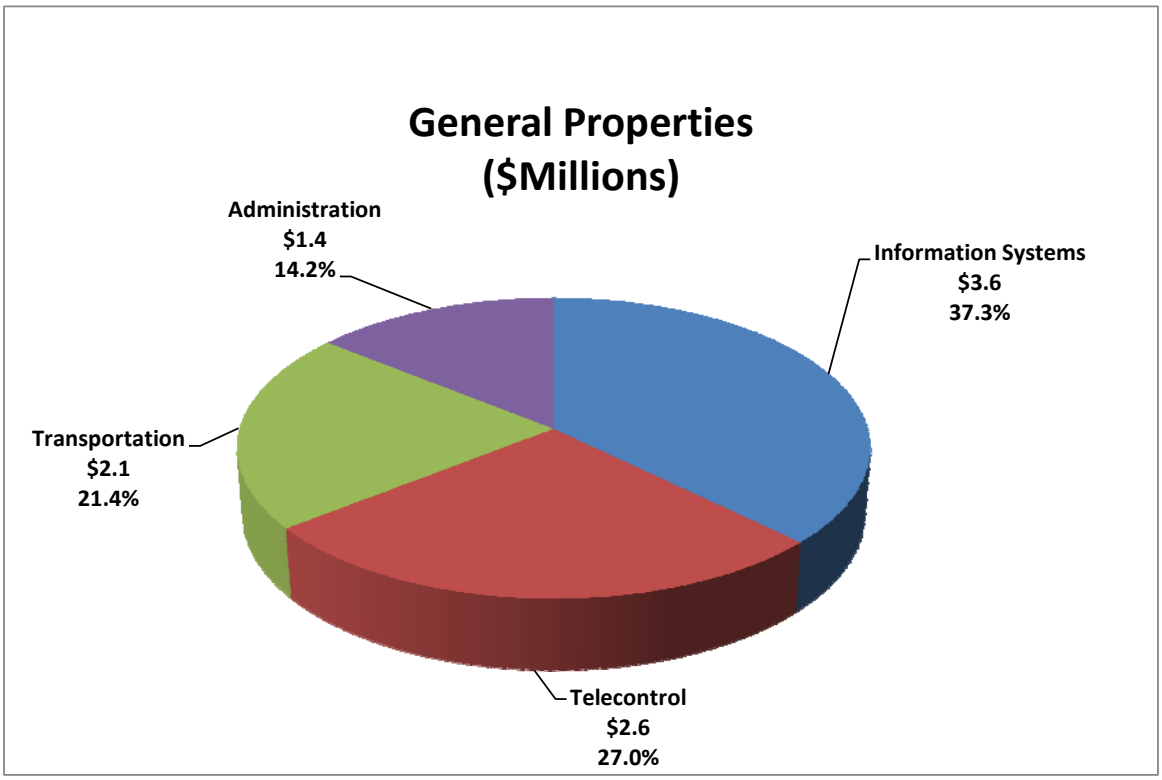
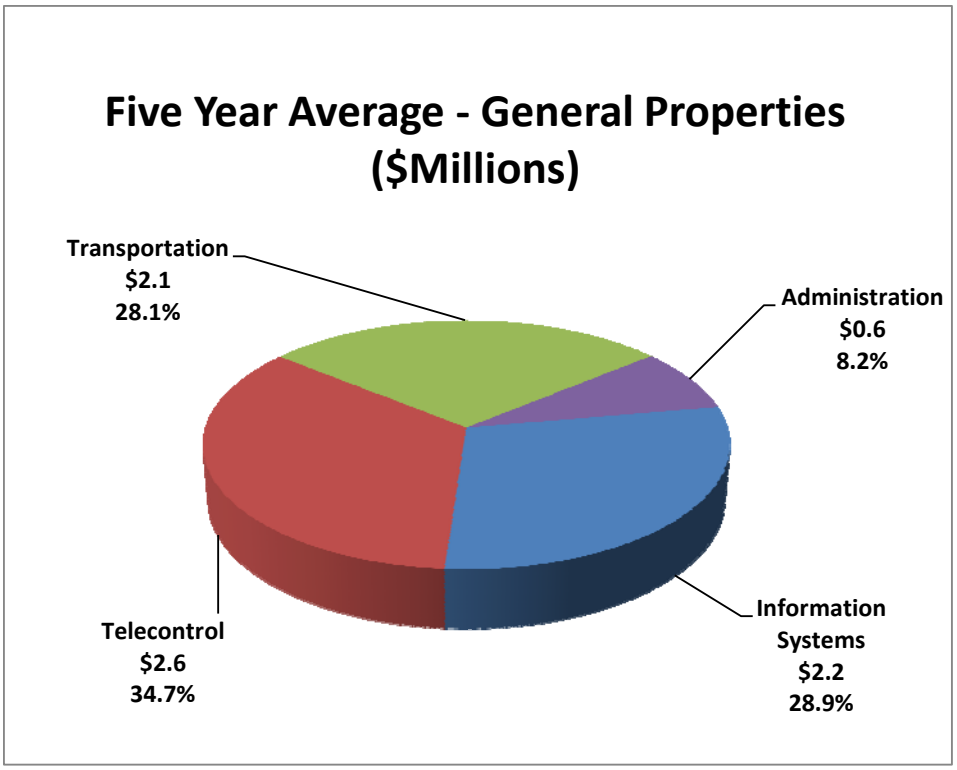


Chart 7: Five-Year Average Capital Expenditures - General Properties (2010-2014)



3.3.1 Information Systems

The Information Systems proposals 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 Hydro, as well as the replacement of personal computers and peripheral infrastructure.

3.3.2 Telecontrol

Operating an integrated electrical system requires reliable communication systems across Hydro's province-wide facilities both to control equipment and to support employee communications, many of whom work in remote locations. The 2016 capital budget proposals in this category include infrastructure replacements, ongoing replacement or refurbishment programs for such items as battery banks and chargers and network communications equipment.

4 GENERAL

4.1 Project Prioritization and Ranking

An overall ranking of 2016 projects is attached as Appendix A.

4.2 Phase 1 Engineering Costs

Hydro has tracked the Phase 1 engineering costs specific to each project and these costs form part of the 2016 capital budget submission. Therefore, Hydro's 2016 capital projects include Phase 1 engineering costs incurred in 2015 in association with those 2016 capital projects and Hydro proposes that the inclusion of those costs be approved.

Hydro has included Phase 1 costs in its capital budget proposals only in those cases in which the Phase 1 costs exceed $1,000 for that specific project. Phase 1 costs related to any specific project not receiving Board approval will not be capitalized. The total of these costs included in the 2016 capital budget submission is $367,975.

APPENDIX A

2016 Project Prioritization

PRIORITIZATION EXPLANATIONS

The following table shows the ranking of Hydro's 2016 capital projects. Rank 1 indicates the projects of the highest importance and in 2016, no projects with a ranking of more than 50 were included in the Application. The total of the projects included is determined based on balancing unit load, overall budget, and other logistical considerations. Projects that received the same score through the prioritization process[1] have the same ranking. The eleven projects which are Rank 1 are considered high priority projects required to address safety, mandatory or system load issues. Please note that the non-prioritized projects in the table are multi-year projects and necessary programs.

2016 Capital Budget and Five Year Plan **2016 Project Prioritization**			
Project Description	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Multi-Year Projects (2016 is 2nd or 3rd Year)	105,998.6	******	105,998.6
TRO Service Extensions and Upgrades	9,040.0	******	115,038.6
Transportation	3,108.9	******	118,147.5
Tools & Equipment	997.5	******	119,145.0
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	477.6	1	119,622.6
Replace Aircraft Markers at Grand Lake Crossing - TL228	589.6	1	120,212.2
Additions for Load Growth - Happy Valley	593.7	1	120,805.9
Additions for Load Growth - L'Anse au Loup and Postville	883.4	1	121,689.3
Upgrade Transformers - Cartwright and Postville	465.2	1	122,154.5
Install Fall Protection Equipment - Various Sites	198.8	1	122,353.3
Remove Safety Hazards - Various Sites	199.3	1	122,552.6
Inspect Fuel Storage Tanks - Various Sites	1,326.9	1	123,879.5
Rehabilitate Shoreline Protection - Cat Arm	112.2	1	123,991.7
Replace PH1 Station Service Transformer - Bay d'Espoir	46.7	1	124,038.4

[1] Hydro has added two new criteria to the prioritization process. These criteria consider customer interruption, numbers and minutes, as well as SAIFI and SAIDI. These criteria were adopted to be used for the prioritization of the 2017 budget.

2016 Capital Budget and Five Year Plan **2016 Project Prioritization**			
Project Description	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods	3,699.0	1	127,737.4
Install Automated Meter Reading - Labrador West	433.8	2	128,171.2
Overhaul Turbine/Generator Units 6 and 7 - Bay d'Espoir	1,345.6	3	129,516.8
Replace Generator Cooling Water Piping - Hinds Lake	181.7	4	129,698.5
Replace Control Room/Communications Room Air Conditioning - Hinds Lake	41.3	5	129,739.8
Install Hydrometeorological Equipment - Various Sites	314.1	6	130,053.9
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir	2,959.6	7	133,013.5
Upgrade Site Facility - Holyrood	2,723.8	8	135,737.3
Overhaul Diesel Units - Various Sites	2,078.4	8	137,815.7
Overhaul Steam Turbine Generator Unit 3 - Holyrood	5,868.6	8	143,684.3
Overhaul Pumps - Holyrood	536.2	8	144,220.5
Perform Wood Pole Line Management Program - Various Sites	2,919.0	9	147,139.5
Upgrade Circuit Breakers - Various Sites (2016-2020)	6,969.1	10	154,108.6
Replace Surge Arrestors - Various Sites	144.4	11	154,253.0
Replace Disconnect Switches - Various Sites (2016-2017)	646.9	12	154,899.9
Upgrade Digital Fault Recorders - Various Sites	197.9	13	155,097.8
Upgrade Data Alarm Systems - Various Sites	74.4	13	155,172.2
Replace Protective Relays - Various Sites	700.6	13	155,872.8
Install Breaker Failure Protection - Various Sites	65.7	13	155,938.5
Upgrade Office Facilities and Control Buildings - Various Sites	1,134.0	13	157,072.5
Upgrade Citrix - Hydro Place	159.6	14	157,232.1
Upgrade SharePoint/Document Repository - Hydro Place	143.5	14	157,375.6
Refresh Security Software - Hydro Place	123.5	15	157,499.1
Implement Industrial Billing Software - Hydro Place	443.1	15	157,942.2
Perform Minor Application Enhancements - Hydro Place	197.9	15	158,140.1
Upgrade Energy Management Systems - Hydro Place	246.2	15	158,386.3
Replace Personal Computers - Various Sites	861.7	15	159,248.0
Replace Peripheral Infrastructure - Various Sites	424.5	15	159,672.5
Upgrade Enterprise Storage Capacity - Hydro Place	337.2	15	160,009.7

2016 Capital Budget and Five Year Plan **2016 Project Prioritization**			
Project Description	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Upgrade Server Technology Program - Hydro Place	264.0	15	160,273.7
Upgrade Microsoft Office Products - Hydro Place	366.6	15	160,640.3
Upgrade Remote Terminal Units - Various Sites	89.6	16	160,729.9
Upgrade Site Facilities - Various Sites	49.5	17	160,779.4
Replace Radomes - Various Sites	235.2	17	161,014.6
Replace Network Communication Equipment - Various Sites	186.4	17	161,201.0
Replace Battery Banks and Chargers - Various Sites	425.0	17	161,626.0
Replace UPS Systems - Hydro Place	889.8	17	162,515.8
Replace Video Conferencing Bridge - Hydro Place	182.6	17	162,698.4
Upgrade Access Roads to Microwave Sites - Various Sites	141.1	17	162,839.5
Replace Air Conditioners - Various Sites	39.9	17	162,879.4
Replace Roof - Hydro Place	639.5	18	163,518.9
Replace Air Conditioning Units 8 and 14 - Hydro Place	34.6	19	163,553.5
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood	2,755.5	20	166,309.0
Perform Condition Assessment of Control Structures - Hinds Lake	323.4	21	166,632.4
Replace Wescom Transceivers - Various Sites	49.3	22	166,681.7
Install Fire Protection Systems - Nain and Cartwright	3,030.7	23	169,712.4
Replace MDR 4000 Microwave Radio East - Various Sites	77.4	24	169,789.8
Upgrade Work - Cat Arm	558.3	25	170,348.1
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir	85.7	26	170,433.8
Refurbish Station Water System - Upper Salmon	96.6	27	170,530.4
Upgrade Telecontrol Facilities - Sandy Brook Hill	101.6	28	170,632.0
Upgrade Terminal Station Equipment Foundations - Various Sites	319.9	29	170,951.9
Install Fire Protection in 230 kV Stations - Bay d'Espoir	200.0	30	171,151.9
Upgrade Distribution Systems - Various Sites (2016-2017)	285.6	31	171,437.5
Construct Overhead Distribution Line - Pilley's Island to Long Island	1,239.9	32	172,677.4
Replace Fuel Piping - Hardwoods and Stephenville	44.8	32	172,722.2
Upgrade Aluminum Support Structure - Holyrood	401.1	33	173,123.3
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir	183.6	34	173,306.9

2016 Capital Budget and Five Year Plan 2016 Project Prioritization			
Project Description	**Cost ($000)**	**Rank**	**Cumulative Project Costs ($000)**
Replace Insulators - TL203	1,985.6	35	175,292.5
Replace Air Receivers and Compressors - St. Anthony	120.7	36	175,413.2
Replace Monitoring Vibration System Unit 7 - Bay d'Espoir	366.0	37	175,779.2
Replace Powerline Carrier - Various Sites	73.4	38	175,852.6
Replace Diesel Units - Cartwright and Charlottetown	1,840.5	39	177,693.1
Install Transfer Switches for Diesel Automation - Happy Valley	148.4	40	177,841.5
Upgrade Terminal Station for Mobile Substation - Cow Head	40.0	41	177,881.5
Study of Space Heating and Boiler Startup Assistance - Holyrood	148.7	42	178,030.2
Upgrade Roof - Indian River	48.3	43	178,078.5
Upgrade Line Depots - Various Sites	861.4	44	178,939.9
Install Spare Transformer - Happy Valley	2,040.9	45	180,980.8
Replace Site Facilities - Bay d'Espoir	928.3	46	181,909.1
Replace Roof on Service Building - Bishop's Falls	612.8	47	182,521.9
Upgrade Human Machine Interface - Various Sites	114.0	48	182,635.9
Install Variable Frequency Drives - Grey River	46.9	49	182,682.8
Upgrade Warehouse Lighting - Bishop's Falls	15.2	50	182,698.0

The table below presents the prioritization criteria and the assigned weights used for the 2016 budget.

Criteria		Factors	Factor Weights
1	Work Classification	Normal	5
	(maximum weight = 85)	Justifiable: Payback (70)	15
		Justifiable: Payback (40)	45
		Justifiable: Payback (10)	85
2	Net present Value	NPV ($0)	0
	(maximum weight = 85)	NPV (<$100K)	5
		NPV (<$500K)	15
		NPV (<1M)	45
		NPV (>1M)	85
3	Goal 1: Safety	Minor	10
	(maximum weight = 100)	Treatment	50
		Lost Time	80
		Disability	100
4	Goal 2: Environment	None	10
	(maximum weight = 100)	Minor	50
		Moderate	80
		Significant	100
5	Goals 3-5: Alignment	None	15
	(maximum weight = 65)	Maps but no documentation	40
		Maps but with documentation	65
6	Schedule Risk	External and internal conflicts	10
	(maximum weight = 65)	Externals affecting completion	20
		No external but internal conflicts	40
		No conflicts	65
7	Continue service to customers	Can	20
	(maximum weight = 70)	Can but with high costs	50
		Cannot	70
8	Number of customers impacted	<100	10
	(maximum weight = 70)	<1000	30

Criteria		Factors	Factor Weights
		<10,000	50
		>10,000	70
9	System Impact: Critical to …	None specific	5
	(maximum weight = 90)	System with standby unit	50
		Plant or station	70
		Entire system	90
10	Impact intensity	Minor	4
	(maximum weight = 90)	Moderate	40
		Significant	70
		High	90
11	Loss Type: Loss of …	No type	5
	(maximum weight = 90)	Equipment	40
		Facility	50
		Production	70
		Customer delivery	90
12	Loss mitigation	Redundant unit	30
	(maximum weight = 90)	Backup option	60
		Nothing	90

A. Level 1

Immediate HIGH Priority Projects

- **Extreme Safety**

The project is required to prevent an incident that could cause a fatality or correct a condition that otherwise left unattended may lead to a fatality.

- **Mandatory**

A capital expenditure that Hydro is obliged to carry out as a result of Legislation, Board Order, Environmental or Safety risk.

- **Load Driven**

The project is needed to meet load requirements determined by Hydro's latest load forecasts. Without the project, Hydro's firm load and/or reliability criteria will be compromised.

B. Level 2

1. Work Classification

- **Normal**

A capital expenditure which is required based on an identified need or historical patterns of repair and replacement.

- **Justifiable**

A capital expenditure which is justified based on a positive cost savings for Hydro. A cost-benefit analysis is required for the project.

- **Payback (70)**

A cost-benefit analysis indicates that the payback period for the project is within 70% of the anticipated life of the project.

- **Payback (40)**

A cost-benefit analysis indicates that the payback period for the project is within 40% of the anticipated life of the project.

- **Payback (10)**

A cost-benefit analysis indicates that the payback period for the project is within 10% of the anticipated life of the project.

2. Net Present Value

- **NPV ($0)**

The capital proposal generates $0 cost savings to Hydro.

- **NPV (<$100K)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $100K for Hydro.

- **NPV (<$500K)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $500K for Hydro.

- **NPV (<$1M)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of less than $1M for Hydro.

- **NPV (>$1M)**

A cost-benefit analysis indicates that the capital proposal generates a positive cost savings of more than $1M for Hydro.

3. Goal 1: Safety

- **Minor**

The project has no or minor safety issues that are insignificant in impact.

- **Treatment**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in the need for medical treatment.

- **Lost Time**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in worker(s) incurring lost time for a short duration.

- **Disability**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in worker(s) incurring long time leave due to inability to continue working on the job.

4. Goal 2: Environment

- **None**

The project has no environmental issues.

- **Minor**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:

  - Is irreversible within 2 years; and/or
  - Will cost more than $10,000 to mitigate; and/or
  - Has aspects observed on Hydro's property (at point of impact); and/or
  - Is perceived as in conflict with specific individuals in the local community.

- **Moderate**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:

  - Is irreversible within 4 years; and/or
  - Will cost more than $25,000 to mitigate; and/or
  - Has aspects observed within a 1 km radius of Hydro's property (from point of impact); and/or
  - Is perceived as in conflict with the local community or other industries.

- **Significant**

The project is required to prevent an incident or correct a condition that otherwise left unattended may result in an environmental impact that:

  - Is irreversible within the foreseeable future; and/or
  - Will cost more than $50,000 to mitigate and/or
  - Has aspects observed at more than 5 km radius of Hydro's property (from point of impact); and/or
  - Is perceived as in conflict with the local community and the general public and other industries.

5. Goals 3-5 Alignment

- **None**

This project does not align with or support any department or corporate goals or objectives.

- **Maps but no Documentation**

This project does align with or support a department or corporate goal or objective but no documentation exists to describe how it maps to the goal or objective.

- **Maps but with Documentation**

This project does align with or support a department or corporate goal or objective and there is documentation that clearly describes how.

6. Schedule Risk

- **Externals and Internal Conflicts**

The project has external (to Hydro) dependencies that affect the completion of the project on time and on budget and has major interfaces with other internal initiatives. Examples of external dependencies are: non-Hydro projects that interfere with Hydro proceeding with its project; unavailability of external contractors.

- **Externals Affecting Completion**

The project has only external dependencies that affect the completion of the project on time and on budget.

- **NO Externals but Internal Conflicts**

The project conflicts with other internal initiatives that affect the completion of the project on time and on budget.

- **NO Conflicts**

The project will not encounter any external or internal conflicts that affect its completion.

7. Continue Service to Customers

- **Can**

Service to customers can continue whether or not this project proceeds. Customers can be defined as either internal or external to Hydro.

- **Can but with High Costs**

Service to customers can continue whether or not this project proceeds but a delay in the project will result in Hydro incurring costs. Customers can be defined as either internal or external to Hydro.

- **Cannot**

Service to customers cannot continue without this project. Customers can be defined as either internal or external to Hydro.

8. # Customers Impacted

- **<100**

The project will impact up to 100 customers.

- **<1000**

The project will impact up to 1000 customers.

- **<10000**

The project will impact up to 10,000 customers.

- **>10000**

The project will impact more than 10,000 customers.

9. System Impact: Critical to.....

- **None Specific**

The project is not critical to any particular system.

- **System with Standby Unit**

The project is critical to a system that has a standby unit which could be used to maintain operation or support continued service in the event of failure.

- **Plant or Station**

The project is critical to the proper operation of a generating plant or a terminal station.

- **Entire System**

The project is critical to ensure the reliable operation of the Hydro system.

10. Impact Intensity

- **Minor**

If this project does not proceed, the repair time is ***less than half*** the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever comes first).

- **Moderate**

If this project does not proceed, the repair time is ***greater than the half but less than 90%*** of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

- **Significant**

If this project does not proceed, the repair time is ***within plus or minus 10%*** of the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

- **High**

If this project does not proceed, the repair time ***exceeds by more than 10%*** the Maximum Acceptable Downtime (MAD) of 830 MWh of unsupplied energy or 2 days (whichever is comes first).

11. Loss Type: Loss of.....

- **No Type**

If the project does not proceed, no loss is expected.

- **Equipment**

If the project does not proceed, there exists a risk of the loss of some equipment.

- **Facility**

If the project does not proceed, there exists a risk of the loss of a facility.

- **Production**

If the project does not proceed, there exists a risk of the loss of production at a Hydro generating plant.

- **Customer Delivery**

If the project does not proceed, there exists a risk of being unable to deliver power to Hydro customer(s).

12. Loss Mitigation

- **Redundant Unit**

If the project does not proceed the expected loss will be mitigated by a redundant unit present on the system.

- **Back-up Option**

If the project does not proceed the expected loss will be mitigated by a back-up option which ensures that service continues.

- **Nothing**

This project is required because there is no available means to mitigate the expected loss.

PROBABILITY

- **Not Likely**

The risk of the impact is very low if the project does not proceed. It would be surprising that there is an impact.

- **Low Likelihood**

The risk of the impact is low if the project does not proceed. There is about 30% chance of the impact in the proposal year. It's less likely to happen than not.

- **Likely**

The risk of the impact is possible if the project does not proceed. There is about 50% chance of the impact in the proposal year. It's as likely to happen as not.

- **Highly Likely**

The risk of the impact is considerable if the project does not proceed. There is about 75% chance of the impact in the proposal year. It's more likely to happen than not.

- **Near Certain**

The risk of the impact is almost certain if the project does not proceed. There is more than 90% chance of the impact in the proposal year. It would be surprising if the impact did not occur.

CONFIDENCE LEVEL

- **Low**

The confidence in the assessment of the impact is low. There are some uncertainties that could significantly change the assessment. The projects risks are not well defined.

- **Medium**

The confidence in the assessment of the impact is uncertain but most likely correct. There are some uncertainties that might moderately change the assessment. The project risks are defined but with some uncertainty.

- **High**

The confidence in the assessment of the impact is very high. The uncertainties won't measurably change the assessment. The project risks are well defined and well controlled.

A Report to the

Board of Commissioners of Public Utilities

2016 - 2020 Capital Plan

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1 Introduction

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 as necessary. Asset additions are also determined through analysis of long term requirements to address future demands for power and energy.

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, which at the time had an uncertain future due to alternative developments under consideration. With the sanction of Muskrat Falls and the Labrador-Island Link developments in December 2012, the future of the Holyrood plant has been established. The Holyrood section of this plan addresses Hydro's forecasted maintenance and capital requirements for the plant for the next five years.

Hydro maintains an asset base of $1.6 billion. Some assets have reached or exceeded 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 and much of Hydro's transmission and distribution systems. Hydro uses an asset management framework to manage these assets.

Hydro has a five year capital plan which contains detail on costs and timing of asset replacement and refurbishment. The five-year plan is a living document and is revised on an ongoing basis as new information about the condition of assets becomes available, as asset management strategies evolve, and as demands and priorities change within asset classes.

The five-year plan supports Hydro's responsibility to maintain its infrastructure providing safe, reliable and least cost electricity for home and business use.

2 Five-Year Plan

Hydro plans to invest $0.9 billion in plant and equipment over the 2016 to 2020 period for an average annual capital expenditure of $175 million. Individual year expenditures will range from a low of $111 million in 2019 to a high of $248 million in 2017. Over the period 2010 to 2014, the average annual capital expenditure was $96 million. The growth in overall capital expenditure reflects the requirement for projects related to replacement and upgrade of deteriorating facilities, ensuring compliance with legislation, additions required to meet load growth, and inflation.

Expenditures for new transmission assets are included in these estimates, specifically for the upgrade of the transmission line corridor between Bay d'Espoir and Western Avalon and the new transmission line between Soldiers Pond and Hardwoods, as well as expenditures in terminal stations, including replacing, in an expedited fashion, aging circuit breakers.

3 Strategic Spending Priorities

Hydro's strategic spending priorities over the next five years address the following areas:

1. Mandatory Issues:
    - Ensuring the safety of Hydro personnel, its contractors, and the general public;
    - Compliance with legislative and regulatory requirements; and
    - Managing environmental risks.
2. Meeting projected load growth and customer requests;
3. Applying a consistent Asset Maintenance Philosophy to ensure system reliability and maintain acceptable asset performance as identified by:
    - Operating experience;
    - Maintenance history;
    - Condition assessments; and
    - Performance evaluation and monitoring.
4. Achieving cost efficiencies.

Hydro's detailed five year capital investment plan is presented in Appendix A. Over this period, the level of capital expenditure is primarily driven by:

- Growth in system demand; and
- Age and condition of current infrastructure and assets.

4 Generation

The requirement to invest sustaining capital in generation facilities increased several years ago as parts of Hydro's generating plants reached or surpassed their normally expected service lives. Primary drivers for these projects are the realization of end of service lives for equipment, reductions in reliability or performance, the availability of more efficient technology, and considerations for safety.

4.1 Hydraulic

The condition of key components of Hydro's hydraulic facilities, including auxiliary systems and equipment as well as the control structures, have deteriorated and some have reached the end of their service lives. Capital investment is required in these areas to ensure the safe reliable operation of the system. The 2016 Capital Plan includes projects to overhaul two generating units at Bay d'Espoir as well as refurbish surge tank 2 at that development. Other projects proposed for 2016 budget include the refurbishment of various auxiliary systems at hydraulic facilities, such as the spherical valve by-pass assemblies replacement and replacing vibration monitoring system on Unit 7 at Bay d'Espoir.

4.2 Thermal

On December 17, 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls development. Holyrood will be required for prime power production until the Labrador Island Link (LIL), is in service and it is intended that the facility will remain fully available for generation in stand-by mode until the 2020–2021 timeframe. Unit 3 will operate primarily in synchronous condenser mode following Muskrat Falls power production to the island, with the option to return to full generating mode. Post the 2020-2021 timeframe, Units 1 and 2 and the steam components of Unit 3 at Holyrood will be decommissioned, and Unit 3 is planned to continue to operate in synchronous condenser mode only with no generation capability.

The Holyrood Generating Station Units 1 and 2 are now 45 years old while Unit 3 is 35 years old. The generally accepted life expectancy for thermal plants is 30 years. The Holyrood plant remains critical to the reliable power supply on the Island Interconnected system. The capital upgrades

contained in this plan are necessary to replace assets which are at the end of their useful lives, and those which must be replaced to maintain reliability.

Also see the Holyrood Overview section for further discussion pertaining to the five year plan for Holyrood.

4.3 Gas Turbines

Maintaining the reliability of Hydro's gas turbine assets, which are relied upon to provide emergency power and peaking power and function as synchronous condensers to help control voltage on the Island and Labrador Interconnected Systems, is a priority. 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.

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. A multiyear life extension project for the Hardwoods plant began in 2010 and completed in 2013. A similar project for Stephenville began in 2014 and will be completed in 2016.

The 123.5 MW new combustion turbine at Holyrood is available for service and full project completion will be achieved in 2015.

Hydro's gas turbine plant located at Happy Valley was constructed in 1992. This plant has required only minor upgrades since that time. The Controls Upgrade project and shaft inspection and stub shaft replacement will be completed in 2015.

Going forward, additional refurbishments will be required at Hardwoods, Stephenville and Happy Valley. Of note, a control system upgrade is planned in Hardwoods while an engine overhaul will be required at Happy Valley, both for 2019-2020.

5 Transmission and Rural Operations

The total investment of capital in transmission and rural operations facilities is seeing an increase for several coming years, primarily due to requirements for new transmission facilities. Other categories of assets are being replaced or refurbished due to age, and a number of components in various facilities have reached or surpassed their normally expected service lives. Projects in the Transmission and Rural Operations category are to address assets that are at, or near the end, of their service lives, to improve reliability or performance, to improve safety or to implement more efficient technology.

5.1 Terminal Stations

Increasing load and maintaining reliability are the principal drivers for terminal station expenditures over the next five years.

Aging equipment is considered when reviewing short and long term plans. The five-year plan contains expenditures, such as programs to upgrade power transformers, install on-line transformer gas monitoring units, replace circuit breakers, and replace disconnect switches. The plan also contains station-specific projects such as performing site work at various terminal stations to accommodate the mobile substation, and installing fire protection. Hydro will continue to consolidate equipment replacements into multi-year programs to ease the administrative effort for both the Board and Hydro and to leverage economies of scale.

Following the events of January 2014, Hydro developed a plan to accelerate air blast circuit breaker replacements and has included the requirements for the 2016 - 2020 accelerated work within its 2016 Capital Budget Application. As a result of the January 2014 events, Hydro completed a review of breaker failure applications, events/alarm recording upgrades and modern digital relay applications. This review resulted in several projects to: install breaker failure protection; upgrade fault recorders; upgrade data alarm systems; and upgrade protection and control.

5.2 Transmission

Transmission investment in the five year plan reflects customer growth and reliability requirements. The major project to upgrade the transmission line corridor between Bay d'Espoir and Western Avalon is underway, to facilitate additional power and energy delivery to the system and meet transmission planning criteria. Hydro received approval to for this project in Board Order No. P. U. 53(2014) and as part of that approval Hydro is required to file, with each capital budget application filed until the completion of the project, a report on the construction of the 230 kV transmission line addressing the work progress, the expenditure and budget status, and an explanation for any deviations from the project scope and budget. This report is presented in Appendix B.

Another key investment in the transmission system in the five year plan is the upgrading of the transmission corridor from Soldier's Pond to Hardwoods. This project is required to ensure the reliable supply of electricity to the St. John's area once power is coming to the Island from Muskrat Falls, and the supply from Holyrood diminishes.

Reliability improvements are also a driver for transmission investment. The wood pole line management program forms the backbone of Hydro's asset management strategy for these facilities. This strategy has been in place for eleven years and its effectiveness and value have 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. Hydro is also continuing to replace insulators on transmission lines, reducing the risk of service interruptions for customers due to insulator failure.

5.3 Distribution

New customer additions and maintaining reliability are the strategic areas addressed by the five-year capital plan for distribution assets. Deteriorated portions of distribution assets must be replaced periodically to ensure reliable service. The majority of the distribution system expenditures for the next five years will consist of service extensions and upgrades to distribution systems, distribution pole replacement, and substation upgrading, all to maintain or improve system performance. Significant projects for the next five years include the replacement of failed submarine cable with an overhead line from Pilley's Island to Long Island and distribution upgrades.

5.4 Rural Generation

The replacement of aging infrastructure is required to ensure reliability for Hydro's 21 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 approximately 100,000 hours of operation. Chart 1 provides the age distribution of the diesel engines in Hydro's rural generating plants. During the next five years Hydro plans to replace or add generating sets in various isolated diesel plants. 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 refurbishment or replacement in the near to medium term. 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. Projects for the replacement and upgrade of diesel plant infrastructure and auxiliary systems are included over the coming five years.

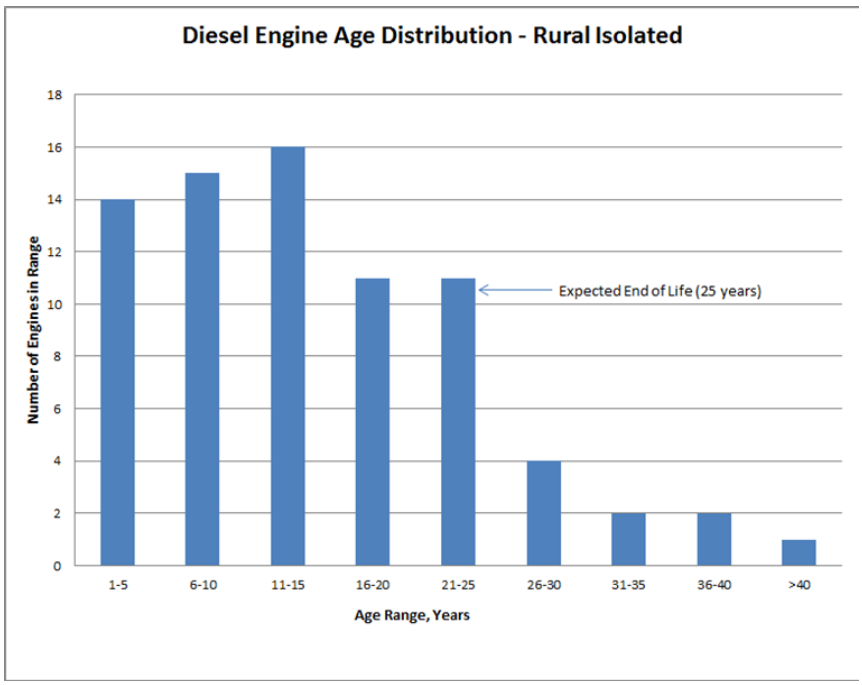

Chart 1: Diesel Engine Age Distribution – Rural Isolated System

6 General Property

Hydro's category of general properties is a broad ranging group of assets, and includes assets such as vehicles, facilities of all size, and information systems infrastructure. Similar to other categories, the assets in general properties requires replacement or refurbishment due to age, obsolescence, and at times, due to growth constraints.

6.1 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 the business. Projects in this category include personal computer and software replacements, and this type of replacement is expected to continue over the next five years.

6.2 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. The five-year plan contains expenditures in the form of several programs to replace battery banks and chargers, replace air conditioners, refurbish microwave sites, and replace obsolete radio equipment. The plan also includes site-specific projects to replace obsolete teleprotection equipment, upgrade telecontrol facilities, and replace UPS units.

6.3 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.

6.4 Administration

Safety, cost efficiencies, reliability and security are the primary drivers of the five-year administration capital plan. Hydro expects to spend an average of $1 million annually on items such as office equipment, building auxiliary systems, and building infrastructure, during the next five years.

APPENDIX A

Five-Year Capital Plan

	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
GENERATION	4,294.3	25,612.7	26,363.2	20,087.5	22,707.1	21,246.6	120,311.4
TRANSMISSION AND RURAL OPERATIONS	22,546.9	147,522.7	206,333.6	182,397.5	79,216.3	85,418.6	723,435.6
GENERAL PROPERTIES	2,422.8	9,562.6	14,058.3	14,822.3	8,212.9	4,641.7	53,720.6
CONTINGENCY FUND		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
TOTAL CAPITAL BUDGET	**29,264.0**	**183,698.0**	**247,755.1**	**218,307.3**	**111,136.3**	**112,306.9**	**902,467.6**

	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
GENERATION							
Hydraulic Plant	1,592.9	10,551.8	14,266.0	13,112.9	11,568.7	10,753.5	61,845.8
Thermal Plant	46.2	12,230.4	10,271.1	6,794.1	10,476.7	7,080.0	46,898.5
Gas Turbines	2,655.2	2,718.6	1,767.0	120.0	600.0	3,350.0	11,210.8
Tools and Equipment	0.0	111.9	59.1	60.5	61.7	63.1	356.3
TOTAL GENERATION	4,294.3	25,612.7	26,363.2	20,087.5	22,707.1	21,246.6	120,311.4
TRANSMISSION AND RURAL OPERATIONS							
Terminal Stations	14,235.1	29,868.1	21,324.5	36,653.0	34,680.4	28,373.6	165,134.7
Transmission	4,642.9	85,515.9	149,136.6	110,901.7	5,337.1	12,066.2	367,600.4
Distribution	1,136.1	11,978.0	16,792.5	18,544.6	25,059.0	32,005.2	105,515.4
Generation	1,482.4	13,716.3	13,567.9	11,446.5	9,226.4	8,330.9	57,770.4
Properties	489.4	3,883.6	3,936.9	4,076.9	4,544.3	4,269.2	21,200.3
Metering	559.9	1,026.0	724.2	191.1	191.4	191.6	2,884.2
Tools and Equipment	1.1	1,534.8	851.0	583.7	177.7	181.9	3,330.2
TOTAL TRANSMISSION AND RURAL OPERATIONS	22,546.9	147,522.7	206,333.6	182,397.5	79,216.3	85,418.6	723,435.6
GENERAL PROPERTIES							
Information Systems	0.0	3,567.8	3,043.5	2,668.5	2,825.2	2,377.8	14,482.8
Telecontrol	0.0	2,586.4	6,117.7	6,428.1	2,448.7	1,548.8	19,129.7
Transportation	2,377.1	2,051.1	3,359.5	5,315.2	2,582.5	292.4	15,977.8
Administrative	45.7	1,357.3	1,537.6	410.5	356.5	422.7	4,130.3
TOTAL GENERAL PROPERTIES	2,422.8	9,562.6	14,058.3	14,822.3	8,212.9	4,641.7	53,720.6
CONTINGENCY FUND		1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	5,000.0
TOTAL CAPITAL BUDGET	29,264.0	183,698.0	247,755.1	218,307.3	111,136.3	112,306.9	902,467.6

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
HYDRAULIC PLANT							
Install Infrared View Ports - Various Sites	83.7	113.1	112.9				309.7
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5					545.2
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	633.3					648.0
Refurbish Unit Relay Protection - Paradise River	8.7	79.7					88.4
Replace Station Service Breakers - Cat Arm	644.9	363.4					1,008.3
Rehabilitate Salmon River Spillway - Bay d'Espoir	745.6	556.8					1,302.4
Refurbish Intakes - Bay d'Espoir	72.6	262.3					334.9
Upgrade Work - Cat Arm		558.3	1,353.0				1,911.3
Replace Site Facilities - Bay d'Espoir		928.3	4,736.3	6,316.7			11,981.3
Replace Control Room/Communications Room Air Conditioning - Hinds Lake		41.3	53.0				94.3
Refurbish Station Water System - Upper Salmon		96.6	197.6				294.2
Replace Generator Cooling Water Piping - Hinds Lake		181.7					181.7
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		477.6	378.0	385.6	315.5	350.0	1,906.7
Install Hydrometeorological Equipment - Various Sites		314.1					314.1
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir		85.7					85.7
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir		2,959.6	1,171.9				4,131.5
Overhaul Turbine/Generator - Various Sites		1,345.6	365.0	400.0	408.2	430.0	2,948.8
Perform Condition Assessment of Control Structure - Hinds Lake		323.4					323.4
Replace Vibration Monitoring System Unit 7 - Bay d'Espoir		366.0					366.0
Replace Powerhouse 1 Station Service Transformer - Bay d'Espoir		46.7	354.5				401.2
Rehabilitate Shoreline Protection - Cat Arm		112.2	1,030.7				1,142.9
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir		183.6	167.9				351.5
Upgrade Generator Bearings Units 5 and 6 - Bay d'Espoir			190.0	200.0			390.0
Refurbish Salmon River Spillway - Bay d'Espoir			200.0	269.0	400.0		869.0
Refurbish Ebbegunbaeg Control Structure - Bay d'Espoir			200.0	258.0	355.0		813.0
Upgrade Powerhouse 1 and 2 Station Service - Bay d'Espoir			429.8				429.8
Upgrade Sump Level System Powerhouse 2 - Bay d'Espoir			185.0				185.0
Replace Slip Rings - Various Sites			100.0	241.0	100.0	159.0	600.0
Install Automated Fuel Monitoring - Various Sites				500.0	100.0	407.0	1,007.0
Install Partial Discharge Monitors - Paradise River			197.0				197.0
Purchase Spare HP Compressor - Bay d'Espoir			142.7				142.7
Replace Shaft Seal System - Upper Salmon			150.0				150.0
Replace Domestic Water Systems - Various Sites			242.6		350.0		592.6

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
HYDRAULIC PLANT (cont'd.)							
Overhaul Main Generator Bearing - Upper Salmon			300.0				300.0
Purchase Generator Bearing Cooler - Hinds Lake			119.7				119.7
Pilot Asset Health Monitoring Template - Upper Salmon			194.4	103.8			298.2
Upgrade Cooling Water System Unit 7 - Bay d'Espoir			665.0				665.0
Replace Ventilation in Both Powerhouses - Bay d'Espoir			200.0	539.0			739.0
Install New Vent Chambers Units 1 to 6 - Bay d'Espoir			200.0	372.0			572.0
Refurbish Generation Units - Various Sites			629.0	1,000.0	750.0	750.0	3,129.0
Replace Dry Air Compressor 1 and 2 - Bay d'Espoir				320.6			320.6
Replace Main Roof on Powerhouse 1 - Bay d'Espoir				534.3			534.3
Refurbish Relay Protection Units 5 to 7 - Bay d'Espoir				200.0	234.0		434.0
Replace Underground Oily Water Separator - Bay d'Espoir				300.0			300.0
Upgrade Roads - Various Sites					1,598.5	1,096.0	2,694.5
Replace Sump Pumps - Various Sites				317.9	109.9		427.8
Replace Firewater Pumps - Various Sites				280.0		230.0	510.0
Install Dynamic Air Gap Monitoring System - USL, HLK				300.0	350.0	450.0	1,100.0
Refurbish Generator Rotor - Hinds Lake					710.0	1,000.0	1,710.0
Replace Control Cable - Bay d'Espoir				275.0	275.0	275.0	825.0
Replace PH #1 Wet Air Compressors #3 and #4 - Bay d'Espoir					500.4		500.4
Refurbish Hydraulic Structures - Bay d'Espoir					1,000.6		1,000.6
Replace Data Acquisition Systems - Bay d'Espoir					174.6		174.6
Replace Plant HP Compressor #2 - Upper Salmon					275.1		275.1
Replace Units 1-7 Flow Measuring Devices - Bay d'Espoir					251.1		251.1
Replace Unit Relay Protection - Upper Salmon					275.8		275.8
Replace Dual Fuel Tank - Bay d'Espoir					75.0		75.0
Upgrade Generator Floor Annunciators - Bay d'Espoir					249.9	175.0	424.9
Replace T/G Cooling Water Pump and Strainer - Hinds Lake					120.0		120.0
Replace Drainage Pumps - Hinds Lake					90.1		90.1
Purchase Set of Turbine Head Cover and Bottom Ring Bushings - Hinds Lake					250.0		250.0
Replace Exciters Units - Bay d'Espoir					1,400.0	800.0	2,200.0
Stabilize PH Slope (Phase 1) - Cat Arm					400.0		400.0
Refurbish Draft Tube Deck - Bay d'Espoir					450.0	495.0	945.0
Purchase Spare Transformer for Unit 7 - Bay d'Espoir						185.0	185.0
Refurbish Intake # 2 Hatch Recs. - Bay d'Espoir						325.0	325.0
Refurbish Burnt Dam Workshop Building and Diesel Building - Bay d'Espoir						175.0	175.0
Replace PH Septic System - Hinds Lake						50.0	50.0
Install Partial Discharge Continuous Monitors - Various Sites						780.0	780.0
Refurbish Intake, Main Dam, and Section of Penstock - Snooks Arm						100.0	100.0
Replace PA System PH #1 - Bay d'Espoir						150.0	150.0
Purchase Set of Turbine Bearing Coolers - Cat Arm						90.0	90.0
Replace Chart Recorders - Various Sites						261.0	261.0
Refurbish Unit 5 Generator Rotor - Bay d'Espoir						210.0	210.0
Replace Emergency Diesel Generator - Hinds Lake						375.0	375.0
Stabilize Powerhouse Slope Phase 2 - Cat Arm						650.0	650.0
Replace Main Fire Header - Bay d'Espoir						147.4	147.4
Replace Diesel Generator 2 Victoria Control Structure - Bay d'Espoir						638.1	638.1
TOTAL HYDRAULIC PLANT	1,592.9	10,551.8	14,266.0	13,112.9	11,568.7	10,753.5	61,845.8

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
THERMAL PLANT							
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	197.6					243.8
Upgrade Powerhouse Building Envelope - Holyrood		2,723.8	2,969.9	784.1			6,477.8
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood		2,755.5					2,755.5
Study of Auxiliary Steam and Space Heating Requirements - Holyrood		148.7					148.7
Overhaul Steam Turbine Generator Unit 3 - Holyrood		5,868.6					5,868.6
Upgrade Plant Access Road - Holyrood					807.0		807.0
Replace Stage 2 Diesel - Holyrood					443.0		443.0
Replace Unit 3 600V Switchgear and Transformers- Holyrood					1,706.0		1,706.0
Overhaul Unit 2 Turbine Valves - Thermal - Holyrood			1,456.2				1,456.2
Overhaul Pumps - Holyrood		536.2	367.9				904.1
Upgrade Waste Water Basin Building - Holyrood			2,087.7				2,087.7
Overhaul Stacks Units 1, 2 and 3 - Holyrood			500.0				500.0
Upgrade Boiler Stop Values Units 1 and 2 - Holyrood			400.0				400.0
ATI Inspection and Clean out/Repairs - Tank No 1			1,000.0				1,000.0
Upgrade Cranes and Hoists - Holyrood			29.3	873.8			903.1
Install Auxiliary Boiler - Holyrood			1,043.0	3,788.2			4,831.2
Upgrade Underground Plant Drainage System - Holyrood			417.1	573.0			990.1
Install New Raw Water Line - Holyrood				500.0	1,500.0		2,000.0
Install New Lube Oil / Seal Oil Systems Unit 3 - Holyrood					250.0	750.0	1,000.0
Upgrade UPS Systems - Holyrood					520.7		520.7
Upgrade Fire Systems				275.0			275.0
Replace Stage 1 4169kV Breakers - Holyrood					1,000.0		1,000.0
Replace Unit 3 258VDC Battery Charger and Batteries - Holyrood					750.0		750.0
Upgrade Unit 3 MCC for Sync Condsr- Holyrood					1,000.0		1,000.0
Upgrade Control Room					500.0	1,000.0	1,500.0
Unit 3 Rewind Stator					2,000.0	3,000.0	5,000.0
Upgrade Electrical MCC's Unit 3 - Holyrood					0.0	1,000.0	1,000.0
Replace Stage 2 4160V AC Breakers - Holyrood						1,030.0	1,030.0
Upgrade Cooling Water System Wet Well Stop Log Unit 3 - Holyrood						300.0	300.0
TOTAL THERMAL PLANT	46.2	12,230.4	10,271.1	6,794.1	10,476.7	7,080.0	46,898.5

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
GAS TURBINES							
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,525.4					5,180.6
Install Transfer Switches for Diesel Automation - Happy Valley		148.4					148.4
Replace Fuel Piping - Hardwoods and Stephenville		44.8	267.0				311.8
Upgrade Electrical Systems - Hardwoods			1,500.0				1,500.0
Replace Compressors - Hardwoods				120.0			120.0
Install Infrared Scanning Ports - Hardwoods					250.0		250.0
Refurbish Bus Duct - Hardwoods and Stephenville					150.0	150.0	300.0
Upgrade Control System - Hardwoods					100.0	1,500.0	1,600.0
Overhaul Engine - Happy Valley					100.0	1,000.0	1,100.0
Replace Fuel Unloading Pumps - Hardwoods						50.0	50.0
Inspect Power Turbine Clutch A - Hardwoods						100.0	100.0
Install Infrared Scanning Ports - Stephenville						250.0	250.0
Upgrade Control System - Stephenville						100.0	100.0
Inspect Power Turbine Clutch - Happy Valley						200.0	200.0
TOTAL GAS TURBINE PLANTS	2,655.2	2,718.6	1,767.0	120.0	600.0	3,350.0	11,210.8
TOOLS AND EQUIPMENT							
Purchase Tools and Equipment Less than $50,000		111.9	59.1	60.5	61.7	63.1	356.3
TOTAL TOOLS AND EQUIPMENT	0.0	111.9	59.1	60.5	61.7	63.1	356.3
TOTAL GENERATION	4,294.3	25,612.7	26,363.2	20,087.5	22,707.1	21,246.6	120,311.4

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
TERMINAL STATIONS							
Replace Instrument Transformers - Various Sites	1,684.4	1,511.7	471.9	1,100.4	650.1	600.0	6,018.5
Replace Disconnect Switches - Various Sites	963.7	642.9					1,606.6
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,873.8					13,062.9
Upgrade Power Transformers - Various Sites	4,440.4	7,002.3	1,988.9	2,036.8	2,085.1	2,000.0	19,553.5
Upgrade Terminal Station Protection and Control - Various Sites	172.7	307.2					479.9
Install Transformer On line Gas Monitoring - Various Sites	700.5	975.7					1,676.2
Replace Station Lighting - Bay d'Espoir	16.7	160.3					177.0
Design and Install Fire Protection in 230 kV Stations - Various Sites	67.6	424.3					491.9
Install Fire Protection in 230 kV Stations - Bay d'Espoir		200.0	566.0	650.0	650.0	650.0	2,716.0
Upgrade Digital Fault Recorders - Various Sites		197.9	304.6	500.0	500.0	500.0	2,002.5
Upgrade Data Alarm Systems - Stony Brook		74.4	234.1	300.0	300.0	300.0	1,208.5
Replace Protective Relays - Various Sites		700.6	1,156.4	1,700.0	1,900.0	1,900.0	7,357.0
Install Breaker Failure Protection - Various Sites		65.7	211.3	250.0	250.0	250.0	1,027.0
Upgrade Roof - Indian River		48.3					48.3
Upgrade Terminal Station for Mobile Substation - Cow Head		40.0	444.7				484.7
Upgrade Terminal Station Equipment Foundations - Various Sites		319.9	328.9	338.1	347.4	357.1	1,691.4
Upgrade Aluminum Support Structure - Holyrood		401.1	357.9	313.6			1,072.6
Replace Disconnect Switches - Various Sites		646.9	1,320.9	983.3	990.3	1,000.0	4,941.4
Upgrade Circuit Breakers - Various Sites		6,969.1	10,808.7	15,408.6	15,247.3	13,026.8	61,460.5
Replace Surge Arrestors - Various Sites		144.4	53.0	195.4	202.6	210.0	805.4
Replace Air Receivers and Compressors - St. Anthony		120.7					120.7
Install Spare Transformer - Happy Valley		2,040.9	84.7	653.4			2,779.0
Perform Site Work for Mobile Substation - Various Sites			175.0	554.2	570.0	585.6	1,884.8
Upgrade Control Building for Staff Working Spaces -Various Sites			453.4	773.5			1,226.9
Replace Telecontrol Building and Upgrade Equipment - Daniels Harbour					57.0	764.0	821.0
Replace Insulators - Various Sites			354.4	362.8	371.4	380.1	1,468.7
Perform Grounding Upgrades - Various Sites			341.5		300.0	300.0	941.5
Upgrade Substation - Wabush			1,568.2	7,018.9	6,959.2		15,546.3
Upgrade Station Service - Oxen Pond and Sunnyside				350.0		300.0	650.0
Replace Outside Service - Holyrood				750.0			750.0
Install Drainage to Stop Surface Flooding - Various Sites				500.0			500.0
Upgrade Access Road with New Topping - Buchans				250.0			250.0
Install 66 kV Breaker By-Pass Switches - Various Sites				515.0		350.0	865.0
Replace T1 2.5 MVA Transformer - Conne River				800.0			800.0
Install Remote Control Sectionalizer TL251(2)(3) - Hampden				349.0			349.0

PROJECT DESCRIPTION	Expended to 2015 ($000)	2016	2017	2018	2019	2020	Total
TERMINAL STATIONS (cont'd.)							
Replace Transformer - Various Sites			100.0		1,300.0	1,300.0	2,700.0
Install Fire Barriers Between T10 and T12 and Between T10 and T11 - Bay d'Espoir					400.0	400.0	800.0
Install Data Acquisition and Trending - Corner Brook					500.0	200.0	700.0
Install Alternate Station Service - Grand Falls					100.0		100.0
Purchase New Mobile Substation - Bishop's Falls					100.0	1,500.0	1,600.0
Construct Fire Separation Wall Between Power Transformers - Happy Valley					400.0	300.0	700.0
Replace Capacitor Banks - Various Sites					400.0		400.0
Upgrade DC Station Service - Various Sites					100.0	200.0	300.0
Replace Corroded Junction Boxes - Various Sites						200.0	200.0
Upgrade Lighting - Various Sites						200.0	200.0
Install Fire Barriers between T1 T2 and T3 - Massey Drive						100.0	100.0
Install Telephone System - Bottom Waters						500.0	500.0
TOTAL TERMINAL STATIONS	14,235.1	29,868.1	21,324.5	36,653.0	34,680.4	28,373.6	165,134.7

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
TRANSMISSION							
Perform Wood Pole Line Management Program - Various Sites		2,919.0	3,201.8	3,473.3	2,513.4	2,094.9	14,202.4
Upgrade Reliability - Hawke's Bay			1,433.9	10,089.9			11,523.8
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	239.9	1,038.4	901.6				2,179.9
Replace Aircraft Markers at Grand Lake Crossing - TL228		589.6	978.3				1,567.9
Replace Insulators - TL203		1,985.6					1,985.6
Construct 230 kV Transmission Line - Bay d'Espoir to Western Avalon	4,403.0	75,284.3	123,739.6	88,231.1			291,658.0
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods		3,699.0	17,489.8	5,372.1			26,560.9
Conduct LIDAR Surveys - Various Sites			283.9	292.0	560.2		1,136.1
Upgrade Transmission Lines - Various Sites			1,107.7	2,437.7	235.6	7,921.0	11,702.0
Construct Transmission Line Equipment Off-Loading Areas - Various Sites				1,005.6	1,027.9	1,050.3	3,083.8
Upgrade Tower Foundations - Various Sites					1,000.0	1,000.0	2,000.0
TOTAL TRANSMISSION	4,642.9	85,515.9	149,136.6	110,901.7	5,337.1	12,066.2	367,600.4

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
DISTRIBUTION							
Upgrade Distribution System - Various Sites (2015-2016)	1,136.1	818.8					1,954.9
Provide Service Extensions - All Service Areas		5,150.0	5,270.0	5,670.0	6,070.0	6,480.0	28,640.0
Upgrade Distribution Systems - All Service Areas		3,890.0	3,820.0	3,780.0	3,730.0	3,680.0	18,900.0
Upgrade Distribution Systems - Various Sites		285.6	6,588.3	2,438.0	4,336.0	9,160.2	22,808.1
Additions for Load Growth - Various Sites		593.7	500.0	500.0	500.0	500.0	2,593.7
Construct Overhead Distribution Line - Pilley's Island to Long Island		1,239.9					1,239.9
Automate Reclosers - Various Sites			47.1	418.6			465.7
Implement Geographical Information System - Various Sites			93.1				93.1
Extend Three Phase to St. Paul's - Cow Head			474.0				474.0
Additions for Load Growth - Labrador South Interconnection				5,738.0	7,923.0		13,661.0
Replace Submarine Cable Farewell Head to Change Islands - FGO					2,500.0	10,125.0	12,625.0
Convert La Scie L7 to 25 kV - Bottom Waters						350.0	350.0
Convert Section Coachman's Cove to 14.4 kV - Fleur De Lys						585.0	585.0
Upgrade L2 and Underground Feeder - South East Bight						325.0	325.0
Replace Dist. Transformers and Power Transformers - Wabush						800.0	800.0
TOTAL DISTRIBUTION	1,136.1	11,978.0	16,792.5	18,544.6	25,059.0	32,005.2	105,515.4

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
GENERATION							
Purchase Diesel Plant Production Data Collection Equipment - Various Sites	538.7	280.7					819.4
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	189.3					199.3
Replace Unit 2038 - Mary's Harbour	103.5	1,241.5					1,345.0
Upgrade Ventilation -Various Sites	175.9	317.3				250.0	743.2
Install Fire Protection - L'Anse Au Loup	220.6	1,126.2					1,346.8
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1				958.0
Replace Diesel Unit 254 - Paradise River	66.8	429.3					496.1
Upgrade Transformers Systems - Cartwright and Postville		465.2					465.2
Additions for Load Growth - Various Sites		883.4	4,746.0	461.7			6,091.1
Replace Diesel Units - Cartwright and Charlottetown		1,840.5	3,098.4				4,938.9
Install Fire Protection Systems - Various Sites		3,030.7	1,476.4	500.0	500.0	500.0	6,007.1
Inspect Fuel Storage Tanks - Various Sites		1,326.9	658.0	676.4	695.4	714.8	4,071.5
Overhaul Diesel Units - Various Sites		2,078.4	1,503.4	1,535.7			5,117.5
Install Variable Frequency Drives - Grey River		46.9	123.0				169.9
Replace Underground Glycol Line - Francois			100.0	0.0	0.0	0.0	100.0
Replace Radiators - Various Sites			500.0	200.0	300.0	100.0	1,100.0
Replace Diesel Units - Various Sites			180.0	1,270.0			1,450.0
Insulate Diesel Plant - St. Anthony			63.5				63.5
Replace Human Machine Interface - Various Sites		114.0	320.0	200.0	200.0	200.0	1,034.0
Install Mobile Diesel Quick Connect/Disconnect - Various Sites			178.8				178.8
Upgrade Fuel Storage - Little Bay Islands			125.3				125.3
Perform Plant Improvements as Per 2012 FEED Project - Various Sites			250.0	250.0	250.0	250.0	1,000.0
Additions for Load Growth - Labrador South Generation				5,000.0	5,000.0		10,000.0
Install Unit Fuel Metering - Various Sites				600.0			600.0
Install Sectionalizing for Cold Load Pickup - Port Hope Simpson				250.0			250.0
Install Nox Monitors at 2 Sites - Various Sites				302.7			302.7
Upgrade Site Facilities - Various Sites						1,677.0	1,677.0
Replace Diesel Plant - Rigolet				200.0	2,000.0	2,050.0	4,250.0
Install Sequence of Events Monitor in Diesel Plants - Various Sites					281.0	289.1	570.1
Replace Unit Breakers - Port Hope Simpson						200.0	200.0
Purchase Mobile Diesel - Bishop's Falls						1,400.0	1,400.0
Install Waste Oil Storage Tank - Various Sites						150.0	150.0
Build Fire Separation Wall Between Transformers - St Anthony						50.0	50.0
Replace Existing Bus with 1,600 Amp Bus - Hopedale						500.0	500.0
TOTAL GENERATION	1,482.4	13,716.3	13,567.9	11,446.5	9,226.4	8,330.9	57,770.4

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
PROPERTIES							
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	1,061.4					1,550.8
Upgrade Warehouse Lighting - Bishop's Falls		15.2	180.4				195.6
Upgrade Office Facilities and Control Buildings - Various Sites		1,134.0	1,340.9	1,458.8	2,002.1	1,997.6	7,933.4
Replace Roof on Services Building - Bishop's Falls		612.8					612.8
Install Fall Protection Equipment - Various Sites		198.8	198.8	199.0	199.2	199.7	995.5
Upgrade Line Depots - Various Sites		861.4	1,497.4	1,620.1	1,787.0	1,751.9	7,517.8
Upgrade Classroom and Boardroom in Main Office - Bishop's Falls			77.4				77.4
Construct Storage Buildings - Makkovik and Springdale			407.2				407.2
Upgrade Outside Properties - Various Sites			234.8			120.0	354.8
Upgrade Fire System - Bishop's Falls				799.0	556.0		1,355.0
Replace Roof on Garage - Bishop's Falls						100.0	100.0
Upgrade HVAC System - Stephenville						100.0	100.0
TOTAL PROPERTIES	489.4	3,883.6	3,936.9	4,076.9	4,544.3	4,269.2	21,200.3
METERING							
Install Automated Meter Reading - Various Sites (2015-2016)	559.9	401.8					961.7
Purchase Meters and Metering Equipment - Various Sites		190.4	190.8	191.1	191.4	191.6	955.3
Install Automated Meter Reading - Labrador West		433.8	533.4				967.2
TOTAL METERING	559.9	1,026.0	724.2	191.1	191.4	191.6	2,884.2
TOOLS AND EQUIPMENT							
Replace Off Road Track Vehicle Unit 7861 - Stephenville	1.1	397.8					398.9
Purchase Tools and Equipment Less than $50,000		477.0	222.6	173.7	177.7	181.9	1,232.9
Replace Light Duty Mobile Equipment - Various Sites		348.0	494.8				842.8
Purchase Backhoe Loaders - Bishop's Falls			133.6				133.6
Replace Off Road Track Vehicle Unit No. 7565 - Stephenville				410.0			410.0
Purchase Excavator - Bay d'Espoir		312.0					312.0
TOTAL TOOLS AND EQUIPMENT	1.1	1,534.8	851.0	583.7	177.7	181.9	3,330.2
TOTAL TRANSMISSION AND RURAL OPERATIONS	22,546.9	147,522.7	206,333.6	182,397.5	79,216.3	85,418.6	723,435.6

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
INFORMATION SYSTEMS							
SOFTWARE APPLICATIONS							
New Infrastructure							
Perform Minor Application Enhancements - Hydro Place		346.7	348.3	358.0	368.0	378.4	1,799.4
Cost Recovery		(148.8)	(149.7)	(153.9)	(158.2)	(162.6)	(773.2)
Upgrade of Technology							
Upgrade Energy Management System - Hydro Place		246.2	206.0	231.5	217.8	223.7	1,125.2
Upgrade Microsoft Office Products - Hydro Place		683.7	953.4	957.3	1,192.5	1,218.4	5,005.3
Cost Recovery		(317.1)	(442.2)	(444.0)	(512.8)	(523.9)	(2,240.0)
Upgrade Citrix - Hydro Place		297.6					297.6
Cost Recovery		(138.0)					(138.0)
Upgrade Sharepoint/Document Repository - Hydro Place		267.6					267.6
Cost Recovery		(124.1)					(124.1)
Refresh Security Software - Hydro Place		230.4	136.2	140.1	144.2		650.9
Cost Recovery		(106.9)	(58.6)	(60.2)	(62.0)		(287.7)
Implement Industrial Billing Software - Hydro Place		443.1					443.1
Upgrade ERP System (JDE) - Hydro Place			866.4				866.4
Cost Recovery			(320.6)				(320.6)
Implement Industrial Billing Software MV90xi - Hydro Place			63.1				63.1
Upgrade Showcase Reporting System			195.3				195.3
Cost Recovery			(72.3)				(72.3)
Upgrade Business Intelligence and Disclosure Management - Hydro Place				414.1			414.1
Cost Recovery				(153.2)			(153.2)
Upgrade Electronic Mail System - Hydro Place				592.5			592.5
Cost Recovery				(219.2)			(219.2)
Upgrade Database Environment - Hydro Place				209.3			209.3
Cost Recovery				(77.4)			(77.4)
Refresh Security Card System - Hydro Place				172.2			172.2
Cost Recovery				(73.7)			(73.7)
Upgrade Electronic Mail System - Hydro Place					709.5		709.5
Cost Recovery					(305.0)		(305.0)
TOTAL SOFTWARE APPLICATIONS		1,680.4	1,725.3	1,893.4	1,594.0	1,134.0	8,027.1

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
COMPUTER OPERATIONS							
Infrastructure Replacement							
Replace Personal Computers - Various Sites		861.7	387.2	386.3	568.2	575.0	2,778.4
Replace Peripheral Infrastructure - Various Sites		611.3	177.3	223.5	213.9	210.0	1,436.0
Cost Recovery		(186.8)					(186.8)
Upgrade Enterprise Storage Capacity - Hydro Place		628.8	553.6	169.2	456.0	475.0	2,282.6
Cost Recovery		(291.6)	(237.9)	(72.7)	(196.0)	(204.3)	(1,002.5)
Upgrade of Technology							
Upgrade Server Technology Program - Hydro Place		492.5	768.2	120.7	331.6	330.0	2,043.0
Cost Recovery		(228.5)	(330.2)	(51.9)	(142.5)	(141.9)	(895.0)
TOTAL COMPUTER OPERATIONS		1,887.4	1,318.2	775.1	1,231.2	1,243.8	6,455.7
TOTAL INFORMATION SYSTEMS		3,567.8	3,043.5	2,668.5	2,825.2	2,377.8	14,482.8

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
TELECONTROL							
NETWORK SERVICES							
Purchase Tools and Equipment Less than $50,000		45.6	46.4	47.6	48.7	49.7	238.0
Replace Network Communication Equipment - Various Sites		186.4	180.0	185.0	180.0	185.0	916.4
Replace Video Conferencing Bridge - Hydro Place		182.6					182.6
Replace Powerline Carrier - Various Sites		73.4	2,259.6	4,662.0			6,995.0
Upgrade Remote Terminal Units - Various Sites		89.6					89.6
Replace Battery Banks and Chargers - Various Sites		425.0	456.6	600.0	600.0	600.0	2,681.6
Replace UPS Systems - Hydro Place		889.8					889.8
Upgrade Telecontrol Facilities - Sandy Brook Hill		101.6	462.4				564.0
Upgrade Access Roads to Microwave Sites - Various Sites		141.1	121.6	124.4	127.0	130.0	644.1
Replace Air Conditioners - Various Sites		39.9	152.0	150.0	150.0	150.0	641.9
Upgrade Site Facilities - Various Sites		49.5	49.4	46.9	48.0	49.1	242.9
Replace Radomes - Various Sites		235.2	196.0	196.0	180.0	185.0	992.2
Replace MDR 4000 Microwave Radio East - Various Sites		77.4	1,093.1				1,170.5
Replace Wescom Transceivers - Various Sites		49.3					49.3
Refurbish Microwave Shelters -Various Sites			90.0	90.0			180.0
Install Substation Communications Management - Various Sites			237.8		90.0		327.8
Build Communications Shelters - Various Sites			360.0				360.0
Replace GPS Clocks - Various Sites			52.8				52.8
Replace PBX Phone Systems - Various Sites			360.0	240.0			600.0
Replace MDR 6000 Microwave Radio (East) - Various Sites				86.2	825.0		911.2
Refurbish Communication Towers - Various Sites					200.0	200.0	400.0
TOTAL TELECONTROL		2,586.4	6,117.7	6,428.1	2,448.7	1,548.8	19,129.7

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
				($000)			
TRANSPORTATION							
Replace Vehicles and Aerial Devices - Various Sites (2015-2016)	2,377.1	225.3					2,602.4
Replace Vehicles and Aerial Devices - Various Sites (2016-2017)		1,443.3	534.2				1,977.5
Purchase Vehicles and Aerial Devices - Various Sites		382.5	172.7				555.2
Replace Vehicles and Aerial Devices - Various Sites			2,652.6	5,315.2	2,582.5	292.4	10,842.7
TOTAL TRANSPORTATION	2,377.1	2,051.1	3,359.5	5,315.2	2,582.5	292.4	15,977.8
ADMINISTRATION							
Purchase Office Equipment		172.6	71.1				243.7
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	311.3					357.0
Replace Roof - Hydro Place		639.5	832.2				1,471.7
Replace Air Conditioning Units 8 and 14 - Hydro Place		34.6	229.5				264.1
Remove Safety Hazards - Various Sites		199.3	204.8	210.5	216.5	222.7	1,053.8
Replace Transfer Switch - Hydro Place			200.0				200.0
Replace Washroom Fixtures - Hydro Place				125.0			125.0
Replace Parking Lot Light Poles - Hydro Place				75.0			75.0
Replace Domestic Water Entrance - Hydro Place					50.0		50.0
Access Emergency Power System - Hydro Place					30.0		30.0
Refurbish Stairways, Railings and Entrance Ways - Hydro Place					60.0		60.0
Replace Elevator Motors and Controls Equipment - Hydro Place						200.0	200.0
TOTAL ADMINISTRATION	45.7	1,357.3	1,537.6	410.5	356.5	422.7	4,130.3
TOTAL GENERAL PROPERTIES	2,422.8	9,562.6	14,058.3	14,822.3	8,212.9	4,641.7	53,720.6

APPENDIX B

TL 267 PROJECT – 230 kV Transmission

Bay d'Espoir to Western Avalon

Report

SUMMARY

The Board of Commissioners of Public Utilities (the Board) approved the Newfoundland and Labrador Hydro Upgrade of Transmission Line Corridor (the Project) on December 12, 2014, with a total capital expenditure of approximately $291M and an in-service date of May 1, 2018. The project includes two terminal station expansions and 188 km of 230 kV transmission line.

Engineering for both the transmission line and terminal stations has commenced and is on schedule to feed the procurement and construction efforts. The environmental assessment process is also on schedule, with the project submitted for registration on July 16, 2015. Procurement plans are on track, with the bulk of the equipment purchases to occur in 2015 and 2016. Construction is scheduled for 2016 to 2018, and all activities to support the required start dates are in progress as planned.

Cost expenditure is tracking as expected and planned, with much of the cost to occur in the 2016 to 2018 years. The re-baselined schedule has been developed based on the new start date and is being used for tracking and control purposes.

Overall, the project is on target for successful completion, on time and within budget.

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1 INTRODUCTION

The Board approved the Project on December 12, 2014. The Project, now known as TL 267, involves design and construction of 188 km of 230 kV steel tower transmission line, as well as station expansions at Bay d'Espoir and Western Avalon at Chapel Arm. The approved capital expenditure is $291,658,000. As directed by the PUB as part of the release of the Project, an annual report shall be filed with each capital budget application until completion of the Project. The Project will continue until commissioning on or before May 1, 2018.

2 PROJECT DESCRIPTION

On April 30, 2014, Hydro filed an application for approval to construct a 230 kV transmission line between Bay d'Espoir (BDE) Hydroelectric Generation Station and Western Avalon Terminal Station (WAV) at Chapel Arm, including upgrades at both stations to accommodate the new infrastructure. The Project was justified based on maintaining system reliability and meeting the long-term power requirements of the Island Interconnected system. It will provide additional capacity, enhance resiliency to system faults and relieve congestion on the existing transmission system. Based on the information supplied by Hydro as part of the Project review process, the PUB released Board Order P.U. 53(2014) on December 12, 2014 approving the Project as described. Given the synergies between the execution of the TL 267 Project and the Lower Churchill Project, the Lower Churchill Management Corporation will provide all project management, engineering and construction management services for this Project.

The Project is comprised of three distinct projects, and two sub projects. The three distinct projects are:

1) the addition of portions of a third breaker and one half station diameter (a row of breakers between two common busses - see photo – "Bay d'Espoir Terminal Station 2") including 2 circuit breakers, 4 disconnect switches and associated electrical and protection and control equipment in Bay d'Espoir Terminal Station 2 (BDE-TS2) using traditional Air Insulated Switchgear (AIS),
2) the addition of gas insulated switchgear (GIS) ring bus in WAV at Chapel Arm , and
3) a new 230 kV transmission line 188 km in length linking the two stations.

The two sub-projects are:

1. modifications to BDE-TS2 to allow for independent isolation of TL 206, converting the existing ring bus to a breaker and one half scheme, and
2. modifications to WAV to connect TL 208, which currently services the VALE site, to the new station expansion.

Given limited outage opportunities, the two sub-projects will be executed after TL 267 goes in service, and as outage coordination and limitations permit.

3 ENGINEERING

The Project, including all station modifications and line designs, will utilize all of the latest industry standards and practices and design criteria currently in use by Hydro. Modifications to the stations will include the latest electrical and protection and control equipment that is currently maintained in the system and form the basis of new designs going forward. Transmission line design will utilize Hydro's operational experience and design criteria applicable along the existing corridor to ensure a reliable addition to the Island Interconnected grid. Two icing zones have been identified for the transmission line: between Bay d'Espoir and Pipers Hole Park with 50 mm radial glaze and between Pipers Hole Park and WAV with 75 mm radial glaze.

The engineering for TL 267 involves the creation of a new tower family capable of structurally maintaining reliable service with the inclusion of shield wire for lighting outage protection. This new tower family includes two new suspension towers, modelled along the same design fundamentals of the 315 kV lines for the Lower Churchill Project. These towers follow the guyed-Y configuration (see Section 9) with the A-Type tower capable of 0° to 1° line angles, and a B-Type tower designed for angles of 0° to 6°. Two new strain towers are required, with a self-supported C-Type tower capable of angles from 0° to 30°, and a full-tension deadend D-Type tower for 0° to 45°. The D-Type tower is capable of anti-cascade failure containment within the range of angles of the tower. The existing Hydro NDD-Type tower, designed for the Avalon Upgrade in the early 2000s, has been verified as adequate for this application and will be utilized for angles between 45° and 90°. Shield wires, including one standard overhead ground wire and one optical ground wire which includes optical fibres for the communication system, will be utilized along the entire length.

Design for the new tower family commenced in January 2015, and foundation design began in May 2015 once tower loads and reaction forces were finalized. All towers are being fully designed in-house, including all necessary documentation for eventual detailing of the tower connection plates, prototype assembly of all towers, full-scale tower testing of the A-type and

D-type towers, as well as mass production by the tower manufacturer. To date, and as planned, all tower designs are 100% complete to the level required for the tender package. Tower foundations are also 100% complete to the level required for the tender package. Tower foundations will be manufactured by the same tower manufacturer awarded the contract following the Public Tender process.

The first step in line design is assessing and selecting a preliminary line route. This route is preliminary given that the environmental assessment process (discussed in Section 4) has not yet been completed. Preliminary line design, which has been completed as planned, quantifies the number, types and heights of the required towers for the entire line using “stick models”. Stick models are representative towers used in the design software and are based on the "as-designed" capacity. Final line design requires the use of the final tower model capacities after detailing by the manufacturer, and will be completed in 2016. The preliminary line design allows for quantification of the towers and hardware for tendering purposes, allowing for accurate bid quantities and initial ordering of the first material deliveries.

Station design involves a significant amount of detailed engineering prior to tendering, given that both station modifications are in existing terminal stations, and it is more efficient to provide the design details to the potential bidders.

For the BDE-TS2, the original station design included space for an additional electrical breaker and one half diameter, and therefore expansion outside the existing station footprint is not required. The new station diameter will include standard AIS using modern circuit breakers and associated equipment and infrastructure. Support equipment, including take-off structures for the overhead lines, will be similar to the existing infrastructure. New protection and control panels will be required in the existing control building, as well as associated station modifications to run the control wiring. Connection to the SCADA system for communication with the Energy Control Centre is also required.

The WAV station involves a new GIS module given the lack of easily usable space around the station, and the cost of developing new land in the area. An investigation confirming the requirement for GIS was completed and verified that GIS is the most economical solution for WAV. Hydro currently has a GIS at the Cat Arm Generating Station which has operated reliably for the past 30 years, and GIS solutions are common in areas when the footprint is limited.

Engineering commenced for WAV and BSE-TS2 with site visits completed in May, 2015. Quantification of the complete work scope and the collection of existing documentation have also begun. BSE-TS2 will involve tendering for the major components including circuit breakers, disconnect switches and associated equipment. A second tender will include all protection and control equipment. Engineering has commenced on detailing the technical specification for the station equipment, both electrical and protection and control.

WAV will be executed as an Engineer Procure and Construct (EPC) contract. Therefore, a detailed technical specification and scope of work are under development as planned, but are only at a preliminary level to date.

4 ENVIROMENTAL ASSESSMENT

Given the size and nature of the Project, registration for environmental assessment (EA) under the Environmental Protection Act is required. Environmental assessment is an evaluation of a project's potential environmental risks and effects before it is carried out. EA also identifies ways to improve project design and implementation to prevent, minimize, mitigate, or compensate for adverse environmental effects and to enhance positive effects. The EA Registration Document for this project is an enhanced registration document, which includes baseline studies for key environmental components such as caribou, avifauna, historic resources, rare plants, and an assessment of the effects of the Project on these components.

Consultation is a cornerstone of the EA process. Hydro consulted with key stakeholders, and held open house sessions in June, 2015, in select communities including, Bay d'Espoir, Come By Chance and Chapel Arm to inform stakeholders about the new line and to have meaningful discussions and identify concerns.

The Project was submitted for registration as an undertaking under Part 10 of the provincial *Environmental Protection Act* on July 16, 2015. Following a public review period, the Minister of Environment and Conservation has 45 days from registration to notify the proponent of release, or that an environmental preview report or environmental impact statement is required. However, the preferred and primary routing through the Bay Du Nord Wilderness Reserve (BDNWR) will delay the decision by the Minister until the process described in the following paragraph is completed.

The primary route for TL 267 is parallel and adjacent to existing transmission lines along the entire 188 km to minimize the environmental impact. As part of the EA, alternative routes will be considered and assessed. The primary route is located within the BDNWR for 13 km. The reserve was established as a Wilderness Reserve under the Newfoundland and Labrador Wilderness and Ecological Reserve Act in 1990. Although it contains two existing transmission lines constructed in the mid-1960s, the Wilderness Reserve Regulations do not allow for the

construction of a new transmission line through the BDNWR. Provisions in the Act outline the process to allow for the Lieutenant-Governor in Council to reduce the size of the reserve. In order to allow for line construction through the BDNWR, the proposed right of way, 40 m wide and 13 km long, would have to be removed from the BDNWR. The process required for this removal was initiated in May 2015, and is currently ongoing. A decision regarding the BDNWR is expected in 7 to 8 months, and will be run concurrently with the EA process. Final release will occur when both processes are complete.

No construction can proceed prior to release by the Minister of Environment and Conservation from the EA process. All required environmental activity is on schedule as planned.

5. PROCUREMENT

Procurement activities reflect the early stage of the Project. Therefore, the contracting strategy is subject to change during execution. The pre-qualification for tower manufacturers has been issued as planned. Results of this pre-qualification effort will be used for the tower and foundation tender, which is on the critical path for the Project. Next steps include tenders to be issued for tower hardware, steel wire, insulators, conductor, electrical and protection and control equipment for BDE-TS2. Tenders will also be issued for the EPC contract for the WAV GIS module, construction for the BDE-TS2 modifications, clearing and access for the transmission line, and construction of the transmission line. A high level schedule for this activity is shown in Appendix A.

6. CONSTRUCTION

Given the early stage of the Project, and the status of the EA process, construction has not commenced; however, this is as planned, with clearing scheduled to start in March 2016. An assessment of the constructability has been completed, including a flyover of the preliminary line route. An access assessment has also been completed. The access assessment is important given that 90 km of the line is accessible from each end only via existing access trails constructed for parallel lines (e.g., TL 202, TL 206). The constructability assessment indicated that there are no significant issues that will restrict line construction, despite the limited access to the central section of the transmission line.

7. COST

A significant portion of the expenditure for this Project will occur in 2016 and 2017. The first 7 months covered by this first annual report primarily includes EA, engineering and planning expenditures and the rate of spend across the project duration will increase as construction commences.

As part of the project execution, a re-baseline of the cash flow was completed based on the actual start date of the project, post Board approval, and based on the execution model detailed previously. This re-baseline will include expenditures of $4.4M (2015), $75.3M (2016) $123.7M (2017) and $88.2M (2018). Approximately $500,000 has been expended during the first seven months of 2015 on transmission and station engineering, environmental work and project management. This is in line with the planned Project start-up. Significant equipment expenditure will be realized prior to the next update in August 2016, when most of the results of the tender packages for line and station equipment will be available. A more detailed report will be presented at that time. The July 2016 Annual Report for this Project will also include the clearing contract cost as it will have been awarded and partially executed.

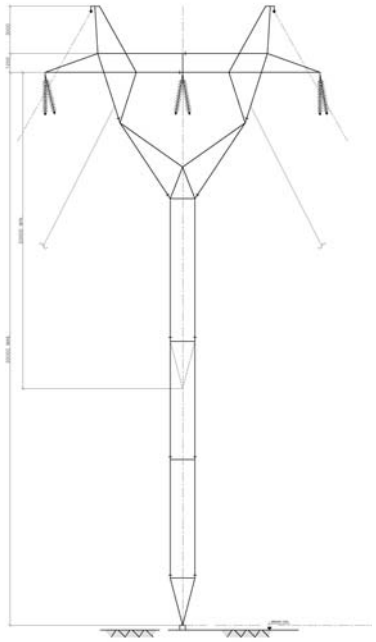
8. SCHEDULE

The updated milestone schedule is in Appendix A.

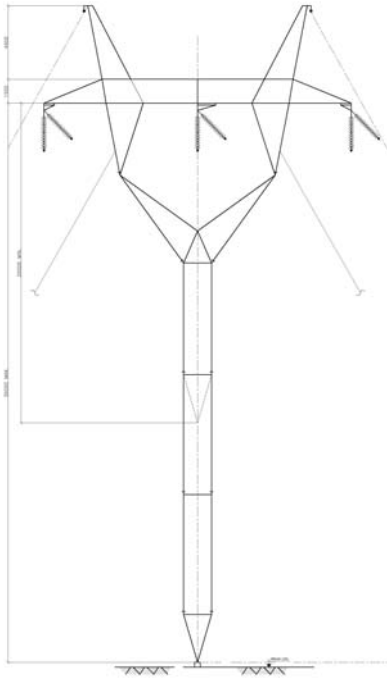
This schedule is currently being used to track progress, and is based on an environmental assessment (EA) release by the Minister in December 2015 to allow for clearing activities to start in March 2016. The Project was submitted for registration for EA on July 16, 2015, and the process to remove the Right of Way from the BDNWR was initiated in May 2015. Overall, at this early point of execution, transmission engineering is on schedule with tower and foundation designs and preliminary line design completed. The tower and foundation tender package is ready to be distributed to the successful pre-qualified bidders. Station engineering, although early in the process, is progressing as planned.

Based on the start date of January 1, 2015, and the in-service date of May 1, 2018, the project is on schedule and there are no schedule challenges identified to date. Environmental assessment approval is currently on schedule; however, delay in release from EA is a known risk for all projects requiring EA approval and is largely outside the control of Hydro. Although not anticipated, this can influence the construction start time.

9. DRAWINGS AND PHOTOS



Tower Type A



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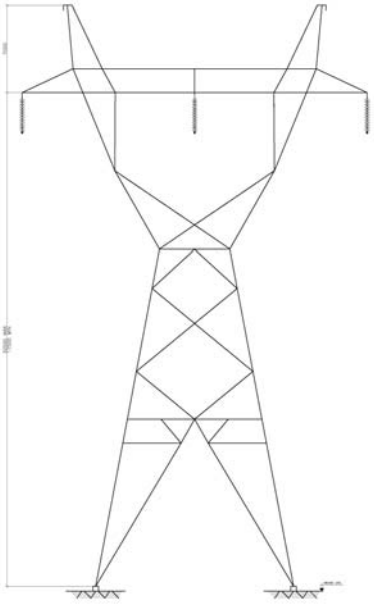
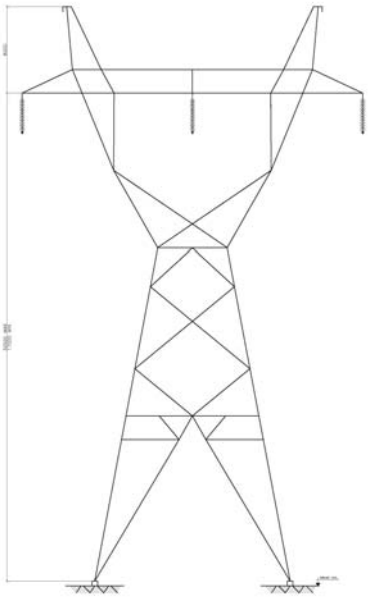
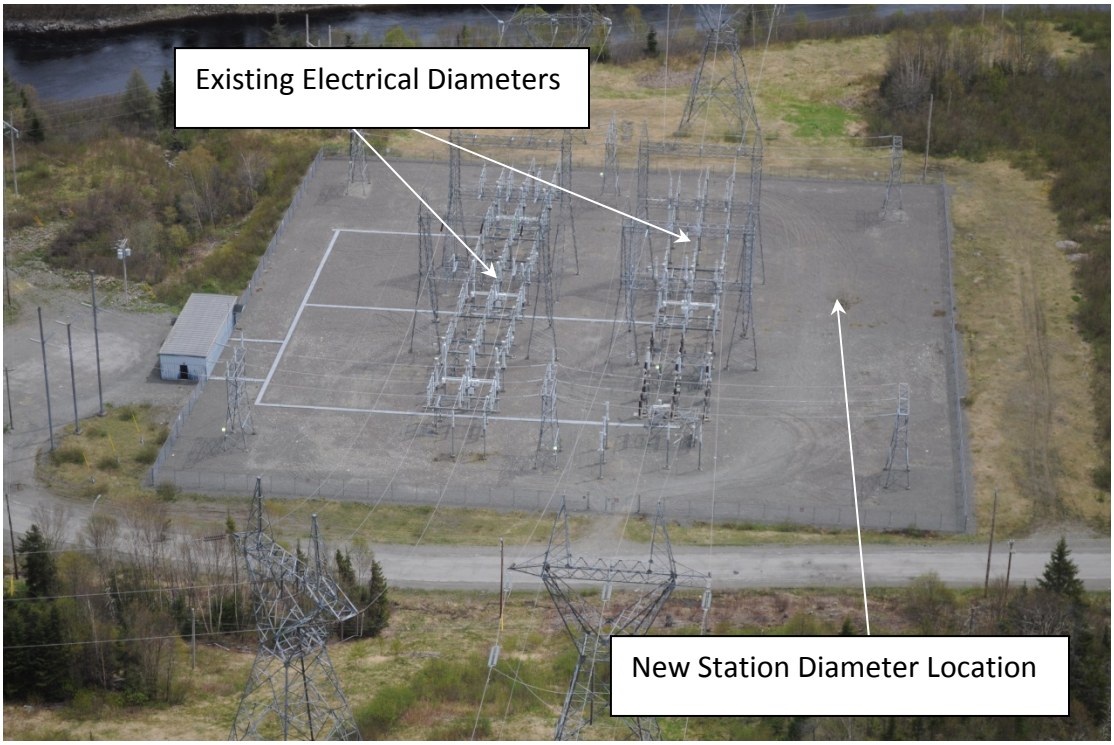


Tower Type C



Tower Type D



Bay d'Espoir Terminal Station 2

Western Avalon Terminal Station

Typical TL 202/TL 206 right of way near BDE; TL 267 will be on the right

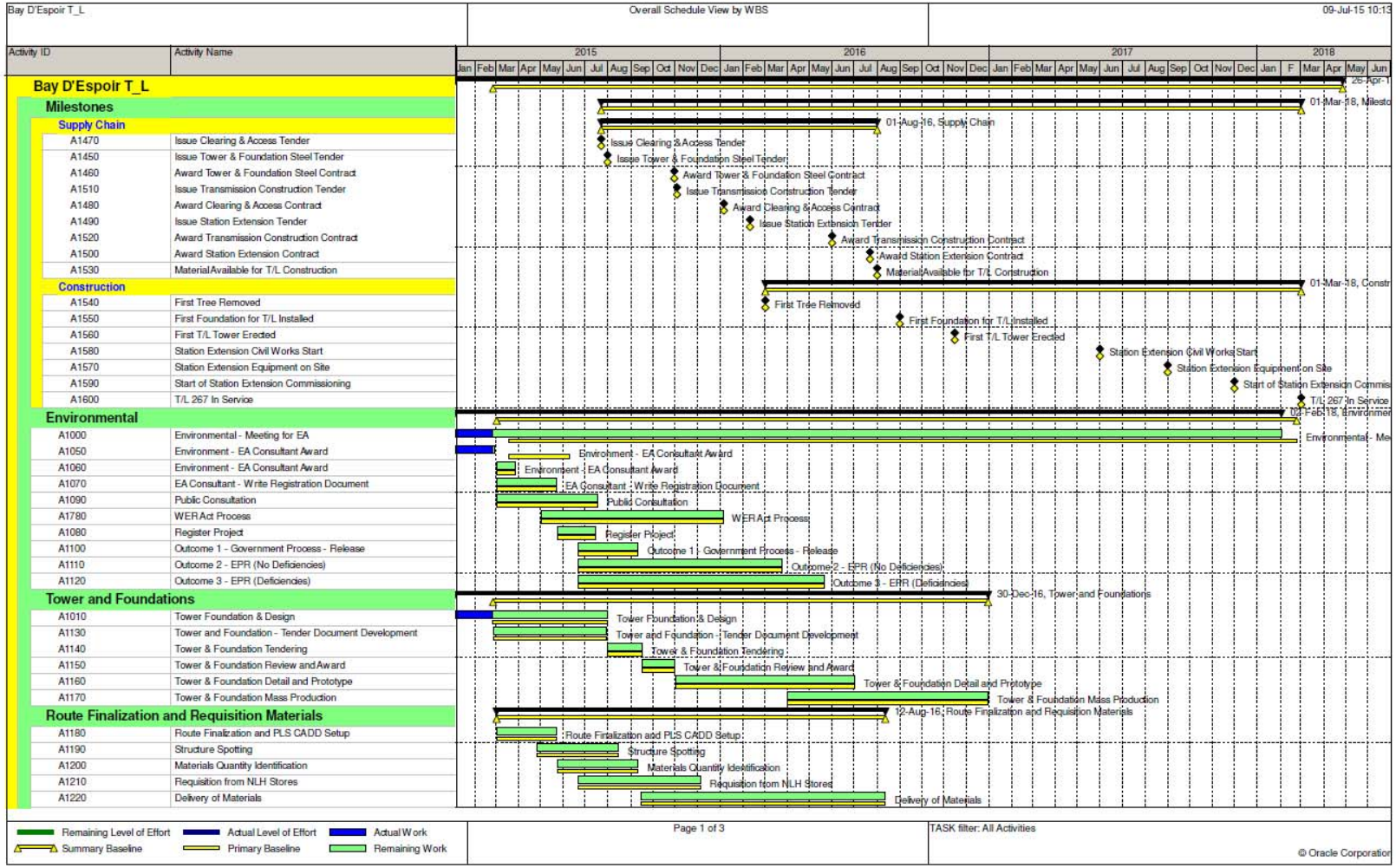
Typical TL 202/TL 206 right of way near BDE; TL 267 will be on the right

TL 202/TL 206 right of way with existing Hydro access bridge within the Bay Du Nord Wilderness Reserve

Typical TL 202/TL 206 right of way in limited available access zone west of Pipers Hole Park

Typical TL 203/TL 237 right of way on the Avalon Peninsula; TL 267 will be on the right

APPENDIX A


Bay D'Espoir T_L
Overall Schedule View by WBS
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Activity ID
Activity Name
2015
2016
2017
2018
Bay D'Espoir T_L
Milestones
Supply Chain
A1470 Issue Clearing & Access Tender
A1450 Issue Tower & Foundation Steel Tender
A1460 Award Tower & Foundation Steel Contract
A1510 Issue Transmission Construction Tender
A1480 Award Clearing & Access Contract
A1490 Issue Station Extension Tender
A1520 Award Transmission Construction Contract
A1500 Award Station Extension Contract
A1530 Material Available for T/L Construction
Construction
A1540 First Tree Removed
A1550 First Foundation for T/L Installed
A1560 First T/L Tower Erected
A1580 Station Extension Civil Works Start
A1570 Station Extension Equipment on Site
A1590 Start of Station Extension Commissioning
A1600 T/L 267 In Service
Environmental
A1000 Environmental - Meeting for EA
A1050 Environment - EA Consultant Award
A1060 Environment - EA Consultant Award
A1070 EA Consultant - Write Registration Document
A1090 Public Consultation
A1780 WER Act Process
A1080 Register Project
A1100 Outcome 1 - Government Process - Release
A1110 Outcome 2 - EPR (No Deficiencies)
A1120 Outcome 3 - EPR (Deficiencies)
Tower and Foundations
A1010 Tower Foundation & Design
A1130 Tower and Foundation - Tender Document Development
A1140 Tower & Foundation Tendering
A1150 Tower & Foundation Review and Award
A1160 Tower & Foundation Detail and Prototype
A1170 Tower & Foundation Mass Production
Route Finalization and Requisition Materials
A1180 Route Finalization and PLS CADD Setup
A1190 Structure Spotting
A1200 Materials Quantity Identification
A1210 Requisition from NLH Stores
A1220 Delivery of Materials
01-Mar-18, Milesto
01-Aug-16, Supply Chain
01-Mar-18, Constr
30-Dec-16, Tower and Foundations
12-Aug-16, Route Finalization and Requisition Materials
Remaining Level of Effort
Actual Level of Effort
Actual Work
Summary Baseline
Primary Baseline
Remaining Work
Page 1 of 3
TASK filter: All Activities
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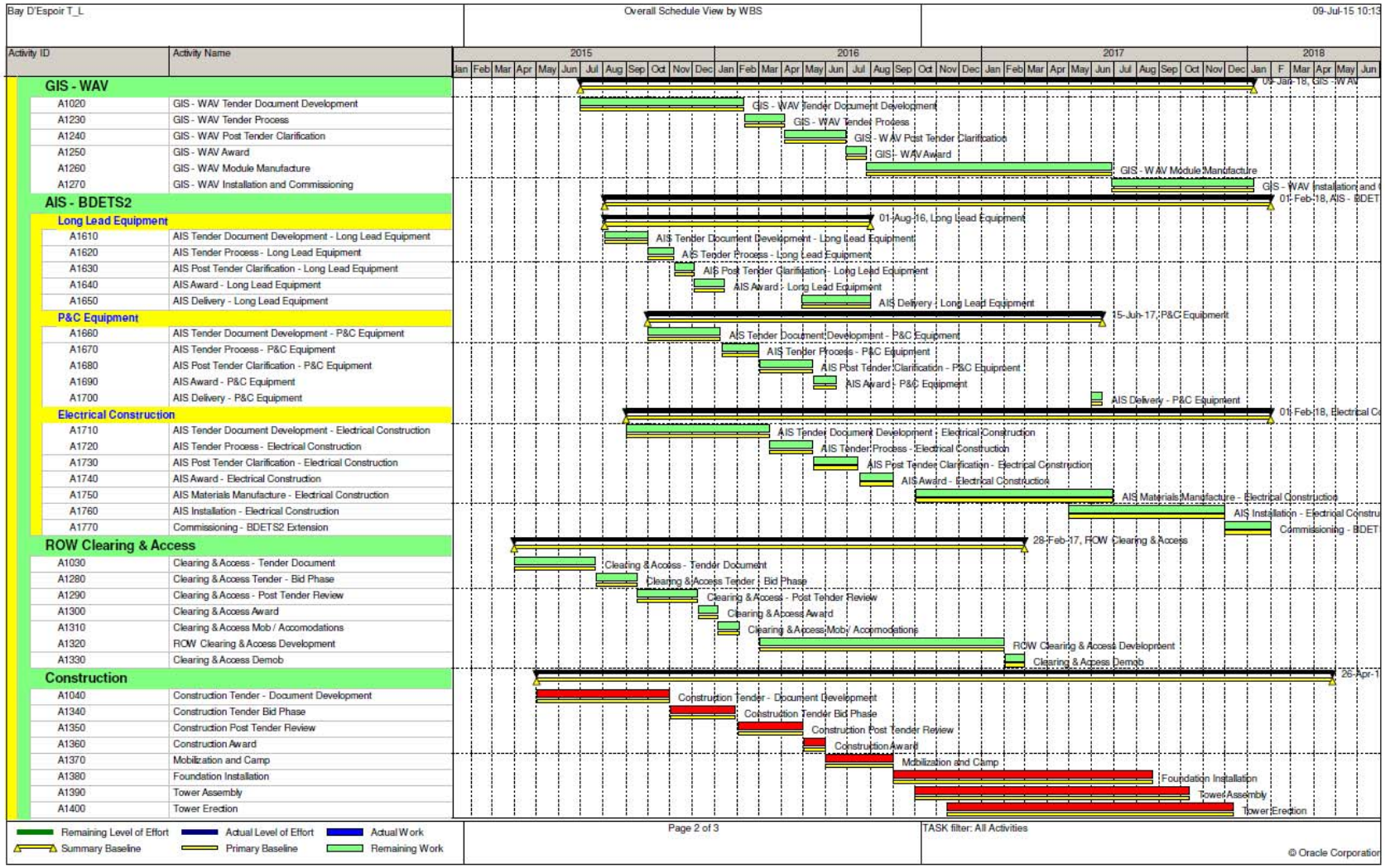
Bay D'Espoir T_L
Overall Schedule View by WBS
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Activity ID
Activity Name
2015
2016
2017
2018
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan F Mar Apr May Jun
GIS - WAV
A1020 GIS - WAV Tender Document Development
A1230 GIS - WAV Tender Process
A1240 GIS - WAV Post Tender Clarification
A1250 GIS - WAV Award
A1260 GIS - WAV Module Manufacture
A1270 GIS - WAV Installation and Commissioning
AIS - BDETS2
Long Lead Equipment
A1610 AIS Tender Document Development - Long Lead Equipment
A1620 AIS Tender Process - Long Lead Equipment
A1630 AIS Post Tender Clarification - Long Lead Equipment
A1640 AIS Award - Long Lead Equipment
A1650 AIS Delivery - Long Lead Equipment
P&C Equipment
A1660 AIS Tender Document Development - P&C Equipment
A1670 AIS Tender Process - P&C Equipment
A1680 AIS Post Tender Clarification - P&C Equipment
A1690 AIS Award - P&C Equipment
A1700 AIS Delivery - P&C Equipment
Electrical Construction
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A1720 AIS Tender Process - Electrical Construction
A1730 AIS Post Tender Clarification - Electrical Construction
A1740 AIS Award - Electrical Construction
A1750 AIS Materials Manufacture - Electrical Construction
A1760 AIS Installation - Electrical Construction
A1770 Commissioning - BDETS2 Extension
ROW Clearing & Access
A1030 Clearing & Access - Tender Document
A1280 Clearing & Access Tender - Bid Phase
A1290 Clearing & Access - Post Tender Review
A1300 Clearing & Access Award
A1310 Clearing & Access Mob / Accomodations
A1320 ROW Clearing & Access Development
A1330 Clearing & Access Demob
Construction
A1040 Construction Tender - Document Development
A1340 Construction Tender Bid Phase
A1350 Construction Post Tender Review
A1360 Construction Award
A1370 Mobilization and Camp
A1380 Foundation Installation
A1390 Tower Assembly
A1400 Tower Erection
GIS - WAV Tender Document Development
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GIS - WAV Award
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AIS Post Tender Clarification - Electrical Construction
AIS Award - Electrical Construction
AIS Materials Manufacture - Electrical Construction
AIS Installation - Electrical Construction
Commissioning - BDETS2 Extension
28-Feb-17, ROW Clearing & Access
Clearing & Access - Tender Document
Clearing & Access Tender - Bid Phase
Clearing & Access - Post Tender Review
Clearing & Access Award
Clearing & Access Mob / Accomodations
ROW Clearing & Access Development
Clearing & Access Demob
Construction Tender - Document Development
Construction Tender Bid Phase
Construction Post Tender Review
Construction Award
Mobilization and Camp
Foundation Installation
Tower Assembly
Tower Erection
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Actual Level of Effort
Actual Work
Summary Baseline
Primary Baseline
Remaining Work
Page 2 of 3
TASK filter: All Activities
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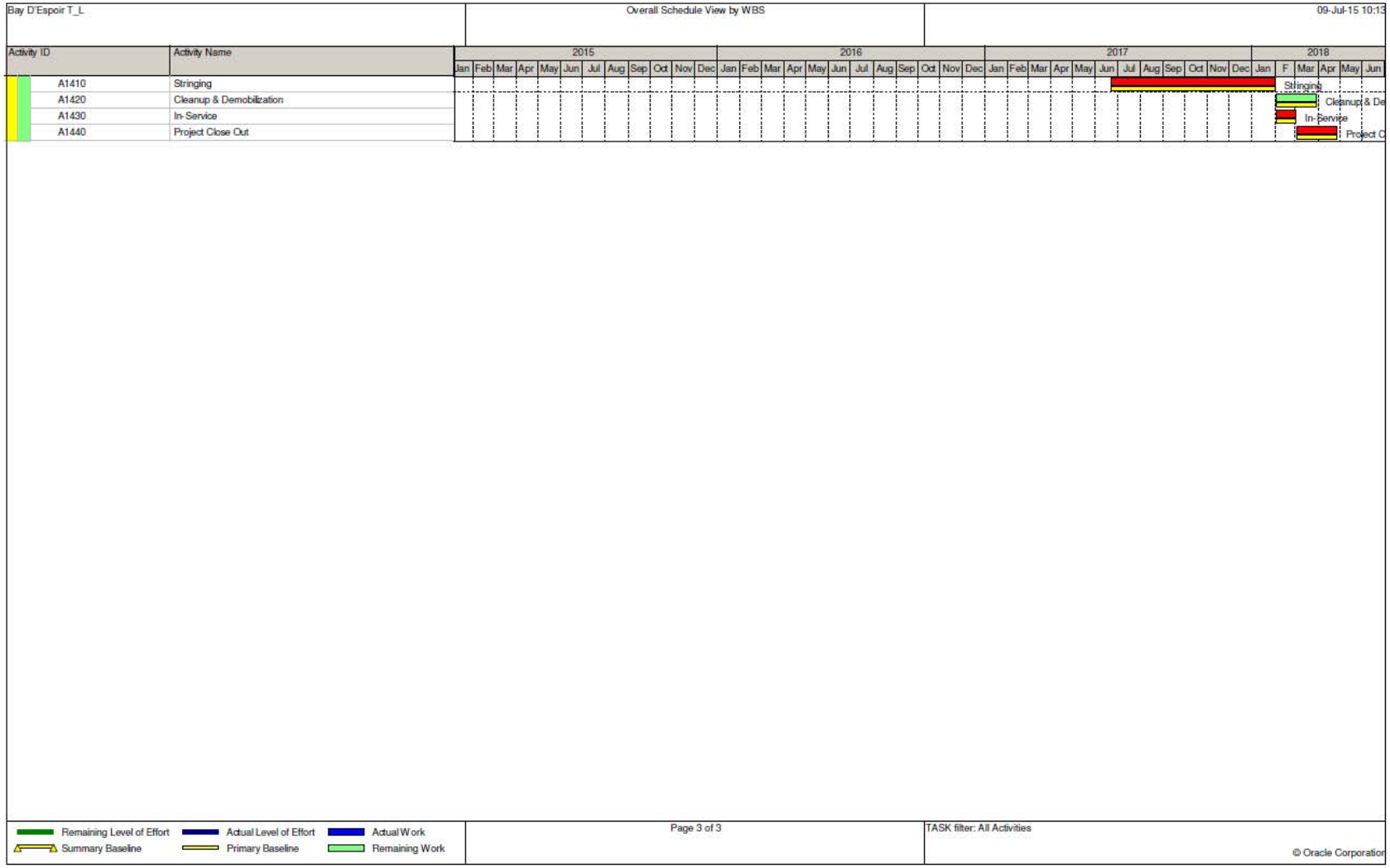
Bay D'Espoir T_L
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Activity Name
2015
2016
2017
2018
A1410 Stringing
A1420 Cleanup & Demobilization
A1430 In-Service
A1440 Project Close Out
Stringing
Cleanup & De
In-Service
Project C
Remaining Level of Effort
Actual Level of Effort
Actual Work
Summary Baseline
Primary Baseline
Remaining Work
Page 3 of 3
TASK filter: All Activities
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A Report to the

Board of Commissioners of Public Utilities

Holyrood Overview

Future Operation and Capital Expenditure Requirements

July 2015

newfoundland labrador hydro
a nalcor energy company

BACKGROUND

The Board of Commissioners of Public Utilities (the Board), in Orders No. P.U. 5(2012) and No. P.U. 4(2013) directed Hydro to file, in conjunction with the 2014 Capital Budget Application, an overview in relation to the proposed capital expenditures for the Holyrood Thermal Generating Station. The Board required that the overview include the following[1]:

1. *An updated outlook regarding anticipated changes in the role of Holyrood on the system;*

2. *An updated schedule of anticipated changes in Holyrood operations that may reasonably be expected to have an impact on capital expenditure requirements;*

3. *A summary description of all proposed Holyrood capital projects, including an explanation of how such projects relate to one another and whether such projects may be impacted by decisions yet to be taken regarding Holyrood's role on the system;*

4. *A summary guide to all internal and external reports filed in support of the capital expenditure proposals, summarizing alternatives considered and recommendations made; and*

5. *An explanation of the necessity of all proposed capital expenditures in the context of the anticipated changes in Holyrood operations.*

The Board of Commissioners of Public Utilities (the Board), in Order No. P.U. 42(2013), further required Hydro to update and file the Holyrood Overview report with future capital budgets. This report contains the update to the future operation and capital expenditure requirements for the Holyrood Thermal Generating Station.

[1] *Order No. P.U. 5(2012)*

INTRODUCTION

Newfoundland and Labrador Hydro's (Hydro) Holyrood Thermal Generating Station (Holyrood) is a critical part of the Island Interconnected System. With three oil fired generating units providing a total capacity of 490 MW (465 MW net), the plant represents approximately one third of Hydro's total Island Interconnected System generating capacity. Further, 490MW is approximately one quarter of the Island Interconnected *system* capacity, which Hydro is now reporting on to the Board of Commissioners of Public Utilities. Units 1 and 2 were commissioned in 1970 and 1971 respectively and Unit 3 in 1979. Units 1 and 2 were originally designed to produce 150 MW, but were upgraded to 175 MW in 1988 and 1989, respectively. Unit 3 retains its original configuration and is rated at 150 MW. In 1986, Unit 3 was retrofitted with synchronous condensing capability to provide voltage support on the eastern end of the Island Interconnected System during periods when power generation from this unit is not required.

The three major components of the thermal generating process are the boiler, the turbine and the generator with supporting systems such as fuel storage and delivery, controls, and cooling and feed water supply systems. Through combustion of No. 6 heavy fuel oil, the power boiler provides high energy steam to the turbine. The turbine is directly coupled to the generator and provides the rotating energy necessary for the generator to produce rated output power to the Island Interconnected System. The generator itself is pressurized and cooled by hydrogen gas to provide maximum efficiency both in heat transfer and reduced windage losses.

The Holyrood Generating Station is essential for meeting winter peak demand as well as overall island annual energy requirements. Hydro's hydro-electric generation is dependent on rainfall and inflows to the reservoirs. Holyrood is required to supply the difference between what is produced by Hydro's other generation sources (including purchases from non-utility generators) and what is required to meet the Island load. During a period of reduced inflows and low water storage levels, this may be significant. The Holyrood units are also critical for securing the transmission and providing voltage support for the major load centres on the Avalon Peninsula.

Figure 1: Holyrood Thermal Generating Station

CURRENT OPERATIONAL OUTLOOK AND SCHEDULE

On December 17, 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls development. The Muskrat Falls development and the Labrador Island Link (LIL) are expected to be in service in late 2017. Holyrood will be required for prime power production throughout the interim period (i.e., to the in-service date of the LIL) and it is intended that the facility remain fully available for generation in stand-by mode until the 2020–2021 timeframe. Unit 3 will operate primarily in synchronous condenser mode beginning in late 2017, with the option to return to full generating mode. Post the 2020-2021 timeframe, Units 1 and 2 and the steam components of Unit 3 will be decommissioned, and Unit 3 will continue to operate in synchronous condenser mode only, with no generation capability.

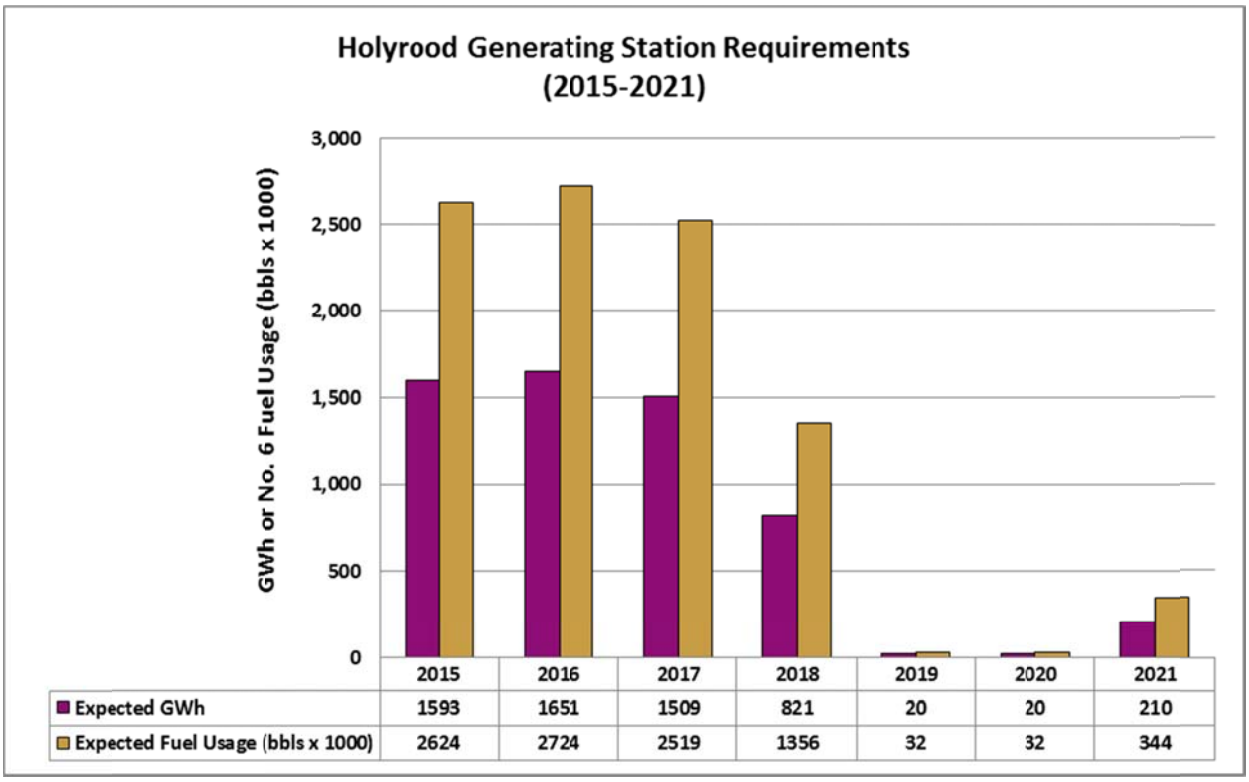

Figure 2: Holyrood Annual Production Requirements 2015 to 2021

Figure 2 indicates the forecasted annual Holyrood production requirements for the seven year period from 2015 to 2021. The forecast for 2015 is based on the average Island hydrologic inflow conditions over the year, and for 2016-2017 is based on average Island hydrologic inflow conditions and 500 GWh of reservoir drawdown. By late 2017, the LIL is expected to be in-service to supply the Island Interconnected System with power and energy from Muskrat Falls. During 2018, commissioning of Muskrat Falls will be completed. During early 2018, production from Holyrood may be required until all commissioning activities are complete.

The production at Holyrood may vary from that forecasted for the 2015 to 2018 period depending on the hydrologic conditions which influence Hydro's hydraulic energy supply capability. During a high inflow period, production from the Holyrood plant would be kept to minimum levels, with units operated only as required for system capacity and Avalon Peninsula transmission reliability considerations. Production during this period could be less than 1,000 GWh annually. On the other hand, during a repeat of the critical dry sequence, annual required production from Holyrood would be

significant, up to 3,000 GWh per year. This requires that all units be operated at maximum capacity outside of their annual planned and maintenance outage requirements.

In summary, the specific phases of operation and the timeframes for each phase are anticipated to be as follows:

Phase 1 (2015 through mid 2018): All three units are available for generation with Unit 3 also available for synchronous condenser operation as required.

Phase 2 (mid 2018 to the 2020-2021 timeframe): Units 1 and 2 are in standby generation mode and Unit 3 is operated in synchronous condenser mode but available for conversion to generation mode as required.

Phase 3 (Post 2020-2021 timeframe): Unit 3 continues to operate as a synchronous condenser only to the end of its service life.

Phase 1 – Normal Production Phase

Prior to full commissioning of the Muskrat Falls development and the Labrador Island Link, there will be continued demands on Holyrood to serve increasing system load requirements. While within the past decade, island industrial demand has declined due to the closure of two paper mills and a reduction of demand at the remaining mill, there has been continued growth in Utility customer requirements. On the Avalon Peninsula, through the next several years, industrial load growth is expected to ramp up as a result of the nickel processing facility at Long Harbour.

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. Holyrood will remain a critically important facility during construction and full commissioning of the Muskrat Falls development and the Labrador Island Link. During this phase of operation, the capability to operate Holyrood at full production is essential to meeting the energy and capacity requirements of the island portion of the province.

Hydro has not developed longer term hourly forecast requirements for synchronous condenser operation. Typically however, under the current isolated Island scenario, Unit 3 has been converted from generator to synchronous condenser mode in the spring when no longer required for generation. It is then converted back to generate mode in the fall – prior to the winter season.

Phase 2 – Standby Production Phase

Following the full commissioning of the Muskrat Falls development and the Labrador Island Link, the Holyrood plant will continue to be an essential component of the Provincial electrical grid. Initially and until the 2020-2021 timeframe, the plant will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the LIL between Labrador and Newfoundland. In this capacity, it can be called upon to provide energy and capacity to the Island in the event of a loss of supply from Labrador.

The annual energy production indicated for the final two years of the standby operation phase assumes an equivalent of one week operation per unit, per year, five days at 100 MW and two days at full load. It is assumed that the plant will produce 20 GWh in each year under this mode of operation. At the end of the standby period, the remaining fuel inventory will be consumed.

During the period of standby operation, Unit 3 will operate primarily in synchronous condenser mode, with the option to return to full generating mode if required.

Table 1, found at the end of this section, provides the forecasted Holyrood unit operating data from 2015 to 2021.

Phase 3 – Synchronous Condenser Operation Phase

Following the standby phase, the thermal aspect of the station required for power production will be decommissioned. After this period, the reliability of the HVdc transmission system is expected to be well established, having been reliably operated for a number of years over a full range of loading. At that time, Unit 3 will continue to operate as a synchronous condenser. The end of power production is currently projected to be in the 2020-2021 timeframe. Hydro does not plan to use Holyrood for emergency use after 2021.

Systems that are no longer required will be decommissioned, including:

- The fuel storage and delivery system, including the tank farm and day tank;
- The boilers, including air systems and emission monitoring systems;
- The feedwater and condensate systems, including the deaerator systems; and
- The marine terminal.

Systems required following the standby phase include:

- Unit 3 synchronous condenser specific equipment including the unit generator and exciter; and
- Auxiliary systems including electrical, controls, cooling water, fire protection, etc.

Table 1: Holyrood Operating Requirements 2015-2020

Holyrood Production and Island Interconnected Load
2015-2020

Year	Holyrood Net Production (GWh)	Total Unit Operating Hours	Holyrood Capacity Factor (%)	Total Island Interconnected Load (GWh)	Holyrood Percentage of Total Load (%)
2015	1,593	14,350	40	7,239	22
2016	1,651	15,450	41	7,431	22
2017	1,509	16,560	38	7,549	20
2018	821	10,872	20	7,676	0
2019	20	744	0	7,714	0
2020	20	744	0	7,764	0

Notes:
Load Forecast for 2015 as per June, 2014 OPLF
Load Forecast for 2016-2020 as per November 2014, OPLF

MAINTENANCE STRATEGY THROUGH THE OPERATIONAL PHASES

During Phase 1 of Holyrood's future operation, no changes are expected in terms of maintenance strategy since the plant is expected to produce with high reliability. The scheduled overhaul of plant equipment such as auxiliary system pumps will continue through this period to ensure plant reliability. The upgrade of equipment at or near the end of its service life will also continue, as will replacement of obsolete equipment which can no longer be maintained.

During Phase 2 of Holyrood's future operation, few changes are expected in terms of maintenance strategy since the plant must be fully available for emergency use until the 2020-2021 timeframe. Hydro has not yet established the maintenance regime required for standby production. The detailed work associated with that analysis is expected to be performed in 2015 and 2016 but no significant

changes are anticipated to the maintenance regime since all three units are expected to be operable to full load during the standby period. While the maintenance strategy is not expected to change, equipment maintenance intervals which are based on annual operating hours may be extended beyond normal timeframes during the standby period, depending on actual operating hours.
During Phase 3 of operation, assets with operational requirements beyond the 2020-2021 timeframe will continue to be optimally maintained with re-investment reflecting that continued requirement.

HOLYROOD 2016 CAPITAL PLAN SUMMARY

The complexity of thermal generating units, along with the age of the Holyrood plant, necessitates a rigorous review of the assets to ensure its future generating requirements can be met. In order to ensure that critical systems receive the appropriate level of refurbishment. Hydro has been concentrating on condition assessments and the formulation of requirements to get Holyrood to the end of its life as a generating facility, and for Unit 3 to operate in synchronous condenser mode beyond that time.

The following tables summarize the projects included in the 2016 capital plan for Holyrood. The plan was prepared in recognition of the anticipated completion of the in-feed from Muskrat Falls in late 2017 and in support of Holyrood generation availability requirements until 2020-2021. The plan was prepared considering asset condition, equipment obsolescence (both end of life and availability of support) and forecast production requirements, to identify the necessary rehabilitation and replacement projects to ensure customer needs can be met.

Table 2 provides a summary description of all proposed Holyrood capital projects for 2016. All of the proposed projects are required to ensure that the Holyrood facility is available to operate at full production which is essential to meeting the energy and capacity requirements of the Island portion of the province through the construction and commissioning of the Muskrat Falls development and the Labrador Island Link.

The first two projects listed are projects related to plant common support systems and infrastructure which are required to ensure the plant can continue to be operated safely, reliably and with regulatory

compliance through the normal operation and standby production phases to 2020-2021. These systems support the overall operation of the plant.

The next three projects relate directly to the major components of the power generation process, the boiler, turbine and generator, and their supporting systems. The first of these projects is related to the boiler feedwater and condensate systems for the generating units. The remaining projects relate to the steam turbines and generators and electrical systems required for their safe operation and shut down.

Table 3 provides a summary guide to all internal and external reports filed in support of the capital expenditure proposals summarizing the alternatives considered and recommendations made.

Table 4 provides an explanation of the necessity of all proposed capital expenditures in the context of the changes in Holyrood operation.

Table 2: Holyrood Projects Included in 2016 Capital Plan

Project	Scope Summary	Proposal Location
Engineering Study of Auxiliary Steam and Space Heating Requirements	This project is required to perform an engineering study to evaluate the following two options for Holyrood Thermal Generating Station (Holyrood): Option 1: Install auxiliary boiler plant Option 2: Install light oil fired air heaters	E-6
Upgrade Building Envelope	The replacement of sections of the exterior siding panels and roofing sections which have deteriorated to the point at which their integrity is compromised.	Tab 2
Overhaul Holyrood Pumps	This project will involve overhauling the Unit 2 east circulating water pump, the Unit 2 north condensate extraction pump, and the Unit 1 west boiler feed pump.	C-26
Rewind Unit 3 Generator Rotor and Install Flux Probe	Rewind the rotor on Unit 3 and to install a flux probe on this unit to monitor the status of the rotor poles in the future. Testing of the rotor has confirmed that there is an electrical short within the rotor winding, which is indicative of insulation degradation. The rewinding of the rotor will address this issue, decrease the potential of damage due to the failure of the rotor, and improve the reliability of the generating station.	Tab 5
Overhaul Unit 3 Steam Turbine Generator	This project is required to perform a scheduled major overhaul of Unit 3 Turbine, Generator and auxiliary systems located at the Holyrood Thermal Generating Station. This major overhaul consists of total dismantling of all turbine stages, removal of the generator rotor, and overhaul of the turbine valves.	Tab 3

Table 3: Reports Filed in Support of 2016 Project Proposals

Project	Reports filed	Alternatives Considered	Recommendation
Upgrade Building Envelope (siding and roofing)	- Holyrood Level 2 Condition Assessment AMEC AM141/RP/002 R00 - Existing Siding Assessment HTGS 176690-0000-CD10-RPT-0001 - Level II Condition Assessment, Civil Structures and Unit 3 Generator (Roof Condition and Risk Summary)	Replace components that are at the end of their service life. Repair components at end of life. Study recommendations	Replace components that are at the end of their service life. Study recommendations
Overhaul Holyrood Pumps	- Flowserve Review – Overhaul Schedule	Overhaul Pumps	Overhaul Pumps
Rewind Unit 3 Generator Rotor & Install Flux Probe	- FM Global Risk Report - Iris Power Holyrood Unit 3 Review Report - AMEC Condition Assessment - Alstom UTGE672108 Holyrood #3 Maintenance Recommendations - Alstom Holyrood Unit 3 Rotor Electrical Test Report - Alstom Holyrood Unit 3 Generator Condition Assessment Summary Report - Alstom Field Service Report FSRG020035 - Alstom Field Service Report FSRG019866	Rewind the rotor in 2016 during a scheduled major overhaul and carry out inspections to determine the time frame for a future stator rewind. Rewind the rotor and stator in 2019 during an additional outage – have rotor and stator rewind kits available. Rewind the rotor and stator in 2022 during a scheduled overhaul – have rotor and stator rewind kits available.	Rewind the rotor in 2016 during a scheduled major overhaul and carry out inspections to determine the time frame for a future stator rewind.

Overhaul Unit 3 Steam Turbine Generator	- General Electric Major Overhaul Report FRS Number 20351250 - Hartford Steam Boiler (HSB) Turbine Outage Optimization Program (TOOP) - AMEC Condition Assessment and Life Assessment Study	Overhaul Turbine Generator	Overhaul Turbine Generator

Table 4: 2016 Project Necessity in the Context of Changing Role of Holyrood

Major System or Subsystem	Project	Necessity by Operational Phase		
		Phase 1	**Phase 2**	**Phase 3**
Fuel Storage & Delivery	No Projects included			
Feedwater & Condensate	Overhaul Holyrood Pumps	**Needed**	**Needed**	**Not needed**
Boiler	No Projects included			
Turbine Generator	Overhaul Unit 3 Steam Turbine Generator	**Needed**	**Needed**	**Needed**[2]
	Rewind Unit 3 Generator Rotor & Install Flux Probe	**Needed**	**Needed**	**Needed**
Cooling Water Systems	Overhaul Holyrood Pumps	**Needed**	**Needed**	**Not needed**
Buildings & Grounds	Upgrade Building Envelope, including siding and roofing	**Needed**	**Needed**	**Needed**
Common Systems	Install Auxiliary Boiler or plant heating system	**Not needed**	**Needed**	**Needed**

[2] The generator is needed, but not the turbine for the synchronous condense mode of operations.

Holyrood 2016-2020 Capital Expenditures Outlook

To ensure continued security of supply, capital investment will be necessary throughout the period 2016 to 2020 to ensure Holyrood can provide the level of service required in generation and synchronous condenser operation. Various types of investments and expenditures for the Holyrood facility are anticipated, including refurbishment, upgrade or replacement of failed or obsolete equipment and general plant infrastructure work.

The Holyrood Generating Station continues to be a critical asset that must be maintained in a reliable least cost manner to meet demand and energy requirements of the Island Interconnected System.

In reviewing future capital projects for Holyrood going forward, Hydro has considered the three phases discussed previously and will submit for approval, only those projects necessary for the safe and reliable operation of the plant as a generator up to the time of decommissioning. Additional capital investment requirements will continue through to synchronous condenser operation.

Capital projects being proposed as part of this and upcoming future budget submissions have been, and will continue to be, reviewed in light of the future plant requirements and are considered to be the minimum amount that is essential to fulfill Hydro's mandate to serve its customers and meet safety and environmental requirements.

The maintenance strategy for Holyrood going forward to its end of life as a generating station, is to extend the life of the existing assets at least cost through continued preventative maintenance, repair and rehabilitation where critical to providing safe and reliable energy at the forecast levels. In cases where repair and rehabilitation are not viable alternatives, and where the associated assets remain critical to operation, assets will be renewed in the least cost manner that meets the need. For Phases 1 and 2 of Holyrood's future operation, few changes are expected in terms of maintenance strategy since the plant is generally expected to produce with high reliability through to completion of Muskrat and LIL commissioning and must be fully available for emergency/standby use until the 2020–2021 timeframe. Non-critical assets will receive minimal attention and may be allowed to degrade where such action does not significantly increase risk to safe and reliable production. Assets with operational requirements beyond 2020-2021 will continue to be optimally maintained with re-investment reflecting

that continued requirement. Data will be collected from inspections, on line monitoring and formal condition assessments and used to determine the right work, on the right assets, at the optimal time in light of the changing role of Holyrood.

Figure 3 provides the planned level of expenditure for Holyrood over the 2016 to 2020 period. The annual average expenditure is $9.4 million, ranging from a high of $12.2 million in 2016 to a low of $6.8 million in 2018. Projects planned for the pending five years include:

- $6.5 million for an upgrade to the building envelope, including siding and roofing,
- $5.9 million for the overhaul of Unit 3 turbine generator; and
- $2.8 million for the rewind of Unit 3 generator rotor and installation of a rotor flux probe.

Planned expenditures for the five year period total $46.9 million.

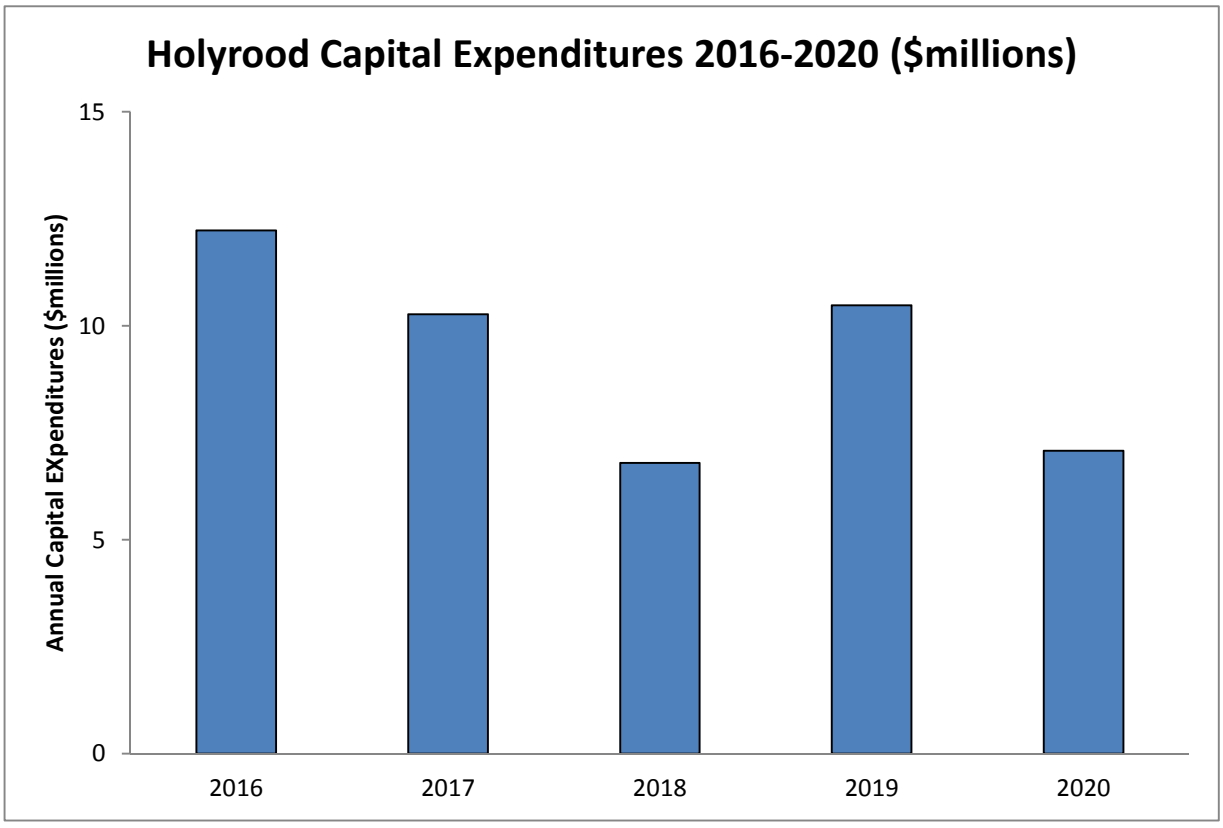

Figure 3: Holyrood Capital Expenditures 2016 to 2020

	Expended to 2015	2016	Future Years	Total
		($000)		
GENERATION	4,294.3	25,612.7	18,230.7	48,137.7
TRANSMISSION AND RURAL OPERATIONS	22,546.9	147,522.7	312,939.7	483,009.3
GENERAL PROPERTIES	2,422.8	9,562.6	4,888.4	16,873.8
ALLOWANCE FOR UNFORESEEN ITEMS		1,000.0		1,000.0
TOTAL CAPITAL BUDGET	29,264.0	183,698.0	336,058.8	549,020.8

	Expended to 2015	2016	Future Years	Total
		($000)		
GENERATION				
Hydraulic Plant	1,592.9	10,551.8	14,209.7	26,354.4
Thermal Plant	46.2	12,230.4	3,754.0	16,030.6
Gas Turbines	2,655.2	2,718.6	267.0	5,640.8
Tools and Equipment		111.9		111.9
TOTAL GENERATION	4,294.3	25,612.7	18,230.7	48,137.7
TRANSMISSION AND RURAL OPERATIONS				
Terminal Stations	14,235.1	29,868.1	59,254.2	103,357.4
Transmission	4,642.9	85,515.9	236,712.5	326,871.3
Distribution	1,136.1	11,978.0	6,350.3	19,464.4
Generation	1,482.4	13,716.3	9,908.9	25,107.6
Properties	489.4	3,883.6	180.4	4,553.4
Metering	559.9	1,026.0	533.4	2,119.3
Tools and Equipment	1.1	1,534.8		1,535.9
TOTAL TRANSMISSION AND RURAL OPERATIONS	22,546.9	147,522.7	312,939.7	483,009.3
GENERAL PROPERTIES				
Information Systems		3,567.8	1,024.5	4,592.3
Telecontrol		2,586.4	2,927.5	5,513.9
Transportation	2,377.1	2,051.1	706.9	5,135.1
Administrative	45.7	1,357.3	229.5	1,632.5
TOTAL GENERAL PROPERTIES	2,422.8	9,562.6	4,888.4	16,873.8
ALLOWANCE FOR UNFORESEEN ITEMS		1,000.0		1,000.0
TOTAL CAPITAL BUDGET	29,264.0	183,698.0	336,058.8	549,020.8

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
HYDRAULIC PLANT					
Replace Site Facilities - Bay d'Espoir		928.3	11,053.0	11,981.3	C-3
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir		2,959.6		2,959.6	C-10
Upgrade Work - Cat Arm		558.3	1,353.0	1,911.3	C-14
Overhaul Turbine/Generator Units 6 and 7 - Bay d'Espoir		1,345.6		1,345.6	C-16
Rehabilitate Salmon River Spillway - Bay d'Espoir	745.6	556.8		1,302.4	
Rehabilitate Shoreline Protection - Cat Arm		112.2	1,030.7	1,142.9	C-24
Replace Station Service Breakers - Cat Arm	644.9	363.4		1,008.3	
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	633.3		648.0	
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5		545.2	
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		477.6		477.6	D-2
Replace Powerhouse 1 Station Service Transformer - Bay d'Espoir		46.7	354.5	401.2	D-27
Replace Vibration Monitoring System Unit 7 - Bay d'Espoir		366.0		366.0	D-95
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir		183.6	167.9	351.5	D-226
Refurbish Intakes - Bay d'Espoir	72.6	262.3		334.9	
Perform Condition Assessment of Control Structure - Hinds Lake		323.4		323.4	D-231
Install Hydrometeorological Equipment - Various Sites		314.1		314.1	D-248
Refurbish Station Water System - Upper Salmon		96.6	197.6	294.2	D-260
Install Infrared View Ports - Various Sites	83.7	113.1		196.8	
Replace Generator Cooling Water Piping - Hinds Lake		181.7		181.7	E-2
Replace Control Room/Communications Room Air Conditioning - Hinds Lake		41.3	53.0	94.3	E-11
Refurbish Unit Relay Protection - Paradise River	8.7	79.7		88.4	
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir		85.7		85.7	E-14
TOTAL HYDRAULIC PLANT	1,592.9	10,551.8	14,209.7	26,354.4	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
THERMAL PLANT					
Upgrade Powerhouse Building Envelope - Holyrood		2,723.8	3,754.0	6,477.8	C-5
Overhaul Steam Turbine Generator Unit 3 - Holyrood		5,868.6		5,868.6	C-8
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood		2,755.5		2,755.5	C-12
Overhaul Pumps - Holyrood		536.2		536.2	C-26
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	197.6		243.8	
Study of Auxiliary Steam and Space Heating Requirements - Holyrood		148.7		148.7	E-6
TOTAL THERMAL PLANT	46.2	12,230.4	3,754.0	16,030.6	
GAS TURBINES					
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,525.4		5,180.6	
Replace Fuel Piping - Hardwoods and Stephenville		44.8	267.0	311.8	D-254
Install Transfer Switches for Diesel Automation - Happy Valley		148.4		148.4	E-9
TOTAL GAS TURBINES	2,655.2	2,718.6	267.0	5,640.8	
TOOLS AND EQUIPMENT					
Purchase Tools and Equipment Less than $50,000		111.9		111.9	
TOTAL TOOLS AND EQUIPMENT		111.9		111.9	
TOTAL GENERATION	4,294.3	25,612.7	18,230.7	48,137.7	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
TERMINAL STATIONS					
Upgrade Circuit Breakers - Various Sites (2016-2020)		6,969.1	54,491.3	61,460.4	C-33
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,873.8		13,062.9	
Upgrade Power Transformers - Various Sites	4,440.4	7,002.3		11,442.7	
Replace Instrument Transformers - Various Sites	1,684.4	1,511.7	471.9	3,668.0	
Install Spare Transformer - Happy Valley		2,040.9		2,040.9	C-56
Replace Disconnect Switches - Various Sites (2016-2017)		646.9	1,320.9	1,967.8	C-60
Replace Protective Relays - Various Sites		700.6	1,156.4	1,857.0	C-62
Install Transformer On line Gas Monitoring - Various Sites	700.5	975.7		1,676.2	
Replace Disconnect Switches - Various Sites	963.7	642.9		1,606.6	
Install Fire Protection in 230 kV Stations - Bay d'Espoir		200.0	566.0	766.0	C-77
Upgrade Digital Fault Recorders - Various Sites		197.9	304.6	502.5	C-83
Design and Install Fire Protection in 230 kV Stations - Various Sites	67.6	424.3		491.9	
Upgrade Terminal Station for Mobile Substation - Cow Head		40.0	444.7	484.7	D-271
Upgrade Terminal Station Protection and Control - Various Sites	172.7	307.2		479.9	
Upgrade Aluminum Support Structure - Holyrood		401.1		401.1	D-298
Upgrade Terminal Station Equipment Foundations - Various Sites		319.9		319.9	D-359
Upgrade Data Alarm Systems - Stony Brook		74.4	234.1	308.5	D-374
Install Breaker Failure Protection - Various Sites		65.7	211.3	277.0	D-388
Replace Surge Arrestors - Various Sites		144.4	53.0	197.4	E-29
Replace Station Lighting - Bay d'Espoir	16.7	160.3		177.0	
Replace Air Receivers and Compressors - St. Anthony		120.7		120.7	E-45
Upgrade Roof - Indian River		48.3		48.3	
TOTAL TERMINAL STATIONS	14,235.1	29,868.1	59,254.2	103,357.4	
TRANSMISSION					
Construct 230 kV Transmission Line - Bay d'Espoir to Western Avalon	4,403.0	75,284.3	211,970.7	291,658.0	
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods		3,699.0	22,861.9	26,560.9	C-35
Perform Wood Pole Line Management Program - Various Sites		2,919.0		2,919.0	C-52
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	239.9	1,038.4	901.6	2,179.9	
Replace Insulators - TL203		1,985.6		1,985.6	C-58
Replace Aircraft Markers at Grand Lake Crossing - TL228		589.6	978.3	1,567.9	C-64
TOTAL TRANSMISSION	4,642.9	85,515.9	236,712.5	326,871.3	
DISTRIBUTION					
Upgrade Distribution Systems - Various Sites (2016-2017)		285.6	6,350.3	6,635.9	C-36
Provide Service Extensions - All Service Areas		5,150.0		5,150.0	C-41
Upgrade Distribution Systems - All Service Areas		3,890.0		3,890.0	C-48
Upgrade Distribution Systems - Various Sites (2015-2016)	1,136.1	818.8		1,954.9	
Construct Overhead Distribution Line - Pilley's Island to Long Island		1,239.9		1,239.9	C-69
Additions for Load Growth - Happy Valley		593.7		593.7	C-81
TOTAL DISTRIBUTION	1,136.1	11,978.0	6,350.3	19,464.4	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
GENERATION					
Additions for Load Growth - L'Anse au Loup and Postville		883.4	4,746.0	5,629.4	C-38
Replace Diesel Units - Cartwright and Charlottetown		1,840.5	3,098.4	4,938.9	C-43
Install Fire Protection Systems - Nain and Cartwright		3,030.7	1,376.4	4,407.1	C-46
Overhaul Diesel Units - Various Sites		2,078.4		2,078.4	C-54
Install Fire Protection - L'Anse Au Loup	220.6	1,126.2		1,346.8	
Replace Unit 2038 - Mary's Harbour	103.5	1,241.5		1,345.0	
Inspect Fuel Storage Tanks - Various Sites		1,326.9		1,326.9	C-66
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1	958.0	
Purchase Diesel Plant Production Data Collection Equipment - Various Sites	538.7	280.7		819.4	
Replace Diesel Unit 254 - Paradise River	66.8	429.3		496.1	
Upgrade Ventilation Systems -Various Sites	175.9	317.3		493.2	
Upgrade Transformers - Cartwright and Postville		465.2		465.2	D-277
Replace Human Machine Interface - Various Sites		114.0	320.0	434.0	D-292
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	189.3		199.3	
Install Variable Frequency Drives - Grey River		46.9	123.0	169.9	E-42
TOTAL GENERATION	1,482.4	13,716.3	9,908.9	25,107.6	
PROPERTIES					
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	1,061.4		1,550.8	
Upgrade Office Facilities and Control Buildings - Various Sites		1,134.0		1,134.0	C-71
Upgrade Line Depots - Various Sites		861.4		861.4	C-75
Replace Roof on Services Building - Bishop's Falls		612.8		612.8	C-79
Install Fall Protection Equipment - Various Sites		198.8		198.8	E-18
Upgrade Warehouse Lighting - Bishop's Falls		15.2	180.4	195.6	E-37
TOTAL PROPERTIES	489.4	3,883.6	180.4	4,553.4	
METERING					
Install Automated Meter Reading - Labrador West		433.8	533.4	967.2	C-73
Install Automated Meter Reading - Various Sites (2015-2016)	559.9	401.8		961.7	
Purchase Meters and Metering Equipment - Various Sites		190.4		190.4	E-39
TOTAL METERING	559.9	1,026.0	533.4	2,119.3	
TOOLS AND EQUIPMENT					
Purchase Tools and Equipment Less than $50,000		477.0		477.0	
Replace Off Road Track Vehicle Unit 7861 - Stephenville	1.1	397.8		398.9	
Replace Light Duty Mobile Equipment - Various Sites		348.0		348.0	D-353
Purchase Excavator - Bay d'Espoir		312.0		312.0	D-370
TOTAL TOOLS AND EQUIPMENT	1.1	1,534.8		1,535.9	
TOTAL TRANSMISSION AND RURAL OPERATIONS	22,546.9	147,522.7	312,939.7	483,009.3	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
INFORMATION SYSTEMS					
SOFTWARE APPLICATIONS					
New Infrastructure					
Perform Minor Application Enhancements - Hydro Place		346.7		346.7	E-50
Cost Recovery		(148.8)		(148.8)	
Upgrade of Technology					
Upgrade Microsoft Office Products - Hydro Place		683.7	1,910.7	2,594.4	C-87
Cost Recovery		(317.1)	(886.2)	(1,203.3)	
Implement Industrial Billing Software - Hydro Place		443.1		443.1	D-395
Upgrade Energy Management System - Hydro Place		246.2		246.2	D-424
Upgrade Citrix - Hydro Place		297.6		297.6	E-58
Cost Recovery		(138.0)		(138.0)	
Upgrade Sharepoint Document Repository - Hydro Place		267.6		267.6	E-64
Cost Recovery		(124.1)		(124.1)	
Refresh Security Software - Hydro Place		230.4		230.4	E-71
Cost Recovery		(106.9)		(106.9)	
TOTAL SOFTWARE APPLICATIONS		1,680.4	1,024.5	2,704.9	
COMPUTER OPERATIONS					
Infrastructure Replacement					
Replace Personal Computers - Various Sites		861.7		861.7	C-96
Replace Peripheral Infrastructure - Various Sites		611.3		611.3	D-397
Cost Recovery		(186.8)		(186.8)	
Upgrade Enterprise Storage Capacity - Hydro Place		628.8		628.8	D-401
Cost Recovery		(291.6)		(291.6)	
Upgrade of Technology					
Upgrade Server Technology Program - Hydro Place		492.5		492.5	D-418
Cost Recovery		(228.5)		(228.5)	
TOTAL COMPUTER OPERATIONS		1,887.4		1,887.4	
TOTAL INFORMATION SYSTEMS		3,567.8	1,024.5	4,592.3	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
TELECONTROL					
NETWORK SERVICES					
Replace MDR 4000 Microwave Radio East - Various Sites		77.4	1,093.1	1,170.5	C-90
Replace UPS Systems - Hydro Place		889.8		889.8	C-92
Replace Battery Banks and Chargers - Various Sites		425.0	456.6	881.6	C-94
Replace Powerline Carrier - Various Sites		73.4	763.4	836.8	C-98
Upgrade Telecontrol Facilities - Sandy Brook Hill		101.6	462.4	564.0	C-102
Replace Radomes - Various Sites		235.2		235.2	D-427
Replace Air Conditioners - Massey Drive and Happy Valley		39.9	152.0	191.9	E-52
Replace Network Communication Equipment - Various Sites		186.4		186.4	E-54
Replace Video Conferencing Bridge - Hydro Place		182.6		182.6	E-56
Upgrade Access Roads to Microwave Sites - Gull Pond Hill and Sandy Brook Hill		141.1		141.1	E-66
Upgrade Remote Terminal Units - Various Sites		89.6		89.6	E-73
Upgrade Site Facilities - Various Sites		49.5		49.5	
Replace Wescom Transceivers - Various Sites		49.3		49.3	
Purchase Tools and Equipment Less than $50,000		45.6		45.6	
TOTAL TELECONTROL		2,586.4	2,927.5	5,513.9	
TRANSPORTATION					
Replace Vehicles and Aerial Devices - Various Sites (2015-2016)	2,377.1	225.3		2,602.4	
Replace Vehicles and Aerial Devices - Various Sites (2016-2017)		1,443.3	534.2	1,977.5	C-85
Purchase Vehicles and Aerial Devices - Various Sites		382.5	172.7	555.2	C-104
TOTAL TRANSPORTATION	2,377.1	2,051.1	706.9	5,135.1	
ADMINISTRATION					
Replace Roof - Hydro Place		639.5		639.5	C-100
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	311.3		357.0	
Replace Air Conditioning Units 8 and 14 - Hydro Place		34.6	229.5	264.1	D-407
Remove Safety Hazards - Various Sites		199.3		199.3	E-47
Purchase Office Equipment		172.6		172.6	
TOTAL ADMINISTRATION	45.7	1,357.3	229.5	1,632.5	
TOTAL GENERAL PROPERTIES	2,422.8	9,562.6	4,888.4	16,873.8	

NEWFOUNDLAND AND LABRADOR HYDRO
2016 CAPITAL BUDGET
($000)

	2016
GENERATION	15,511.1
TRANSMISSION AND RURAL OPERATIONS	26,188.7
GENERAL PROPERTIES	5,764.7
ALLOWANCE FOR UNFORESEEN EVENTS	1,000.0
TOTAL PROJECTS UNDER $50,000	954.2
MULTI-YEAR (2016 Expenditures):	
Multi-year Projects Commencing in 2016	27,657.6
Multi-year Projects Commencing in 2015	104,829.3
Multi-year Projects Commencing Prior to 2015:	
Replace Instrument Transformers - Various Sites	1,511.7
Purchase Diesel Plant Production Data Collection Equipment - Various Sites	280.7
TOTAL CAPITAL BUDGET	**183,698.0**

NEWFOUNDLAND AND LABRADOR HYDRO
2016 CAPITAL BUDGET
SINGLE YEAR PROJECTS OVER $50,000
($000)

PROJECT DESCRIPTION	**2016**
Generation	
HYDRAULIC PLANT	
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir	2,959.6
Overhaul Turbine/Generator Units 6 and 7 - Bay d'Espoir	1,345.6
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	477.6
Replace Vibration Monitoring System Unit 7 - Bay d'Espoir	366.0
Perform Condition Assessment of Control Structure - Hinds Lake	323.4
Install Hydrometeorological Equipment - Various Sites	314.1
Replace Generator Cooling Water Piping - Hinds Lake	181.7
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir	85.7
THERMAL PLANT	
Overhaul Steam Turbine Generator Unit 3 - Holyrood	5,868.6
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood	2,755.5
Overhaul Pumps - Holyrood	536.2
Study of Auxiliary Steam and Space Heating Requirements - Holyrood	148.7
GAS TURBINES	
Install Transfer Switches for Diesel Automation - Happy Valley	148.4
TOTAL GENERATION	15,511.1

NEWFOUNDLAND AND LABRADOR HYDRO
2016 CAPITAL BUDGET
SINGLE YEAR PROJECTS OVER $50,000
($000)

PROJECT DESCRIPTION	**2016**
Transmission and Rural Operations	
TERMINAL STATIONS	
Install Spare Transformer - Happy Valley	2,040.9
Upgrade Aluminum Support Structure - Holyrood	401.1
Upgrade Terminal Station Equipment Foundations - Various Sites	319.9
Replace Air Receivers and Compressors - St. Anthony	120.7
TRANSMISSION	
Perform Wood Pole Line Management Program - Various Sites	2,919.0
Replace Insulators - TL203	1,985.6
DISTRIBUTION	
Provide Service Extensions - All Service Areas	5,150.0
Upgrade Distribution Systems - All Service Areas	3,890.0
Construct Overhead Distribution Line - Pilley's Island to Long Island	1,239.9
Additions for Load Growth - Happy Valley	593.7
GENERATION	
Overhaul Diesel Units - Various Sites	2,078.4
Inspect Fuel Storage Tanks - Various Sites	1,326.9
Upgrade Transformers - Cartwright and Postville	465.2
PROPERTIES	
Upgrade Office Facilities and Control Buildings - Various Sites	1,134.0
Upgrade Line Depots - Various Sites	861.4
Replace Roof on Services Building - Bishop's Falls	612.8
Install Fall Protection Equipment - Various Sites	198.8
METERING	
Purchase Meters and Metering Equipment - Various Sites	190.4
TOOLS AND EQUIPMENT	
Replace Light Duty Mobile Equipment - Various Sites	348.0
Purchase Excavator - Bay d'Espoir	312.0
TOTAL TRANSMISSION AND RURAL OPERATIONS	26,188.7

NEWFOUNDLAND AND LABRADOR HYDRO
2016 CAPITAL BUDGET
SINGLE YEAR PROJECTS OVER $50,000
($000)

PROJECT DESCRIPTION	2016
General Properties	
INFORMATION SYSTEMS	
SOFTWARE APPLICATIONS	
New Infrastructure	
Perform Minor Application Enhancements - Hydro Place	346.7
Cost Recovery	(148.8)
Upgrade of Technology	
Implement Industrial Billing Software - Hydro Place	443.1
Upgrade Energy Management System - Hydro Place	246.2
Upgrade Citrix - Hydro Place	297.6
Cost Recovery	(138.0)
Upgrade Sharepoint Document Repository - Hydro Place	267.6
Cost Recovery	(124.1)
Refresh Security Software - Hydro Place	230.4
Cost Recovery	(106.9)
COMPUTER OPERATIONS	
Infrastructure Replacement	
Replace Personal Computers - Various Sites	861.7
Replace Peripheral Infrastructure - Various Sites	611.3
Cost Recovery	(186.8)
Upgrade Enterprise Storage Capacity - Hydro Place	628.8
Cost Recovery	(291.6)
Upgrade of Technology	
Upgrade Server Technology Program - Hydro Place	492.5
Cost Recovery	(228.5)
TELECONTROL	
NETWORK SERVICES	
Replace UPS Systems - Hydro Place	889.8
Replace Radomes - Various Sites	235.2
Replace Network Communication Equipment - Various Sites	186.4
Replace Video Conferencing Bridge - Hydro Place	182.6
Upgrade Access Roads to Microwave Sites - Gull Pond Hill and Sandy Hill	141.1
Upgrade Remote Terminal Units - Various Sites	89.6
ADMINISTRATION	
Remove Safety Hazards - Various Sites	199.3
Replace Roof - Hydro Place	639.5
TOTAL GENERAL PROPERTIES	5,764.7
TOTAL SINGLE YEAR PROJECTS OVER $50,000	**47,464.5**

NEWFOUNDLAND AND LABRADOR HYDRO
2016 CAPITAL BUDGET
PROJECTS OVER $50,000
MULTI-YEAR PROJECTS
($000)

Multi-year Projects Commencing in 2016

PROJECT DESCRIPTION	2016	2017	2018	2019	2020	Total
Upgrade Circuit Breakers - Various Sites (2016-2020)	6,969.1	10,808.7	15,408.6	15,247.3	13,026.7	61,460.4
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods	3,699.0	17,489.8	5,372.1			26,560.9
Replace Site Facilities - Bay d'Espoir	928.3	4,736.3	6,316.7			11,981.3
Upgrade Distribution Systems - Various Sites (2016-2017)	285.6	6,350.3				6,635.9
Upgrade Powerhouse Building Envelope - Holyrood	2,723.8	3,754.0				6,477.8
Additions for Load Growth - L'Anse au Loup and Postville	883.4	4,746.0				5,629.4
Replace Diesel Units - Cartwright and Charlottetown	1,840.5	3,098.4				4,938.9
Install Fire Protection Systems - Nain and Cartwright	3,030.7	1,376.4				4,407.1
Replace Vehicles and Aerial Devices - Various Sites (2016-2017)	1,443.3	534.2				1,977.5
Replace Disconnect Switches - Various Sites (2016-2017)	646.9	1,320.9				1,967.8
Upgrade Work - Cat Arm	558.3	1,353.0				1,911.3
Replace Protective Relays - Various Sites	700.6	1,156.4				1,857.0
Replace Aircraft Markers at Grand Lake Crossing - TL228	589.6	978.3				1,567.9
Upgrade Microsoft Office Products - Hydro Place	366.6	1,024.5				1,391.1
Replace MDR 4000 Microwave Radio East - Various Sites	77.4	1,093.1				1,170.5
Rehabilitate Shoreline Protection - Cat Arm	112.2	1,030.7				1,142.9
Install Automated Meter Reading - Labrador West	433.8	533.4				967.2
Replace Battery Banks and Chargers - Various Sites	425.0	456.6				881.6
Replace Powerline Carrier - Various Sites	73.4	763.4				836.8
Install Fire Protection in 230 kV Stations - Bay d'Espoir	200.0	566.0				766.0
Upgrade Telecontrol Facilities - Sandy Brook Hill	101.6	462.4				564.0
Purchase Vehicles and Aerial Devices - Various Sites	382.5	172.7				555.2
Upgrade Digital Fault Recorders - Various Sites	197.9	304.6				502.5
Upgrade Terminal Station for Mobile Substation - Cow Head	40.0	444.7				484.7
Replace Human Machine Interface - Various Sites	114.0	320.0				434.0
Replace Powerhouse 1 Station Service Transformer - Bay d'Espoir	46.7	354.5				401.2
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir	183.6	167.9				351.5
Replace Fuel Piping - Hardwoods and Stephenville	44.8	267.0				311.8
Upgrade Data Alarm Systems - Stony Brook	74.4	234.1				308.5
Refurbish Station Water System - Upper Salmon	96.6	197.6				294.2
Install Breaker Failure Protection - Various Sites	65.7	211.3				277.0
Replace Air Conditioning Units 8 and 14 - Hydro Place	34.6	229.5				264.1
Replace Surge Arrestors - Various Sites	144.4	53.0				197.4
Upgrade Warehouse Lighting - Bishop's Falls	15.2	180.4				195.6
Replace Air Conditioners - Massey Drive and Happy Valley	39.9	152.0				191.9
Install Variable Frequency Drives - Grey River	46.9	123.0				169.9
Replace Control Room/Communications Room Air Conditioning - Hinds Lake	41.3	53.0				94.3
Total Multi-Year Projects over $50,000 commencing in 2016	**27,657.6**	**67,098.1**	**27,097.4**	**15,247.3**	**13,026.7**	**150,127.1**

NEWFOUNDLAND AND LABRADOR HYDRO
2016 CAPITAL BUDGET
PROJECTS OVER $50,000
MULTI-YEAR PROJECTS
($000)

Multi-year Projects Commencing in 2015

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
Construct 230 kV Transmission Line - Bay d'Espoir to Western Avalon	4,403.0	75,284.3	123,739.6	88,231.1			291,658.0
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,873.8					13,062.9
Upgrade Power Transformers - Various Sites	4,440.4	7,002.3					11,442.7
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,525.4					5,180.6
Replace Vehicles and Aerial Devices - Various Sites (2015-2016)	2,377.1	225.3					2,602.4
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	239.9	1,038.4	901.6				2,179.9
Upgrade Distribution Systems - Various Sites (2015-2016)	1,136.1	818.8					1,954.9
Install Transformer On line Gas Monitoring - Various Sites	700.5	975.7					1,676.2
Replace Disconnect Switches - Various Sites	963.7	642.9					1,606.6
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	1,061.4					1,550.8
Install Fire Protection - L'Anse Au Loup	220.6	1,126.2					1,346.8
Replace Unit 2038 - Mary's Harbour	103.5	1,241.5					1,345.0
Rehabilitate Salmon River Spillway - Bay d'Espoir	745.6	556.8					1,302.4
Replace Station Service Breakers - Cat Arm	644.9	363.4					1,008.3
Install Automated Meter Reading - Various Sites (2015-2016)	559.9	401.8					961.7
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1				958.0
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	633.3					648.0
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5					545.2
Replace Diesel Unit 254 - Paradise River	66.8	429.3					496.1
Upgrade Ventilation Systems-Various Sites	175.9	317.3					493.2
Design and Install Fire Protection in 230 kV Stations - Various Sites	67.6	424.3					491.9
Upgrade Terminal Station Protection and Control - Various Sites	172.7	307.2					479.9
Replace Off Road Track Vehicle Unit 7861 - Stephenville	1.1	397.8					398.9
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	311.3					357.0
Refurbish Intakes - Bay d'Espoir	72.6	262.3					334.9
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	197.6					243.8
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	189.3					199.3
Install Infrared View Ports - Various Sites	83.7	113.1					196.8
Replace Station Lighting - Bay d'Espoir	16.7	160.3					177.0
Refurbish Unit Relay Protection - Paradise River	8.7	79.7					88.4
TOTAL MULTI-YEAR PROJECTS OVER $50,000 COMMENCING 2015	**27,040.9**	**104,829.3**	**124,886.3**	**88,231.1**	**0.0**	**0.0**	**344,987.6**

Multi-year Projects Commencing before 2015

PROJECT DESCRIPTION	Expended to 2015	2016	2017	2018	2019	2020	Total
Replace Instrument Transformers - Various Sites	1,684.4	1,511.7	471.9				3,668.0
Purchase Diesel Plant Production Data Collection Equipment - Various Sites	538.7	280.7					819.4
Total Multi Year Projects over $50K commencing before 2014	**2,223.1**	**1,792.4**	**471.9**	**0.0**	**0.0**	**0.0**	**4,487.4**

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
GENERATION					
Replace Site Facilities - Bay d'Espoir		928.3	11,053.0	11,981.3	C-3
Upgrade Powerhouse Building Envelope - Holyrood		2,723.8	3,754.0	6,477.8	C-5
Overhaul Steam Turbine Generator Unit 3 - Holyrood		5,868.6		5,868.6	C-8
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,525.4		5,180.6	
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir		2,959.6		2,959.6	C-10
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood		2,755.5		2,755.5	C-12
Upgrade Work - Cat Arm		558.3	1,353.0	1,911.3	C-14
Overhaul Turbine/Generator Units 6 and 7 - Bay d'Espoir		1,345.6		1,345.6	C-16
Rehabilitate Salmon River Spillway - Bay d'Espoir	745.6	556.8		1,302.4	
Rehabilitate Shoreline Protection - Cat Arm		112.2	1,030.7	1,142.9	C-24
Replace Station Service Breakers - Cat Arm	644.9	363.4		1,008.3	
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	633.3		648.0	
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5		545.2	
Overhaul Pumps - Holyrood		536.2		536.2	C-26
TOTAL GENERATION	4,083.1	22,389.5	17,190.7	43,663.3	
TRANSMISSION AND RURAL OPERATIONS					
Construct 230 kV Transmission Line - Bay d'Espoir to Western Avalon	4,403.0	75,284.3	211,970.7	291,658.0	
Upgrade Circuit Breakers - Various Sites (2016-2020)		6,969.1	54,491.3	61,460.4	C-33
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods		3,699.0	22,861.9	26,560.9	C-35
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,873.8		13,062.9	
Upgrade Power Transformers - Various Sites	4,440.4	7,002.3		11,442.7	
Upgrade Distribution Systems - Various Sites (2016-2017)		285.6	6,350.3	6,635.9	C-36
Additions for Load Growth - L'Anse au Loup and Postville		883.4	4,746.0	5,629.4	C-38
Provide Service Extensions - All Service Areas		5,150.0		5,150.0	C-41
Replace Diesel Units - Cartwright and Charlottetown		1,840.5	3,098.4	4,938.9	C-43
Install Fire Protection Systems - Nain and Cartwright		3,030.7	1,376.4	4,407.1	C-46
Upgrade Distribution Systems - All Service Areas		3,890.0		3,890.0	C-48
Replace Instrument Transformers - Various Sites	1,684.4	1,511.7	471.9	3,668.0	
Perform Wood Pole Line Management Program - Various Sites		2,919.0		2,919.0	C-52
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	239.9	1,038.4	901.6	2,179.9	
Overhaul Diesel Units - Various Sites		2,078.4		2,078.4	C-54
Install Spare Transformer - Happy Valley		2,040.9		2,040.9	C-56
Replace Insulators - TL203		1,985.6		1,985.6	C-58
Replace Disconnect Switches - Various Sites (2016-2017)		646.9	1,320.9	1,967.8	C-60
Upgrade Distribution Systems - Various Sites (2015-2016)	1,136.1	818.8		1,954.9	
Replace Protective Relays - Various Sites		700.6	1,156.4	1,857.0	C-62
Install Transformer On line Gas Monitoring - Various Sites	700.5	975.7		1,676.2	
Replace Disconnect Switches - Various Sites	963.7	642.9		1,606.6	
Replace Aircraft Markers at Grand Lake Crossing - TL228		589.6	978.3	1,567.9	C-64
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	1,061.4		1,550.8	
Install Fire Protection - L'Anse au Loup	220.6	1,126.2		1,346.8	
Replace Unit 2038 - Mary's Harbour	103.5	1,241.5		1,345.0	
Inspect Fuel Storage Tanks - Various Sites		1,326.9		1,326.9	C-66
Construct Overhead Distribution Line - Pilley's Island to Long Island		1,239.9		1,239.9	C-69
Upgrade Office Facilities and Control Buildings - Various Sites		1,134.0		1,134.0	C-71
Install Automated Meter Reading - Labrador West		433.8	533.4	967.2	C-73
Install Automated Meter Reading - Various Sites (2015-2016)	559.9	401.8		961.7	
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1	958.0	
Upgrade Line Depots - Various Sites		861.4		861.4	C-75
Purchase Diesel Plant Production Data Collection Equipment - Various Sites	538.7	280.7		819.4	
Install Fire Protection in 230 kV Stations - Bay d'Espoir		200.0	566.0	766.0	C-77
Replace Roof on Services Building - Bishop's Falls		612.8		612.8	C-79
Additions for Load Growth - Happy Valley		593.7		593.7	C-81
Upgrade Digital Fault Recorders - Various Sites		197.9	304.6	502.5	C-83
TOTAL TRANSMISSION AND RURAL OPERATIONS	22,036.1	141,915.2	311,373.2	475,324.5	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
GENERAL PROPERTIES					
Replace Vehicles and Aerial Devices - Various Sites (2015-2016)	2,377.1	225.3		2,602.4	
Replace Vehicles and Aerial Devices - Various Sites (2016-2017)		1,443.3	534.2	1,977.5	C-85
Upgrade Microsoft Office Products - Hydro Place		366.6	1,024.5	1,391.1	C-87
Replace MDR 4000 Microwave Radio East - Various Sites		77.4	1,093.1	1,170.5	C-90
Replace UPS Systems - Hydro Place		889.8		889.8	C-92
Replace Battery Banks and Chargers - Various Sites		425.0	456.6	881.6	C-94
Replace Personal Computers - Various Sites		861.7		861.7	C-96
Replace Powerline Carrier - Various Sites		73.4	763.4	836.8	C-98
Replace Roof - Hydro Place		639.5		639.5	C-100
Upgrade Telecontrol Facilities - Sandy Brook Hill		101.6	462.4	564.0	C-102
Purchase Vehicles and Aerial Devices - Various Sites		382.5	172.7	555.2	C-104
TOTAL GENERAL PROPERTIES	2,377.1	5,486.1	4,506.9	12,370.1	
TOTAL PROJECTS $500,000 AND OVER	28,496.3	169,790.8	333,070.8	531,357.9	

Project Title: Replace Site Facilities

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

The project involves the replacement of the maintenance garage, carpentry shop and warehouse with a consolidated building that will contain the functionality of these existing facilities. The scope includes:

- Finalized preliminary design of a new building;
- Detailed engineering and tender document development for the new building; and
- Construction of a new building.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	220.0	297.0	205.6	722.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	650.0	3,960.0	4,130.0	8,740.0
Other Direct Costs	13.0	83.4	83.4	179.7
Interest and Escalation	45.3	395.9	933.6	1,374.8
Contingency	0.0	0.0	964.2	964.2
TOTAL	**928.3**	**4,736.3**	**6,316.7**	**11,981.3**

Operating Experience:

These buildings support maintenance activities such as storage of replacements parts and materials as well as equipment maintenance which includes welding and fabrication. These buildings also house supervisor offices as well as employee personal protective equipment required to perform their jobs. The maintenance activities performed utilizing these facilities are essential to the safe, efficient operation of the 604 MW Bay d'Espoir Hydroelectric Generating Station.

Project Justification:

These buildings range in age between 30 and 53 years old. The maintenance garage and carpentry shop were built as temporary buildings to facilitate the construction of the Bay d'Espoir Hydroelectric

Generating Station in the early 1960s. Two condition assessments and a needs assessment have been completed for these buildings and multiple structural, electrical code and safety deficiencies have been identified. The condition assessment report developed in 2012 recommended immediate replacement of both the maintenance garage and the carpentry shop.

The condition of these three buildings is such that continued use into the future is not appropriate as the buildings are not acceptable for a safe working environment, and the existing facilities are not functional or efficient to the operation of the hydro development. As a result, 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. A cost benefit analysis has been prepared comparing three acceptable options for upgrading the deteriorated operations buildings in Bay d'Espoir. These include:

1. Refurbish all three buildings to increase life expectancy to 25 years;
2. Replace each building individually with a new same sized building for a total of three new buildings; and
3. Replace the buildings with a new consolidated building.

The three alternatives were evaluated to determine the least cost option over the next 25 years. Option 3 - replace the maintenance garage, carpentry shop and warehouse with a new consolidated building, was shown to be the least cost alternative.

This project includes replacing the maintenance garage, carpentry shop and warehouse with a new consolidated building that will serve the needs of the operation while maintaining the safety of our employees.

Future Plans:

None.

Attachments:

See report entitled "Replace Site Facilities – Bay d'Espoir" located in Volume II, Tab 1 for further project details.

Project Title: Upgrade Powerhouse Building Envelope

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is a multi-year program for the completion of upgrades to the Holyrood powerhouse building envelope. Work generally includes: the replacement of roof sections, deemed to have a remaining service life of less than two years, and replacement of sections of the exterior siding panels which have deteriorated to the point at which their integrity is compromised. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	492.7	492.7	259.4	1,244.7
Consultant	90.0	90.0	30.0	210.0
Contract Work	1,462.5	1,605.9	250.0	3,318.4
Other Direct Costs	111.4	112.4	52.9	276.7
Interest and Escalation	136.1	208.8	73.3	418.2
Contingency	431.2	460.1	118.5	1,009.8
TOTAL	**2,723.8**	**2,969.9**	**784.1**	**6,477.8**

Operating Experience:

The Holyrood Thermal Generating station is one of the primary contributors to the generation supply on the Island Integrated System. These generation units, housed within the structure, will be required to continue generating electricity until the Labrador Island Link is in service and providing power to the Island. Beyond that time frame, the powerhouse will remain in operation as a synchronous condenser facility until the year 2041.

The powerhouse building envelope is nearing the end of its service life. Exposed to strong, onshore winds on a regular basis, the continued battering of the weakened building envelope components creates a high potential for a repeat occurrence of the siding failure experienced in 2013, or of roofing leaks.

Project Justification:

The Holyrood powerhouse contains the three oil-fired generating units and their associated controls equipment. This equipment is vital to the Island Interconnected System and the continued performance of the powerhouse building envelope is essential to ensure that the equipment is protected from the elements, enabling it to be operated in a safe and reliable manner.

In 2013, Hydro engaged AMEC to complete a Level 2 condition assessment of various civil structures and the Unit 3 generator. When completing the assessment, AMEC considered the future of the plant and optimization of the plan when identifying the prioritized list of replacement items. The assessment found that the majority of the powerhouse's 23 roofing areas are at the end of their service life and their replacement was recommended within five years from the time of the assessment.

Following the completion of the 2013 condition assessment, a large metal siding panel was ripped from the south side of powerhouse during a winter storm. While it is fortunate that there was no damage to persons or property, the event highlighted issues with the exterior siding and necessitated a closer look at the siding system. Consequently, Hydro engaged AMEC to further assess the powerhouse siding during the spring of 2014. The assessment found that various sections of the siding, in addition to the roof, are at the end of their service life and their replacement was recommended.

Given the age and noted condition of the powerhouse building envelope components, the occurrence of leaks is imminent and the probability of a repeat "blow-off", whereby components of the envelope system could become completely detached from the structure, during periods of high wind, is greatly increased. While spot repairs can be enacted to address the occurrence of leaks, any repairs completed would be topical in nature and will not address the risk associated with the complete failure of the envelope components. Detachment of the envelope components could prove disastrous, leaving the building contents fully exposed and/or resulting in significant damage to persons and/or equipment. A proactive approach is required to ensure that the envelope, including siding and roof, upgrades can be completed prior to its failure.

Future Plans:

None.

Attachments:

See report entitled “Upgrade Powerhouse Envelope - Holyrood” located in Volume II, Tab 2, for further project details.

Project Title: Overhaul Steam Turbine Generator Unit 3

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to perform a scheduled major overhaul of Unit 3 Turbine, Generator and auxiliary systems located at the Holyrood Thermal Generating Station. This major overhaul consists of total dismantling of all turbine stages, removal of the generator rotor, and internal inspections of all auxiliary equipment. The work will be completed by contracted services with assistance from plant personnel as required. The contracted work consists of technical services, labor, materials and supervision. Plant support is required for work protection application and services, removal of specific monitoring and control systems, overall project supervision and liaison with Hydro's management personnel.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	420.0	0.0	0.0	420.0
Labour	500.0	0.0	0.0	500.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	3,800.0	0.0	0.0	3,800.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	204.6	0.0	0.0	204.6
Contingency	944.0	0.0	0.0	944.0
TOTAL	**5,868.6**	**0.0**	**0.0**	**5,868.6**

Operating Experience:

The operating hours for Unit 3, up to June 2015, is 145,579. Assuming the generator operates for approximately 3400 hours per year until the next overhaul, it is expected to attain approximately 149,000 hours before the next major overhaul in 2016. Unit 3 has undergone scheduled major overhauls and valve overhauls on a six-year and three-year basis respectively from 1971 to 2005. Starting in 2007, major overhauls on Unit 3 have been done on a nine-year frequency.

Project Justification:

This project is justified on the requirement to maintain the generating equipment in its optimal operating condition for Hydro to provide safe, least-cost, reliable electrical service to its customers. The purpose of the major overhaul is to return the turbine, generator and auxiliary systems to design specifications such that they can perform safely, efficiently, and reliably to meet system demands. The overhaul will also identify any internal conditions that if not corrected or controlled could lead to premature failure of the equipment.

Future Plans:

Unit 3 at the Holyrood Thermal Generating Station is scheduled for a generator overhaul in 2022. Unit 3 will continue to operate post in-service of the Labrador Island Link as a synchronous condenser.

Attachments:

See report entitled "Overhaul Steam Turbine Generator – Unit 3" located in Volume II, Tab 3, for further project details.

Project Title: Replace Interior and Exterior Protective Coating on Surge Tank 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project includes cleaning of the tank and riser, structural repairs to tank bowl, bracing, legs and compression ring and application of new coating for the interior and exterior of Surge Tank 2. The interior coating of the surge tank has failed, resulting in the metal being exposed and corroded. The interior riser and exterior of the tank has localized failure of the coating. The condition of the tank was documented during a condition assessment completed in 2014. Structural refurbishments and coating replacement are required to ensure the integrity of the tank and riser.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	185.7	0.0	0.0	185.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	2,309.4	0.0	0.0	2,309.4
Other Direct Costs	16.2	0.0	0.0	16.2
Interest and Escalation	190.7	0.0	0.0	190.7
Contingency	257.5	0.0	0.0	257.5
TOTAL	**2,959.6**	**0.0**	**0.0**	**2,959.6**

Operating Experience:

The overall height of the surge tank is 112 meters and it was installed in 1967 during Stage II construction of the Bay d'Espoir Hydroelectric Generating Station powerhouse. Surge Tank 2 is surge protection for Units 3 and 4 at Bay d'Espoir. Each surge tank is an integral part of the hydraulic system of the plant with its primary use being for water pressure protection of the penstock. During a sudden change in water pressure in the penstock, the water in the surge tank rises quickly to release the water pressure in the penstock line and prevent water hammer damage to the penstock. As a result of this function, the interior surface of the surge tank is subject to frequently changing wet and dry conditions which causes corrosion. A corrosion protection system (Cathodic Protection system) is located within the tank but is confirmed to be not functioning properly. As a result of the failed coating and lack of

cathodic protection, the tank is corroding. Outages to Bay d'Espoir Units 3 and 4 are required to complete work on the tank and riser interior.

Project Justification:

This project is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe and reliable operation of Surge Tank 2 and Generating Units 3 and 4 at the Bay d'Espoir Hydroelectric Generating Station.

A condition assessment of the tank and riser interior was completed by an engineering consultant in 2014. The consultant identified significant deterioration of the surge tank and recommended corrosion removal and recoating of the interior and exterior of the surge tank and riser, as well as structural refurbishments.

Corrosion in the surge tank and/or riser section can ultimately result in leaks, and if severe enough, structural failure of the metal. A significant leak in this structure would require immediate repair from the inside, requiring the tank to be fully drained and resulting in an unscheduled outage. Depending on the magnitude of the leak or structural failure, an unscheduled outage could be four to eight weeks in duration. Removing the corrosion, completing structural repairs and recoating the tank and riser will extend the life and reliability of the structure. As this surge tank is located on the penstock supplying water to Generating Units 3 and 4, a failure of the tank and the resulting outage would affect both Units 3 and 4 with a combined maximum generation capacity of 150 MW.

Given the degradation of the structure, this work is high priority.

Future Plans:

Surge Tank 1 is planned for condition assessment in 2015 with refurbishment, as required, in 2017. Interior coating and structural repair on Surge Tank 3 will be completed in 2015 as was previously approved under the 2015 Capital Budget Application.

Attachments:

See report entitled "Replace Interior and Exterior Coating on Surge Tank 2" located in Volume II ,Tab 4 for further project details.

Project Title: Rewind Rotor and Install Flux Probe Unit 3

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

The proposed schedule of rewind for the Unit 3 rotor is based around planned major unit outages. As such, Hydro's intention is to rewind the rotor of Unit 3 in 2016.

The proposal work schedule includes:

- In early 2016, tendering for the contract work associated with rewind of the rotor;
- In 2016, completion of the contract work during the summer outage period coincident with the planned major turbine generator maintenance for Unit 3; and
- The installation of the flux probe prior to the reinstallation of the rotor.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	90.0	0.0	0.0	90.0
Labour	467.0	0.0	0.0	467.0
Consultant	14.8	0.0	0.0	14.8
Contract Work	1,600.0	0.0	0.0	1,600.0
Other Direct Costs	10.6	0.0	0.0	10.6
Interest and Escalation	136.6	0.0	0.0	136.6
Contingency	436.5	0.0	0.0	436.5
TOTAL	**2,755.5**	**0.0**	**0.0**	**2,755.5**

Operating Experience:

Unit 3 of the Holyrood Generating Station is designed for continuous operation with varying loads. It is typically operated as seasonally loaded in the November to March period to meet system peak winter requirements. It is then generally operated as a synchronous condenser during the summer months. This unit has been operating in this mode, within their design capabilities, since 1986.

Project Justification:

This proposal is justified to maintain system reliability by rewinding the rotor of Unit 3 before a failure occurs. The most appropriate timing would see this work being completed during the next generator outage in 2016. Should the rotor fail while in service, it could cause significant damage to the generating unit, impairing Hydro's ability to provide cost effective power and reliable electrical service to the Island Interconnected System.

The rotor's insulation is nearing the end of its useful service life. Electrical testing performed in 2013 has confirmed the existence of a shorted turn which had not been noted in previous tests.

Inspections were completed on Unit 3 in 2013 and 2014 by Alstom. The findings from these inspections were reviewed by independent consultants (AMEC and IRIS Power) in 2014. These reviews state that a rotor rewind should be completed in the near future. In order to minimize costs and reduce the risk of a forced outage and/or failure, Hydro proposes that the rewind work be completed in 2016.

Future Plans:

None.

Attachments:

See report entitled "Rewind Rotor and Install Flux Probe Unit 3" located in Volume II, Tab 5, for further project details.

Project Title: Upgrade Work

Location: Cat Arm

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This two year project will upgrade the spherical valve control system and replace the deflector servomotors on both Generating Units 1 and 2 at the Cat Arm Generating Station. The project scope of work will include the replacement of hydraulic control valves and piping and upgrading the control panel on the spherical valve control system. Included in this project is the design and fabrication of both deflector servomotors, and delivery to site.

The project budget estimate is provided in Table 1.

Table 1: Project Budget Estimate.

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	314.1	110	0.0	424.1
Labour	75.5	638.3	0.0	713.8
Consultant	133.2	0.0	0.0	133.2
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	174.4	0.0	174.4
Interest and Escalation	35.5	141.3	0.0	176.8
Contingency	0.0	289.1	0.0	289.1
TOTAL	**558.3**	**1,353.0**	**0.0**	**1,911.3**

Operating Experience:

The spherical valve control system and deflector servomotors were commissioned in 1985 and have reached the end of their useful life.

The spherical valve control valve system is in a deteriorated condition and no longer can ensure that the spherical valve functions properly and closes automatically when required. The solenoid actuated valves that control the opening and closing of the spherical valve do not always respond correctly. Jumpers have been used in the relay control panel to complete the opening and closing operation which is exposing operators and maintenance crews to hazards. The three solenoid actuated valves (directional

valves) are sticking and do not work automatically. These directional valves are obsolete and no longer available. Also, some devices such as limit switches and pressure switches are not working properly. The deflector servomotors are constantly leaking water. In 2012, the spare deflector servomotor was installed on Generating Unit 1. After a few months of operation, there were problems with the spare servomotor. After an inspection, it was determined that the spare servomotor had machined pieces left inside the servomotor causing major damage to the internal surfaces and required replacement. The old servomotor at that time was still on site and was reinstalled on Generating Unit 1.

Project Justification:

The project is justified on the requirement to maintain a reliable and safe operation at Cat Arm.

The spherical valve is considered a critical isolation point and protection device for the generating units. Should the automatic control fail to close the spherical valve in an emergency situation, the damage to the power plant and penstock could be catastrophic. The spherical valves also allow maintenance crews to perform work safely on the generating units without dewatering the penstock. During maintenance work, a malfunction of the spherical valve control system can create hazardous conditions to operating staff. A condition assessment to the spherical valve control system on both Generating Units 1 and 2 was carried out by an engineering firm, Worley Parsons. It was concluded in the condition assessment report that the current condition of the spherical valve control system could lead to operation problems and accidents. Being a remote plant, accessible only by snow machines in winter, response times to alarms takes time. Leakage of the aged pipes and valves (30 years old) at 550 psi over an extended period of time may cause a significant flooding in the plant.

Currently, the existing deflector servomotors on both generating units are deteriorated. If the deflector servomotor fails on either generating unit, that unit will be out of operation until the servomotor is repaired or a replacement servomotor is installed.

Future Plans:

None.

Attachments:

See report entitled “Upgrade Work for Cat Arm, Units 1 and 2” located in Volume II, Tab 6, for further project details.

Project Title: Overhaul Turbine/Generator Units 6 and 7

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to partially dismantle the Bay d'Espoir Unit 6 and Unit 7 turbine/generator units to inspect, test, clean, repair and replace equipment components. This overhaul involves cleaning and inspection of the rotor and stator assembly, electrical testing on the rotor/stator assembly, runner repairs, calibration and testing of the turbine and generator protection devices, inspection of the bearing and seal clearances and a thorough inspection of the turbine, governor, and draft tube. Any required corrective maintenance will also be completed at this time. The generator guide bearing and bearing coolers will be replaced on Unit 7 by Hydro's internal forces. As well, a generator rotor modification will be performed on Unit 7 to address the excessive vibration history and repeated outage extensions to correct vibration issues.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	324.0	0.0	0.0	324.0
Labour	327.7	0.0	0.0	327.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	425.0	0.0	0.0	425.0
Other Direct Costs	2.6	0.0	0.0	2.6
Interest and Escalation	50.4	0.0	0.0	50.4
Contingency	215.9	0.0	0.0	215.9
TOTAL	**1,345.6**	**0.0**	**0.0**	**1,345.6**

Justification:

Regular overhauls and inspections are required for hydraulic generators to improve operation and reliability. During the winter months, these units are required to be available nearly 100 percent of the time in order to meet the electricity demands of the Island Interconnected System. In order to achieve this, these units need to have all major components inspected, tested and/or repaired on a six year frequency to minimize forced outages, forced de-ratings or unplanned maintenance outages, which can result in customer interruptions. This frequency is based on the recommendations outlined in Hydro's

AMS (Asset Maintenance Strategy) Program. In addition, these inspections/overhauls programs are re-evaluated regularly by Hydro's Long Term Asset Planning team and maintenance groups to ensure they are efficient and effective.

It has been identified that Unit 7 requires a generator guide bearing replacement based on earlier inspections and the condition of the current guide bearing. The bearing in service will be refurbished and used as a spare after removal. The generator coolers on Unit 7 will also be replaced during the overhaul. The currently installed coolers have previously been repaired and their reliability level has been compromised.

The historical pattern of excessive vibration on Unit 7 traditionally required a maintenance intervention for balancing on a four to five year cycle. Recently, this period of time has been getting shorter. Even after having balanced the unit in 2014, the operating generator vibration levels in June of 2015 are similar to what they were in June of 2014 prior to the required balancing effort. Andritz (formerly Canadian General Electric) is the original equipment manufacturer for this generator. They have successfully corrected the vibration issue on other generating units for other customers by modifying the rotor design. Given the longer than normal maintenance outage on Unit 7 in 2016 due to the Generator main step-up transformer replacement, performing this work in 2016 aligns major work on this generating unit.

Existing System:

Age of equipment or system

- Bay d'Espoir Unit 6 - 1970 (45 years)
- Bay d'Espoir Unit 7 - 1977 (38 years)

Unit Capacity

- Bay d'Espoir Unit 6 - 80 MW
- Bay d'Espoir Unit 7 - 154.4 MW

The seven generating units at Bay d'Espoir utilize approximately 176 m of head to produce a rated output of 604 MW with a rated flow of 397m^3/s. The plant produces an average of 2,650 GWh annually, making it the largest hydroelectric plant on the Island. Unit 7 is the largest hydroelectric generator at the Bay d'Espoir generating station. It is the only unit at Bay d'Espoir that has the capability of running in synchronous condenser mode, which is a process that is critical in maintaining grid stability.

Figure 1 is a photograph of the Bay d'Espoir Generating Station.

Figure 1: Bay d'Espoir Generating Station

Table 2: Major Work or Upgrades – Bay d'Espoir Unit 6

Year	Major Work/Upgrade	Comments
2014	Excitation transformer replaced	Resulting from a failure
2014	Turbine bearing replacement	Bonding issues
2014	Spherical valve by-pass line replacement	Ensure safe operation of valve
1975	Trabon greasing system upgraded	Environmental concerns addressed
2013	Auto grease replacement	Reliability issue with existing system
2010	Major inspection/overhaul	Preventative Maintenance
2006	Spherical valve controls upgrade	Worker/unit protection
2000	Turbine bearing cooler replacement	Replaced with OEM parts
2000	Generator bearing cooler replacement	Replaced with OEM parts
1995	Exciter Replacement	Unable to source parts for original
1995	Stainless steel runner installed	Increased MW output
1981	Concrete repairs to draft tube	Cavitation repairs

Table 3: Major Work or Upgrades – Bay d'Espoir Unit 7

Year	Major Work/Upgrade	Comments
2014	Excitation transformer replaced	Based on test results
2014	Generator/turbine unit balancing	Vibration issue addressed
2013	Generator deluge automated	Unit fire protection
2010	Major inspection/overhaul	Preventative Maintenance
2004	Exciter replacement	Unable to source parts for original
1998	Replaced synchronous condense compressor	System stability
1998	Air gap monitoring installed	Unit protection
1982	Generator braking ring replaced	Resulting from a failure
1982	Generator guide bearing replaced	Resulting from a failure

Operating Experience:

Bay d'Espoir Unit 6 and 7 Turbine/Generator Units went into service in 1970 and 1977, respectively. All turbine/generator units are given a major inspection and overhaul every six years.

Reliability Performance

Tables 4 and 5 show the forced and planned outages for the units.

Tables 4 and 5: Outage Statistics

Bay d'Espoir Unit 6

Year	Forced Outages	Maintenance And planned Outages	Total Outages
2014	3	1	4
2013	1	3	4
2012	4	2	6
2011	0	2	2
2010	0	4	4

Bay d'Espoir Unit 7

Year	Forced Outages	Maintenance and planned Outages	Total Outages
2014	2	2	4
2013	0	2	2
2012	0	1	1
2011	0	1	1
2010	0	10	10

Safety Performance

The activities that take place during inspections are well documented and defined. Any tasks that have been identified as critical with respect to safety have safe work methods available to follow to ensure all safety hazards are controlled or eliminated.

Environmental Performance

There are no environmental issues with the overhaul of these units other than the disposal of waste oil. Any waste oil generated from this overhaul will be disposed in an environmentally friendly manner that is in compliance with Hydro's Environmental Management System.

Industry Experience

Work performed during major inspections and overhauls is based on operational experience and manufacturer recommendations. A comprehensive preventative maintenance program adds reliability and extends the life of the asset. Failures and forced outages are reduced when the maintenance program is completed.

Vendor Recommendations

Vendor maintenance recommendations were considered and applied where applicable when the major inspection programs were developed.

Maintenance or Support Arrangements

Maintenance of hydroelectric generators is conducted by Hydro personnel. Contractors and consultants

are typically utilized to perform large, exceptional pieces of work where the skill sets are not available internally.

Maintenance History

The five-year maintenance costs history for Bay d'Espoir Unit 6 is shown in Table 6.

Table 6: Five-Year Maintenance History – Bay d'Espoir Unit 6

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	81	203	284
2013	32	48	80
2012	30	50	80
2011	43	33	76
2010	74	38	112

Note: Unexpected failure of the excitation transformer, failure of the spare excitation transformer, and the need to replace the turbine bearing resulted in increased operating maintenance expenses for Bay d'Espoir Unit 6 in 2014.

The five-year maintenance costs history for Bay d'Espoir Unit 7 is shown in Table 7.

Table 7: Five-Year Maintenance History – Bay d'Espoir Unit 7

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	49	262	311
2013	41	53	94
2012	29	48	77
2011	64	28	92
2010	65	75	140

Note: Unexpected failure of a generator bearing cooler resulted in increased operating maintenance costs for Bay d'Espoir Unit 7 in 2014. Unit 7 also experienced higher than normal vibration levels in 2014. A consultant was hired to perform a detailed analysis and to assist with the balancing of the unit.

Historical Information

The historical cost information is recorded in the table below:

Table 8: Hydraulic Unit Overhaul Capital Budget and Expenditures History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Locations
2015B	304.4	ongoing	Paradise River and Bay d'Espoir Unit 5
2014	485.0	481.2	Hinds Lake and Bay d'Espoir Unit 3
2013	428.1	214.4	Bay d'Espoir Unit 1 and Cat Arm Unit 2

Hydraulic turbine/generator inspection/overhauls are typically performed on a six year frequency. Typically two hydraulic turbine/generator units in the Hydro fleet are overhauled every year. This proposal is associated with a higher cost than previous overhaul projects due to generator rotor modification work required to improve generation reliability by changing the rotor design to correct a vibration issue inherent with the design. This work is not expected to be a normal component of future overhauls on this unit.

Anticipated Useful Life

The overhaul of the turbine/generator units is completed every six years. Therefore, the useful life of this overhaul is six years. The lifespan of hydro electric generators can be increased by completing the regular scheduled maintenance program and overhauling major components as required.

Development of Alternatives

All hydroelectric generators require regularly scheduled major overhauls. To ensure the long term reliability of these hydro assets, maintenance repairs and major overhauls have no viable alternatives.

Conclusion:

Hydroelectric generators are required to operate in an efficient manner and are required to be reliable in order to meet system load requirements on a daily basis. Increased reliability and a reduced failure rate can be achieved by completing a timely preventative maintenance program that inspects and overhauls all vital components of the generating unit. Major inspections and overhauls are essential and critical to the reliability of the Island Interconnected System.

Project Schedule:

Major inspections and overhauls are performed by Hydro personnel. The schedule varies between three and four weeks. At times, planned outages have to be extended up to an additional week to deal with corrective maintenance items.

The anticipated project schedule is shown in Table 9.

Table 9: Project Schedule

Activity		Start Date	End Date
Design	Detailed plan for the overhaul outage	January 2016	May 2016
Procurement	Specify material requirements	March 2016	September 2016
Construction	Perform the major inspection / overhaul Unit 6	May 2016	June 2016
Construction	Perform the major inspection / overhaul Unit 7	September 2016	October 2016
Commissioning	Return the unit to service Unit 6	June 2016	June 2016
Commissioning	Return the unit to service Unit 7	October 2016	October 2016
Closeout	Closeout the project	November 2016	December 2016

Project Title: Rehabilitate Shoreline Protection

Location: Cat Arm

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

The 127 MW Cat Arm Hydroelectric Development (Cat Arm), situated on the east side of the Great Northern Peninsula, was completed in 1984. Access to the plant is via a 25km long gravel road off route 420 near Jackson's Arm. An 80 m section of this road near the powerhouse at Devil's Cove is deteriorated and needs to be restored. The project scope of work involves the rehabilitation of the shoreline protection as recommended by AMEC, in their 2014 feasibility study to address rock armour erosion at Cat Arm.

The project will require approvals from the Provincial Department of Environment and Conservation, Provincial Department of Natural Resources and the Federal Department of Fisheries and Oceans. The work will be performed under contract with site supervision by a consultant. The budget estimate for the project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	56.5	84.8	0.0	141.2
Consultant	44.0	56.0	0.0	100.0
Contract Work	0.0	602.6	0.0	602.6
Other Direct Costs	4.0	25.2	0.0	29.2
Interest and Escalation	7.7	87.6	0.0	95.3
Contingency	0.0	174.6	0.0	174.6
TOTAL	**112.2**	**1,030.7**	**0.0**	**1,142.9**

Operating Experience:

Approximately one kilometer of the Cat Arm access road, in the vicinity of the powerhouse, was constructed on an exposed sea cliff. This section of road has experienced erosion since the road's completion in 1984.

An armour stone shoreline protection barrier, which was completed in 2005, has eroded over a portion of its length. The loss of the protective armour stone layer has left the remaining rock fill and filter

material exposed to the elements. This exposed, smaller material is easily eroded by the wave action to which it is exposed. If left unattended, the roadway's driving surface will be impacted by the loss of foundation support.

As part of other road work undertaken in 2012, Hydro submitted an application for Permission to Occupy to Crown Lands in 2012. Hydro subsequently applied for and received a Crown Easement to the road lands. This easement form of title has been determined to be appropriate for Hydro's needs as Hydro does not need to exclude others from using the road but it does require the legal right to have secure access over it, to make improvements to the road and to build and maintain structures such as guide rails, bridges and culverts. This is the form of title upon which Hydro holds a significant amount of its distribution and transmission plant.

Project Justification:

The road is used on a daily basis by Hydro's operating staff and at regular intervals by maintenance personnel. Vehicles transporting personnel and maintenance material must travel this access road.

A recent review of the shoreline protection barrier by Hydro staff and a geotechnical consultant, AMEC Earth and Environmental (AMEC), has concluded that on-going erosion is anticipated during periods of high waves combined with storm surges or higher tides and should be rehabilitated to prevent further erosion of the embankment. The erosion will progress to the point where the re-built road section will become degraded such that the road driving surface will again be reduced to a single lane. In a worst case scenario, this access for operational and maintenance personnel could be lost, which could have an impact on plant reliability and power supply to Hydro's customers.

A permanent and safe access road is required for the long term reliable operation of Cat Arm.

Future Plans:

Future road upgrades will be proposed in future capital budget applications.

Attachments:

See report entitled "Rehabilitate Shoreline Protection – Cat Arm" located in Volume II, Tab 7, for further project details.

Project Title: Overhaul Pumps

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project will involve overhauling the Unit 2 east circulating water pump, the Unit 2 north condensate extraction pump, and the Unit 1 west boiler feed pump.

The unit circulating water (CW) pumps provide circulating water to the turbine condenser, which is required for unit operation. Each pump, east and west, provides approximately 50 percent of the required circulating water necessary for full operation of the unit. The CW pumps, located in the pump houses, draw sea water from Conception Bay to the turbine condenser located on the first floor of the power house.

The condensate extraction pumps supplies water at moderate pressure for the low pressure feed water system. Unit 2 has two condensate extraction pumps which can provide up to approximately 80% of the units required maximum capacity. The condensate extraction pumps draw condensate from the condenser.

The boiler feed water pump supplies water at high pressure to the boiler for producing steam. Unit 1 boiler has two boiler feed water pumps; each pump is capable of supplying feed water for 50% capacity of the boiler. The boiler feed water pump draws water from the deaerator feed water tank.

Budget estimate for the pump overhauls is as follows:

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	33.0	0.0	0.0	33.0
Labour	59.0	0.0	0.0	59.0
Consultant	55.0	0.0	0.0	55.0
Contract Work	285.0	0.0	0.0	285.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	17.8	0.0	0.0	17.8
Contingency	86.4	0.0	0.0	86.4
TOTAL	**536.2**	**0.0**	**0.0**	**536.2**

Figure 1: Unit 1 Boiler Feed Pump West

Figure 2: Unit 2 Condensate Extraction Pump North

Figure 3: Unit 2 Circulating Water Pump East

Operating Experience:

One CW pump is in service until Unit 2 reaches approximately 50 percent of its operating capacity at which point the second pump is needed to provide sufficient volume of circulating water to generate above 90 MW. With two pumps available, they also provide some protection against a forced outage should a single CW pump fail, when the unit is operating below 90 MW.

One condensate extraction pump is in service up to 80 percent of Unit 2's capacity at which point the second pump is put into service. Below 80 percent the other extraction pump is in standby, ready to be taken into service when the normal operating pump fails or is out of service for maintenance. The limit is due to the condensate extraction pumps not being modified when Unit 2 was up-rated from 150 MW to 175 MW.

Typically one boiler water feed pump is in service until Unit 1 is producing 80 MW, at which point a second boiler water feed pump is necessary to provide sufficient feed water if the generation is to be increased above 80 MW.

Project Justification:

All pumps are required to be operating for the generating units at Holyrood to produce 100 percent power. Pump specialists Flowserve, were consulted for optimization of the overhaul schedule for pumps at the Holyrood Thermal Generating Station. Flowserve recommendations and agreed upon overhaul schedules for pumps can be found in Appendix A.

Future Plans:

Additional pump overhaul projects will be proposed in future capital budget applications.

Project Schedule:

The anticipated project schedule is shown in Table 5. Schedule may adjust based on finalizing annual maintenance outage timings.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Project initialization, refine schedule	January 2016	January 2016
Design	Project design	February 2016	February 2016
Procurement	Equipment/part procurement	March 2016	March 2016
Construction	Remove and repairs to pumps	April 2016	June 2016
Commissioning	Commissioning and testing of pumps	June 2016	July 2016
Closeout	Project completion and closeout, lessons learned	August 2016	September 2016

APPENDIX A

FLOWSERVE REVIEW – OVERHAUL SCHEDULE (MAY 24, 2011)

Pumps	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	
1 CW Pump East			X												76,762.00					1 CW Pump East
1 CW Pump West											75,000.00									1 CW Pump West
2 CW Pump East	X				X							66,750.00					84,438.00			2 CW Pump East
2 CW Pump West																				2 CW Pump West
3 CW Pump East		X									75,000.00									3 CW Pump East
3 CW Pump West						75,000.00												105,500.00		3 CW Pump West
1 Ext Pump North	X												79,000.00							1 Ext Pump North
1 Ext Pump South			X												91,500.00					1 Ext Pump South
2 Ext Pump North					10,000.00												100,500.00			2 Ext Pump North
2 Ext Pump South		X												80,500.00						2 Ext Pump South
3 Ext Pump North						60,000.00												75,000.00		3 Ext Pump North
3 Ext Pump South				X												68,000.00				3 Ext Pump South
1 Vac Pump North											25,000.00									1 Vac Pump North
1 Vac Pump South			X												28,000.00					1 Vac Pump South
2 Vac Pump North				X												29,000.00				2 Vac Pump North
2 Vac Pump South							15,000.00												32,000.00	2 Vac Pump South
3 Vac Pump North				X												29,000.00				3 Vac Pump North
3 Vac Pump South			X												28,000.00					3 Vac Pump South
1 BF Pump East		X								100,000.00						140,000.00				1 BF Pump East
1 BF Pump West				X							160,000.00						154,500.00			1 BF Pump West
2 BF Pump East					70,000.00								160,000.00						162,000.00	2 BF Pump East
2 BF Pump West			X									179,500.00						147,000.00		2 BF Pump West
3 BF Pump East	X								100,000.00						145,000.00					3 BF Pump East
3 BF Pump West	X					10,000.00								138,000.00						3 BF Pump West
Total					80,000.00	145,000.00	15,000.00		100,000.00	100,000.00	335,000.00	246,250.00	239,000.00	218,500.00	369,262.00	266,000.00	339,438.00	327,500.00	194,000.00	

Project Title: Upgrade Circuit Breakers

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

Hydro has many circuit breakers which have been in service for more than 30 years and are approaching the end of their service life. This project is to replace or refurbish SF_6 circuit breakers, and to replace air blast and oil circuit breakers throughout Hydro's System. The refurbishment and replacement of all the circuit breakers are given a priority determined by the criteria or plan for each circuit breaker type, as the criteria is different for different breaker types.

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

Table 1: Budget Estimate

Project Cost ($ x 1,000):	2016	2017	Beyond	TOTAL
Material Supply	100.0	100.0	300.0	500.0
Labour	2,061.7	2,494.9	9,221.7	13,778.2
Consultant	211.6	423.3	2,243.7	2,878.6
Contract Work	3,519.5	5,927.5	22,726.7	32,173.8
Other Direct Costs	87.0	139.2	587.1	813.4
Interest and Escalation	391.2	815.4	5,095.5	6,302.1
Contingency	598.0	908.5	3,507.9	5,014.4
TOTAL	**6,969.1**	**10,808.7**	**43,682.6**	**61,460.4**

Operating Experience:

The average age of the overall population of circuit breakers is well past a utility estimated circuit breaker's midlife of 20 years and is approaching the manufacturers' specified design end-of-life of 40 years.

Hydro has experienced increased maintenance problems and the unavailability of circuit breakers which include:

- air blast circuit breakers with air leaks and sticking valves; and
- SF_6 circuit breakers with SF_6 gas leaks and problems with the operating mechanism.

These problems experienced by Hydro are common in the utility industry and owners of these circuit breakers have addressed such problems though similar upgrading programs.

There has been no major refurbishment work associated with oil circuit breakers. The plan is to replace all oil circuit breakers by 2025 to ensure Hydro is compliant with the latest PCB regulations.

Project Justification:

This project is justified on the requirement to replace failing or deteriorated circuit breakers in order for Hydro to provide safe, reliable electrical service, and to comply with PCB regulations.

To maintain the reliability of in-service circuit breakers, Hydro has implemented a plan to address the aging circuit breaker fleet. To balance the financial impacts and system outage constraints, Hydro has developed a long term asset management plan for circuit breaker replacement and refurbishment.

The plan will see all the current in-service air blast circuit breakers replaced by 2020, all current in-service SF_6 circuit breakers overhauled at mid-life and replaced at or near age 40, and all oil circuit breakers replaced by 2023.

Future Plans:

Circuit breaker overhauls and replacements not addressed in the schedule up to 2020 will be proposed in future capital budget applications.

Attachments:

See report entitled “Upgrade Circuit Breakers” located in Volume II, Tab 8, for further project details.

Project Title: Construct 230 kV Transmission Line

Location: Soldiers Pond to Hardwoods

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

An investigation has been performed relating to an increase of capacity in Hydro's transmission system in the corridor between Soldiers Pond and Hardwoods. The proposed corridor upgrade consists of the construction of a new 230 kV transmission line, 16 km in length. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	520.0	4,616.0	0.0	5,136.0
Labour	936.0	1,616.5	291.0	2,843.5
Consultant	1,000.0	0.0	0.0	1,000.0
Contract Work	600.0	9,226.0	0.0	9,826.0
Other Direct Costs	444.0	403.0	72.0	919.0
Interest and Escalation	199.0	1,628.3	1,064.2	2,891.5
Contingency	0.0	0.0	3,944.9	3,944.9
TOTAL	**3,699.0**	**17,489.8**	**5,372.1**	**26,560.9**

Justification:

Following completion of the Lower Churchill Project, the power supply to the St. John's regional area will decrease from the Holyrood plant and increase along the route between Soldiers Pond and terminal stations in St. John's. The increased power flows will result in violations to System Planning Criteria as transmission lines will be overloaded under contingency conditions. A capital project is therefore proposed to increase the capacity of this corridor.

Future Plans:

None.

Attachments:

See report entitled "Soldiers Pond to Hardwoods Corridor Upgrade" located in Volume II, Tab 9, for further project details.

Project Title: Upgrade Distribution Systems

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

Hydro provides service to residents in select rural communities within the province through the use of distribution systems. The distribution systems typically consist of a substation coupled with a wood pole distribution line that supplies power from the station to service drops throughout the community. This project proposal includes distribution lines located in the distribution systems of Farewell Head, King's Point, Coney Arm, Grandy Brook, Bay d'Espoir, Sally's Cove, L'anse au Loup, Happy Valley and Paradise River that have been identified as requiring upgrades to the existing infrastructure. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	90.0	1,400.0	0.0	1,490.0
Labour	180.0	1,060.0	0.0	1,240.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	2,350.0	0.0	2,350.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	15.6	524.3	0.0	539.9
Contingency	0.0	266.0	0.0	1,016.0
TOTAL	**285.6**	**6,350.3**	**0.0**	**6,635.9**

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 expected service life of 30 years. In addition, standardized inspection and testing procedures indicate line components are deteriorated and have remaining life spans of only one to five years before failure occurs.

Project Justification:

This project is justified based 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 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 proposed in future capital budget applications. See five-year capital plan (Capital Plan 2016 Tab, Appendix A).

Attachments:

See report entitled "Distribution Upgrades 2016" located in Volume II, Tab 10, for further project details.

Project Title: Additions for Load Growth

Location: L'Anse au Loup and Postville

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This is a two year project and will involve increasing the firm capacity of the L'Anse au Loup and Postville diesel plants, by replacing existing units with ones of a larger prime rating. A more detailed scope is summarized below.

The generation expansion at the L'Anse au Loup diesel plant will be achieved by replacing a 600 kW diesel genset (Unit 246) with a new 1,500 kW, 1,800 RPM diesel genset. Due to the limited physical space in the engine hall, this project will also require relocating Unit 2005 to the current position of Unit 246. The current location of Unit 2005 is the only engine bay that can accommodate a larger 1,500 kW unit. The new 1,500 kW genset will require a new control panel, breaker, power cables, exhaust stack, radiator and aftercooler, and all other necessary equipment to facilitate a new unit. Additional ventilation will be required as the new larger genset will create more heat than the unit it is replacing (Unit 246).

The installation of a larger genset is also expected to increase station service demand to the point where upgrades will be required. The existing station service transformer must be replaced to accommodate the increase in station service demand.

Currently there is no available wall space to mount the motor starters associated with the new motor loads and therefore a Motor Control Centre (MCC) must be purchased and installed. An MCC is a single compact enclosure that can house each motor starter and therefore provide more space in the engine hall. Also, during the execution of an Arc Flash Remediation project, it was recommended to install new current-limiting fuses in each starter to reduce arc flash levels. Unfortunately, the existing motor starters are not designed to support these current-limiting fuses and therefore they must be replaced to achieve the desired arc flash levels.

The generation expansion at the Postville Diesel plant will be achieved by replacing a 252 kW diesel genset (Unit 577) with a new 450 kW, 1,800 RPM diesel genset. To complete this work new power cables, control panels, and piping must be procured, installed and commissioned.

The total estimated capital cost for both projects is approximately $5,629,400. A breakout of the estimated capital costs is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	350.0	1,434.0	0.0	1,784.0
Labour	242.0	1,082.0	0.0	1,324.0
Consultant	131.4	247.8	0.0	379.2
Contract Work	45.0	250.0	0.0	295.0
Other Direct Costs	42.8	332.7	0.0	375.6
Interest and Escalation	72.2	567.8	0.0	640.0
Contingency	0.0	831.6	0.0	831.6
TOTAL	**883.4**	**4,746.0**	**0.0**	**5,629.4**

Operating Experience:

The load forecast is indicating that the system load will surpass the firm capacity of the L'Anse au Loup and Postville diesel plants by the winter of 2015/2016. Based on the previous Operating Load forecasts, this violation in the firm capacity criteria was not expected until 2019 in L'Anse au Loup and 2022 in Postville. However, the sudden addition of a couple of relatively large customers on both distribution systems has advanced the need to install more generation capacity in L'Anse au Loup and Postville.

Project Justification:

This project is justified on the requirement to meet growing electricity needs of Hydro's customers serviced by the L'Anse au Loup and Postville diesel plants. Sufficient generation capacity must be available in an isolated system on a firm basis such that the peak load can be met at all times. Otherwise, when the load exceeds the available generation capacity, a power outage will result which would reduce the overall reliability of the system. In determining what a sufficient amount of generation is, Hydro applies a set of criteria that compares peak demand to the existing system capacity. This criteria is stated below:

- The Diesel System should have sufficient firm capacity to supply the peak load of the system.
    - The firm generating capacity shall be greater than the peak demand.
    - Firm generation capacity is defined as the total installed prime capacity on the system

minus the prime capacity of the largest unit.[1]

- Hydro installs a minimum of three units in each system to meet the load requirements of the system.

Attachments:

See report entitled "Additions for Load Growth - Isolated Generating Stations" located in Volume III, Tab 11.

[1] For L'Anse au Loup, Hydro considers the line capacity of the interconnection from Hydro Quebec as the largest unit on the system. 1,100 kW is also discounted from the installed capacity of the L'Anse au Loup Plant.

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)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	2,358.0	0.0	0.0	2,358.0
Labour	2,000.0	0.0	0.0	2,000.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	170.0	0.0	0.0	170.0
Other Direct Costs	136.0	0.0	0.0	136.0
Interest and Escalation	225.0	0.0	0.0	225.0
Contingency	461.0	0.0	0.0	461.0
Sub-Total	5,350.0	0.0	0.0	5,350.0
Cost Recoveries	(200.0)	0.0	0.0	(200.0)
TOTAL	**5,150.0**	**0.0**	**0.0**	**5,150.0**

Operating Experience:

An analysis of average historical expenditures on new customer connections by region was developed. All historical dollars were converted to 2014 dollars using the Statistics Canada Utility Distribution Line Construction index.

The five year actual expenditures for service extensions by region are shown in Table 2.

Table 2: Five Year Expenditures

Expenditures ($000)										
	2010		2011		2012		2013		2014	
Region	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Central	1,045	1,886	1,200	1,231	1,437	1,231	1,437	1,751	1,490	1,600
Northern	1,092	1,040	1,267	1,728	1,371	1,728	1,371	1,218	1,460	1,366
Labrador	1,248	2,665	1,705	3,073	2,198	3,073	2,198	2,720	3,220	1,848
Total	3,385	5,591	4,172	6,032	5,006	6,032	5,006	5,689	6,170	4,814

Project Justification:

In recent years, rural areas of the province have experienced increased expenditures for service extensions due to higher customer growth and economic activity. Because of this, for 2016, a one year historical average was used to determine the service extension budget for the Labrador region. These expenditures are forecast to decline across the next three to four years. A four year historical average was used for the Central Region and a five year historical average was used for the Northern Region respectively. The 2016 budget was developed assuming distribution line costs escalation of approximately two percent over 2015. The budget by region is shown in Table 3 below.

Table 3: Budget for 2016 Distribution System

Region	Budget ($000)
Central	1,750
Northern	1,470
Labrador	1,930
Total	**5,150**

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 (2016 Capital Plan Tab, Appendix A).

Project Title: Replace Diesel Units

Location: Cartwright and Charlottetown

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This is a two year project involving the replacement of a diesel generating unit (genset) in both Cartwright and Charlottetown diesel plants. The genset at the Cartwright Diesel Generating Station is up for replacement due to being at the end of its service life and the genset in Charlottetown has been identified for replacement due to repeated premature failures. A more detailed scope is summarized below:

The Cartwright Generating Station houses four gensets. One of the units has reached the age criteria for replacement. The 720 kW unit at this location is proposed to be replaced with a 925 kW 1200 RPM unit. The project will include piping modifications to the existing cooling system, upgrade of the associated switch gear, and modification of the auxiliary systems to accommodate the new unit. The existing exhaust system will be reused with minor modifications. Available new gensets on the market require a larger footprint than the old gensets. Therefore, re-arrangement of existing gensets inside the powerhouse will be required to allow enough space around the new genset for cooling and maintenance. The new genset is scheduled to be in service by September 2017.

The Charlottetown Generating Station houses three gensets. One unit is scheduled for replacement. The 759 kW unit at this location is proposed to be replaced with a 725 kW 1,800 RPM unit. The project will include piping modifications to the existing cooling system, upgrade of the associated switch gear, and modification of the auxiliary systems to accommodate the new unit. The existing exhaust system will be reused with minor modifications. Also, if required, modifications to the exhaust system for the other units will be performed based on the environmental modeling results. The new genset is scheduled to be in service by February 2017.

The long delivery item, for both locations, is the gensets which has an estimated lead time of 24-30 weeks. The work will be performed by Hydro personnel.

The total estimated capital cost for both locations is approximately $4,938,900. A breakout of the estimated capital costs is shown in Table 1.

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	798.9	892.0	0.0	1690.9
Labour	460.2	891.4	0.0	1351.4
Consultant	198.0	283.0	0.0	481.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	88.6	218.4	0.0	306.9
Interest and Escalation	72.3	270.4	0.0	342.7
Contingency	222.7	543.3	0.0	766.0
TOTAL	**1,840.5**	**3,098.4**	**0.0**	**4,938.9**

Operating Experience:

In Cartwright, Unit 2052 has been in service for 13 years. During the 13 years of service life, the unit has been overhauled three times. In 2018, the unit is forecast to have incurred over 100,000 hours of operation. Continued use of Unit 2052 beyond 2018 could reduce the reliability of the Cartwright Diesel Plant.

In Charlottetown, Unit 2079 was installed in April of 2006 and was in service for only 7.5 years, and had accumulated less than 40,000 operating hours before its most recent failure in November 2013. Prior to failure, the unit had been overhauled 3 times following failures. In consultation with the Original Equipment Manufacturer, Hydro asset managers attempted to ascertain the reason for the failure but it cannot be conclusively determined, and therefore rectified through overhauls.

Project Justification:

The project in Cartwright is justified based on Hydro's asset management strategy to replace gensets when they approach 100,000 operating hours. Unit 2052 at the Cartwright Generating Station is forecasted to incur 100,000 hours in 2018. The new unit will be installed in 2017.

Diesel generating Unit 2079 was installed at Charlottetown in 2006. It received its first scheduled engine overhaul four years later in 2010 after accumulating the standard amount of operating hours before completing a planned overhaul. Since that time, the engine has incurred three sudden failures, each time after accumulating limited operating hours. The most recent failure was in November of 2013. All failures required the engine to undergo a major overhaul before it could be placed back in service.

The engine had a history of exhibiting high exhaust gas temperatures. After consultation with the manufacturer, this was not conclusively determined to be the cause of the failures and a definitive cause could not be determined. Overhauls took place following the first two sudden failures but a third overhaul has not taken place to bring the unit back in service after the most recent failure. Hydro has implemented temporary measures to provide generating capacity in lieu of overhauling the unit, while a proposal for replacement was applied for.

Considering the history of premature engine failures over its last 42 months of operation, the existing Charlottetown unit is not considered to be reliable. Analysis of several alternatives for serving the community according to Hydro generation planning criteria concluded the most prudent solution is to replace Unit 2079 with a new genset of similar size and configuration fitted with a more reliable model of diesel engine.

Attachments:

See report entitled "Replace Diesel Units – Cartwright and Charlottetown" located in Volume III, Tab 12, for further project details.

Project Title: Install Fire Protection Systems

Location: Nain and Cartwright

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This proposed project is a continuation of a multi-year program to equip diesel plants with automatic fire protection systems. Automatic fire protection systems will be installed at Nain and Cartwright diesel plants in the diesel generator main hall area and other interior spaces requiring fire protection including the supervisory control room, battery room and the lube and coolant storage room.

The estimated budget for this project is provided in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	45.0	0.0	0.0	45
Labour	338.3	50.5	0.0	388.8
Consultant	118.4	0.0	0.0	118.4
Contract Work	1855	988	0.0	2843
Other Direct Costs	56.2	2.6	0.0	58.8
Interest and Escalation	149.8	112.6	0.0	262.4
Contingency	468.1	222.7	0.0	690.8
TOTAL	**3,030.7**	**1,376.4**	**0.0**	**4,407.1**

Operating Experience:

Cartwright diesel plant experienced a fire to engine components and wiring in 2002 due to an oil leakage over hot exhaust manifold. The fire was extinguished by an employee using a fire extinguisher.

In 1973, Nain diesel plant was destroyed by fire when it was under the ownership of Labrador Services Division. The plant was rebuilt and in 1993, there was another major fire caused by a catastrophic engine failure. In 2006, a new plant was constructed at a different site near the community and it experienced a major fire in 2008. That fire destroyed one generating unit, damaged the other two, and caused significant damage to the auxiliary equipment and building finishes. The total refurbishment cost was $5,000,000. There have been other fires at Hydro's diesel plants which have resulted in extensive damage or total loss of plants.

Although Hydro's diesel plants are equipped with fire detection systems, they are not staffed 24 hours per day, seven days per week, and they do not have automatic fire protection systems. During the fire in 2008 at Nain, the existing fire alarm system performed as designed and alerted Energy Control Center (ECC) in St. John's and the plant operator. The fire was extinguished by the Nain Volunteer Fire Department but not before extensive damage was experienced.

Project Justification:

This project is justified by the requirement to protect critical assets at the diesel plants in Nain and Cartwright from potential catastrophic consequences in the event of a fire. As both diesel plants are not staffed 24 hours per day seven days a week, the potential for a fire to be left unchecked for a period of time is a significant risk. The result could be the community being left without power for an extended period of time which would have both operational and health and safety concerns for the community.

In 2011/2012, Hydro engaged an engineering consulting firm, Hatch, to complete a study and recommend measures that could be taken to reduce the risk of fire and minimize fire damages to diesel generating stations. In addition, Hydro's insurer, Factory Mutual Global, has recommended that diesel plants be equipped with automatic fire protection systems.

Future Plans:

Hydro owns and operates 25 diesel plants. It is anticipated that Hydro will submit other proposals in subsequent years to have automatic fire protection systems installed at other remote diesel plants.

Attachments:

See report entitled "Install Fire Protection in Diesel Plants" located in Volume III, Tab 13, for further project details.

Project Title: Upgrade Distribution Systems

Location: All Service Areas

Category: Transmission and Rural Operations - Distribution

Definition: Pooled

Classification: Normal

Project Description:

This project is annual allotment based on historical expenditures to provide for the replacement of deteriorated poles, substandard structures, corroded and damaged conductors, corroded 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)*	**2016**	**Beyond**	**Total**
Material Supply	2,108.0	0.0	2,108.0
Labour	1,220.0	0.0	1,220.0
Consultant	0.0	0.0	0.0
Contract Work	153.0	0.0	153.0
Other Direct Costs	3.0	0.0	3.0
Interest and Escalation	168.0	0.0	168.0
Contingency	338.0	0.0	338.0
Sub-Total	3,990.0	0.0	3,990.0
Cost Recoveries	(100.0)	0.0	(100.0)
TOTAL	**3,890.0**	**0.0**	**3,890.0**

Operating Experience:

An analysis of average historical expenditures on distribution upgrades by region was performed. All historical dollars were converted to 2014 dollars using the Statistics Canada Utility Distribution Line Construction index.

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

Table 2: Five Year Expenditures

Expenditures ($000)										
	2010		2011		2012		2013		2014	
Region	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**
Central	1,032	1,037	998	1,365	993	1,854	1,095	1,692	1,700	1,861
Northern	1,072	1,071	1,051	1,489	1,089	1,010	1,237	678	1,270	854
Labrador	468	191	450	548	426	270	458	604	400	859
Total	2,572	2,299	2,499	3,402	2,508	3,134	2,790	2,974	3,370	3,574

Other specifically approved projects for 2010 – 2014 are listed in Table 4.

Project Justification:

Based on the five-year average for distribution system upgrades for the period 2010 – 2014 the budget shown in Table 3 was developed for the Northern Region. The budget for the Central area was developed using a two year average and the budget for Labrador was developed using a one year average. The 2016 budget was developed assuming distribution line cost escalation in 2015 of approximately two percent over 2015.

Table 3: Budget for 2016 Distribution System

Region	Budget ($000)
Central	1,870
Northern	1,120
Labrador	900
Total	**3,890**

Future Plans:

This is an annual allotment which is adjusted from year to year depending on historical expenditures. See the five-year capital plan (2016 Capital Plan Tab, Appendix A).

Table 4 shows the history of other specific distribution system upgrades that have been completed over the past five years as well as the budget for 2015.

Table 4: Historical Information

Year	Project Description	Budget ($000)	Actuals ($000)
2015B	Upgrade Distribution Feeder – Line 1, 3, 4, 6 and 7 Bottom Waters (Year 1 of 2)	42.7	
	Pole Replacements – Pinsent's Arm and Labrador City	593.4	
	Insulator Replacements – Farewell Head	500.0	
	Relocate Voltage Regulators – Hawke's Bay	166.4	
	Install Second Distribution Feeder - Nain	1050.3	
	Upgrade Distribution Feeder - Line 1 Nain (Year 2 of 2)	261.0	
	Upgrade Distribution Feeder - Line 1 Daniel's Hr. (Year 2 of 2)	877.8	
	Upgrade Distribution Feeder - Line 1 and 2 Main Brook (Year 2 of 2)	837.1	
	Upgrade Distribution Feeder - Line 1 Plum Point (Year 2 of 2)	1,440.9	
	Upgrade Distribution Feeder - Line 1 Hampden (Year 2 of 2)	733.2	
2014	Upgrade Distribution Feeder - Line 1 Nain (Year 1 of 2)	43.0	10.0
	Upgrade Distribution Feeder – Happy Valley (Year 1 of 2)	64.3	26.6
	Upgrade Distribution Feeder - Line 1 Daniel's Hr. (Year 1 of 2)	69.7	14.9
	Upgrade Distribution Feeder - Line 1 and 2 Main Brook (Year 1 of 2)	64.3	104.7
	Upgrade Distribution Feeder - Line 1 Plum Point (Year 1 of 2)	75.3	6.4
	Upgrade Distribution Feeder - Line 1 Hampden (Year 1 of 2)	53.6	30.5
	Upgrade Distribution Feeder - Line 1 McCallum	359.1	320.1
	Upgrade Distribution Feeder - Line 1, 2, 4 and 5 Barachoix	583.7	553.8
	Upgrade Distribution Feeder - Line 1 Bay d'Espoir	692.6	632.3
	Upgrade Distribution Feeder - Line 1 Conne River	494.2	443.2
	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 2 of 2)	908.1	740.5
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 2 of 2)	1,259.5	1366.7
	Upgrade Distribution System - Charlottetown (Year 2 of 2)	365.0	269.2
	Upgrade Distribution System - South Brook (Year 2 of 2)	975.8	846.2
	Upgrade Distribution Feeder - Line 1 Grey River (Year 2 of 2)	487.1	410.8
2013	Upgrade Distribution Feeder - Line 1 St. Lewis (Year 1 of 2)	76.9	23.3
	Upgrade Distribution Feeder - Line 1 and 3 Roddickton (Year 1 of 2)	98.4	106.5
	Upgrade Distribution System - Charlottetown (Year 1 of 2)	27.8	22.8
	Upgrade Distribution System - South Brook (Year 1 of 2)	76.3	108.5
	Upgrade Distribution Feeder - Line 1 Grey River (Year 1 of 2)	32.5	111.9
	Upgrade Distribution Feeder - Line 1 Cow Head	665.6	658.4
	Upgrade Distribution Feeder - Line 1 St. Brendan's	330.2	310.7
	Upgrade Distribution Feeder - Line 1 Holyrood	632.4	372.1
	Upgrade Distribution Feeder - Line 11 Wabush	400.8	513.2
	Upgrade Distribution Voltage - Line 6 St. Anthony	641.9	648.6
	Upgrade Distribution Feeder - Line 6 Farewell Head	961.9	980.0
	Upgrade Distribution Feeder - Line 5 Farewell Head	1,110.1	1,184.9
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 2 of 2)	1,110.5	1,276.2

Year	Project Description	Budget ($000)	Actuals ($000)
2012	Upgrade Distribution Feeder - Line 1 Bay d'Espoir	856.6	896.9
	Upgrade Distribution Feeder - Line 2 Bay d'Espoir	952.9	811.2
	Upgrade Distribution Feeder - Line 1 Francois	440.9	650.4
	Upgrade Distribution Feeder - Line 1 Parson's Pond	381.9	344.7
	Upgrade Distribution Feeder - Line 2 Plum Point (Year 1 of 2)	50.4	33.2
	Upgrade Distribution Feeder - Line 7 Happy Valley	1,260.1	1,163.6
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 3 of 4)	2,114.6	1,895.0
	Reconfigure Feeders – Wabush	55.4	55.4
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 2 of 2)	725.7	658.5
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2) (Materials ordered in 2011)	799.5	612.6
2011	Replace Poles – Westport	256.4	279.3
	Replace Poles - Grandy Brook	286.4	312.4
	Replace Poles - Farewell Head	339.6	393.9
	Upgrade Distribution Feeder - Line 1 Rigolet (Year 1of 2)	72.0	10.5
	Upgrade Distribution Feeder - Line 1 Francois	440.9	116.0
	Upgrade Distribution Feeder - Line 8 Happy Valley	553.5	488.2
	Upgrade Distribution Feeder - Line 4 Roddickton (Year 2 of 2)	902.6	1,106.2
	Upgrade Distribution Feeder - Line 1 Makkovik (Year 2 of 2)	742.4	137.3
	Upgrade Distribution Feeder - Line 2 Glenburnie (Year 2 of 4)	578.2	527.8
2010	Replace Poles - English Harbour West	274.8	249.8
	Replace Poles - Line 1 Fleur De Lys	269.2	246.9
	Replace Poles – Barachoix	273.3	256.1
	Upgrade Distribution System - Line 1 Makkovik (Year 1 of 2)	57.1	25.1
	Upgrade Distribution System - Line 4 Roddickton (Year 1 of 2)	160.6	98.4
	Upgrade Distribution System - Line 2 Glenburnie (Year 1 of 4)	267.3	134.8
	Upgrade Distribution System - Line 4 Happy Valley	265.3	251.6

Project Title: Perform Wood Pole Line Management Program

Location: Various Sites

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

The objective of the Wood Pole Line Management (WPLM) 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.

Under the program, transmission line inspection data in each year is analyzed and appropriate recommendations made for necessary refurbishment and/or replacement of line components such as poles/structures, hardware and conductor in the subsequent year. The inspection data and any refurbishment and/or replacement of assets are recorded in a centralized database for future access and tracking.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	472.0	0.0	0.0	472.0
Labour	1,695.0	0.0	0.0	1,695.0
Consultant	100.0	0.0	0.0	100.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	84.8	0.0	0.0	84.8
Interest and Escalation	96.8	0.0	0.0	96.8
Contingency	470.4	0.0	0.0	470.4
TOTAL	**2,919.0**	**0.0**	**0.0**	**2,919.0**

Operating Experience:

Hydro operates approximately 2,500 kilometers of wood pole transmission lines, including approximately 26,000 poles. Hydro inspects and treats approximately 10% of these poles each year, and these inspections indicate decreasing preservative levels and increasing decay in aging poles.

Project Justification:

As wood poles age, their preservative retention levels decrease and the poles become increasingly subjected to deterioration by different agents including fungi and insects. Wood poles must therefore be regularly inspected and treated to proactively identify and assess any deterioration. The WPLM program detects “danger poles” and other deteriorated line components early to avoid safety hazards and to identify poles that are at early stages of decay to ensure that corrective measures can be taken to extend the average life of these poles. Money is saved in the long term by deferring the cost of rebuilding lines and avoiding forced outages.

In addition to proactively managing wood poles, the project detects deteriorated line components before the integrity of a structure is jeopardized. If the deterioration of the components is not detected early enough then the reduced integrity of the structure will affect the reliability of the line and the system as a whole and could lead to increased failure costs and potentially, customer interruptions.

Future Plans:

The program is based on two ten year inspection cycles that began 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 the anticipated five- year capital schedule in Appendix A of the attached report entitled “Wood Pole Line Management”

Attachment:

See report entitled "Wood Pole Line Management Program" located in Volume III, Tab 14, for further project details.

Project Title: Overhaul Diesel Units

Location: Various Sites

Category: Transmission and Rural Operations - Generation

Definition: Pooled

Classification: Normal

Project Description:

This project is required to overhaul the diesel engines at diesel generating plants. The project consists of the 14 overhauls that are scheduled in 2016. This schedule is based on the engines being overhauled every 20,000 hours of operation (with the exception of the 100,000 hours milestone at which point the engine is replaced instead of being overhauled).

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	1,141.2	0.0	0.0	1,141.2
Labour	362.2	0.0	0.0	362.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	87.0	0.0	0.0	87.0
Other Direct Costs	79.2	0.0	0.0	79.2
Interest and Escalation	74.9	0.0	0.0	74.9
Contingency	333.9	0.0	0.0	333.9
TOTAL	**2,078.4**	**0.0**	**0.0**	**2,078.4**

Operating Experience:

Isolated diesel generation plants operate continuously since they provide the primary source of electricity to communities isolated from the province's electrical grid. A given unit is not in service continually since the number of units in service varies based on the demand. Emergency backup diesel generation plants operate only in emergency situations which are rare but critical.

In automated plants the engine mix is automatically controlled by a control system to maximize fuel efficiency while in a manual plant this control is completed by the operator. In any of the plants the operator has the flexibility to shut down engines for maintenance provided there is another engine available to take the load for that time. As a result, outages to engines can occur without outages to customers.

Project Justification:

Newfoundland and Labrador Hydro's current maintenance philosophy is to complete an engine overhaul on all diesel engines every 20,000 hours. This philosophy was established as a result of a 2003 review of the maintenance tactics and failure history. Performing overhauls too frequently results in additional expenditure for negligible improvement in reliability. An overhaul interval of 20,000 hours is considered to be the optimum interval for providing least-cost, reliable electrical service.

Future Plans:

The overhaul of diesel engines is a continuous program that will need to continue as long as there are prime power diesel generating plants. The long term plan for diesel engine overhauls projects 44 overhauls over the next five years (i.e. 2016 - 2020) which is an average of 8.8 overhauls annually and is based on an overhaul interval of 20,000 operating hours. The long term plan is based on the present-day operating conditions which are subject to change as the loading on a plant or other factors changes with time. Changes to the operating conditions can change the average number of annual overhauls.

Attachments:

See report entitled "Overhaul Diesel Engines" located in Volume III, Tab 15, for further project details.

Project Title: Install Spare Transformer

Location: Happy Valley

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

The scope of work identified within this project includes the addition of equipment required to make the spare transformer in the Happy Valley Terminal Station ready for service. The 15/20/25 MVA transformer is currently situated in the station. The project includes the installation of bus work, a 138 kV disconnect, a 25 kV breaker, a 25 kV disconnect, and a transformer protection panel. These additions are required such that the spare transformer can be placed into service and to ensure that it is monitored and protected.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	550.5	0.0	0.0	550.5
Labour	554.0	0.0	0.0	554.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	432.0	0.0	0.0	432.0
Other Direct Costs	69.6	0.0	0.0	69.6
Interest and Escalation	113.6	0.0	0.0	113.6
Contingency	321.2	0.0	0.0	321.2
TOTAL	**2,040.9**	**0.0**	**0.0**	**2,040.9**

Operating Experience:

There have been no significant issues with the performance of this terminal station. In the event of a transformer failure, the existing configuration would not allow the spare transformer to be energized within the two day period stipulated within Hydro's Business Continuity plan.

Project Justification:

A review of the contingency plan to place the spare transformer into service (in the event of a failure of one of the existing transformers in this station) within a period of two days was conducted. This review concluded that the spare transformer could not be put into service in timely fashion in the event of a failure of one of the other transformers, potentially resulting in power rotation or outages. The review

indicated that system modifications are required in order to be compliant with Hydro's Business Continuity Plan.

Future Plans:

None.

Attachments:

See report entitled "Install Spare Transformer" located in Volume III, Tab 16, for further project details.

Project Title: Replace Insulators

Location: TL203

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Normal

Project Description:

Throughout the 2013-2014 winter season, high winds and adverse weather conditions were experienced on many transmission lines in Hydro's system. These weather conditions escalated insulator pin failures on both TL201 and TL203. The first failure of the winter season occurred on Structure 163 (TL203) on January 12, 2014.

Inspections of both lines began immediately after the January, 2014 failure and continued until April, 2014. Through the inspection of TL201, a total of 153 structures were identified with corrosion issues in the insulators, while 30 structures were identified on TL203. Given the extent of the corrosion and frequency of previous line failures on TL201, all insulators were replaced and TL 203 underwent insulator replacement on selectively identified structures from September to December, 2014. This proposal is for the remaining insulators on TL203 to be replaced.

The project scope of work is to replace insulators on 155 transmission structures of TL 203.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	582.8	0.0	0.0	582.8
Labour	182.2	0.0	0.0	182.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	627.9	0.0	0.0	627.9
Other Direct Costs	180.0	0.0	0.0	180.0
Interest and Escalation	98.1	0.0	0.0	98.1
Contingency	314.6	0.0	0.0	314.6
TOTAL	**1,985.6**	**0.0**	**0.0**	**1,985.6**

Operating Experience:

TL203 is one of the oldest transmission lines in Hydro's system. This line supplies electrical service to the most densely populated areas of the province. Much of the line traverses very rough terrain which is

subject to high winds and icing conditions.

The frequency of recent insulator failures has an impact on the reliability of the line and raises the risk of additional failures. Insulator replacement is necessary to ensure the reliability of the system.

Project Justification:

An insulator replacement is justified on the requirement to replace failing or deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service.

The reliability of the insulators affects the reliability of the line and the system as a whole and could lead to increased failure costs. Insulator string separation can also create safety issues and hazards for Hydro personnel and for the general public.

Attachments:

See report entitled “Insulator Replacement - TL203” located in Volume III, Tab 17, for further project details.

Project Title: Replace Disconnect Switches

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Pooled

Classification: Normal

Project Description:

This project is part of an ongoing program to replace aging 69 kV, 138 kV and 230 kV disconnect switches in Hydro's terminal stations on the Island Interconnected System. This project proposal is for the purchase and replacement of fourteen disconnect switches scheduled for replacement in 2016/17. The disconnect switches identified for replacement are located in Bay d'Espoir, Bottom Brook, Hampden Tap, Holyrood, and Massey Drive. The schedule for this work will be planned over a two year period and will involve engineering and material procurement in the first year and construction and commissioning in the second year.

The budget estimate for this work is shown in the Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	69.0	30.0	0.0	99.0
Labour	532.0	795.5	0.0	1,327.5
Consultant	0.0	7.4	0.0	7.4
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	7.4	52.5	0.0	59.9
Interest and Escalation	38.5	136.8	0.0	175.3
Contingency	0.0	298.7	0.0	298.7
TOTAL	**646.9**	**1,320.9**	**0.0**	**1,967.8**

Operating Experience:

The disconnect switches included in the replacement plan have reached the end of their normal service lives and, in some cases, no longer perform their intended function. In the case where faulty or damaged disconnect switches are inoperative, they are tagged out of service, which means the switch cannot be opened or closed. As a result, equipment cannot be isolated by the inoperative disconnect switch and adjacent disconnect switches must be operated in order to isolate the equipment. This decreases system reliability and performance since additional equipment and customers will be included in the outage/isolation for a longer duration of time. This scenario also increases the safety risk to

personnel who have to execute a more complicated switching order, involving a remote disconnect switch not typically included in the isolation of the equipment.

Project Justification:

Disconnect switches are used to isolate equipment either for maintenance activities or system operation and control. Proper operation of these switches is essential for a safe work environment and for reliable and secure system operation. Faulty and/or malfunctioning disconnect switches that do not operate properly prevent reliable and secure system operation and create a safety hazard. The switches scheduled for replacement have problems such as inoperable mechanical linkages, misalignment of switch blades, broken insulators, and seizing of moving parts. Additionally, the switches have reached the end of their service life and replacement parts are not available.

Future Plans:

Future disconnect switch replacements will be proposed in future capital budget applications.

Attachments:

See report entitled “Replace Disconnect Switches” located in Volume III, Tab 18, for further project details.

Project Title: Replace Protective Relays

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

The proposal covers replacement of protective relays at various terminal and generating stations throughout the Hydro system. Relays will be replaced on transformers T1,T2,T4,T5,T6,T7 at Bay d'Espoir Generating Station; T1 at Cat Arm Generating Station and T5 at Holyrood Terminal Station. A second digital multifunction relay will be added to T3 at Bay d'Espoir Generating Station. Relays will be replaced on transmission lines TL202 (Bay d'Espoir and Sunnyside Terminal Stations), 38L and 39L (Holyrood Terminal Station) and 64L (Western Avalon Terminal Station).

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	264.0	227.6	0.0	491.6
Labour	338.0	463.0	0.0	801.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	47.7	47.4	0.0	95.1
Interest and Escalation	50.9	140.9	0.0	191.8
Contingency	0.0	277.5	0.0	277.5
TOTAL	**700.6**	**1,156.4**	**0.0**	**1,857.0**

Operating Experience:

The existing relays are the electromechanical and older solid state types and they need to be replaced due to age and performance limitations. Modern digital multifunction have increased setting flexibility, fault disturbance monitoring, communications capability and metering functionality and they offer greater dependability and security.

Project Justification:

In 2014, Hydro completed a review of existing transformer, bus and line protection relays on 230 kV, 138 kV and 69 kV systems. As a first priority, a replacement plan was developed for the 230 kV transformers, transmission lines and buses. Transformers T1, T2, T4, T5, T6 and T7 at Bay d'Espoir; T5 at Holyrood and TL202 at Bay d'Espoir and Sunnyside were scheduled in the plan for 2016. The second multifunction relay for T3 at Bay d'Espoir was added to this proposal. Transformer T1 at Cat Arm is

being replaced in 2016 and the protective relays were added to this proposal for replacement during the same outage.

Newfoundland Power has replaced the relays at stations in the transmission loops between Holyrood, Western Avalon and Hardwoods. The remaining relays to be replaced are owned by Hydro. These relays use older electromechanical and solid state technologies whereas the new relays will be modern microprocessor type.

Future Plans:

Additional protective relay replacements will be proposed in the future capital budget applications.

Attachment

See report entitled “Replace Protective Relays – Various Sites” located in Volume III, Tab 19, for further project details.

Project Title: Replace Aircraft Markers at Grand Lake Crossing

Location: TL228

Category: Transmission and Rural Operations - Transmission

Definition: Other

Classification: Mandatory

Project Description:

The aircraft obstruction lighting systems on the TL228 Grand Lake crossings require replacement due to aging, outdated, and failing equipment. The replacement will cover all system components including solar panels, battery banks, strobe lights, controllers and other miscellaneous components at the four crossing sites.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	308.5	0.0	0.0	308.5
Labour	112.0	198.7	0.0	310.7
Consultant	7.4	0.0	0.0	7.4
Contract Work	100.0	245.5	0.0	345.5
Other Direct Costs	26.9	186.0	0.0	212.9
Interest and Escalation	34.8	111.2	0.0	146.0
Contingency	0.0	237.0	0.0	237.0
TOTAL	**589.6**	**978.3**	**0.0**	**1,567.9**

Operating Experience:

TL228 Crosses Grand Lake at two separate locations and aircraft markers are installed on structures on each side of the two Grand Lake crossings. Each of these four sites has an aircraft marker system comprised of a solar array (26 panels at three of the sites and 36 panels at the other site), 24V battery bank (four modules with three cells per module at each site), system controller, strobe light and strobe light controller. The marker systems were installed in 1993.

Since installation, semi-annual inspections have been carried out and preventative and corrective maintenance has been performed as required. Component failure, corrective maintenance, and trips (requiring the system to be manually reset) have become frequent in recent years. Recent component failures on the existing systems have included photo cells, DC/DC converters, batteries and solar panels etc.

Project Justification:

Aircraft markers are required to identify the presence of the transmission infrastructure at the Grand Lake crossing. The existing system is outdated and experiences significant downtime which is a safety concern for aircraft. Inspection and maintenance of the marker systems is carried out regularly, however, failure of the outdated equipment is now becoming commonplace and some replacement components are difficult to source because of their vintage. A more modern and reliable marker system is required at these sites.

Future Plans:

These new marker systems will replace the existing system. Regular inspection and maintenance practices will be applied for the life of the new systems.

Attachments:

See report entitled “Replace Aircraft Obstruction Lighting” located in Volume III, Tab 20 for further project details.

Project Title: Inspect Fuel Storage Tanks

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

The purpose of this project is to complete detailed inspections of the above ground fuel storage tanks and associated fuel supply systems. The inspections will serve to identify and complete corrective and preventive maintenance items. Identifying and completing the necessary maintenance will maximize the service life, ensuring that these assets are in reliable operating condition.

The scope of work involves the completion of the ten-year internal tank inspection as outlined in the American Petroleum Institute (API) Standard 653 and the completion of upgrades as identified during the inspection. The tanks to be inspected in 2016 under this proposal include those listed below, however, Hydro may inspect a higher priority tank should conditions change and defer the lowest priority tank in the list below.

- Two 45,400 Litre, horizontal fuel storage tanks, located at the Hawkes Bay diesel plant; and
- One 600,000 Litre, vertical fuel storage tank; Three 144,140 Litre, vertical fuel storage tanks; and One 45,400 Litre, horizontal fuel storage tank, located the Nain diesel plant.

Routine upgrade costs have been included based on expected condition from similar tank inspections in the past. Hydro will complete the minimum work necessary to enable the tanks to continue to perform as designed, ensuring that they are structurally sound, suitable for operation, and not at risk of releasing fuel into the environment.

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

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	202.1	0.0	0.0	202.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	799.7	0.0	0.0	799.7
Other Direct Costs	37.3	0.0	0.0	37.3
Interest and Escalation	80.0	0.0	0.0	80.0
Contingency	207.8	0.0	0.0	207.8
TOTAL	**1,326.9**	**0.0**	**0.0**	**1,326.9**

Operating Experience:

75% of Hydro's aboveground fuel storage tanks provide fuel storage for its isolated diesel generation plants. These tanks are critical to ensuring the continued supply of reliable power to the communities in which they are located.

Project Justification:

In the interest of maximizing the service life of its assets and adhering to Hydro's Environmental Policy and Guiding Principles, Hydro has completed routine inspections of its above ground fuel storage tanks in the past, however, these inspections were not conducted in a systematic fashion. In order to implement a standardized approach for the completion of all future tank inspections, Hydro has adopted the tank inspection procedures outlined by The American Petroleum Institute[2] (API). While it is recognized that the API Standard applies to vertical storage tanks, in the absence of a suitable horizontal storage tank inspection standard, Hydro has adopted the API guidelines pertaining to inspection frequency for its horizontal storage tanks. The application of the recommended API inspection frequency to its horizontal storage tanks is considered to be an interim measure as Hydro works to develop its own horizontal tank inspection guidelines.

The American Petroleum Institute (API) recommends that above ground fuel storage tanks undergo an internal inspection every ten years after its initial service date. The required inspection procedures are outlined in API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, Section 6. This project will ensure that the tanks are inspected in accordance with the requirements identified in the API 653 standard.

[2] The American Petroleum Institute has been the leader in developing equipment and operating standards for the oil and natural gas industry since 1924.

Hydro must ensure that its fuel storage tanks are maintained in a safe, reliable operating condition. Tank inspections serve to identify maintenance and repair items, enabling the work to be completed in a timely fashion. This proactive maintenance approach will enable the tanks to continue to perform as designed, ensuring that they are structurally sound, suitable for operation, and not at risk of releasing fuel into the environment.

Completing the tank inspections under a planned approach also allows for continued reliable service to the communities as inspections are completed when tanks can be taken out of service due to reduced load (ex. Summer season).

Future Plans:

Future plans will see the continuation of the multi-year tank inspection program.

Attachments:

See report entitled “Inspect Fuel Storage Tanks” located in Volume III, Tab 21, for further project

Project Title: Construct Overhead Distribution Line

Location: Pilley's Island to Long Island

Category: Transmission and Rural Operations – Transmission

Definition: Other

Classification: Normal

Project Description:

Hydro provides service to residents in select rural communities within the province through the use of existing distribution systems. The distribution systems typically consist of a substation coupled with a wood pole distribution line that supplies power from the station to service drops throughout the community. Currently Long Island is being supplied by a submarine cable from Pilley's Island which, in 2014, was damaged by an iceberg that also severely damaged the spare cables.

Hydro has chosen to extend the overhead distribution line from Pilley's Island to Long Island, spanning across the Long Island Tickle. This alternative will require the installation of two, transmission type structures to provide suitable overhead clearance across the Long Island Tickle. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	358.7	0.0	0.0	358.7
Labour	200.0	0.0	0.0	200.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	360.0	0.0	0.0	360.0
Other Direct Costs	60.0	0.0	0.0	60.0
Interest and Escalation	65.5	0.0	0.0	65.5
Contingency	195.7	0.0	0.0	195.7
TOTAL	**1,239.9**	**0.0**	**0.0**	**1,239.9**

Operating Experience:

Four submarine cables were originally installed 35 years ago, and have exceeded their life expectancy of 30 years. In 2007, the only three phase customer on Long Island shut down and the cables were reconfigured to supply single phase power, leaving three cables to serve as spares.

In addition to age deterioration, in 2014, an iceberg passed through the Long Island Tickle and contacted the submarine cables. Hydro had a diving inspection completed and a video was created which showed the damage sustained by the cables.

The damage due to iceberg contact left three out of four cables unable to supply power, and the fourth cable damaged but still operable. Given the condition of the remaining cable, a mobile diesel generator has been rented and positioned on Long Island in standby to provide power in the event that the damaged submarine cable fails.

If the remaining cable fails, the customers on Long Island will be supplied by Diesel generation which is less efficient and more expensive to supply, and therefore, not an appropriate choice for long term operation.

Project Justification:

This project is justified based on reliability. The conditions of the cables could result in system failures and have a negative effect on the safety and reliability performance of the line. The failure of 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:

None.

Attachments:

See report entitled “Construct Overhead Distribution Line - Pilley’s Island to Long Island” located in Volume III, Tab 22, for further project details.

Project Title: Upgrade Office Facilities and Control Buildings

Location: Various Sites

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

The program will include detailed assessments, engineering and refurbishment of the aging facilities including the regional offices, area offices and control buildings at terminal stations within Hydro's Transmission and Rural Operations (TRO) regions.

Office Facilities Upgrades:

Condition assessments were completed for the Bishop's Falls Service Building and Port Saunders office. Recommendations from these condition assessments include civil, mechanical and electrical replacements and/or upgrades. The work includes replacement of doors, windows, siding, new septic field, electrical upgrades, installation of waterproof enclosures and installation of fire stopping around wall penetrations. Also, building condition assessments will be completed for other TRO facilities.

Control Building Upgrades:

A condition assessment was completed for the Control building at the Sunnyside Terminal station. Recommendations from this condition assessment included replacement of the entire roof membrane system.

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

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	227.6	0.0	0.0	227.6
Consultant	231.5	0.0	0.0	231.5
Contract Work	398.0	0.0	0.0	398.0
Other Direct Costs	34.6	0.0	0.0	34.6
Interest and Escalation	64.0	0.0	0.0	64.0
Contingency	178.3	0.0	0.0	178.3
TOTAL	**1,134.0**	**0.0**	**0.0**	**1,134.0**

Operating Experience:

The TRO regional offices, area offices and terminal station facilities are used by personnel as office space, storage space, workshops and control buildings. These offices and workshops are essential in continuing the daily planning and operations of Hydro. The control buildings ensure that reliable electricity is distributed to the customers of Newfoundland and Labrador. All Hydro's facilities need to be in good operating condition, structurally sound, secure and weather tight to ensure a safe and healthy environment for all employees.

Project Justification:

Many of Hydro's office buildings and facilities in TRO were constructed in the 1970s and 1980s and have not had detailed assessments or significant upgrades performed since that time. Having facilities that are sound, well maintained and functional is essential in allowing employees to perform their work safely and efficiently. Many of the doors, windows and siding are at the end of their life expectancy and need replacement or repair. There have also been a number of fire safety deficiencies identified including missing fire or smoke stopping and caulking at penetrations within the garage and maintenance areas. Also, at Port Saunders the septic field is located close to the building and has improperly worked in the past and requires to be replaced. Additionally, due to the age and current condition of the Sunnyside Control Building roof, it is necessary to replace the built-up roof system.

Future Plans:

A list has been developed prioritizing the office and control building condition assessments and upgrades. It is anticipated that this program will continue until 2024. Condition assessments will be completed in the first year of the identified schedule, the assessments will be reviewed and work prioritized in the second year, detailed engineering will be completed in the third year and construction will be completed in either the third and/or fourth year depending on the upgrades required.

Attachments:

See report entitled, "Upgrade Office Facilities and Control Buildings Condition Assessment and Refurbishment Program" located in Volume III, Tab 23, for further project details.

Project Title: Install Automated Meter Reading

Location: Labrador West

Category: Transmission and Rural Operations - Metering

Definition: Pooled

Classification: Justifiable

Project Description:

This project is required to install Automatic Meter Reader (AMR) equipment in the Labrador City area. In this area, a meter reader is retiring and Hydro will utilize AMR upon retirement. The AMR head end equipment will be installed in the Vanier and Quartzite substations on a total of four feeders. Customers will include both residential as well as demand customers who will have their current meters replaced with new AMR units. The use of AMR equipment allows for customer usage (billing) data to be retrieved without requiring meter reader personnel to physically visit a customer's property. The system will allow accurate billing throughout the year regardless of the weather conditions thus eliminating in most cases of estimated billings.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	272.8	225.0	0.0	497.8
Labour	87.4	87.4	0.0	174.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	36.2	0.0	0.0	36.2
Other Direct Costs	10.1	6.9	0.0	17.0
Interest and Escalation	27.3	68.9	0.0	96.2
Contingency	0.0	145.2	0.0	145.2
TOTAL	**433.8**	**533.4**	**0.0**	**967.2**

Operating Experience:

The AMR system will replace:

(i) manual handheld devices used to collect meter readings at each customer's site;

(ii) supporting infrastructure (computers and modems) used to retrieve the data; and

(iii) a requirement for personnel to travel to each customer location to read meters.

Previous AMR projects have been completed by Hydro in a number of other the service areas. The AMR system being implemented has proven to be reliable and accurate.

Project Justification:

This project is primarily justified on the results of a cost-benefit analysis which shows that the new AMR system has economic benefits over the existing system through a reduction in controllable costs. The new system also provides benefits in customer service through improvements in accuracy, frequency and detail of reporting. Implementation of AMR will also enhance safety by reducing employee risk exposure and will provide a benefit to the environment as a result of less vehicle usage.

Future Plans:

This proposed project is part of an ongoing program to implement AMR in Hydro's service areas.

Attachments:

See report entitled “Automated Meter Reading” located in Volume III, Tab 24 for further project details.

Project Title: Upgrade Line Depots

Location: Various Sites

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

This report outlines the 2016 year of a multiyear program to refurbish Hydro's aging line depot infrastructure up to the year 2023. This program includes continuing detailed assessment, engineering and construction of line depot upgrades and replacements as well as replacements of specific line depot storage ramps and storage sheds which have been identified previously as needing replacement.

Line Depot Upgrades:

A condition assessment was completed in 2014 for the Wabush line depot. Recommendations from this condition assessment include civil, mechanical and electrical replacements and /or upgrades. The work includes replacement of windows, doors and heating units, upgrades to lighting for energy efficiency gains, life safety code additions and upgrades, as well as upgrades relating to electrical code deficiencies.

Hydro is requesting approval for the year 2016 expenditures in this application. Hydro offers the estimate and forecast for the next five years in this as shown in Table 1.

Table 1: 5 Year Budget Forecast

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	197.9	0.0	0.0	197.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	440.0	0.0	0.0	440.0
Other Direct Costs	35.9	0.0	0.0	35.9
Interest and Escalation	52.8	0.0	0.0	52.8
Contingency	134.8	0.0	0.0	134.8
TOTAL	**861.4**	**0.0**	**0.0**	**861.4**

Operating Experience:

The purpose of these facilities is to provide line workers with a safe and protected area to store, load and prepare materials and equipment used to maintain the integrity of Hydro's transmission lines. During emergency repairs in winter, under adverse weather conditions, working with frozen

transmission line materials is difficult for the workers and many times, the weather conditions can be too adverse to assemble materials on site. As such, the line depots provide a sheltered location to repair equipment and keep materials protected from the weather so they don't freeze together. These depots also provide a location for workers to return to during adverse weather, when workers are required to be in outside for extended periods during emergencies, sometimes for long hours.

Project Justification:

As outlined in the *Line Depot Condition Assessment and Refurbishment Strategy Report* filed with the 2015 Capital Budget Application, these depot buildings are in the range of 25-40 years old. Many of the windows and doors, as well as heating and cooling units are at the end of their expected life cycle and need replacement. Many of the HRV systems do not meet code requirements for ventilation and require new HRV systems installed at each depot office. There have been a number of items identified as safety issues relating to the electrical system such as incorrectly wired exterior plugs, code deficient panel barriers, overloaded circuits for identified use and lack of Ground fault circuits in wet areas. There have also been a number of fire safety deficiencies identified including missing fire detectors, illuminated exits signs and emergency light wall packs. These condition assessments also identify the replacement of storage ramps that are dilapidated and unsafe for workers to use.

Future Plans:

A list has been developed prioritizing line depot detailed assessments and upgrades. It is anticipated this program will continue to 2023 where, in general, the detailed assessments will be completed in the first year of the identified schedule, detailed engineering will be completed in the second year and construction will be completed in the third year.

Attachments:

See report entitled “Line Depot Condition Assessment and Refurbishment Strategy” located in Volume III, Tab 25, for further project details.

Project Title: Install Fire protection in 230 kV Stations

Location: Bay d'Espoir

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project will include the detailed design and installation of a fire suppression system in the control building at the Bay d'Espoir 230 kV and 69 kV Terminal Station. The system will be designed to protect the control cabinets and cables and any other critical equipment from being destroyed by a fire through the use of a gaseous extinguishing system using the clean agent - Inergen. Design and installation of the system will be completed by a contractor. Management of the project will be completed by Hydro's internal engineering, and a Hydro On Site Representative. The budget estimate for this project is shown in Table 1.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	2.5	0.0	2.5
Labour	36.2	81.1	0.0	117.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	150.0	310.0	0.0	460.0
Other Direct Costs	1.6	7.8	0.0	9.4
Interest and Escalation	12.2	46.8	0.0	59.0
Contingency	0.0	117.8	0.0	117.8
TOTAL	**200.0**	**566.0**	**0.0**	**766.0**

Operating Experience:

Inergen fire suppression systems were installed throughout Hydro in the 1990s to replace Halon fire suppression systems due to the fact that Halon was determined to be an ozone depleting substance. Installation of the Inergen systems mainly included Hydro's telecontrol and communication rooms, control rooms in unattended power plants and in the gas turbine plants. There have not been any operational issues with these systems and maintenance requirements are completed to meet NFPA and ULC code requirements.

Project Justification:

Presently, Hydro's terminal stations are not equipped with a fire suppression system. This poses a risk to the system, as has been identified by Hydro's risk and Insurance agent, FM Global. A project started

in 2015 at the terminal station at Holyrood to install a gaseous extinguishing system using the clean agent, Inergen, and this project will be completed in 2016.

The Bay d'Espoir terminal station building includes the switchyard control and protection equipment for 230 kV and 69 KV transmission lines and supply from the generating units in Bay d'Espoir. Terminal stations control power flow on the grid transmission lines and reduce the grid voltage to sub transmission voltage. The control room in the terminal station building contains control cabinets with a significant combustible loading due to the number of cables. As the facility is unattended, a fire in the cable trenches or cabinets could quickly spread, causing severe damage to the equipment in the building. Loss of this building or severe damage to the equipment from fire would reduce power from Bay d'Espoir for an extensive period of time. Powerhouse 1 and 2 in Bay d'Espoir house seven generating units that have a capacity of approximately 600 MW, this is approximately 40% of the winter peak demand.

Further, the addition of any protection, suppression and/or detection system within our facilities will, in the long term, ensure property insurance rates remain competitive.

Future Plans:

Other terminal stations have been proposed to be upgraded to have a fire protection system. The tentative schedule for the other locations is as follows:

2017-2018: Hardwoods and Western Avalon Terminal Stations;

2018-2019: Oxen Pond, Sunnyside, and Stony Brook Terminal Stations;

2019-2020: Massey Drive, Buchans, and Voisey's Bay Nickel Terminal Stations; and

2020-2021: Deer Lake, Come By Chance, and Bottom Brook Terminal Stations.

These other terminal stations will have separate proposals developed in the appropriate year

Attachments:

See report entitled "Install Fire Protection – Bay d'Espoir" located in Volume III Tab 26, for further project details.

Project Title: Replace Roof on Services Building

Location: Bishop's Falls

Category: Transmission and Rural Operations - Properties Central

Definition: Other

Classification: Normal

Project Description:

This project comprises the replacement of the roofing system for the Bishop's Falls Services building with a new mechanically fastened roofing system. Work includes replacement of deteriorated wood blocking; reinforcement of all perimeters, projections and roof/wall junctions; supply and installation of new projection sleeves and insert drains; supply and installation of new vapour barrier and composite insulation; supply and installation of new cold-applied roofing system; and the supply and installation of flashing. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	79.0	0.0	0.0	79.0
Consultant	45.0	0.0	0.0	45.0
Contract Work	359.3	0.0	0.0	359.3
Other Direct Costs	2.3	0.0	0.0	2.3
Interest and Escalation	30.1	0.0	0.0	30.1
Contingency	97.1	0.0	0.0	97.1
TOTAL	**612.8**	**0.0**	**0.0**	**612.8**

Operating Experience:

The Services building's roof is at the end of its service life and has started to show signs of deterioration, typical of its age. Noteworthy items include considerable organic growth, visible membrane settlement, evidence of leakage within transition flashing, and evidence of previous membrane repairs.

Project Justification:

Constructed in 1989, the Bishop's Falls Service Building provides maintenance, storage and administrative space. It is strategically located in Central Newfoundland and serves as the hub for Hydro's central and northern operating groups.

A condition assessment, completed by Coles Associates in 2013, noted that the existing roofing system was nearing the end of its service life and its replacement was recommended.

Given the roofing systems age and noted condition, the occurrence of leaks is imminent and the probability of a "blow-off", whereby the roofing system could become completely detached from the structure during periods of high wind, is greatly increased. While spot repairs can be enacted to address the occurrence of leaks, any repairs completed on the roof would be topical in nature and will not address the risk associated with the complete failure of the membrane. Detachment of the roofing membrane could prove disastrous, leaving the building contents fully exposed and/or resulting in significant damage to persons and/or equipment. A proactive approach is required to ensure that the roof replacement can be completed prior to the failure of the roofing membrane system.

Future Plans:

Additional roof replacements with be proposed in future capital budget applications.

Attachments:

See report entitled "Replace Roof on Services Building - Bishop's Falls" located in Volume III, Tab 27, for further project details.

Project Title: Additions for Load Growth

Location: Happy Valley

Category: Transmission and Rural Operations - Distribution

Definition: Other

Classification: Normal

Project Description:

This project will involve converting a portion of the feeder NS11 from 4.16 kV to 25 kV and transferring the load to the feeder HV7. The portion of line that will be converted to 25 kV runs along Toronto Ave in Happy Valley.

The budget estimate for the total project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	230.0	0.0	0.0	230.0
Labour	135.0	0.0	0.0	135.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	100.0	0.0	0.0	100.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	35.7	0.0	0.0	35.7
Contingency	93.0	0.0	0.0	93.0
TOTAL	**593.7**	**0.0**	**0.0**	**593.7**

Operating Experience:

According to load flow analysis, it was determined that under peak conditions there are currently, overloaded conductors at the beginning on NS11 on Ottawa Avenue and an overloaded transformer in the Happy Valley – Goose Bay North Side substation.

Project Justification:

This project is justified on the requirement to meet the growing electricity need of Hydro's customers on the Happy Valley – Goose Bay distribution system. If the status quo is maintained, some customers in Happy Valley – Goose Bay will continue to experience a greater chance incurring a power outage due to overloaded equipment.

Transferring load to HV7 from NS11 reduces the conductor and transformer overloading presently on this feeder.

Future Plans:

None.

Attachments:

See report entitled “Additions for Load Growth – Happy Valley - Goose Bay” located in Volume III, Tab 28, for further project details.

Project Title: Upgrade Digital Fault Recorders

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

The scope of the work is to upgrade eight existing standalone Mehta Tech Inc. digital fault recorders (DFRs).

Mehta Tech Inc. completed a full review of all existing fault recorders on October 20, 2014, and determined there are eight stations requiring extensive hardware upgrades, due to electronic components which have become obsolete. The eight digital fault recorders requiring upgrades are located at Hardwoods, Plum Point, Western Avalon, Sunnyside, Cat Arm, Stony Brook, Upper Salmon and Holyrood. The upgrades are necessary to ensure the reliability of the DFRs used by Hydro.

Only specific obsolete components of the electronic chassis will require replacement. The existing cabling to the DFR cabinets, the internal wiring of the cabinets and the blocking and testing switches will not be replaced. The master station software will also not require replacement. The scope of work will also include increasing the number of analog channels from 32 to 48 at five of these stations to provide more information when analyzing system disturbance events.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	105.0	89.5	0.0	194.5
Labour	69.1	92.3	0.0	161.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	10.5	7.6	0.0	18.1
Interest and Escalation	13.3	40.4	0.0	53.7
Contingency	0.0	74.8	0.0	74.8
TOTAL	**197.9**	**304.6**	**0.0**	**502.5**

Operating Experience:

The information stored in the DFRs is regularly monitored by personnel in Protection and Control Engineering and Systems Operations and, generally, the DFRs perform their intended function. However, during the power outages of January 2014, some system events could not be analyzed and re-constructed due to a DFR which had failed. It was discovered after the power outages that the hard drive at Western Avalon had failed and as a result did not capture any data during the system disturbance events. Upgrading the obsolete components of the DFRs will help to avoid this issue in the future.

The report authored by Hydro in late 2014 completed a review of all analog channels on the existing DFRs and identified five stations which would benefit from an increase in the number of analog channels from 32 to 48 to capture additional data for analyzing system disturbance events.

Project Justification:

This project is necessary to upgrade the older DFRs in Hydro's system by replacing the obsolete components, as determined by the original manufacturer Mehta Tech Inc.

Future Plans:

This proposal covers only stations with existing DFRs which require upgrades. It is expected that during the course of this project a review of stations without DFRs will be completed to determine which, if any, would benefit from having a DFR installed. If necessary, additional DFR projects will be proposed in future capital budget applications.

Attachments:

See report "Upgrade Digital Fault Recorders" located in Volume III, Tab 29, for further project details.

Project Title: Replace Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project proposes the replacement of 37 light-duty vehicles and threeheavy-duty vehicles in accordance with the established replacement criteria for vehicle age and kilometers (km) as follows in Table 1. Also indicated below are the replacement criteria of three other Atlantic electric utilities as surveyed by Hydro in 2014 (see Table 2).

Table 1: Replacement Criteria - Hydro

Hydro	
Light-duty vehicles	5-7 years or > 150,000 km and Condition/Maintenance Cost
Heavy-duty vehicles:	
- Class 4, 5 and 6	6-8 years or > 200,000 km and Condition/Maintenance Cost
- Class 7 and 8	7-9 years or > 200,000 km and Condition/Maintenance Cost

Table 2: Replacement Criteria - Other Atlantic Electric Utilities

Utility #1	
Light-duty vehicles	5 years or 200,000 km
Heavy-duty vehicles:	8 years or 300,000 km
Utility #2	
Light-duty vehicles	5-6 years or 200,000 km
Heavy-duty vehicles:	
- Class 3, 4, 5 and 6	8 years or 300,000 km
- Class 7 and 8	10 years or 300,000 km
Utility #3	
Light-duty vehicles	5 years or 150,000 km
Heavy-duty vehicles	10 years or 250,000 km

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

Table 3: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	1,378.8	411.1	0.0	1,789.9
Labour	8.0	2.0	0.0	10.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.0	3.0	0.0	6.0
Interest and Escalation	53.5	27.8	0.0	81.3
Contingency	0.0	90.3	0.0	90.3
TOTAL	**1,443.3**	**534.2**	**0.0**	**1,977.5**

Operating Experience:

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Hydro employees maintain the electrical system 24 hours a day, seven days a week and require dependable and safe vehicles for their work. As vehicles age, they experience increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

Project Justification:

Hydro operates in many diverse locations across the Province and it is critical to the provision of economical and reliable electricity that employees are provided with safe and reliable vehicles.

Future Plans:

Future replacement of vehicles and aerial devices will be proposed in future capital budget applications

Attachments:

See report entitled “Replace Vehicles and Aerial Devices” located in Volume III, Tab 30 for further project details.

Project Title: Upgrade Microsoft Office Products

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

The scope of this proposal is to renew the Enterprise Agreement (EA) with Microsoft (MS) Corporation such that specified MS products in use within the company will be able to be upgraded to the latest versions available for the life of the agreement. Through the Microsoft Enterprise Agreement the company achieves an overall cost savings. Cost will be spread over a three year period with equal payments in each year, commencing in 2016. The licensing required for key systems is acquired under the EA agreement pricing levels. The licenses are required to be able to maintain key systems at current Windows server versions.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	633.1	633.1	633.1	1899.3
Labour	28.8	108.0	28.8	165.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	162.8	0.0	162.8
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	21.8	49.5	72.6	143.9
Contingency	0.0	0.0	222.8	222.8
Sub-Total	**683.7**	**953.4**	**957.3**	**2,594.4**
Cost Recoveries	**(317.1)**	**(442.2)**	**(444.0)**	**(1,203.3)**
TOTAL	**366.6**	**511.2**	**513.3**	**1,391.1**

Operating Experience:

The company currently deploys a standard desktop that includes the Microsoft (MS) Office Suite of products and the Windows 7 Desktop Operating System on corporate desktops and laptops. The laptop/desktop environment and server infrastructure is based on the MS Windows Operating System. Within the operating environment, the company also uses a number of MS Tools and applications to ensure efficient operation. During the life of the agreement, Windows 7 will move out of the mainstream support stage with Microsoft, meaning the current deployed fleet should begin

transitioning to the next version of Windows. The project includes funding in the second year (2017) to begin the transition to a new desktop operating system for new deployments of PCs. Licenses maintained under the Enterprise Agreement permit transition to the new version without requiring a repurchase of licenses.

This project will see the company continue its Enterprise Agreement (EA) with Microsoft such that all of the products currently in use will remain available to be upgraded to the latest versions. The company will also maintain access to reduced rates on any new products we decide to implement for the life of the agreement. Other benefits of the EA include ability to upgrade to the latest version of products for the life of the agreement, benefit from training and e-learning resources.

The EA is a three year agreement and is proposed to be paid for in three equal payments to be spread over the three years of the agreement. This agreement, upon budget approval, will renew in 2016 and end in 2019.

Project Justification:

This project is a part of the Corporation's ongoing effort to ensure that users are able to meet ongoing productivity requirements and to effectively collaborate with outside resources as required. This is achieved by ensuring that the desktop application base is maintained to the appropriate version levels to limit incompatibilities.

The company supports a standard desktop that includes the Microsoft (MS) Office Suite of products and the MS Windows 7 Desktop Operating Systems. The laptop/desktop environment and server infrastructure is based on the MS Windows Operating System. Within the computer infrastructure environment the company also uses a number of Microsoft technologies to ensure efficient operation, including but not limited to MS SQL server for databases, MS System Center for server and PC management, and MS Terminal Services with Citrix technology for application delivery to users.

As a result of the investment made in the existing Enterprise Agreement, The desktop and server software is maintained at current, supported standards which enables more effective collaboration both internally and externally. Server software used to manage the desktop and server environments as well as database servers many key systems depend on are also maintained under this agreement.

The costs to acquire and maintain business software from Microsoft is reduced under the Enterprise Agreement.

The Enterprise Agreement allows the company to upgrade to the current server, desktop and application versions over the life of the agreement. This agreement renewal would be for a three year period.

Future Plans:

This is an ongoing software assurance contract with yearly evaluations of the products purchased based on business needs.

Attachments:

See report entitled “Upgrade Microsoft Office Software” located in Volume III, Tab 31, for further project details.

Project Title: Replace MDR 4000 Microwave Radio East

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project will replace the high-capacity OC-03 MDR-4000 Radio System that was installed in 2001 between the Energy Control Center in Hydro Place and the Bull Arm Hill Microwave Repeater Site. This radio system provides teleprotection, supervisory control, departmental and administrative voice and administrative data between Hydro Place and all major terminal stations and generating stations. High speed and reliable telecommunication facilities are required to ensure the stability and reliability of the provincial power grid. The radios to be replaced include ECC-PHH, PHH-FMH, FMH-CAH and CAH-BAH.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	13.0	680.5	0.0	693.5
Labour	44.0	131.7	0.0	175.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	16.0	2.2	0.0	18.2
Interest and Escalation	4.4	101.2	0.0	105.6
Contingency	0.0	177.5	0.0	177.5
TOTAL	**77.4**	**1,093.1**	**0.0**	**1,170.5**

Operating Experience:

The original Alcatel MDR-4000 radio and 1603 multiplexers were installed in 2001 and have proved to be valuable assets in the remote control and monitoring of the provincial power system. This equipment has been discontinued by Alcatel.

Project Justification:

The project is justified on the fact that the Alcatel MDR-4000S radio has been discontinued since 2004. The manufacturer will not guarantee that failed modules can be repaired due to the obsolescence of the components within the modules. Hydro has obtained some components from the used market,

however this supply is unreliable. The replacement of the radio system is required to ensure a reliable and safe operation of the Island power system.

Future Plans:

None.

Attachment:

See report entitled "Replace MDR-4000 Microwave Radio East" located in Volume III, Tab 32, for further project details.

Project Title: Replace UPS Systems

Location: Hydro place

Category: General Properties - Telecontrol

Definition: Pooled

Classification: Normal

Project Description:

Uninterruptable Power Systems (UPS) are used at Hydro Place to provide backup AC power to the critical equipment used by the Energy Management Systems (EMS) and Information Systems (IS). This includes supplying backup power to the Energy Control Center and other critical networks used within Hydro Place. Backup power is required upon the loss of the main power into Hydro Place until diesel generators located in the building can be started. This proposal plans to replace the five existing UPS systems with two larger ones. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	608.6	0.0	0.0	608.6
Labour	48.2	0.0	0.0	48.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	45.0	0.0	0.0	45.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	47.6	0.0	0.0	47.6
Contingency	140.4	0.0	0.0	140.4
TOTAL	**889.8**	**0.0**	**0.0**	**889.8**

Operating Experience:

Two of the existing UPS systems have been in service since 2003 and the other three since 2005. These units have performed well and have been serviced by a contractor who also provides routine preventative maintenance. The VRLA batteries used in these systems have proven not be reliable. They are now undersized for the application and have reduced capacity.

Project Justification:

Vendor support for the existing UPS controllers will end in 2017 at which time the manufacturer will no longer offer service support or repair parts. During the supply interruptions in 2014, the existing batteries were exhausted before the backup diesel generators could be started (due to challenges with the diesel units). The reserve time of three hours of this new UPS system will be sufficient for providing temporary backup power to critical systems in an emergency.

Future Plans:

Future replacements of UPS Systems will be proposed in future capital budget applications.

Attachments:

See report entitled “Replace UPS Systems – Hydro Place” located in Volume III, Tab 33, for further project details.

Project Title: Replace Battery Banks and Chargers

Location: Various Sites

Category: Transmission and Rural Operations - Transmission

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 either a direct current (DC) power source and thus require a charging system that converts alternating current (AC) to direct current or UPS batteries that also convert back to AC.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	190.8	112.0	0.0	302.8
Labour	166.9	116.7	0.0	283.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	38.1	30.9	0.0	69.0
Interest and Escalation	29.2	65.9	0.0	95.1
Contingency	0.0	131.1	0.0	131.1
TOTAL	**425.0**	**456.6**	**0.0**	**881.6**

Operating Experience:

Hydro generally inspects its batteries semi-annually, or more often, as needed, depending on age and condition. From these inspections 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% 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 when

they have deteriorated to the 80 % capacity level. Batteries have to be replaced before total failure occurs to ensure continued reliable operation.

Future Plans:

Replacement of battery banks and chargers will be proposed in future capital budget applications.

Attachments:

See report entitled “Replace Battery Banks and Chargers” located in Volume III, Tab 34, for further project details.

Project Title: Replace Personal Computers

Location: Various Sites

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

The Personal Computer (PC) Replacement program is an on-going program required to enhance the efficiency of Hydro's employees by replacing the PCs used for their day to day requirements.

This project will enable Hydro to replace 195 Thin Clients, Desktops, Workstations and laptops. There are 27 Thin Clients, 144 Laptops, 12 Desktops, and 12 Workstations to be replaced. A workstation is a more powerful desktop that is used for specialized applications that require more power and resources, such as AutoCAD for drafting.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	535.1	0.0	0.0	535.1
Labour	33.6	0.0	0.0	33.6
Consultant	118.4	0.0	0.0	118.4
Contract Work	88.5	0.0	0.0	88.5
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	8.5	0.0	0.0	8.5
Contingency	77.6	0.0	0.0	77.6
TOTAL	**861.7**	**0.0**	**0.0**	**861.7**

Operating Experience:

Hydro has approximately 900 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, desktops every five years and thin clients every six years.

Project 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.

Future Plans:

This is an ongoing refresh program to maintain the personal computers of employees.

Attachments:

See report entitled “Replace Personal Computers” located in Volume III, Tab 35, for further project details.

Project Title: Replace Powerline Carrier

Location: Various Sites

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This Project is required to design, supply, install and commission communications equipment to replace the existing Powerline Carrier (PLC) and associated coupling equipment on TL214 between the Bottom Brook and Doyles Terminal Stations and TL239 between the Deer Lake and Berry Hill Terminal Stations. In both cases, the powerline carrier systems transport power system protection circuits as well as operational voice and data in support of the Energy Control Centre.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	405.2	0.0	405.2
Labour	59.9	140.7	0.0	200.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.7	24.0	0.0	32.7
Interest and Escalation	4.8	65.6	0.0	70.4
Contingency	0.0	127.8	0.0	127.8
TOTAL	**73.4**	**763.4**	**0.0**	**836.8**

Operating Experience:

The TL214 PLC was last replaced in 2000 by repurposing PLC equipment that had been previously installed in 1990 between the Bottom Brook and Buchans Terminal Stations. The TL239 PLC was last replaced in 1990. There have been no recorded failures of the either the TL214 and TL239 PLC equipment. However, due to high reliability requirements for teleprotection and SCADA traffic, the unavailability of replacement parts and the lack of support from the manufacturer warrants replacement of this equipment before significant outages are allowed to occur, resulting in possible impact on customers or to HV equipment. This communications equipment is critical to the operation of the power grid and must operate continuously on a 7x24 hour basis, 365 days a year.

Project Justification:

The TL214 and TL239 PLC equipment will have been in service for over 24 years and are now obsolete (PLCs have an asset depreciation life of 15 years). The ABB model ETI21 PLC with the NSD 60 teleprotection module has been phased out by the manufacturer ABB since the mid-1990s. The manufacturer has indicated that, due to the unavailability of components, the discontinued products can rarely be repaired. As such, continued utilization of this equipment poses the risk of failure and hence loss of communications required for the protection and control of the power system. Replacement of the powerline carriers ensures communications to monitor and control power devices to provide uninterrupted service to our customers and protection of the transmission assets.

Future Plans:

None.

Attachments:

See report entitled "Replace Powerline Carrier – TL214 and TL239" located in Volume III, Tab 36, for further project details

Project Title: Replace Roof

Location: Hydro Place

Category: General Properties - Administrative

Definition: Other

Classification: Normal

Project Description:

This project is the second year of a three year program for the completion of roof upgrades at Hydro Place. Upgrades include supply and installation of a new, mechanically fastened roofing system, and the completion of interior repairs to various areas damaged as a result of water infiltration. The roof areas to receive upgrades in 2016 include levels 3 and 4. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	113.4	0.0	0.0	113.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	390.8	0.0	0.0	390.8
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	34.5	0.0	0.0	34.5
Contingency	100.8	0.0	0.0	100.8
TOTAL	**639.5**	**0.0**	**0.0**	**639.5**

Operating Experience:

Hydro Place serves as the head office for Hydro. It provides office space for approximately 500 employees, and houses Hydro's Energy Control Center, which allows System Operators to monitor the amount of power being generated throughout the system, voltage conditions across the system and the status of virtually all equipment on the main power grid. This allows for the optimization of system performance and reliability.

Project Justification:

A condition assessment, completed by BAE-Newplan Group Limited in 2009, noted that the existing roofing system was nearing the end of its service life and its replacement was recommended. In an effort to prolong the requirement for a complete roof replacement, Hydro has closely monitored the roof's condition, particularly during the spring thaw when snow melt and rainfall combine to generate an influx of water. Numerous repairs have been enacted to remedy any leaks, however, the repairs are

often short lived; in some instances the leaks have reoccurred and/or new leaks have formed at different locations.

Given the roofing system's age, the formation leaks will continue to pose a problem to building maintenance personnel and occupants. If left unaddressed these leaks may impact the use of the building and result in deterioration and mold growth.

The replacement of the roof must be completed to mitigate this risk and to provide a new roofing system capable of providing maintenance free protection for the next 20 years.

Future Plans:

An additional roof upgrade project will be proposed in the 2017 capital budget applications as part of a three year roof replacement program.

Attachments:

See report entitled "Replace Roof, Hydro Place" located in Volume II, Tab 37, for further project details.

Project Title: Upgrade Telecontrol Facilities

Location: Sandy Brook Hill

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project includes the following:

- replacement of the standby generator including the generator enclosure and all the associated auxiliary equipment;
- refurbishment of the microwave shelter; and
- including replacement of siding, insulation, doors, roofing and refurbishment of concrete foundations.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	58.9	82.9	0.0	141.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	33.0	242.6	0.0	275.6
Other Direct Costs	2.9	9.2	0.0	12.1
Interest and Escalation	6.8	41.8	0.0	48.6
Contingency	0.0	85.9	0.0	85.9
TOTAL	**101.6**	**462.4**	**0.0**	**564.0**

Operating Experience:

The Sandy Brook Hill (SBH) communications site is a hub on the communications and SCADA control system for Hydro.

The microwave shelter protects critical communications equipment from water, ice and wind damage which ensures uninterrupted communications between ECC and Hydro's facilities around the island. The shelter shows signs of deterioration of the external components, namely siding, foundations and roof. The siding and roofing on the microwave shelter are now 35 to 40 years old and require significant upgrades to ensure the shelter continues to resist leaking and settlement; both of which can cause

damage to the equipment inside.

The backup generator at SBH supplies power to the communications equipment so that, in the case of an electrical outage, critical equipment data will not be lost, and Hydro's SCADA and communication system remains operational. With the addition of equipment at the site over the last ten years, the power required to operate the communications equipment has increased and the existing back up power system is inadequate. A three day power outage in 2012, proved the inadequacy of the existing genset and the need for a larger sized genset.

Project Justification:

The microwave shelter refurbishment project is justified on the requirement to upgrade aged and deteriorated infrastructure in order for Hydro to provide safe, least-cost, reliable electrical service. A cost benefit analysis was completed to compare the cost to replace or refurbish the microwave shelter with refurbishment being the least cost and thus preferred option.

The stand-by generator replacement project is justified on the requirement to replace the old stand-by propane generator (genset) on site that is now at the end of its service life. In addition, the genset is undersized for the equipment additions that have occurred at this site over the last ten years.

Future Plans:

None.

Attachments:

See report entitled "Upgrade Telecontrol Facilities" located in Volume III, Tab 38, for further project details.

Project Title: Purchase Vehicles and Aerial Devices

Location: Various Sites

Category: General Properties - Transportation

Definition: Other

Classification: Normal

Project Description:

This project is to purchase 15 vehicles for various positions across the Hydro system. The budget estimate for this project is shown in Table 1.

Table 1: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	366.2	136.1	0.0	502.3
Labour	2.5	0.5	0.0	3.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	2.0	0.0	2.0
Interest and Escalation	13.8	8.7	0.0	22.5
Contingency	0.0	25.4	0.0	25.4
TOTAL	**382.5**	**172.7**	**0.0**	**555.2**

Operating Experience:

Work vehicles are an essential requirement for employees to complete their work on an ongoing basis across the Hydro system in Central, Labrador and Northern regions.

Due to the increase in personnel positions and the requirement to respond to trouble calls and to report to work across the Hydro system, there is a requirement to add vehicles to the existing fleet.

Project Justification:

Hydro's requirements for additional 15 fleet vehicles are as follows:

- To fill the need as a result of a larger workforce;
- To improve reliability of and reduce Operating and Maintenance costs on heavy duty vehicles;
- To improve system response and restoration times; and
- To ensure Hydro is providing safe reliable vehicles for its employees that do a significant amount of driving to perform their role.

The workload at Hydro has been increasing over the last few years, which has necessitated the addition full time, part-time employees, line person apprentice trainees on an ongoing basis. The current complement of vehicles is unable to support the vehicle demands of the increased staff. An additional 15 vehicles are required.

- The additional Protection and Control technicians and Terminal stations electricians across the system will require three new additional vehicles to provide transportation for the employees.
- Most of our support vehicles are designed to carry two employees and cannot be re-configured or built to carry three employees because of safety reasons and equipment mounted in the cab. This necessitates the need for Nine new additional vehicles to transport the line crews and apprentices to their worksites. These vehicles are also needed to transport personnel to meetings or training sessions across the system and be available for use when the heavy-duty vehicles are in the garage for maintenance, or when a lighter duty vehicle is the more economic choice.
- There is a requirement for one new additional pool vehicles to provide transportation for office staff Bishop's Falls, as a result of higher demands.
- Two vehicles are required for meter readers at the Port Saunders Office and Springdale Office.

Future Plans:

None.

Attachments:

See report entitled “Vehicles and Aerial Devices Fleet Additions”, located in Volume III, Tab 39, for further project details.

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
			($000)		
GENERATION					
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		477.6		477.6	D-2
Replace Powerhouse 1 Station Service Transformer - Bay d'Espoir		46.7	354.5	401.2	D-27
Replace Vibration Monitoring System Unit 7 - Bay d'Espoir		366.0		366.0	D-95
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir		183.6	167.9	351.5	D-226
Refurbish Intakes - Bay d'Espoir	72.6	262.3		334.9	
Perform Condition Assessment of Control Structure - Hinds Lake		323.4		323.4	D-231
Install Hydrometeorological Equipment - Various Sites		314.1		314.1	D-248
Replace Fuel Piping - Hardwoods and Stephenville		44.8	267.0	311.8	D-254
Refurbish Station Water System - Upper Salmon		96.6	197.6	294.2	D-260
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	197.6		243.8	
TOTAL GENERATION	118.8	2,312.7	987.0	3,418.5	
TRANSMISSION AND RURAL OPERATIONS					
Replace Diesel Unit 254 - Paradise River	66.8	429.3		496.1	
Upgrade Ventilation Systems-Various Sites	175.9	317.3		493.2	
Design and Install Fire Protection in 230 kV Stations - Holyrood	67.6	424.3		491.9	
Upgrade Terminal Station for Mobile Substation - Cow Head		40.0	444.7	484.7	D-271
Upgrade Terminal Station Protection and Control - Various Sites	172.7	307.2		479.9	
Upgrade Transformers - Cartwright and Postville		465.2		465.2	D-277
Replace Human Machine Interface - Various Sites		114.0	320.0	434.0	D-292
Upgrade Aluminum Support Structure - Holyrood		401.1		401.1	D-298
Replace Off Road Track Vehicle Unit 7861 - Stephenville	1.1	397.8		398.9	
Replace Light Duty Mobile Equipment - Various Sites		348.0		348.0	D-353
Upgrade Terminal Station Equipment Foundations - Various Sites		319.9		319.9	D-359
Purchase Excavator - Bay d'Espoir		312.0		312.0	D-370
Upgrade Data Alarm Systems - Stony Brook		74.4	234.1	308.5	D-374
Install Breaker Failure Protection - Various Sites		65.7	211.3	277.0	D-388
TOTAL TRANSMISSION AND RURAL OPERATIONS	484.1	4,016.2	1,210.1	5,710.4	
GENERAL PROPERTIES					
Implement Industrial Billing Software - Hydro Place		443.1		443.1	D-395
Replace Peripheral Infrastructure - Various Sites		424.5		424.5	D-397
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	311.3		357.0	
Upgrade Enterprise Storage Capacity - Hydro Place		337.2		337.2	D-401
Replace Air Conditioning Units 8 and 14 - Hydro Place		34.6	229.5	264.1	D-407
Upgrade Server Technology Program - Hydro Place		264.0		264.0	D-418
Upgrade Energy Management System - Hydro Place		246.2		246.2	D-424
Replace Radomes - Various Sites		235.2		235.2	D-427
TOTAL GENERAL PROPERTIES	45.7	2,296.1	229.5	2,571.3	
TOTAL PROJECTS OVER $200,000 AND UNDER $500,000	648.6	8,625.0	2,426.6	11,700.2	

Project Title: Upgrade Public Safety around Dams and Waterways

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Pooled

Classification: Normal

Project Description:

This project is a continuation of a program that started in 2011. It is required to comply with the Canadian Dam Association Guidelines pertaining to public safety around dams and associated waterways. The guidelines apply to appropriate signage, alarms, warnings, buoys, waterway booms and public awareness as a result of public interaction around dams and waterways. The Canadian Dam Association recognized a need for guidelines pertaining to public safety around dams so that dam owners could meet their responsibilities to protect the public as a result of increased public interaction around dams. This increased presence by the public has led to incidents at dams, the most notable occurring at an Ontario Power Generation Facility in 2002 in which two people drowned and seven more were injured during release of water from one of their reservoirs.

The work plan is dictated by a phased approach to risk treatment. The plan is as follows:

2014 - Purchase and install control improvements on the Meelpaeg Reservoir structures that were identified in the 2012 risk assessment.

2014 - Conduct Public Safety Risk Assessment of structures at the Granite Canal Development and other upstream structures on the Granite Reservoir.

2015 - Purchase and install Phase I control improvements on the Granite Reservoir System structures that were identified in the 2013 risk assessment.

2015 - Conduct Public Safety Risk Assessment of structures on the Burnt Pond and Victoria Reservoir systems.

2016 - Purchase and install Phase II control improvements on the Granite Reservoir System structures that were identified in the 2013 risk assessment including signage at Granite Canal structures as well as fencing, railings and guiderails.

Typical control improvements are as follows:

- Public education;
- Operational control measures;

- Effective signage;
- Spillway emergency signals;
- Fencing;
- Buoys; and
- Safety Booms.

Of those mentioned above, lower cost control improvements include effective signage and fencing, whereas control improvements such as buoys and safety booms would fall under the category of higher cost control improvements.

A Public Safety Risk Assessment of the Granite Canal and Granite Reservoir System was completed in 2013. Coming out of this risk assessment a Public Safety Measures Plan was prepared and issued, outlining the required control measures and an associated cost estimate to supply and install these control measures. These control measures will be implemented over three years. The Public Safety Measures Plan included a number of recommendations that are attached as Appendix A.

The budget estimate for year two of this three year project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	161.0	0.0	0.0	161.0
Labour	62.0	0.0	0.0	62.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	174.0	0.0	0.0	174.0
Other Direct Costs	12.0	0.0	0.0	12.0
Interest and Escalation	27.7	0.0	0.0	27.7
Contingency	40.9	0.0	0.0	40.9
TOTAL	**477.6**	**0.0**	**0.0**	**477.6**

Introduction:

The Canadian Dam Association (CDA) is recognized as the leading authority in Canada considering dam safety issues. They published the Canadian Dam Safety Guidelines in 2007 dealing with the safe operation, surveillance and maintenance of dams. Utilities across Canada have adopted these CDA guidelines, in the absence of Provincial Regulations, to manage their Dam Safety Programs. These guidelines address the various hazards which can lead to failure of a dam and present methods for management of those risks.

A new CDA guideline entitled "Guidelines for Public Safety around Dams" was released in 2011. (Refer to a similar 2014 submission on Upgrading Public Safety Around Dams and Waterways). The document provides guidance for dam owners to meet their responsibilities to protect the public. Guidance in this matter is needed for the following reasons:

- Increased public interaction;
- Perceived right of the public to access sites;
- Increased public interest in extreme sports;
- Improved access by use of recreational vehicles;
- Public unawareness of the hazards;
- Remote operation of dams and Hydro stations; and
- Occurrence of fatalities and serious injuries.

These guidelines address the risk of accidents or incidents in which a member of the public encounters a hazard created by the presence or operation of a dam.

Justification:

Dam owners are responsible for assessing and managing the risks to the public caused by the presence and operation of a dam. The first principle of the CDA guidelines identifies this responsibility. It states "*The dam owner is responsible for managing the public safety risks caused by a dam, as far upstream and downstream as the owner has property rights. Beyond this property, the dam owner may have additional responsibility to assess locations where the hazards are known by the owner to result directly from the dam or its operations and to inform the public and other affected property owners of these hazards".*

Accidental deaths have occurred around dams and associated structures in North America. The cause of these deaths is often an unawareness of the hazards in the area. Hydro does not have any documented cases of near misses or incidents on its systems. However, Hydro has a due diligence obligation to offer protection to the general public from potential hazards around dams and waterways. Therefore, Hydro needs to proceed with a managed system to make people more aware of the hazards around dams but to also protect them from those hazards when they interact with dams and waterways.

Operating Experience:

Hydro currently operates more than 100 dams, dykes and hydraulic structures on the island of Newfoundland. During the 2013 Public Safety Audit of the Granite Canal Development and Granite Reservoir Structures, gaps were identified at the dams, and flow control structures, in the form of inadequate control measures warning the public of potential safety hazards. The accepted standard for proper control measures has evolved in light of incidents experienced over the past ten years at other utilities. As such, the original design of the Bay d'Espoir system did not address these measures.

This Public Safety Audit was a continuation of the program started by Hydro in 2011 to look more closely at existing control measures that are in place. The Granite Canal Development and Granite Reservoir could be considered remote but are accessed by fishermen, hunters and other occasional users. The risk assessment completed in 2013 identified the lack of appropriate signage, alarms and/or warning systems that alert the public to potential safety hazards and further identified the need for control measures at dams and structures on the Granite Reservoir System.

Industry Experience

As noted earlier, in 2002, downstream of an Ontario Power Generation facility, seven people sustained injuries and two people drowned during release of water from a reservoir. As a result of this, Ontario Power Generation started a comprehensive program addressing the safety of the public around their hydroelectric facilities. Additional research by Ontario Power Generation has identified more than 300 incidents associated with fatalities, injuries or rescues at dams throughout North America since 2003. As a result of these fatalities, larger utilities have taken an active role in assessing hazards at their hydroelectric facilities and installing control measures to either mitigate or eliminate identified hazards.

Safety Performance

This project is being done to protect the public from hazards associated with the normal operation of hydroelectric facilities including dams and waterways. There are inherent hazards around these facilities such as fast moving water, remotely operated gates and extreme changes in water levels of which the public may be unaware. This project will help educate, and thus, protect the public from those hazards.

Legislative and Regulatory Requirements

Although there are no specific legislative or regulatory requirements, Hydro follows the industry accepted CDA guidelines.

Status Quo

The only control measures that Hydro has in place to alert the public of hazards are some signs that are inconsistent in the messaging and sizing as well as others with faded out or words that are worn off. Not all sites have signage and where there are signs they lack sufficient visibility due to their size and do not conform to the CDA guidelines. In addition, some water control structures and spillways have audible alarms. There are no larger control measures such as buoys and booms in place. Fencing upgrades and additions are also required.

Historical Information

Similar project costs that have been incurred to date are included in Table 2 below.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2015	483.9		On-going
2014	352.8	246.7	
2013	298.1	340.6	
2012	48.3	50.1	
2011	49.4	48.4	

Conclusion:

Hydro has been following the CDA "Dam Safety Guidelines" pertaining to dam safety for more than ten years as part of an overall dam safety program and have also made a decision to follow the new CDA guideline entitled, "Guidelines for Public Safety around Dams", dealing with public safety around dams, which was released in 2011.

Incidents involving the public have occurred at hydroelectric facilities throughout North America. This is a concern for utilities and as a result, utilities have accepted the responsibility to protect the public by making them aware of hazards around dams, waterways and hydroelectric facilities. Hydro recognizes this trend in the industry and is putting a program in place that addresses those responsibilities.

By following the CDA guidelines, Hydro is taking a proactive approach to ensure that the public are aware of hazards around hydroelectric facilities and to install protection from those hazards. Hydro plans to undertake risk assessments of hazards around hydroelectric facilities, rank the hazards in order of significance, evaluate the need for control measures, such as signage, fencing, alarms, buoys and/or safety booms and install control measures. This project is a continuation of that effort started in 2011. The risk assessment done at Granite Reservoir System was a continuation of a program that started in 2011 and will be continuing for the next several years and the 2016 program continues with the implementation of significant control measures at the Granite Reservoir System.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open Project File	March 2016	March 2016
Design	Finalize sign requirements	April 2016	April 2016
Procurement	Purchase Materials for Control Measures	May 2016	June 2016
Construction	Install Control Measures	June 2016	September 2016
Closeout	Finalize Payments and prepare closeout documentation	October 2016	November 2016

Future Plans:

Hydro plans to continue with this program on an annual basis by installing necessary control measures identified in specific risk assessments. This will continue for all risks identified at a particular site by addressing the most appropriate means of mitigating the risk, either by reducing the likelihood of the hazard and or by reducing the consequence. Risk levels will be addressed on a priority basis from high to medium to low.

An Asset Management Strategy Report is attached in Appendix B outlining Hydro's plans for identifying hazards at their various facilities through on-going risk assessments and procurement and installation of appropriate control measures to either warn the public of the hazard or to prevent exposure of the public to the hazard.

APPENDIX A

Risk Assessment

Recommendations

Location	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
MD-10	Fishing from Boat	Medium (10)	Install appropriately messaged and sized red Danger signage.	Low (6)
MD-10	Ice Fishing	High (25)	Install appropriately messaged and sized red Danger signage.	Medium (10)
MD-10	Snowmobiling	High (25)	Install appropriately messaged and sized red Danger signage.	Medium (10)
MD-10	Fishing from Shore	High (25)	It is recommended that a railing be installed to stop inadvertent access to the Burnt Canal Weir and Appropriately messaged and sized red Danger signage should be installed.	Low (5)
MD-10	ATV Driving on crest	High (25)	It is recommended that appropriately messaged and sized yellow warning signs be placed on either side of the embankment leading to the embankment structure notifying the public that this is a dam and that they should use the toe road.	Medium (10)
MD-10	Vehicle Driving on Crest	High (25)	Install appropriately messaged and sized red Danger signage.	High (25)
MD-9	ATV Driving on Crest	High (20)	Install appropriately messaged and sized red Danger signage.	High (20)
MD-9	Vehicle Driving on Crest	High (20)	Install appropriately messaged and sized red Danger signage.	High (20)
MSD-8, 7 and 6	Fishing from boat	Medium (10)	Install appropriately messaged and sized yellow Warning signage.	Medium (10)

Location	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
MSD-8, 7 and 6	Fishing from shore	Medium (10)	Install appropriately messaged and sized yellow Warning signage.	Medium (10)
MSD-8, 7 and 6	Camping	High (15)	Install appropriately messaged and sized yellow Warning signage.	Medium (10)
MSD-8, 7 and 6	ATV	High (15)	Documentation of operating procedures should be clipped to operating orders. Also install appropriately messaged and sized yellow Warning signage.	Medium (10)
MSD-8, 7 and 6	Driving	High (15)	Documentation of operating procedures should be clipped to operating orders. Also install appropriately messaged and sized yellow Warning signage.	Medium (10)
Granite Canal (Original)	Fishing from boat	High (15)	Install boom at extreme point where flow rate exceeds recommended usage for a boat. Install appropriately messaged and sized red Danger signage.	Low (3)
Granite Canal (Original)	Fishing from shore	High (25)	Install appropriately messaged and sized red Danger signage.	Medium (10)
Granite Canal (Original)	Bathing	High (25)	Install appropriately messaged and sized red Danger signage.	Medium (10)
Power Canal	ATV	High (25)	Install guiderail at bridge to prevent inadvertent access to the Power Canal. Also install appropriately messaged and sized yellow Warning signage and red Danger signage.	Low (5)
Power Canal	Driving (Vehicle)	High (25)	Install guiderail at bridge to prevent inadvertent access to the Power Canal. Also install appropriately messaged and sized yellow Warning signage and red Danger signage.	Low (5)
Power Canal	Hunting	High (25)	Install appropriately messaged and sized red Danger signage.	High (25)

Location	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
GD-IN and Intake Structure	Walking	Medium (10)	Must ensure that unauthorized vehicular, ATV or people access is not permissible. Install appropriately messaged and sized red Danger signage.	Medium (10)
GD-IN and Intake Structure	ATV	Medium (10)	Must ensure that unauthorized vehicular, ATV or people access is not permissible. Install appropriately messaged and sized red Danger signage.	Medium (10)
Tailrace	Fishing from boat	High (15)	Install appropriately messaged and sized red Danger signage.	Low (6)
Tailrace	Ice fishing	High (25)	Install appropriately messaged and sized red Danger signage.	Medium (10)
Tailrace	Snowmobiling	High (25)	Install appropriately messaged and sized red Danger signage.	Medium (10)
Tailrace	Fishing from shore	Medium (10)	Install appropriately messaged and sized red Danger signage.	Medium (10)
Granite Dam – Bypass GD-BYP	Fishing from shore	High (25)	Fencing required on upstream and downstream on abutment to limit access. Also install appropriately messaged and sized red Danger signage.	Medium (10)
Granite Dam – Bypass GD-BYP	ATV	High (15)	Install guiderail at bridge corners to guide traffic. Also install appropriately messaged and sized yellow Warning and red Danger signage.	Low (5)
Granite Dam – Bypass GD-BYP	Driving	High (15)	Install guiderail at bridge corners to guide traffic. Also install appropriately messaged and sized yellow Warning and red Danger signage.	Low (5)

Location	Activity	Current Risk Rating Level	Recommended Risk Treatments	Anticipated Risk Rating
RR Pond Spillway	Fishing from shore	High (15)	Install appropriately messaged and sized yellow Warning signage.	Medium (12)
RR Pond Spillway	ATV	High (15)	Install railing to prevent inadvertent access to drop off location and install appropriately messaged and sized yellow Warning signage.	Low (5)
Fish Compensation Inlet Works	Fishing from shore	High (25)	Install railing on upstream side of culverts to permit safe access for monitoring and maintenance and install appropriately messaged and sized red Danger signage. Also establish health and safety practices for cleaning of trash grates as well as maintenance protocols for assessing condition.	Low (6)
Fish Compensation Inlet Works	ATV	High (25)	Install appropriately messaged and sized yellow Warning signage.	Low (5)
Fish Compensation Inlet Works	Driving	High (15)	Install appropriately messaged and sized yellow Warning signage.	Low (5)
Fish Compensation Inlet Works	Accessing Data loggers	Medium (10)	Education Plan for fisheries Personnel describing risks of site, as well as site protocols, operational procedures and health and safety requirements.	Low (5)
Fish Compensation Inlet Works	Bathing	High (25)	Install appropriately messaged and sized red Danger signage.	Low (6)

APPENDIX B

PUBLIC SAFETY AROUND DAMS

ASSET MANAGEMENT STRATEGY REPORT

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Appendix A – Ten Year Public Safety Around Dams Plan

Appendix B – Public Safety Around Dams Project List

1.0 INTRODUCTION

This report outlines Hydro's responsibilities, as an Owner, for managing the public safety risks caused by the presence and operation of dams and associated hydraulic structures.

Keeping the public safe is one of the main reasons why the dam industry works hard to ensure structural integrity and prevent failures. However, an increasing number of incidents are giving cause for concern that non-structural hazards are also endangering lives at dam projects.

It is more common in most countries for people to die as a result of operational issues at dams than because of actual dam failures. It is no different in Canada or the United States as these statistics demonstrate. Dating from 1905, there have been only 11 fatalities in Canada as a result of 5 recorded dam failures – with the last being in 1966. In contrast, according to the Canadian Lifesaving Society, 27 people have drowned at dams across the country during the period from 1995 – 2004. During an even smaller time span from June 21 to July 8, 2013, 39 public safety incidents at North America dams which led to 23 fatalities were reported in the media.

These alarming figures have made public safety around dams an area of increasing importance for the dam industry. These incidences appear to be on the rise because the public is changing and there is an increase in public interaction at facilities. People are participating in more recreational and extreme sporting activities near dams. Previously, access to projects was difficult, but all-terrain vehicles and personal watercraft have made dams more accessible.

The potential risks associated with dams and hydro facilities are also often underestimated by the public. The sudden opening of spillways or start up of hydropower generation on a sunny day can turn relatively tranquil conditions into dangerous turbulent waters. This is not always obvious to the public, especially those unfamiliar with rivers and the operations. Problems can also be exacerbated as many dams are no longer managed and operated by on site personnel. More are remotely controlled.

All dams pose some level of risk to public safety, regardless of size or impoundment. Outlined below is a long term program for Hydro to identify and manage risk to the public associated with the operation of their numerous hydroelectric generating plants, hydraulic structures, dykes and dams. The report identifies the numerous assets owned by Hydro, introduces a management system to manage the risks associated with those structures and identifies some of the control measures that will have to be implemented to warn and protect the public against risks associated with the operation of hydroelectric plants and their associated hydraulic structures and dams.

To that end, Hydro is embarking on a program of identifying the hazards at its facilities to determine the appropriate control measures that can be put in place to either warn the public of the hazard or to remove the hazard.

2.0 BACKGROUND

2.1 Hydro's Hydroelectric Generating Stations

Hydro is the primary generator of power on the island of Newfoundland. The generating assets are varied and include nine hydroelectric plants, one oil-fired plant, four gas turbines and 25 diesel plants. The focus here will be on the nine hydroelectric generating plants.

These generating plants are located all over the island of Newfoundland and are comprised of multiple assets consisting of reservoir systems, powerhouses, intakes, spillways, control structures, dams and dykes.

The following outlines the totals of each:

Generating Stations	-	9
Reservoirs	-	21
Hydraulic Structures	-	44
Dams and Dykes	-	61

2.2 Canadian Dam Association Guidelines

The Canadian Dam Association (CDA) Dam Safety Guidelines were revised and published in 2007 to address the various hazards which can lead to failure of a dam and to present methods for management of those risks. However, as mentioned above, in Canada, more people have died in accidents around dam sites that are not associated with structural failure of dams but rather normal operational issues at dams. This is a matter of considerable concern to dam owners, who are seeking guidance on how they can meet their responsibilities to protect public safety.

As a result, in 2011, CDA published Guidelines for Public Safety Around Dams. These guidelines address the risks of accidents or incidents in which a member of the public encounters a hazard created by the presence or operation of a dam.

Hydro has been following the 2007 Dam Safety Guidelines when it comes to managing its Dam Safety Program and more recently made a decision to follow the 2011 Guidelines for Public Safety Around Dams. Hydro has formed an internal work

group to ensure best practices with regard to a Public Safety Around Dams Program which includes the following:

- Develop and maintain the Corporate Public Safety Around Dams Program;
- Ensure the Public Safety Around Dams Program is consistent with industry best practice;
- Develop Public Safety Around Dams Standards that promotes consistency with regard to identification of hazards, risk assessment and implementation of control measures that help warn and protect the public.

3.0 PUBLIC SAFETY AROUND DAMS IMPLEMENTATION PLAN

Outlined below is a brief description of the many parts to implementation of a successful Public Safety Around Dams Program.

3.1 Risk Assessment

Risk assessment includes identification analysis and evaluation of risks. The assessment addresses the risk of a "public safety incident" which is defined as a potential or actual interaction between a member of the public and a hazard created as a direct result of the dams operation. In general, any analysis of the risk associated with public interaction at a dam involves the determination of:

- Exposure to hazards (number of people exposed to hazardous event);
- Likelihood of adverse consequences occurring if a person is exposed to the hazards;
- Consequences (outcome of the adverse event)

3.2 Risk Treatment

After the risks have been identified at a site, decisions can then be made related to the most appropriate means to mitigate the risk, either by reducing the likelihood or by reducing the consequence. Risk treatment and control can take the following forms:

- Eliminate the hazards where practical, as the most effective means of risk reduction;
- Mitigate the hazards where practical, for example by altering operations;
- Control the exposure to the hazards typically by installing physical control measures to warn or deter access by the public to hazardous zones;
- Educate the public of the hazards associated with the operation of dams and generating stations; and

- Prepare for emergency response, for example by providing 24/7 emergency contact numbers, or discuss plans for rescue with first responders.

3.3 Phased Approach

The risk assessment provides information needed to prioritize and implement control measures in a phased approach as outlined in Table 1 below.

Table 1 – Phased Approach to Risk Treatment

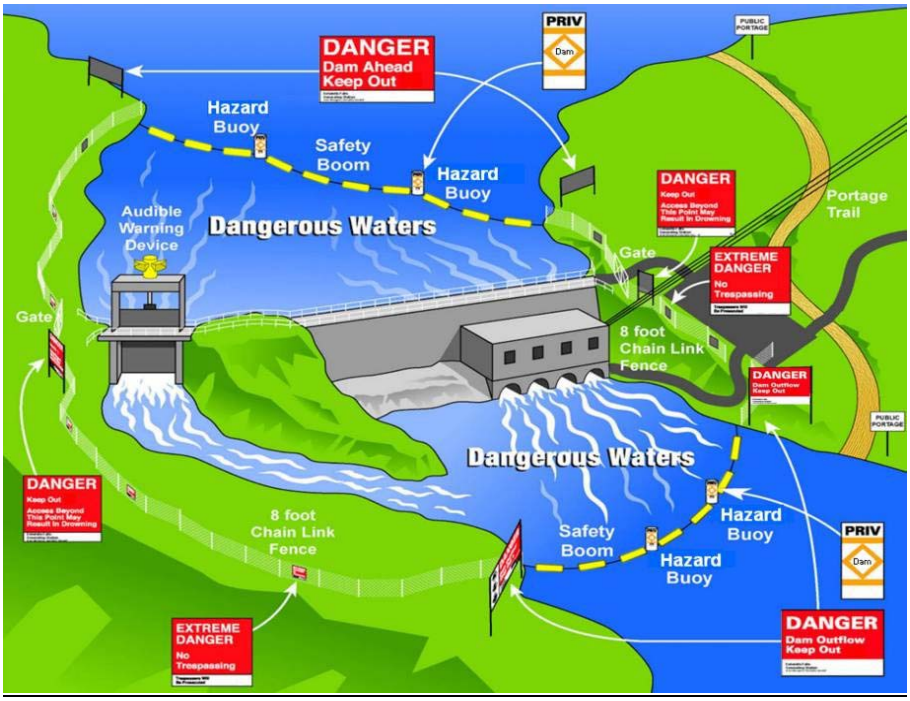
Phase	Control Measures for Risk Treatment
	• Public Education • Operational control measures • Effective signage • Spillway emergency signals • Buoys • Safety booms
	• Additional fencing, gates and barricades • Additional safety booms
	• Security patrols • Video surveillance

3.4 Physical Control Measures

Once it has been determined that it is not practical to eliminate the hazards, physical control measures should be considered, including such items as signage, booms, buoys, audible alarms , strobe lights, fencing and barricades.

An example of physical control measures that may be implemented at a facility following a risk assessment is shown in Figure 1 below.

Figure 1 – Example of Public Safety Control Measures at a Control Structure



4.0 APPROACH

Work started on this program in 2011 and continues today. To date, 3 risk assessments have been completed and control measures have been put in place on one reservoir system, with plans for implementation of control measures on a second reservoir system in 2014. Additionally, estimated costs for implementation of control measures on the third reservoir system have been completed and this will form the basis of the 2015 budget proposal.

The program plan going forward is viewed as a 4 – 5 year rotating cycle, depending on the size of the reservoir system, as follows:

Year 1 – Reservoir Risk Assessment
Year 2 – Costs identified from risk assessment submitted for approval
Year 3 – Design and Procurement of Control Measures
Year 4 – Implementation of Phase 1 Control Measures
Year 5 – Implementation of Phase 2 Control Measures

With this template in place and the number of reservoirs and structures to be completed, as identified earlier in the report, it is estimated that it will take in excess of ten years to address all. The proposed plan is included in Appendix A.

5.0 PUBLIC SAFETY AROUND DAMS CAPITAL BUDGET PRESENTATION

As indicated above, there has already been work done on three reservoirs, including Long Pond, Meelpaeg and Granite. Each of the reservoirs have had risk assessments completed and control measures have been installed at the Long Pond reservoir. In 2016, the majority of the costs identified in the capital program will be associated with costs identified for the Granite Reservoir System during the risk assessment that was completed in 2013. The year 2016 is year two of a three year program. This work involves procurement and installation of signs, fencing, railings and guiderails identified in the 2013 risk assessment. The budget estimate for year two of this project is shown in Table 2.

Table 2: 2016 Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	161.0	0.0	0.0	161.0
Labour	62.0	0.0	0.0	62.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	174.0	0.0	0.0	174.0
Other Direct Costs	12.0	0.0	0.0	12.0
IDC and Escalation	27.7	0.0	0.0	27.7
Contingency	40.9	0.0	0.0	40.9
TOTAL	**477.6**	**0.0**	**0.0**	**477.6**

APPENDIX A

PUBLIC SAFETY AROUND DAMS PROJECTED SCHEDULE

YEAR	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
RESERVOIR										
GRANITE	Year 1 Implementation	Year 2 Implementation	Year 3 Implementation							
BURNT/VICTORIA	Risk Assessment	Cost Estimates	Year 1 Implementation	Year 2 Implementation	Year 3 Implementation					
CAT ARM			Risk Assessment	Cost Estimates	Year 1 Implementation	Year 2 Implementation	Year 3 Implementation			
UPPER SALMON				Risk Assessment	Cost Estimates	Year 1 Implementation	Year 2 Implementation	Year 3 Implementation		
HINDS LAKE					Risk Assessment	Cost Estimates	Year 1 Implementation	Year 2 Implementation	Year 3 Implementation	
PARADISE RIVER						Risk Assessment	Cost Estimates	Year 1 Implementation	Year 2 Implementation	
SNOOK'S ARM AND VENAM'S BIGHT							Risk Assessment	Cost Estimates	Year 1 Implementation	Year 2 Implementation

APPENDIX B

PUBLIC SAFETY AROUND DAMS PROJECT LIST

Location	Description	Comment
Meelpaeg		
Ebbegunbaeg	Fencing Signage Boom – anchor design, purchase and install	Planned for 2014
Pudops	Signage	Planned for 2014
Grey River	Fencing Signage Purchase and install buoys	Planned for 2014

Location	Description	Comment
Granite		
Granite Canal Development	Signage	Planned for 2015
Burnt & Victoria		
Burnt & Victoria Structures	Risk Assessment	Planned for 2015

Location	Description	Comment
Granite		
Granite Structures	Signage, fencing, railings and guiderails	Future projects
Granite Canal	Anchor design, purchase and install boom	Future projects
Burnt & Victoria		
Burnt Structures	Signage	Future projects
	Fencing	Future projects
	Booms and/or buoys	Future projects
Victoria Structures	Signage	Future projects
	Fencing	Future projects
	Booms and/or buoys	Future projects
Cat Arm		
Cat Arm Structures	Risk Assessment	Future projects
	Signage	Future projects
	Fencing	Future projects
	Booms and/or buoys	Future projects
Upper Salmon		
Upper Salmon Structures	Risk Assessment	Future projects
	Signage	Future projects
	Fencing	Future projects
	Booms and/or buoys	Future projects
Hinds Lake		
Hinds Lake Structures	Risk Assessment	Future projects
	Signage	Future projects
	Fencing	Future projects
	Booms and/or buoys	Future projects

Paradise River		
Paradise River Structures	Risk Assessment Signage Fencing Booms and/or buoys	Future projects Future projects Future projects Future projects
Snook's Arm and Venam's Bight		
Snook's Arm and Venam's Bight Structures	Risk Assessment Signage Fencing Booms and/or buoys	Future projects Future projects Future projects Future projects
Roddickton		
Roddickton Structure	Risk Assessment Signage Fencing Booms and/or buoys	Future projects Future projects Future projects Future projects

Project Title: Replace Powerhouse No. 1 Station Service Transformer

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to replace the existing station service transformers (a total of six 167kVA distribution transformers) with a 0.75/1.0 MVA padmount transformer.

The project will address a number of issues, including the elimination of protective coordination issues and the reduction of fault and arc flash levels within the powerhouse's station service system. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	70.0	0.0	70.0
Labour	43.4	153.5	0.0	196.9
Consultant	0.0	7.4	0.0	7.4
Contract Work	0.0	21.4	0.0	21.4
Other Direct Costs	0.0	9.4	0.0	9.4
Interest and Escalation	3.3	31.8	0.0	35.1
Contingency	0.0	61.0	0.0	61.0
TOTAL	**46.7**	**354.5**	**0.0**	**401.2**

Justification:

The justification for this project is based upon a study completed in December 2012 by Diesel Injection Sales and Service (see Appendix A) which recommends the replacement of the overhead distribution type station service transformers with a padmount unit. This study makes several recommendations. Protection setting changes and low cost protective device are in the process of being completed. Installing this new station service transformer addresses the majority of safety issues and is the most critical recommendation. Other items will be addressed through the capital plan on a prioritized basis after the new transformer is installed.

The existing transformers, which provide the normal source of supply for the main 575 V station service bus, consist of two banks of 167kVA pole top distribution transformers. Each bank consists of three individual units. The high voltage fuses for these banks do not coordinate very well with the

incoming breaker (52SSL) and it is not recommended that the fuse sizes be changed as this would limit the overcurrent protection for the transformers. Each bank of transformers also acts as a source of ground fault current for the local 25 kV distribution system in St. Alban's which can result in mis-operation of protective devices.

The new padmount transformer will also reduce the fault levels and arc flash levels within the powerhouse's station service system. The maximum available fault levels exceed the fault interrupting ratings of several panelboards within the powerhouse, which is a safety and operational concern.

Existing System:

The Bay d'Espoir generating plant consists of seven generating units with six in Powerhouse No. 1 rated at 85 MVA each and one unit in Powerhouse No. 2 rated at 172 MVA for a total generating capacity of 682 MVA. Powerhouse No. 1 has three sources of supply for its main 575 V station service switchboard. The normal source of supply is the two banks of distribution transformers (a total of six 167kVA units) connected to the terminal station 25 kV bus. There are alternate supplies from station service transformers connected to the 13.8 kV busses for generating Units No. 1 and No. 3.

Figure 1 shows a picture of the existing station service transformers.

Figure 1: Powerhouse No. 1 Station Service Transformers

There have been no major upgrades on the station service transformers since their installation.

Operating Experience:

The station service transformers have not failed since their installation, though they do not provide adequate fault current protection.

Safety Performance

The replacement of the existing station service transformers with a padmount transformer will reduce the fault levels and arc flash levels inside the powerhouse, providing a smaller arc flash boundary and more ergonomic PPE requirements for employees when performing maintenance. The existing fault levels exceed the interrupting ratings of some equipment within the station service system. This is a safety concern for both the equipment and personnel working on or near this equipment.

Maintenance History

Maintenance costs for the existing station service transformers are not available.

Anticipated Useful Life

Distribution and padmount transformers have an estimated service life of 40 years.

Conclusion:

The existing fault levels within Powerhouse No. 1 exceed the ratings of some of the station service equipment. This is a safety risk for the equipment and personnel. The replacement of the existing station service transformers will decrease fault levels and arc flash levels.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Scope, schedule, cost, risk, quality and communications planning	January 2016	February 2016
Design 1	Complete detailed electrical design	March 2016	April 2016
Procurement 1	Specify and order padmount transformer	May 2016	July 2016
Design 2	Complete civil design	February 2017	March 2017
Procurement 2	Tender for civil works	March 2017	April 2017
Construction	Remove existing structure; install new structure; civil work; install new padmount transformer	April 2017	June 2017
Commissioning	Commission new equipment	July 2017	July 2017
Closeout	As built drawing review, financial close out, post implementation review	August 2017	November 2017

APPENDIX A

Report:

Bay d'Espoir Station Service Review

Bay D'Espoir Station Service Review

Powerhouse No. 1 & No. 2

Final

Prepared for

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Rick Leggo

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Project Execution & Technical Services

Prepared by

DIESEL INJECTION SALES AND SERVICE

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Industrial Controls Division

December 24, 2012

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PEGNL License

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Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

1. Introduction and Scope

Introduction

The Bay D'Espoir (BDE) Hydro Generating Plant consists of seven generating units with six in Powerhouse No. 1 rated at 85MVA each and one larger unit in Powerhouse No. 2 rated at 172MVA for a total generating capacity of 682 MVA or 614MW @ 0.9 pf. The Powerhouse No. 1 has three sources of supply for its main 575V station service switchboard that being two banks of distribution transformers connected to the terminal station 25kV bus and two station service power transformers connected to the 13.8kV bus for Units No. 1 and No. 3. Within that powerhouse there is also an emergency backup diesel generator as well as a small mini hydro unit with the former being a new 500kW installed in 2012. Powerhouse No. 2 has two sources of supply for its main 600V station service switchboard that being a bank of distribution transformers connected to the terminal station 25kV bus and a station service power transformer connected to the 13.8kV bus for Unit No. 7. This powerhouse also has an emergency 600V supply from Powerhouse No. 1 for black start of Unit No. 7 but that is limited to 200 kVA. There is one 25kV terminal station breaker which feeds the two banks of distribution transformers for Powerhouse No. 1 as well as the single bank of transformers for Powerhouse No. 2 and which would be the normal sources of station service supply for the BDE Hydro Generating Plant.

Scope

This engineering review of the station service infrastructure within Powerhouse No. 1 and No. 2 would involve the various sources of station service supply for both normal and emergency backup operation. As part of that review would be an assessment of the 25kV breaker and power fuses associated with the three outside station service transformer banks. The review would also include recommendations for coordinated operation of the protective relay schemes for the station service breakers and MCC panelboards within each powerhouse. ASPEN Oneliner software will be used to model the entire station service distribution network within both powerhouses including the station service transformers and 25kV breaker at the main terminal station. Confirmation of protective relay coordination will also be done under various operating scenarios for the BDE Hydro Generating Plant. However, not included in this station service review would be the effect on existing arc flash hazard designations within each powerhouse for the protective relay settings changes as recommended in this report.

2. Comments and Recommendations – Powerhouse No. 1

The following comments and recommendations are made for Powerhouse No. 1 based on the results of the station service review:

1. The normal source of supply for the main 575V station service bus is the outside station service transformers which consist of two banks of 3 x 167kVA pole top distribution units connected in parallel. The high voltage side distribution class fuses for each of those transformer banks do not coordinate very well with the incoming breaker 52SSL and to increase the fuse rating would limit the fault protection for those distribution transformers. As well, each bank of 3 x 167kVA pole top distribution transformers is connected as wye grounded on the 25kv side and closed delta on the 575V side thus they act as a source of ground fault current for the local 25kV distribution system in St. Alban's. This can result in tripping of the 25kV station service breaker BD3-R1 for power line faults on the 25kV distribution system thus the recommendation is to replace both banks of distribution transformers with a new 1/1.5 MVA 3-phase power transformer with a delta/delta winding configuration. As well, when compared to the existing two banks of 3 x 167kVA pole top distribution units this new station service power transformer will reduce the 3-phase fault level at the main station service switchboard from 35.5kA to 17.2kA. This in turn reduces the arc flash incident level at that location by 50% which is significant in terms of the arc flash boundary and related PPE requirements when maintenance work is being performed in that area.

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

2. Comments and Recommendations – Powerhouse No. 1

2. The 25kV station service breaker BD3-R1 is a 1980's vintage McGraw Edison hydraulic recloser which has a very limited selection for both phase and ground trip timing operation, thus its sensitivity as backup protection for each of the outside station service transformers is limited. The 25kV station service breaker is also the single source of supply from the main terminal station for Powerhouse No. 1 thus alternate sources of station service supply within the powerhouse would have to be utilized for any scheduled maintenance or emergency repair of that breaker. It is therefore recommended that the existing 25kV station service breaker be replaced with a new 25kV vacuum breaker with digital control and directional overcurrent function.

3. The 13.8kV circuit breakers 52AT-1 and 52AT-2 associated with hydro generating units No. 1 and No. 3 and their respective station service power transformer SST1 and SST2 are a 1970's vintage air blast design which is obsolete. These breakers have inherently higher maintenance costs because of the complexity of the breaker itself and the maintenance servicing of those breakers and its compressed air handling system which are very labour intensive. This leads to longer downtime for the air blast breaker and the station service supply from that hydro generating unit. Any potential failure of that breaker under fault conditions on the unit 13.8 kV bus is critical since the 3-phase fault level with the generator on line is 40kA. Possible elimination of the 13.8kV station service breakers 52AT-1 and 52AT-2 will not be addressed in this report since it would require a more comprehensive fault protection review for each of the hydro generating units and their respective station service transformers. Needless to say replacement of these two air blast circuit breakers with a more modern vacuum or SF_6 circuit breaker is certainly a viable option since breaker manufacturers do offer direct replacement retrofit to reduce downtime time and installation costs.

4. The Federal Pioneer Ltd (FPL) 50H-3 breakers used for the main station service switchboard (cells 1 to 8) are a 2000A frame size with an interrupting rating of 50kA. The maximum 3-phase fault level at the main station service switchboard is 56.6kA when all three sources of station service supply are simultaneous connected however switching procedures are in place including automated controls to prevent that. This fault level reduces to 35.5kA for the terminal station feed only and to 14.3kA for station service supply from one hydro generating unit. These fault levels would also include a 3.5kA fault contribution from the various 3-phase induction motors within the powerhouse. All of these station service faults would be subtransient in nature and that is especially true for the 3-phase induction motors whose fault contribution collapses very rapidly.

5. The original 300kW emergency diesel generator is being replaced with a new 500kW electronic controlled unit which offers increased reliability and power handling capability for black start of the hydro generating plant. The fault contribution from this new emergency diesel generator to the main station service switchboard would be in the order of 4.9kA.

6. The 200MVA mini hydro unit is not being considered in this review since its operating history has been limited as a backup supply and is not designed to operate in parallel with the emergency diesel generator.

7. The USD-31R overcurrent trip unit used for each of the FPL 50H-3 feeder breakers on the main 600V station service bus as listed below has a time margin of only 0.10 seconds for fault protection coordination with downstream panelboard breakers and that would be with its short time element set at its maximum time setting. Therefore replacement of the existing USD-31R overcurrent trip unit on these FPL breakers with a digital type trip unit that has expanded short time settings is recommended. One such digital trip unit is the AC-PRO retrofit kit shown in **Appendix A**. The remaining FPL 50H-3 station service supply breakers on the main 600V station service bus have a time margin of 0.44 seconds for fault protection coordination with each of the FPL 50H-3 feeder load breakers as well as the downstream panelboard breakers.

   FPL 50H-3 feeder breakers:
   52ESB1, 52ESB2, 52FB1/4, 52FB2/7, 52FB3/6, 52FB5/8, 52FB9/10, 52SSD, 52SSL, 52SST1, 52SST2, 52SSTB

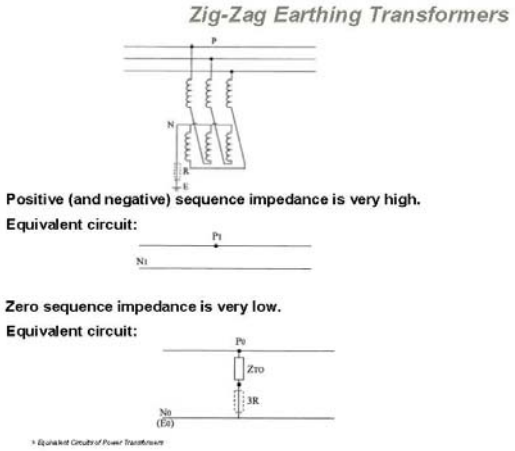
Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

2. Comments and Recommendations – Powerhouse No. 1

8. The molded case type main circuit breaker for each of the 600V station service panelboards as listed below does not coordinate under fault conditions with any of its branch breakers, thus the entire panelboard would be tripped for a branch circuit fault. It is therefore recommended that the main circuit breaker for each of these panelboards be replaced with an electronic style thermal breaker which will then enable coordinated tripping for each of the branch breakers.
   Station Service Panelboards:
   6100, 6200, 6300, 6400, 6500, 6600, 6700, 6800, 6900, 7000

9. The interrupting rating (symmetrical) for the molded case circuit breakers on each of the above panelboards is 10kA and 14kA whereas the 3-phase fault level at those same locations ranges from 15.8kA to 32.9kA when the powerhouse station service is being supplied from the parallel bank of distribution transformers SSL at the main terminal station. The reason for the much higher fault contribution from these distribution transformers is their lower impedance of 1.6% as compared to the 5.75% typical impedance for an equal kVA size in a 3-phase transformer design. These two banks of distribution transformers are also connected in parallel thus the equivalent impedence for fault calculations would be ½ of the 1.6% or 0.8%. For a new 3-phase 1 MVA power transformer with 5.75% impedance the fault level at the main station service switchboard will be reduced to 17.2kA. **Appendix B** contains a summary of the fault interrupting rating (symmetrical) for the main breakers and branch breakers for the various station service panelboards within Powerhouse No. 1.

10. At present all of the station service transformers for Powerhouse No. 1 are a delta configuration thus the entire system has no ground source and that was intentional at the time to prevent protection trips for single phase to ground faults. The main station service switchboard was fitted with bus PTs to detect and alarm that operating condition however trying to determine the source of the ground fault is very much a manual process with de-energization of station service panelboard branch circuits and possibly main switchgear breakers. A Zig-Zag grounding transformer as illustrated below has been an industry standard for the detection of phase to ground faults on an ungrounded (delta) power systems. The size of the neutral grounding resistor chosen for the Zig-Zag transformer would control not only the level of ground current for coordinated overcurrent protection operation but also the duration of the phase-to-ground overvoltage and thus the electrical stress on station service equipment including power cables. It is therefore recommended that a Zig-Zag grounding transformer c/w switchable grounding resistor and a ground fault sensing relay (67N) be added to the main station service bus for Powerhouse No. 1.



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Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

3. Comments and Recommendations – Powerhouse No. 2

The following comments and recommendations are made for Powerhouse No. 2 based on the results of the station service review:

1. The normal source of supply for the main 600V station service bus is the outside station service transformer which consists of a bank of 3 x 167kVA pole top distribution units. The high voltage distribution class fuses for this transformer bank do not coordinate very well with the incoming breaker 52SS4 and to increase the fuse rating would limit the fault protection for those distribution transformers. As well, this bank of 3 x 167kVA pole top distribution transformers is connected as wye grounded on the 25kv side and closed delta on the 600V side thus they act as a source of ground fault current for the local 25kV distribution system in St. Alban's. This can result in tripping of the 25kV station service breaker BD3-R1 for power line faults on the 25kV distribution system thus the recommendation is to replace the bank of distribution transformers with a new 0.75/1.0 MVA 3-phase power transformer with a delta/delta winding configuration.

2. The 25kV station service breaker BD3-R1 is a 1980's vintage McGraw Edison hydraulic recloser which has a very limited selection for both phase and ground trip timing operation, thus its sensitivity as backup protection for each of the outside station service transformers is limited. The 25kV station service breaker is also the single source of supply from the main terminal station for Powerhouse No. 2 thus alternate sources of station service supply within the powerhouse would have to be utilized for any scheduled maintenance or emergency repair of that breaker. It is therefore recommended that the existing 25kV station service breaker be replaced with a new 25kV vacuum breaker with digital control and directional overcurrent.

3. The 13.8kV circuit breaker 52AT-3 associated with hydro generating unit No. 7 and its station service power transformer SST3 is a 1970's vintage air blast design which is obsolete. This breaker has inherently higher maintenance costs because of the complexity of the breaker itself and the maintenance servicing of the breaker and its compressed air handling system which are very labour intensive. This leads to longer downtime for the air blast breaker and that station service supply from the hydro generating unit. Any potential failure of that breaker under fault conditions on the unit 13.8 kV bus is critical since the 3-phase fault level with the generator on line is 87kA. Possible elimination of the 13.8kV station service breaker 52AT-3 will not be addressed in this report since it would require a more comprehensive fault protection review for the hydro generating unit and its respective station service transformer. Needless to say replacement of this air blast circuit breaker with a more modern vacuum or SF_6 circuit breaker is certainly a viable option especially since breaker manufacturers do offer direct replacement retrofit to reduce downtime time and installation costs.

4. In order for the 13.8kv breaker 52AT-3 to provide adequate backup protection for the station service transformer SST4 as well as coordinated fault clearing operation with the main station service breakers then it is recommended that the existing IAC55 protective relays should be changed to an IAC53 (very inverse) type with revised settings.

5. Revised protection settings are being recommended for the two main station service breakers 52SS3 and 52SS4 in order to coordinate with both of the station service panelboards 7000 (east) & 7000 (west).

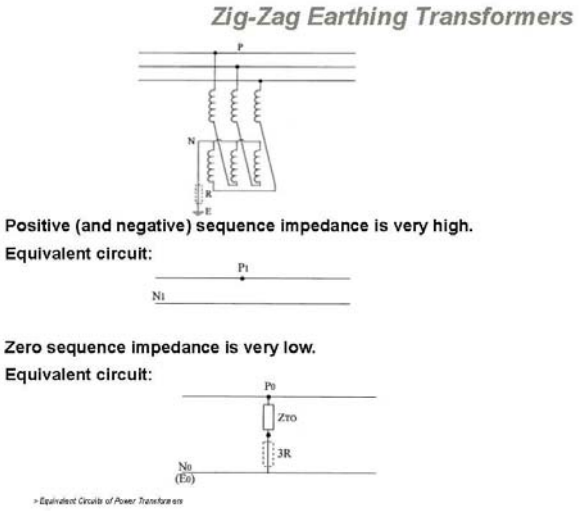
6. Upgrades of the two main station service breakers 52SS3 and 52SS4 should be coordinated with any future upgrades for the FPL 50H-3 breakers in Powerhouse No. 1.

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

3. Comments and Recommendations – Powerhouse No. 2

7. All of the 225A molded case breakers for the main station service panelboards 7000 (East) & 7000 (West) do not coordinate under multi-phase fault conditions with the downstream panelboards as listed below, thus the main station service panelboard(s) would be tripped. It is therefore recommended that the main circuit breaker for each of these panelboards be replaced with an electronic style thermal breaker which will enable coordinated tripping with each of the branch breakers.
   Main Station Service Panelboards:
   7100, 7200, 7300, 7400, 7500

8. At present all of the station service transformers for Powerhouse No. 2 are a delta configuration thus the entire system has no ground source and that was intentional at the time to prevent any protection trips for single phase to ground faults. The main station service switchboard was fitted with bus PTs to detect and alarm that operating condition however trying to determine the source of the ground fault is very much a manual process with de-energization of station service panelboard branch circuits and possibly main switchgear breakers. A Zig-Zag grounding transformer as illustrated below has been an industry standard for the detection of phase to ground faults on an ungrounded (delta) power systems. The size of the neutral grounding resistor chosen for the Zig-Zag transformer would control not only the level of ground current for coordinated overcurrent protection operation but also the duration of the phase-to-ground overvoltage and thus the electrical stress on station service equipment including power cables. It is therefore recommended that a Zig-Zag grounding transformer c/w switchable grounding resistor and a ground fault sensing relay (67N) be added to the main station service bus for Powerhouse No. 2.



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Transformers SSL

The normal source of supply for the main 600V station service bus in Powerhouse No. 1 is the outside station service transformers which consist of two banks of 3 x 167kVA pole top distribution units connected in parallel. The high voltage side (25kV) fuses for each of those transformer banks do not coordinate very well with the incoming 600V breaker 52SSL and to increase the fuse rating would limit the fault protection for those distribution transformers. Refer to **Appendix C** for plots of those fuse curves and the incoming 600V breaker 52SSL. As well, each bank of 3 x 167kVA pole top distribution transformers is connected as wye grounded on the 25kv side and closed delta on the 600V side thus they act as a source of ground fault current for the local 25kV distribution system in St. Alban's. The 25kV recloser which is the normal source of station service supply for Powerhouse No. 1 is sensitive enough to detect that back feed of ground current since that type of distribution recloser does not have a directional current control function.

Station Service Transformers SST1 & SST2

The alternate sources of supply for the main 600V station service bus in Powerhouse No. 1 are the two station service transformers SST1 and SST2 associated with hydro generating units No. 1 and No. 3 and both are rated at 750/1000kVA with a delta/delta winding configuration. The fault clearing device for these station service transformers would be the two 13.8kV air blast breakers 52AT-1 and 52AT-2 with the former for Unit No. 1 and the latter for Unit No. 3. These two breakers also have 13.8kV isolation switches 29AT-1 and 29AT-2 respectively. The protective relay used for both these air blast breakers is a GE type IAC53 which are both 1970's vintage.

The table below is a listing of the protective relay settings for the two 13.8kV station service breakers.

13.8kV Station Service Breakers Protective Relay Settings

Breaker Number	CT Ratio	Relay Info.	Relay Settings			Application Notes
		Type	Pickup	Delay	Inst	
52AT-1	400/5A	GE IAC53	3A	10	40A	Trip Setting = 5.74 MVA
52AT-2	800/5A	GE IAC53	3A	10	40A	Trip Setting = 11.5 MVA

The existing IAC53 protective relay settings for breaker 52AT-1 and 52AT-2 are set very high when compared to the rating of their respective station service transformer with the former 7.5 times and the latter 15 times the transformer base rating of 0.75 MVA. Thus these protective relay settings do not provide adequate backup protection for the station service transformers SST1 and SST2 including close-in faults on the 575V side. Refer to **Appendix D** for plots of those relay curves. This fault protection issue can be improved somewhat with the existing relays by implementing the protective relay settings listed in the table below, however, reducing the CT ratio to 200:5A would best improve the fault detection capability for the existing protective relays.

The table below is a listing of the recommended protective relay settings for the two 13.8kV station service breakers.

13.8kV Station Service Breakers Protective Relay Settings

Breaker Number	CT Ratio	Relay Info.	Relay Settings			Application Notes
		Type	Pickup	Delay	Inst	
52AT-1	400/5A	GE IAC53	3A	2	40A	Trip Setting = 5.74 MVA
52AT-2	800/5A	GE IAC53	1.5A	2	20A	Trip Setting = 5.74 MVA

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Main Station Service Switchboard

The Main Station Service Switchboard for Powerhouse No. 1 has eight cells with five of those used for incoming supply breakers, one for a bus tie breaker and the remaining three cells used for outgoing supply breakers to the various station service panelboards within the powerhouse. The breaker used for all of those cells is a Federal Pioneer Ltd type 50H-3 which has a 1600A frame size and a current sensor range of 400A to 1600A. Each breaker is fitted with an FPL type USD-31R overcurrent trip unit. The table below is a listing of the twelve switchboard breakers which includes the present sensor tap rating and its USD-31R overcurrent trip unit settings. Please note that the instantaneous setting for all breaker overcurrent relays is presently set to the Off position, so as to avoid fault protection coordination issues with downstream panelboard circuit breakers.

Main Station Service Switchboard Breaker USD-31R Overcurrent Trip Settings

Breaker Number	Sensor Tap Rating	Short Time Settings		Long Time Settings		Inst. Setting
		Pickup	Delay	Pickup	Delay	Pickup
52-SSL	1200A	0	3	2	0	9 (Off)
52-SST1	1200A	0	3	2	0	9 (Off)
52-SST2	1200A	0	3	2	0	9 (Off)
52-SSTB	1200A	0	2	1	0	9 (Off)
52-SSD	800A	1	3	5	1	9 (Off)
52-ESB1	600A	0	0	2	1	9 (Off)
52-ESB2	600A	0	0	2	1	9 (Off)
52-FB 1/4	600A	0	0	2	1	9 (Off)
52-FB 2/7	600A	0	0	2	1	9 (Off)
52-FB 3/6	600A	0	0	2	1	9 (Off)
52-FB 5/8	600A	0	0	2	1	9 (Off)
52-FB 9/10	600A	0	0	2	1	9 (Off)

The maximum time margin that can be achieved between the USD-31R trip unit and a downstream panelboard breaker under multi-phase fault conditions is 0.10 seconds. The Short Time delay setting for all of station service feeder breakers is at its lowest value of 0 in order to coordinate with the station service source breaker(s) and that time margin is 0.44 seconds. Because of that there is no fault protection coordination between each of the station service feeder breakers and the various downstream station service panelboards within the powerhouse. Plots of those breaker curves are included in **Appendix E**. One solution would be to replace each of the USD-31R overcurrent trip units with a digital trip unit which has a greater selection of operating curves and time delays.

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

There are twelve station service panelboards within Powerhouse No. 1 with two designated as essential supply for the six hydro generating units and the remainder considered either non-essential or general purpose as required for various heating, lighting, and other motor loads within the powerhouse and main terminal station. The only exception to that would be Panelboard 6900 which has a branch circuit utilized as an emergency station service feed to Powerhouse No. 2. In that situation a 200kVA booster transformer is used since the station service voltage for Powerhouse No. 1 is 575V whereas Powerhouse No. 2 is 600V.

The main breaker for each of these panels does not coordinate with any of its branch breakers, thus the entire panelboard would be tripped for a branch circuit multi-phase type fault. Examples of the miscoordination between the main breaker and its panelboard breakers within Powerhouse No. 1 are shown in **Appendix F**.

The tables that follow are a listing of the various breakers types and ratings for those twelve station service panelboards.

Panelboard ESB1 (Essential Service #1)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
Main Brk	Siemens	MD6	600A	500 MCM Cable Infeed
ESB1-1	Siemens	ED6	70A	Governor Oil Pump No. 2 (25HP)
ESB1-2	Siemens	ED6	70A	Governor Oil Pump No. 3 (25HP)
ESB1-3	Siemens	ED6	70A	Governor Oil Pump No. 4 (25HP)
ESB1-4	Siemens	ED6	100A	Sump Pump No. 2 (40HP)
ESB1-5	Siemens	ED6	40A	Air Compressor No. 1 (15HP)
ESB1-6	Siemens	ED6	40A	Air Compressor No. 3 (9HP)
ESB1-7	Siemens	ED6	40A	Sump Pump No. 3 (20HP)
ESB1-8	Siemens	ED6	15A	Unit 3 Exciter A.C. Field Flashing
ESB1-9	Siemens	ED6	40A	Emergency Diesel Control Unit
ESB1-10	Siemens	ED6	40A	Essential Service Lighting Transformer (37.5kVA)
ESB1-11	Siemens	ED6	15A	Spare
ESB1-12	Siemens	ED6	15A	Battery Charger No. 1
ESB1-13	Siemens	ED6	15A	Unit 2 Exciter A.C. Field Flashing
ESB1-14	Siemens	ED6	15A	Unit 4 Exciter A.C. Field Flashing

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

Panelboard ESB2 (Essential Service #2)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
Main Brk	Siemens	MD6	600A	500 MCM Cable Infeed
ESB2-1	Siemens	ED6	150A	Spare
ESB2-2	Siemens	ED6		Spare
ESB2-3	Siemens	ED6	40A	Sump Pump No. 1 (20HP)
ESB2-4	Siemens	ED6	40A	Air Compressor No. 2 (15HP)
ESB2-5	Siemens	ED6	70A	Governor Oil Pump No. 1 (25HP)
ESB2-6	Siemens	ED6	70A	Governor Oil Pump No. 5 (25HP)
ESB2-7	Siemens	ED6	70A	Governor Oil Pump No. 6 (25HP)
ESB2-8	Siemens	ED6	15A	Spare
ESB2-9	Siemens	ED6	15A	Battery Charger No. 2
ESB2-10	Siemens	ED6	40A	Air Compressor No. 4 (9HP)
ESB2-11	Siemens	ED6	15A	Unit 5 Exciter A.C. Field Flashing
ESB2-12	Siemens	ED6	30A	Essential Service Lighting Transformer (37.5kVA)
ESB2-13	Siemens	ED6	15A	Unit 6 Exciter A.C. Field Flashing
ESB2-14	Siemens	ED6	15A	Unit 1 Exciter A.C. Field Flashing

Panelboard 6100 (Unit #1 Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6109	Cutler-Hammer	FDB	225A	Main Brk (300 MCM Cable Infeed)
6101	Cutler-Hammer	GBH	40A	Spherical Valve Pit Heater (10kW)
6102	Cutler-Hammer	GBH	100A	Spare
6103	Cutler-Hammer	GBH	15A	Exciter No. 1 Test Supply
6104	Cutler-Hammer	GBH	15A	Powerhouse Vent Fan (3 HP)
6105	Cutler-Hammer	GBH	50A	Lighting Panel C (25kVA trf)
6106	Cutler-Hammer	GBH	15A	Battery Charger No. 3
6107	Cutler-Hammer	GBH	100A	Spare
6108	Cutler-Hammer	GBH	70A	Cooling Water Pump (50 HP)
6110	Cutler-Hammer	GBH	15A	Spherical Valve No. 1 By-Pass Motor (1.3 HP)

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

Panelboard 6200 (Unit #2 Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6211	Federal Pioneer	NFJ	225A	Main Brk (300 MCM Cable Infeed)
6201	Federal Pioneer	NF		Spare
6202	Federal Pioneer	NF	15A	Air Conditioner Shielded Room
6203	Federal Pioneer	NF	15A	Powerhouse Vent Fan (3 HP)
6204	Federal Pioneer	NF	70A	Oil Process Transformer (30kVA)
6205	Federal Pioneer	NF	15A	Exciter No. 2 Test Supply
6206	Federal Pioneer	NF	15A	Spherical Valve No. 2 By-Pass Motor (1.3 HP)
6207	Federal Pioneer	NF	50A	Lighting Panel D (25kVA Trf)
6208	Federal Pioneer	NF	40A	Spherical Valve No. 2 Pit Heater (10kW)
6209	Federal Pioneer	NF	100A	Gen Rm. & Basement Receptacles
6210	Federal Pioneer	NF	15A	Spare
6212	Federal Pioneer	NF	100A	Gen #2 Cooling Water System

Panelboard 6300 (Unit #3 Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6311	Cutler-Hammer	FDB	225A	Main Brk (300 MCM Cable Infeed)
6301	Cutler-Hammer	GBH	15A	Diesel Battery Charger
6302	Cutler-Hammer	GBH	15A	Spherical Valve No. 3 Pit Heater (10 kW)
6303	Cutler-Hammer	GBH	15A	Powerhouse Vent Fan (3 HP)
6304	Cutler-Hammer	GBH		Spare
6305	Cutler-Hammer	GBH	15A	Exciter No. 3 Test Supply
6306	Cutler-Hammer	GBH	15A	Spherical Valve No. 3 By-Pass Motor (1.3 HP)
6307	Cutler-Hammer	GBH	50A	Lighting Panel E (25kVA)
6308	Cutler-Hammer	GBH		Spare
6309	Cutler-Hammer	GBH	100A	Basement Receptacles
6310	Cutler-Hammer	GBH	70A	Cooling Water Pump (50 HP)

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

Panelboard 6400 (Unit #4 Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6412	Cutler-Hammer	FDB	225A	Main Brk (300 MCM Cable Infeed)
6401	Cutler-Hammer	GBH		Spare
6402	Cutler-Hammer	GBH		Spare
6403	Cutler-Hammer	GBH	15A	Powerhouse Vent Fan (3 HP)
6404	Cutler-Hammer	GBH	15A	Spherical Valve No. 4 By-Pass Motor (1.3 HP)
6405	Cutler-Hammer	GBH	15A	Exciter No. 4 Test Supply
6406	Cutler-Hammer	GBH	40A	Gen Room G.P. Receptacle
6407	Cutler-Hammer	GBH	40A	Lighting Panel F (25kVA)
6408	Cutler-Hammer	GBH	15A	Spherical Valve No. 4 Pit Heater (10kW)
6409	Cutler-Hammer	GBH	100A	Basement & Bus Tunnel Receptacles
6410	Cutler-Hammer	GBH	40A	T4 Transformer Main Fans
6411	Cutler-Hammer	GBH	15A	Spare

Panelboard 6500 (Unit #5 Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6511	Cutler-Hammer	FDB	225A	Main Brk (300 MCM Cable Infeed)
6501	Cutler-Hammer	GBH		Spare
6502	Cutler-Hammer	GBH		Spare
6503	Cutler-Hammer	GBH	15A	Exciter No. 5 Test Supply
6504	Cutler-Hammer	GBH	15A	Powerhouse Vent Fan (3 HP)
6505	Cutler-Hammer	GBH	15A	Spherical Valve No. 5 By-Pass Motor (1.3 HP)
6506	Cutler-Hammer	GBH	40A	Spare
6507	Cutler-Hammer	GBH	40A	Spare
6508	Cutler-Hammer	GBH	70A	No. 5 Cooling Water Pump (30 HP)
6509	Cutler-Hammer	GBH	50A	Lighting Panel G (25kVA)
6510	Cutler-Hammer	GBH	100A	Trf. Deck & Basement Receptacles

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Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

Panelboard 6600 (Unit #6 Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6611	Cutler-Hammer	FDB	225A	Main Brk (300 MCM Cable Infeed)
6601	Cutler-Hammer	GBH	15A	Exciter No. 6 Test Supply
6602	Cutler-Hammer	GBH	15A	Spare
6603	Cutler-Hammer	GBH	50A	Spare
6604	Cutler-Hammer	GBH	15A	Powerhouse Vent Fan (3 HP)
6605	Cutler-Hammer	GBH	40A	Spare
6606	Cutler-Hammer	GBH	50A	Lighting Panel H (25kVA)
6607	Cutler-Hammer	GBH	15A	Spherical Valve No. 6 By-Pass Motor (1.3 HP)
6608	Cutler-Hammer	GBH	100A	Trf. Deck & Basement Receptacles
6609	Cutler-Hammer	GBH	150A	Cooling Water Pump No. 6 (30 HP)
6610	Cutler-Hammer	GBH	150A	Cooling Water Pump No. 4 (30 HP)
6612	Cutler-Hammer	GBH		Spare

Panelboard 6700 (General Purpose)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6713	Federal Pioneer	NFJ	225A	Main Brk (300 MCM Cable Infeed)
6701	Federal Pioneer	NF	15A	Spare
6702	Federal Pioneer	NF	125A	230kV Switchgear Lighting
6703	Federal Pioneer	NF	125A	Powerhouse Crane
6704	Federal Pioneer	NF	100A	Trf Deck Receptacles
6705	Federal Pioneer	NF	70A	Heating Trf G (37.5kVA)
6706	Federal Pioneer	NF	70A	Lighting Panel A (37.5kVA Trf)
6707	Federal Pioneer	NF	15A	Trf Deck Street Lights
6708	Federal Pioneer	NF	40A	Spare
6709	Federal Pioneer	NF	40A	Office Area Air Conditioning Unit
6710	Federal Pioneer	NF	40A	Office Area Air Conditioning Unit (30 kW)
6711	Federal Pioneer	NF	70A	Lighting Panel B (37.5kVA Trf)
6712	Federal Pioneer	NF	70A	Air Conditioner Panel I
6714	Federal Pioneer	NF	225A	Spare

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Powerhouse No. 1 & No. 2

4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

Panelboard 6800 (Non-Essential)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6812	Federal Pioneer	NFJ	225A	Main Brk (300 MCM Cable Infeed)
6801	Federal Pioneer	NF		Spare
6802	Federal Pioneer	NF	70A	GP Receptacle OS Wall South Repair Bay
6803	Federal Pioneer	NF	40A	Heating Air Conditioner Control Room
6804	Federal Pioneer	NF	40A	Air Conditioner Control Room
6805	Federal Pioneer	NF	70A	GP Receptacle OS Wall South Repair Bay
6806	Federal Pioneer	NF	15A	South End Powerhouse Door
6807	Federal Pioneer	NF	100A	Heating Trf J (37.5kVA)
6808	Federal Pioneer	NF	100A	Compressor Room
6809	Federal Pioneer	NF	30A	Main Entrance & Road Lighting
6810	Federal Pioneer	NF	70A	Spare
6811	Federal Pioneer	NF	175A	Spare

Panelboard 6900 (Non-Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
6913	Federal Pioneer	NFJ	225A	Main Brk (300 MCM Cable Infeed)
6901	Federal Pioneer	NF	15A	Spare
6902	Federal Pioneer	NF	40A	GP Receptacle
6903	Federal Pioneer	NF	30A	North End Ph & Trans Deck Lighting
6904	Federal Pioneer	NF	225A	Spare
6905	Federal Pioneer	NF	40A	North End Repair Bay Main Door
6906	Federal Pioneer	NF	40A	Fish Hatchery GTB Pumps
6907	Federal Pioneer	NF	100A	Electrical Shop North End (Panel 6907-A)
6908	Federal Pioneer	NF	100A	GP Receptacle
6909	Federal Pioneer	NF	70A	Spare
6910	Federal Pioneer	NF	100A	Fish Hatchery SAC Pumps
6911	Federal Pioneer	NF		Spare
6912	Federal Pioneer	NF	25A	Spare
6914	Federal Pioneer	NF		Spare
6915	Cutler-Hammer	HFD	200A	Emg Feed Unit #7 via Booster Trans (3-ph, 200A)

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4. Station Service Fault Protection - Powerhouse No. 1

Station Service Panelboards

Panelboard 7000 (General Purpose)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
Main Brk	Cutler-Hammer	FDB	400A	Main Brk (500 MCM Cable Infeed)
7001	Cutler-Hammer	GBH	40A	Gen Room Heaters (2 x 10kW)
7002	Cutler-Hammer	GBH	40A	Basement Emg Diesel Heaters (3 x 10kW)
7003	Cutler-Hammer	GBH	60A	Gen Room Heaters (5 x 10kW)
7004	Cutler-Hammer	GBH	40A	Gen Room Heaters (3 x 10kW)
7005	Cutler-Hammer	GBH	60A	SV #5 Gen Rm Basement Heaters (4 x 10kW)
7006	Cutler-Hammer	GBH	60A	SV #6 Gen Rm Basement Heaters (4 x 10kW)
7007	Cutler-Hammer	GBH	60A	Gen Room, Elect Shop, Bus Tunnel And Comp Room Heaters (3 x 10kW)
7008	Cutler-Hammer	GBH	40A	Gen Room Basement (2 x 10kW)
7009	Cutler-Hammer	GBH	40A	Electrical Shop Heaters (3 x 10kW)
7010	Cutler-Hammer	GBH	40A	North End Repair Bay Heater (30kW)
7011	Cutler-Hammer	GBH	40A	Lunch Rm & North End Lgt Panel (37.5kVA Trf)
7012	Cutler-Hammer	GBH	30A	Utilidor Heater (20kW)
7013	Cutler-Hammer	GBH	40A	Spare
7014	Cutler-Hammer	GBH	40A	Spare
7015	Cutler-Hammer	GBH	30A	Heater Near Battery Room (20kW)
7016	Cutler-Hammer	GBH		Spare

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Powerhouse No. 1 & No. 2

5. Station Service Fault Protection - Powerhouse No. 2

Station Service Transformer SST4

The normal source of supply for the main 600V station service bus in Powerhouse No. 2 is the outside station service transformer SST4 which consists of a bank of 3 x 167kVA pole top distribution units. The high voltage side (25kV) fuses for that transformer bank do not coordinate very well with the incoming 600V breaker 52SS4 and to increase the fuse rating would limit the fault protection for those distribution transformers. Refer to **Appendix G** for plots of those fuse curves and the incoming 600V breaker 52SS4. As well, this bank of distribution transformers is connected as wye grounded on the 25kv side and closed delta on the 600V side thus they act as a source of ground fault current for the local 25kV distribution system in St. Alban's. The 25kV breaker associated with station service transformer SST4 is sensitive enough to operate for this ground fault current since it does not have a directional current function. The result would be the lose of station service supply from SST4.

Station Service Transformer SST3

The alternate source of supply for the main 600V station service bus in Powerhouse No. 2 is the station service transformer SST3 associated with hydro generating Unit No. 7 and rated at 750/1000kVA with a delta/delta winding configuration. The fault clearing device for this station service transformer would be the 13.8kV air blast breaker 52AT-3 and its isolation switch 29AT-3. The protective relay used for this air blast breaker is the GE type IAC55 which is late 1970's vintage.

The table below is a listing of the protective relay settings for the 13.8kV air blast breaker.

13.8kV Station Service Breakers Protective Relay Settings

Breaker Number	CT Ratio	Relay Info.	Relay Settings			Application Notes
		Type	Pickup	Delay	Inst	
52AT-3	200/5A	GE IAC55	6A	10	-	Trip Setting = 5.74 MVA

The existing GE IAC55 protective relay settings for breaker 52AT-3 are set very high when compared to the rating of the station service transformer which are 7 ½ times the transformer base rating of 0.75 MVA thus these relay settings do not provide adequate backup protection for SST3 including close-in faults on the 600V side. Refer to **Appendix H** for plots of those relay curves. This fault protection issue can be improved by changing the existing IAC55 relay to an IAC 53 (very inverse) type and implementing the protective relay settings as listed in the table below.

13.8kV Station Service Breakers Protective Relay Settings

Breaker Number	CT Ratio	Relay Info.	Relay Settings			Application Notes
		Type	Pickup	Delay	Inst	
52AT-3	200/5A	GE IAC53	3A	6	40A	Trip Setting = 2.87 MVA

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

5. Station Service Fault Protection - Powerhouse No. 2

Main Station Service Switchboard

The Main Station Service Switchboard in Powerhouse No. 2 has five cells with two of those for incoming supply breakers, one for a bus tie breaker and the remaining two cells for main station service panelboards which supply the various station service panelboards within the powerhouse. The breaker used for the incoming supply and bus tie is an ITE type K-1600 rated 42kA short circuit (sym.) which has a 1600A frame size and a current sensor of 1600A. The incoming supply breaker 52SS4 is fitted with a Westinghouse Amptector I-A overcurrent trip unit whereas the incoming supply breaker 52SS3 is fitted with ITE Current Shield type overcurrent relays one being a time delay type 51IM and the other an instantaneous type 50D.

The tables below are a listing of the protective relay settings for the two incoming supply breakers.

Main Station Service Switchboard Breaker 52SS3 Protective Relay Settings

Breaker Number	CT Ratio	Relay Info.		Relay Settings		Application Notes
		Type	Rating	Pickup	Delay	
52SS3	600/5A	ITE 51IM		10A	6	Trip = 1200A
52SS3	600/5A	ITE 50D	8A	5 x Rating	0.5	Trip = 4800A

Main Station Service Switchboard Breaker 52SS4 Protective Relay Settings

Breaker Number	Sensor Tap Rating	Short Time Settings		Long Time Settings		Inst. Setting
		Pickup	Delay	Pickup	Delay	Pickup
52SS4	1600A	4	0.33	1	12	6

In order to provide better fault protection coordination with the protective relay settings proposed for the 13.8kV station service breaker 52AT-3 then the protective relay settings for breaker 52SS3 have to be revised accordingly. Thus for the ITE 51IM protective relay its time delay would be changed from 6 to 1 and for the ITE 50D protective relay its pickup would be increased from 40A to its the maximum setting of 80A. These new protective relay settings also coordinate with the 225A molded case breakers for the two main station service panelboards, 7000 (East) and 7000 (West). Refer to **Appendix I** for plots of those relay curves.

Likewise, the Amptector I-A trip settings for breaker 52SS4 would better coordinate with the two main station service panelboards, 7000 (East) and 7000 (West) if its short time delay is set at 0.5 seconds and instantaneous to 12 or 19,200A. This effectively blocks the instantaneous element from operating.

The tables below are a listing of the recommended protective relay settings for the incoming supply breakers.

Main Station Service Switchboard Breaker 52SS3 Protective Relay Settings

Breaker Number	CT Ratio	Relay Info.		Relay Settings		Application Notes
		Type	Rating	Pickup	Delay	
52SS3	600/5A	ITE 51M		10	1	Trip = 1200A
52SS3	600/5A	ITE 50D	8A	10 x Rating	0.5	Trip = 9,600A

Main Station Service Switchboard Breaker 52SS4 Protective Relay Settings

Breaker Number	Sensor Tap Rating	Short Time Settings		Long Time Settings		Inst. Setting
		Pickup	Delay	Pickup	Delay	Pickup
52SS4	1600A	4	0.5	1	12	12

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

5. Station Service Fault Protection - Powerhouse No. 2

Main Station Service Switchboard

The two main station service panelboards 7000 (East) and 7000 (West) are an ITE type CDP each rated at 1200A. The existing molded case circuit breakers for both of these panelboards do not coordinate very well with each of the downstream panelboards as they have a fixed overcurrent trip setting as compared to a more modern molded case circuit breaker with an electronic trip unit. Examples of the miscoordination between the main breaker and its panelboard breakers within Powerhouse No. 2 are shown in **Appendix J**.

The tables below are a listing of the branch circuit breakers for each main station service panelboard.

Main Station Service Panelboard 7000 (West)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7001	Federal Pioneer	NFJ	225A	Spare
7002	Federal Pioneer	NFJ	225A	Spare
7003	Federal Pioneer	NFJ	225A	Transfer Switch 7017 (400A)
7004	Federal Pioneer	NFJ	225A	Transfer Switch 7018 (400A)
7005	Federal Pioneer	NFJ	225A	Transfer Switch 7028 (400A)
7006	Federal Pioneer	NFJ	225A	Spare
7007	Federal Pioneer	NFJ	225A	Transfer Switch 7027 (400A)
7008	Federal Pioneer	NFJ	225A	Spare

Main Station Service Panelboard 7000 (East)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7009	Federal Pioneer	NFJ	225A	Spare
7010	Federal Pioneer	NFJ	225A	Transfer Switch 7027 (400A)
7011	Federal Pioneer	NFJ	225A	Spare
7012	Federal Pioneer	NFJ	225A	Transfer Switch 7028 (400A)
7013	Federal Pioneer	NFJ	70A	Spare
7014	Federal Pioneer	NFJ	225A	Transfer Switch 7017 (400A)
7015	Federal Pioneer	NFJ	225A	Spare
7016	Federal Pioneer	NFJ	225A	Transfer Switch 7018 (400A)

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

5. Station Service Fault Protection - Powerhouse No. 2

Station Service Panelboards

There are five station service panelboards within Powerhouse No. 2 with one being the essential supply for Generating Unit No. 7, one an emergency supply from Powerhouse No. 1 and the remainder considered general purpose including backup as required for various heating, lighting, and other motor loads within the powerhouse.

The tables below are a listing of the various breakers types and ratings for those five station service panelboards.

Panelboard 7100 (Unit #7 Essential Service)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7101	Square D	FA		Spare
7102	Square D	FA		Spare
7103	Square D	FA	40A	Synchronous Condenser Blower
7104	Square D	FA	15A	125Vdc Battery Charger
7105	Square D	FA	15A	Spare
7106	Square D	FA	15A	Standby Compressor
7107	Square D	FA	15A	Jockey Pump (3HP)
7108	Square D	FA	15A	Unit 7 Exciter A.C. Field Flashing
7109	Square D	FA	15A	Station Services Air Compressor (10HP)
7110	Square D	FA	15A	F1 Exhaust Fan Above Unit 7 (5HP)
7111	Square D	FA	15A	Spare
7112	Square D	FA	20A	Sump Pump (10HP)
7113	Square D	FA	40A	Blower Heaters (2 x 10kW)
7114	Square D	FA	50A	172 MVA Power Trans Fan Control
7115	Square D	FA	70A	Draft Tube Dewatering Pump No. 1 (40HP)
7116	Square D	FA	70A	Governor Oil Pump (40HP)
7117	Square D	FA	70A	Lighting Panels C & C-C Transformer (37.5kVA)
7118	Square D	FA	70A	Draft Tube Dewatering Compressor (50HP)
7119	Square D	FA	100A	Standby Fire Pump (50HP)
7120	Square D	FA	100A	600V Receptacles
7121	Square D	FA	100A	600V Receptacles
7122	Square D	FA	100A	600V Receptacles

Panelboard 7200 (Unit #7 Emergency Supply)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7201	Square D	NFJ	225A	Spare
7202	Square D		225A	Emergency Feed For Panel 7100
7203	Square D	FA	100A	Spare
7204	Square D	FA	15A	Battery Charger No. 1

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

5. Station Service Fault Protection - Powerhouse No. 2

Station Service Panelboards

Panelboard 7300 (Unit #7 Repair Bay)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7301	Square D	FA		Spare
7302	Square D	FA		Spare
7303	Square D	FA		Spare
7304	Square D	FA		Spare
7305	Square D	FA	30A	Repair Bay West
7306	Square D	FA	70A	Elevation 12'-0"
7307	Square D	FA	100A	Powerhouse Crane
7308	Square D	FA	100A	Receptacles Repair Bay West & North
7309	Square D	FA	40A	Blower Heaters Repair Bay West (3 x 10kW)
7310	Square D	FA	15A	Repair Bay Door Hoist

Panelboard 7400 (Unit #7 Powerhouse)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7401	Square D	FA	15A	Unit No. 7 Exciter Test Supply
7402	Square D	FA	15A	Battery Charger #1
7403	Square D	FA	50A	Lighting Panels B & B-B Transformer (25kVA)
7404	Square D	FA	100A	Receptacles Dewatering Shaft & EL. 12'-0"
7405	Square D	FA	100A	Receptacles North & East, Repair Bay East
7406	Square D	FA	70A	Blower Heaters EL. 26'-0" (5 x 10kW)
7407	Square D	FA	50A	Blower Heaters Repair Bay East (4 x 10kW)
7408	Square D	FA	40A	Blower Heaters Untanking Area (2 x 10kW)
7409	Square D	FA	15A	Exhaust Fan Above Repair Bay (5 HP)
7410	Square D	FA	30A	Sump Tunnel Heating

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

5. Station Service Fault Protection - Powerhouse No. 2

Station Service Panelboards

Panelboard 7500 (Unit #7 Powerhouse)

Breaker Number	Breaker Manuf.	Breaker Type	Breaker Rating	Comments
7501	Square D	FA	15A	SS Air Compressor Changeover Switch
7502	Square D	FA	15A	Draft Tube Gate Hoist Control
7503	Square D	FA	30A	Pumphouse East EL. 4'-0"
7504	Square D	FA	40A	Blower Heaters EL 4' & 12' (2 x 5kW, 2 x 10kw)
7505	Square D	FA	15A	Jockey Pump Changeover Switch
7506	Square D	FA	70A	Governor Oil Pump (40 HP)
7507	Square D	FA	70A	Draft Tube Dewatering Pump No. 2 (40 HP)
7508	Square D	FA	70A	Draft Tube Air Compressor Changeover Switch
7509	Square D	FA	100A	Receptacles Untanking Area
7510	Square D	FA	100A	Standby Fire Pump Changeover Switch

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

6. Station Service Breaker BD3-R1

The 25kV station service breaker BD3-R1 is a 1980's vintage Cooper (McGraw Edison) RV hydraulic recloser with 160A phase trip coils and a 63.5A ground trip solenoid and has an interrupting rating of 6kA. This hydraulic recloser has a very limited selection for both phase and ground trip timing operation, thus its sensitivity as backup protection for the station service transformers SSL and SST4 is limited. Refer to **Appendix K** for both the phase and ground trip curves that are typical for this hydraulic recloser as well as plots of the present trip curves being used for fault protection coordination with the power fuses associated with station service transformers SSL. This 25kV station service breaker is also the single source of supply from the main terminal station for both Powerhouse No. 1 and Powerhouse No. 2 thus alternate sources of station service supply within each powerhouse would have to be utilized for any scheduled maintenance or emergency repair of that breaker. It is therefore recommended that the existing 25kV station service breaker be replaced with a new 25kV vacuum breaker with digital control and which has a directional overcurrent function. Implementation of directional overcurrent control would also require 14,400/120V PTs at the 25kV terminal station bus.

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

7. References

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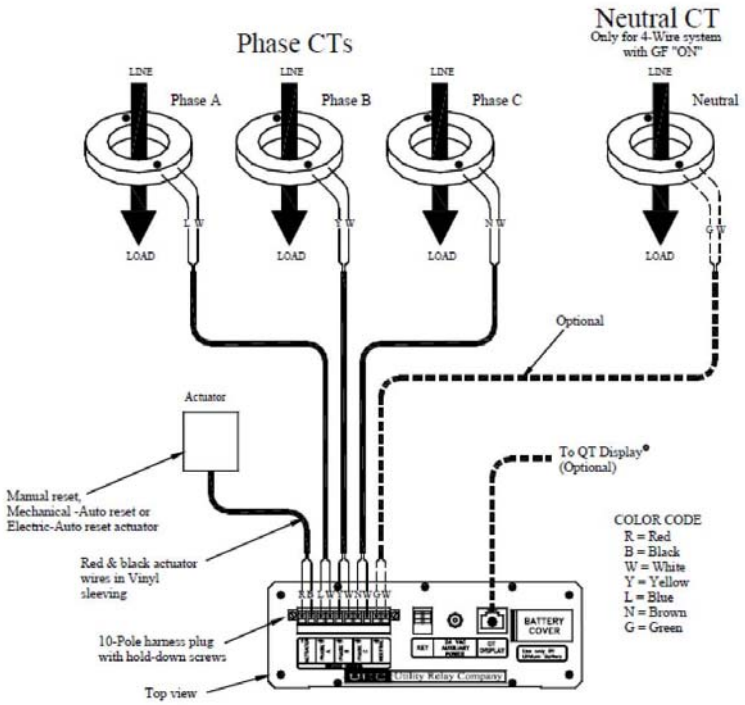
Powerhouse No. 1 & No. 2

Appendix A



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix B

Station Service Panelboards in Powerhouse No. 1

Panelboard Breaker Data

Panelboard Number	Panelboard Circuit Breakers	Breaker Manufacturer	Breaker Type	Breaker Rating (A)	Interrupting Rating (kA)	Fault Level (kA)
ESB1	Main	Siemens	MD6	600	25	32.9
	Branch	Siemens	ED6	15 - 100	18	32.9
ESB2	Main	Siemens	MD6	600	25	32.4
	Branch	Siemens	ED6	15 - 100	18	32.4
6100	Main	Cutler Hammer	FDB	225	14	28.6
	Branch	Cutler Hammer	GBH	15 - 100	10	28.6
6200	Main	FPE	NFJ	225	14	27.4
	Branch	FPE	NF	15 - 100	14	27.4
6300	Main	Cutler Hammer	FDB	225	14	25.4
	Branch	Cutler Hammer	GBH	15 - 100	10	25.4
6400	Main	Cutler Hammer	FDB	225	14	20.9
	Branch	Cutler Hammer	GBH	15 - 100	10	20.9
6500	Main	Cutler Hammer	FDB	225	14	19.9
	Branch	Cutler Hammer	GBH	15 - 100	10	19.9
6600	Main	Cutler Hammer	FDB	225	14	17.8
	Branch	Cutler Hammer	GBH	15 - 100	10	17.8
6700	Main	FPE	NFJ	225	14	28.8
	Branch	FPE	NF	15 - 100	14	28.8
6800	Main	FPE	NFJ	225	14	24.6
	Branch	FPE	NF	15 - 100	14	24.6
6900	Main	FPE	NFJ	225	14	15.8
	Branch	FPE	NF	15 - 100	14	15.8
7000	Main	Cutler Hammer	FDB	400	14	30.3
	Branch	Cutler Hammer	GBH	30 - 60	10	30.3

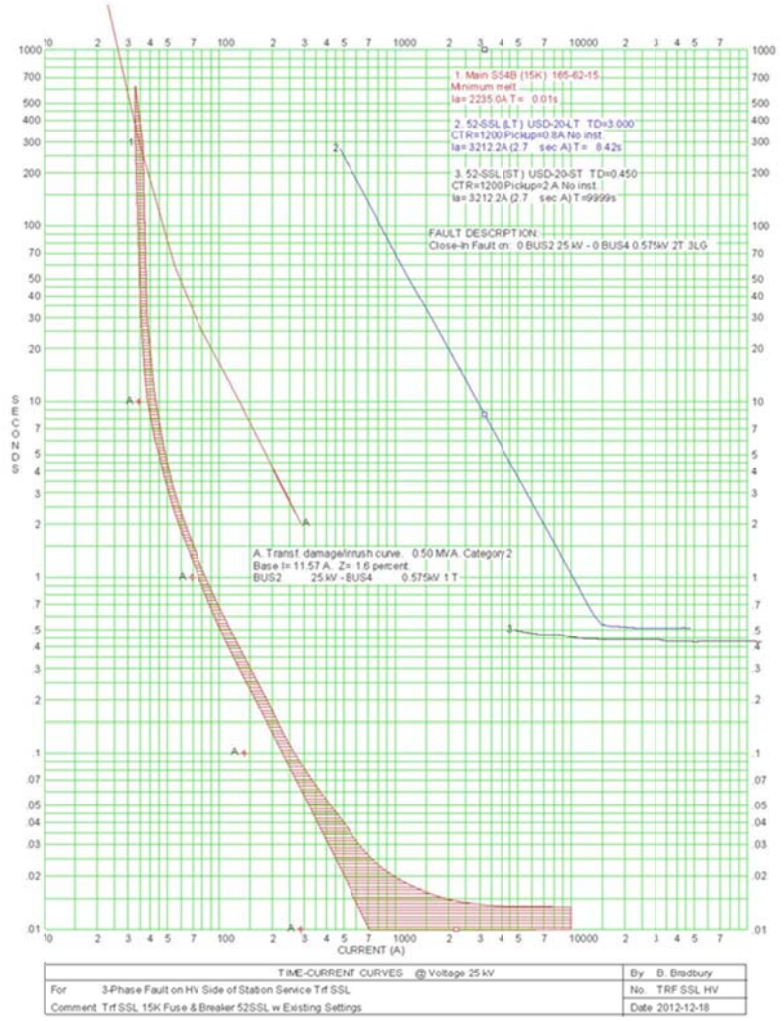
Notes:

1. The fault level listed for each of the above panelboards would be with the powerhouse station service being supplied from the parallel bank of distribution transformers SSL at the main terminal station.
2. The rated short-time withstand current for a molded case circuit breaker is defined by ANSI 37.13 as the maximum RMS current that it can carry momentarily without electrical, thermal or mechanical damage. Under UL 489 for a thermal-magnetic type molded case circuit breaker that rated short-time withstand current is typically lower than its interrupting rating. However, the more modern electronic type molded case circuit breaker has a rated short-time withstand current which is typically comparable to its interrupting rating.

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix C

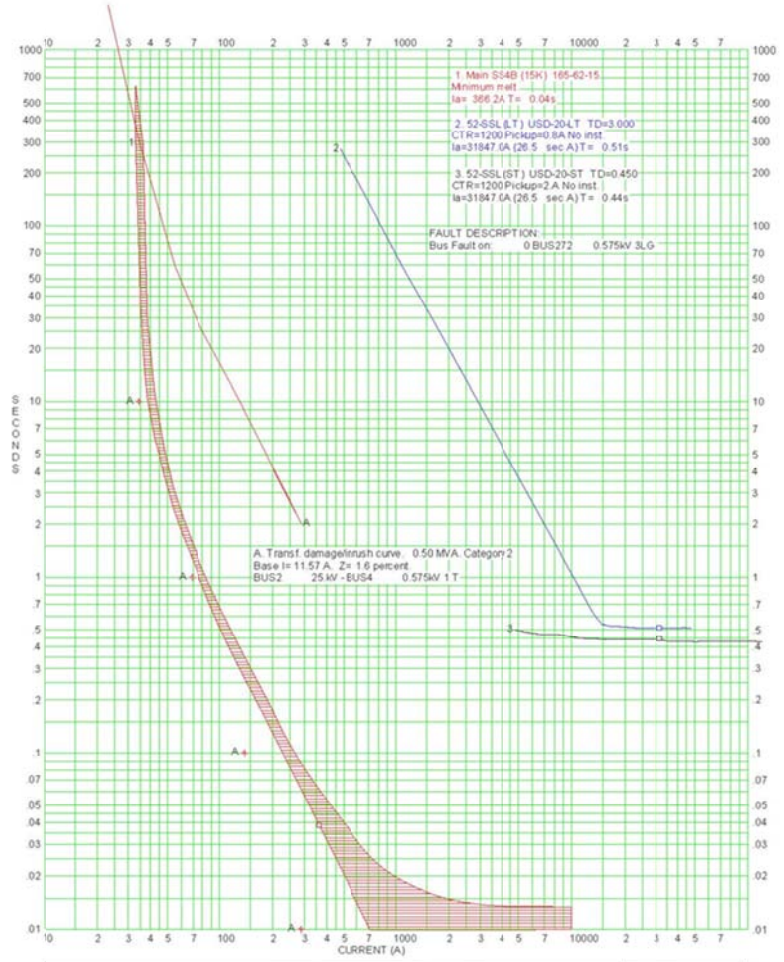
Station Service Transformer SSL



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix C

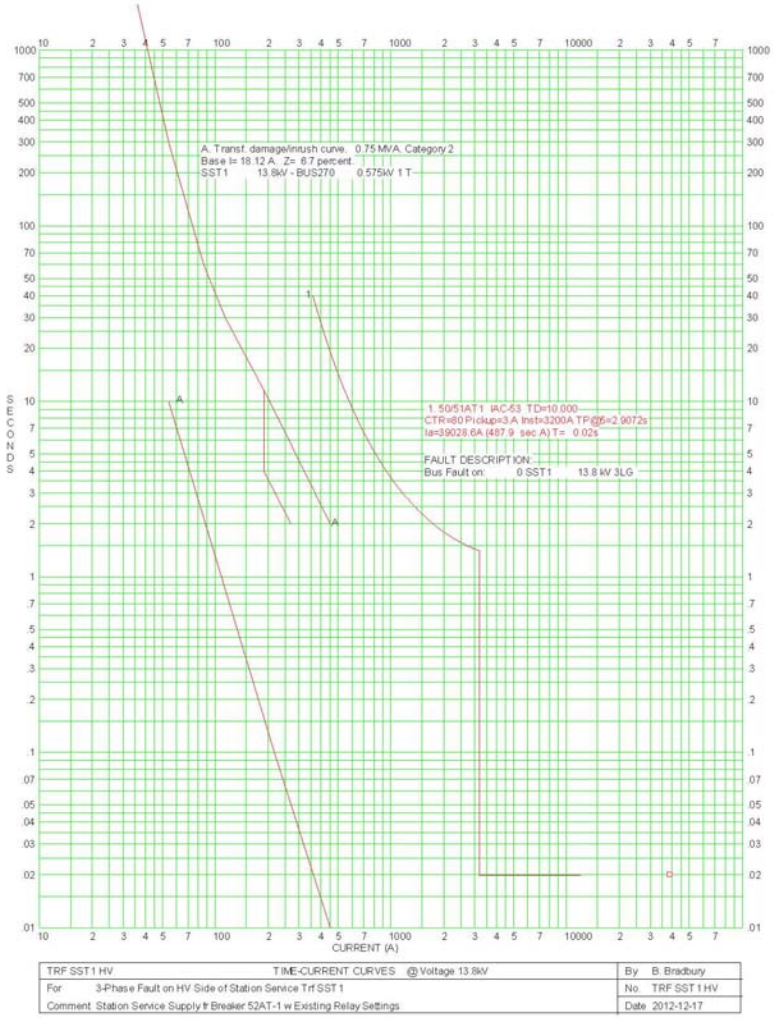
Station Service Transformer SSL



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix D

Station Service Transformer SST1 (Existing Relay Settings)



Bay D'Espoir Station Service Review
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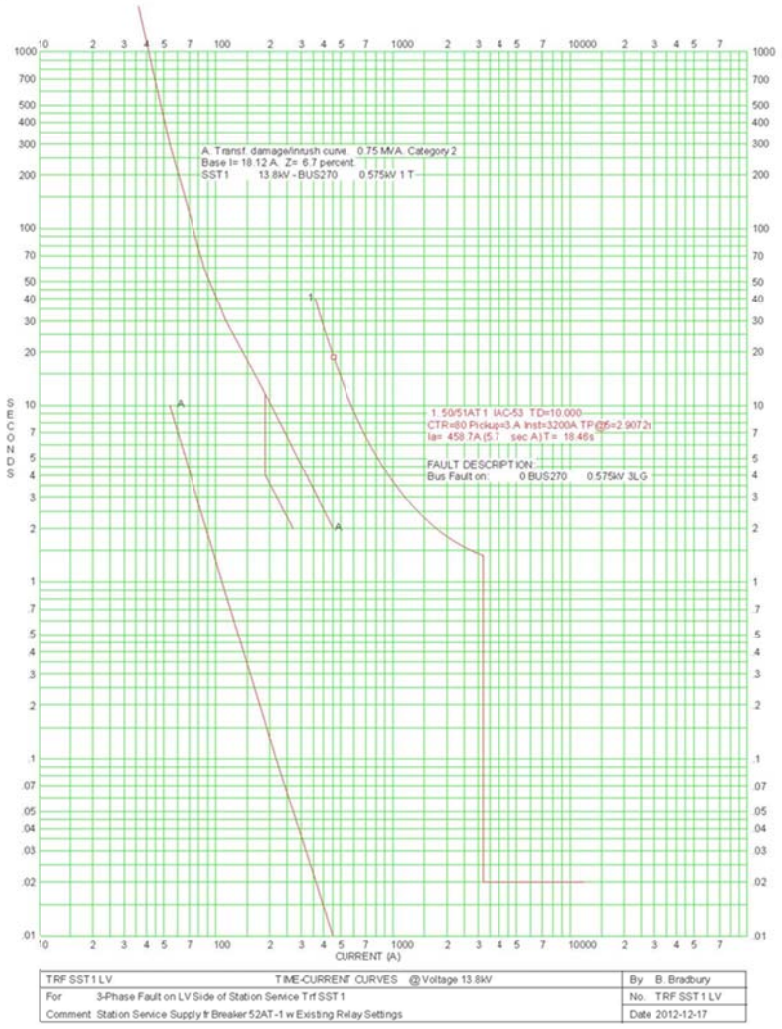
Appendix D

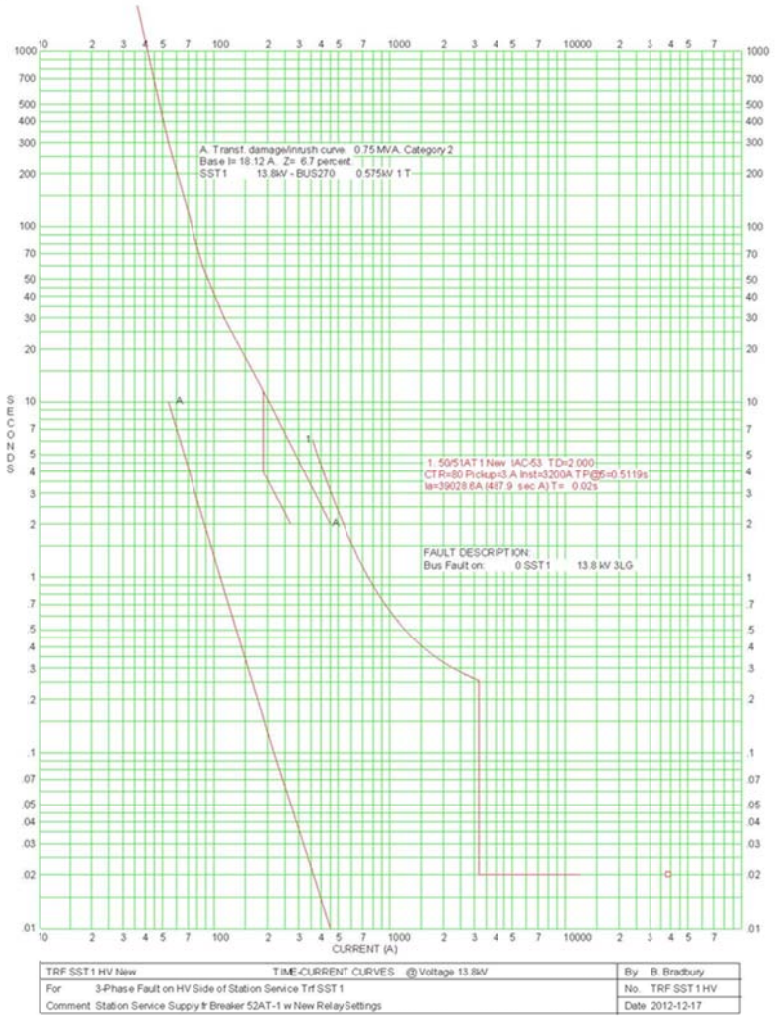
Station Service Transformer SST1 (Existing Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix D

Station Service Transformer SST1 (New Relay Settings)



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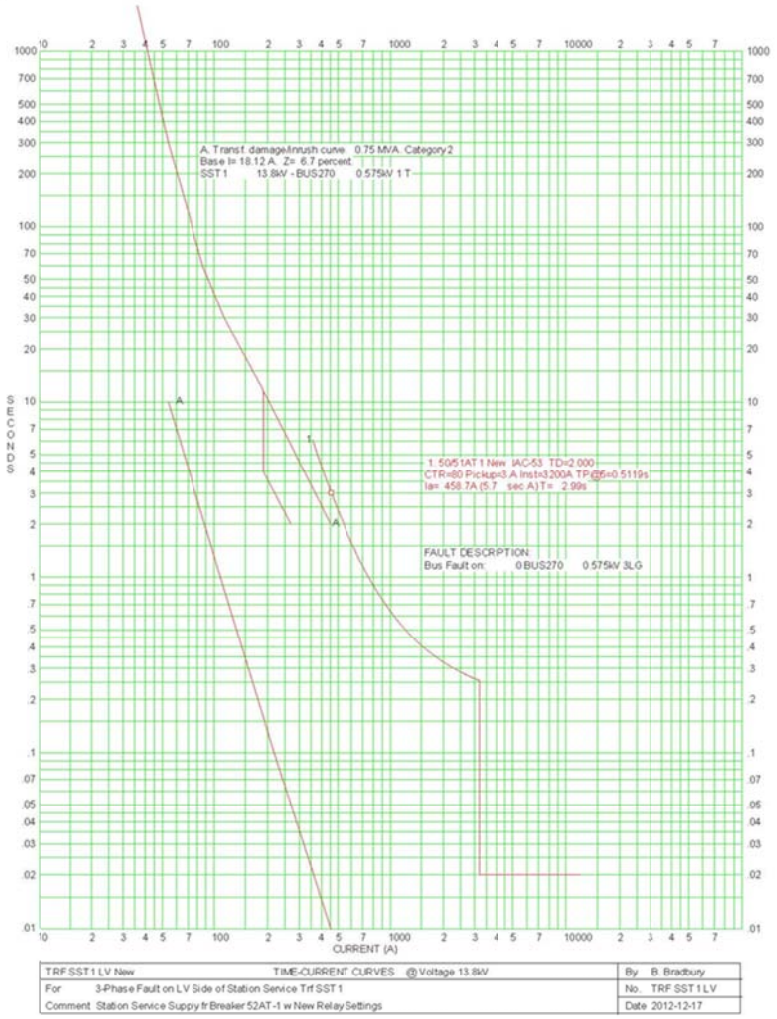
Appendix D

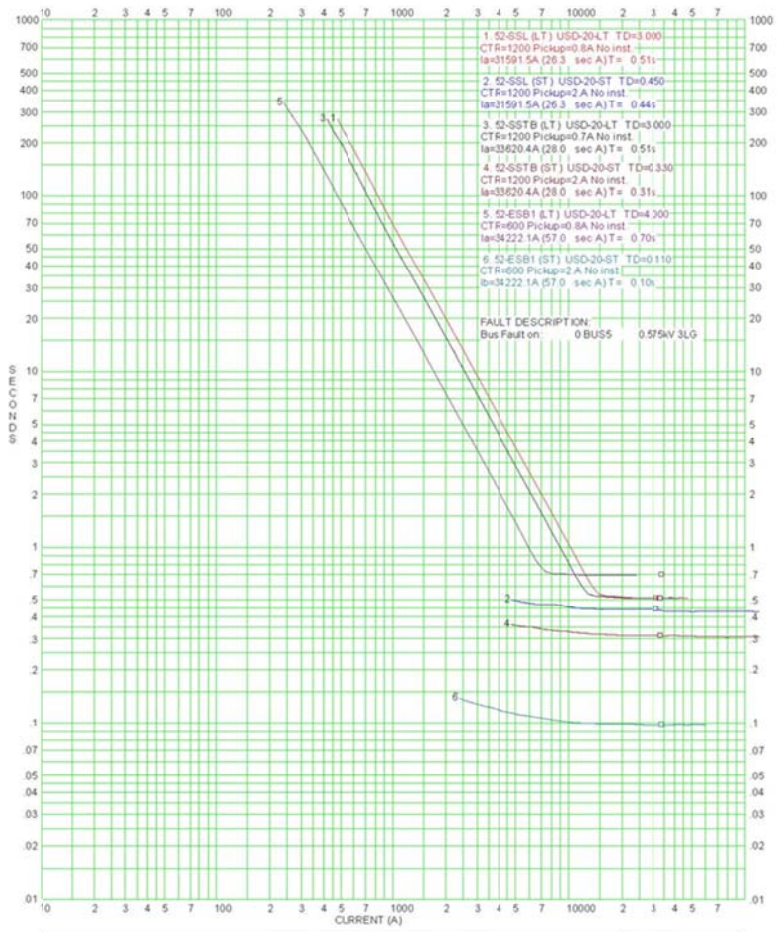
Station Service Transformer SST1 (New Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix E

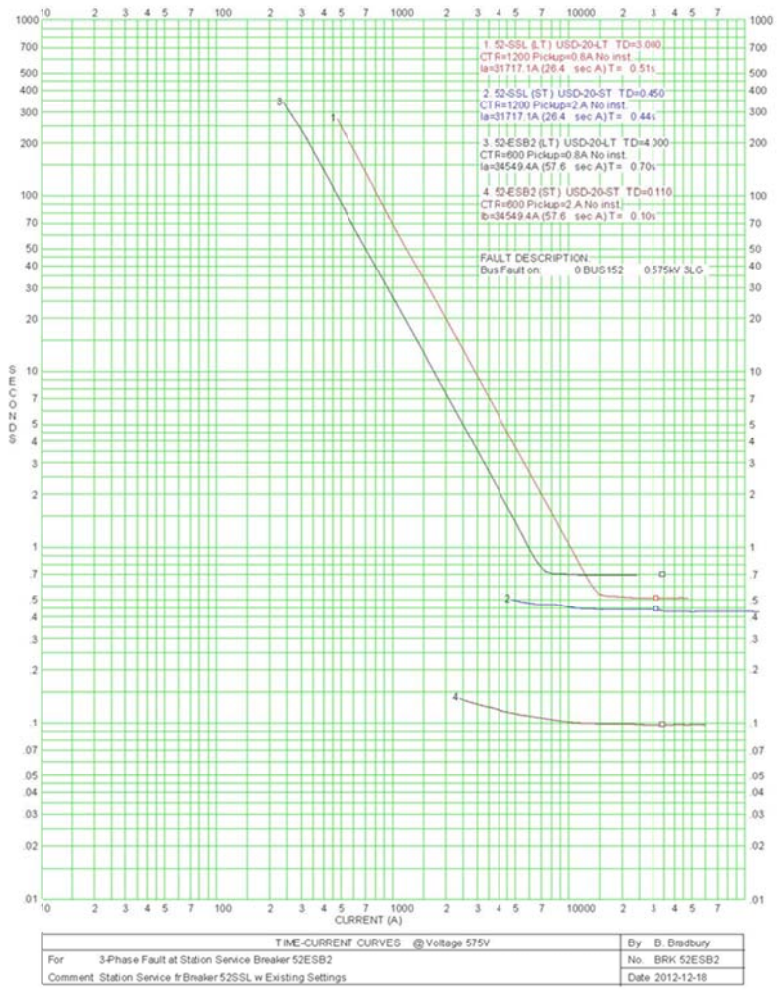
Station Service Breaker 52ESB1 in Powerhouse No. 1



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix E

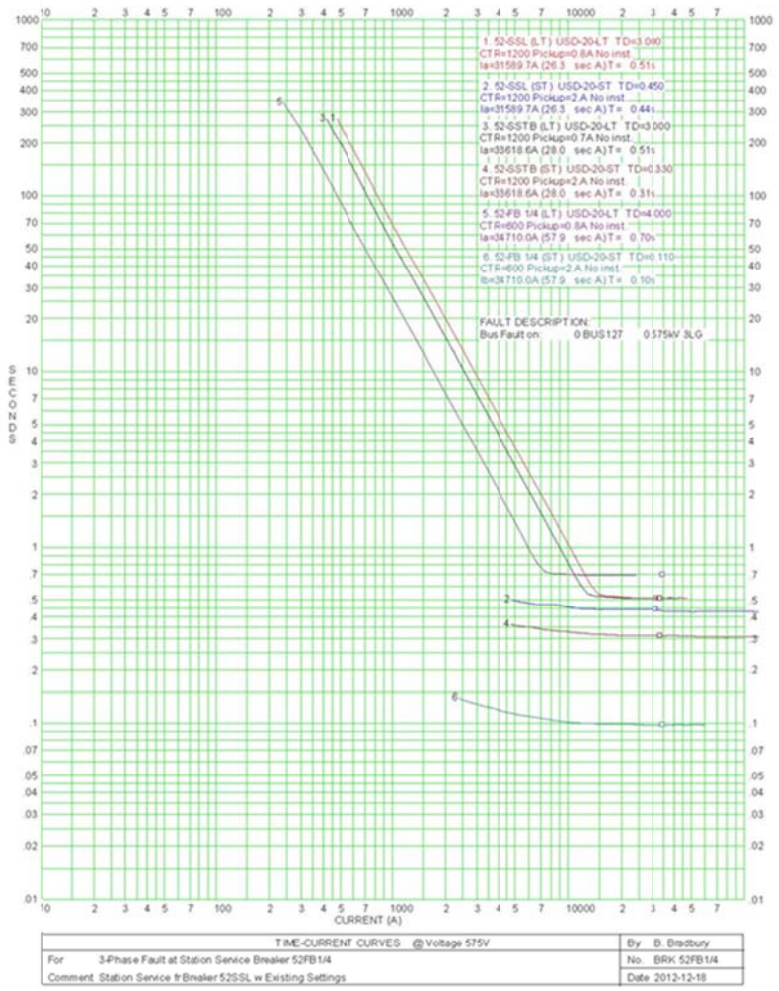
Station Service Breaker 52ESB2 in Powerhouse No. 1



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix E

Station Service Breaker 52FB1/4 in Powerhouse No. 1



Bay D'Espoir Station Service Review
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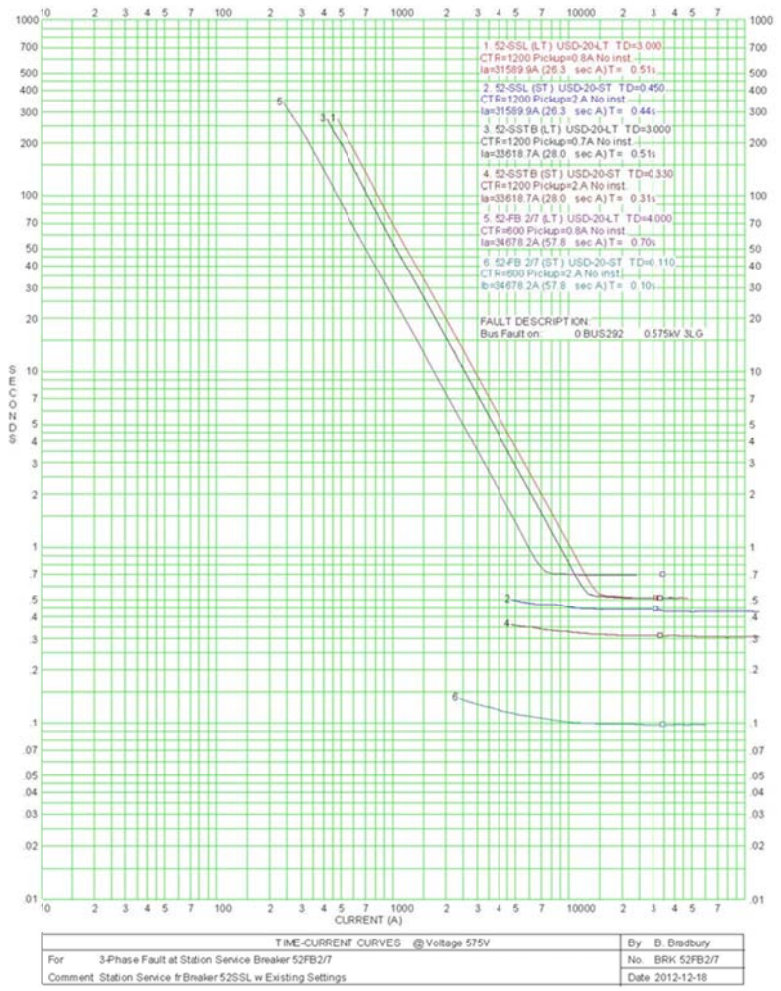
Appendix E

Station Service Breaker 52FB2/7 in Powerhouse No. 1



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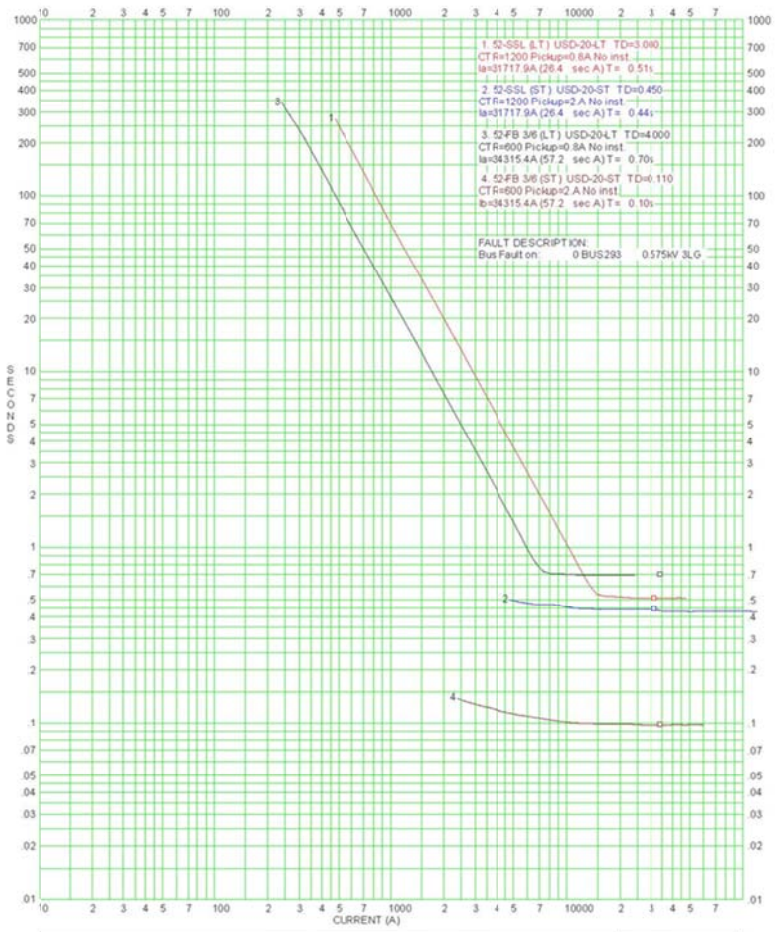
Powerhouse No. 1 & No. 2

Appendix E

Station Service Breaker 52FB3/6 in Powerhouse No. 1



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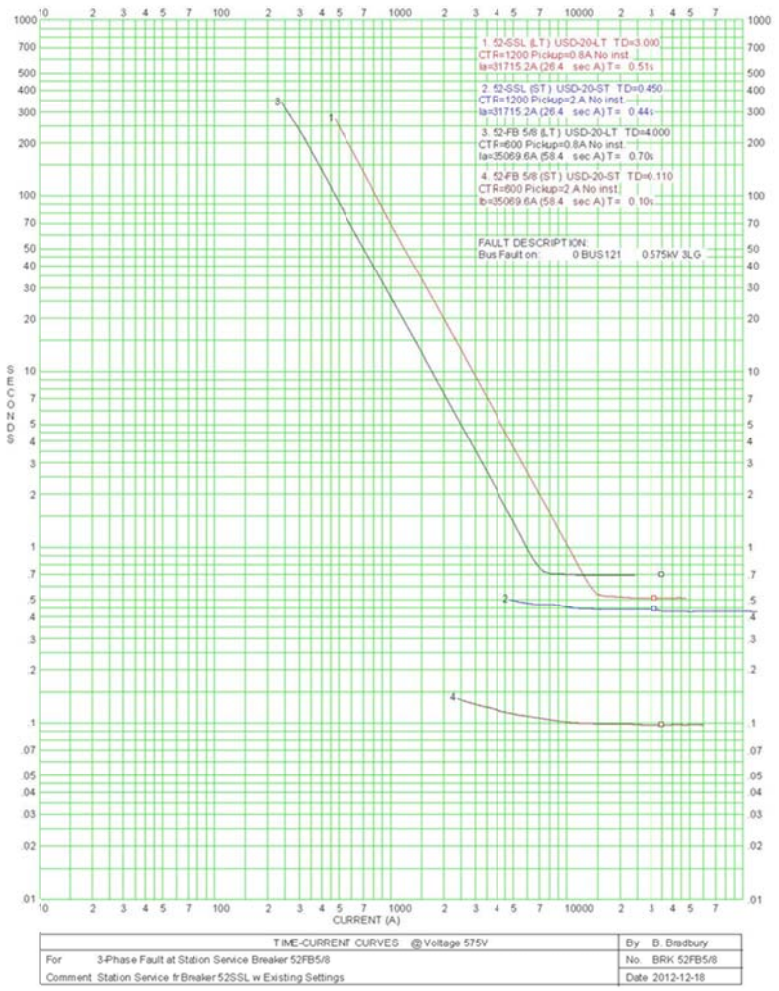
Appendix E

Station Service Breaker 52FB5/8 in Powerhouse No. 1



TIME-CURRENT CURVES @ Voltage 575V	By B. Bradbury
For 3-Phase Fault at Station Service Breaker 52FB5/8	No. BRK 52FB5/8
Comment Station Service fr Breaker 52SSL w Existing Settings	Date 2012-12-18

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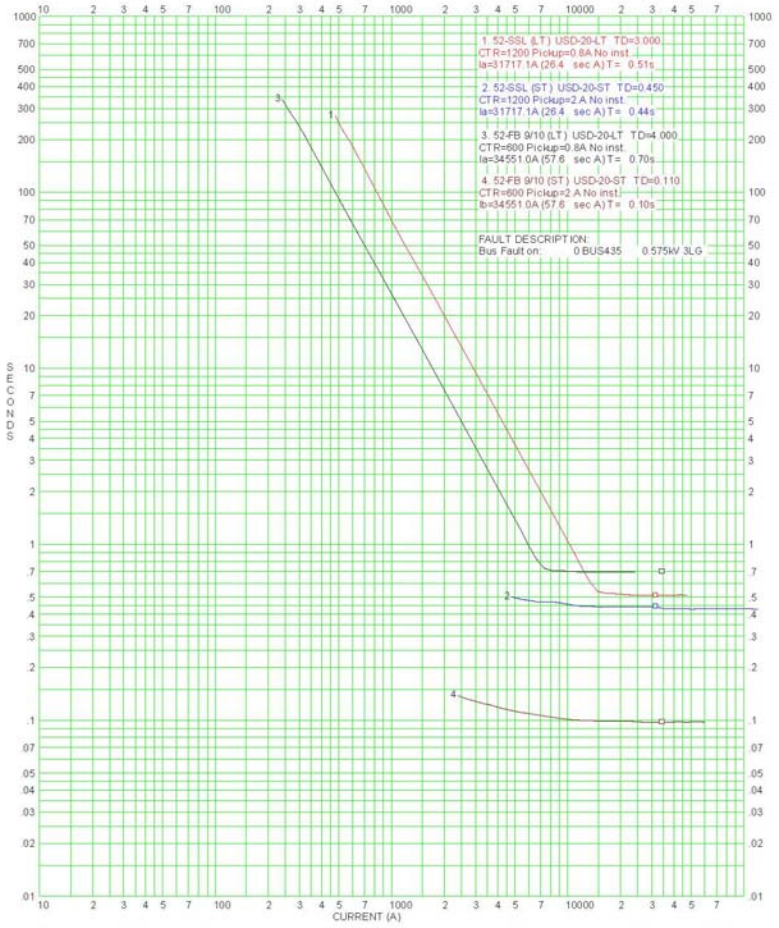
Appendix E

Station Service Breaker 52FB9/10 in Powerhouse No. 1

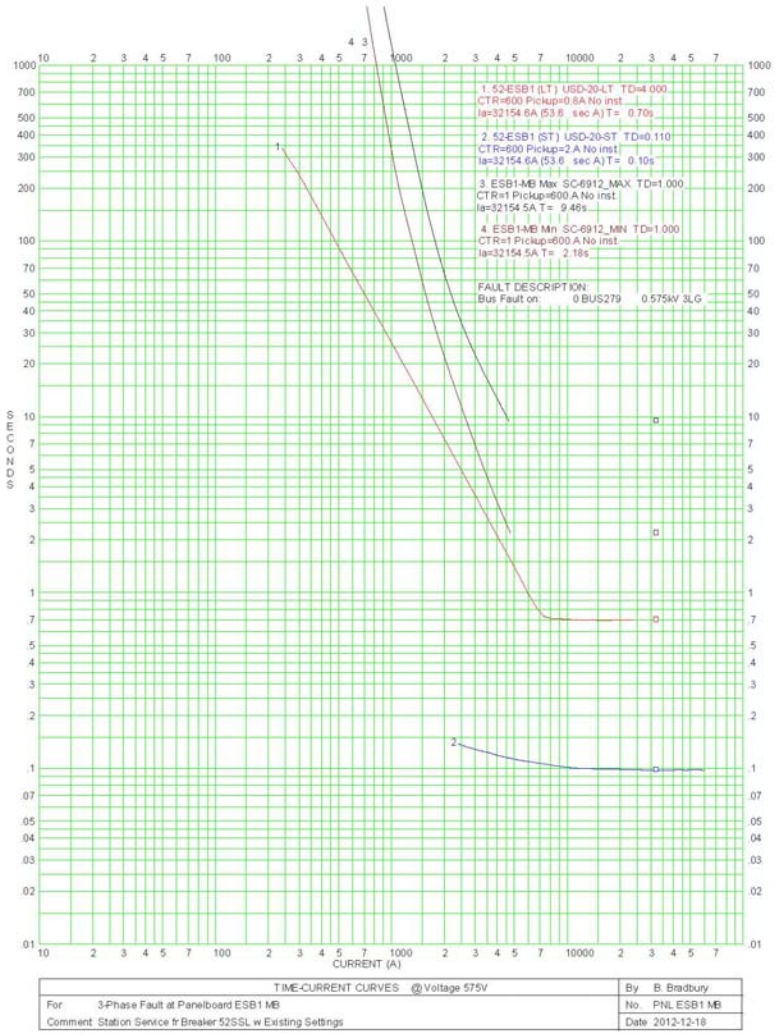


TIME-CURRENT CURVES @ Voltage 575V	By B. Bradbury
For 3-Phase Fault at Station Service Breaker 52FB9/10	No. BRK 52FB9/10
Comment Station Service fr Breaker 52SSL w Existing Settings	Date 2012-12-18

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix E

Station Service Panelboard ESB1 in Powerhouse No. 1



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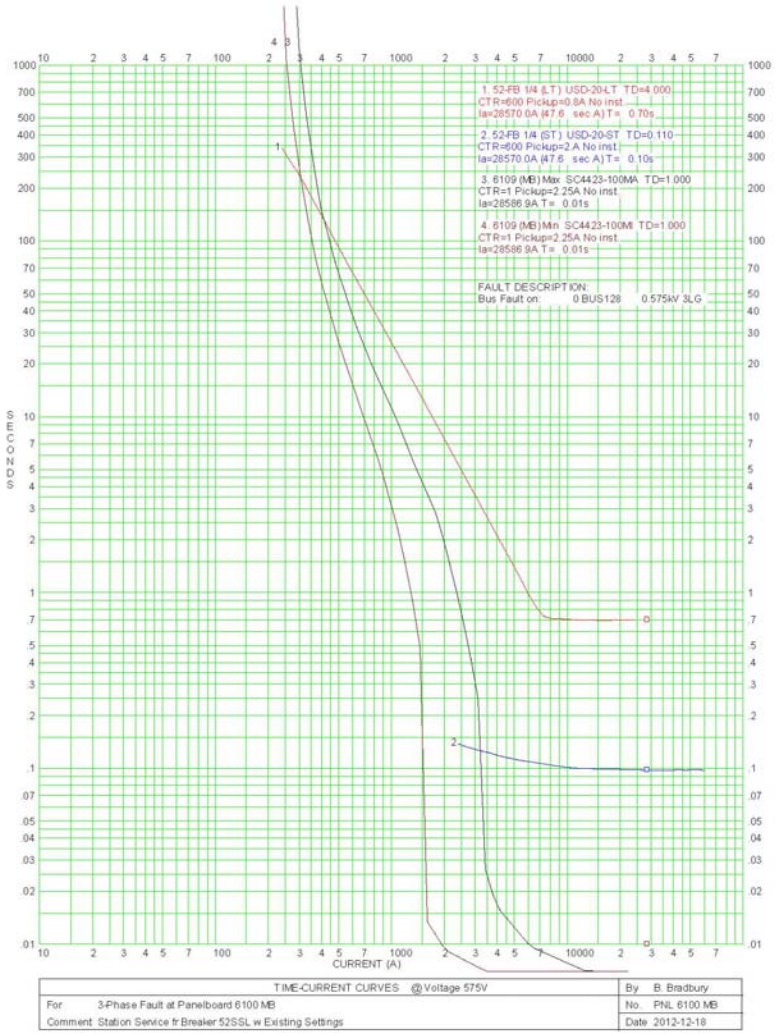
Powerhouse No. 1 & No. 2

Appendix E

Station Service Panelboard 6100 in Powerhouse No. 1



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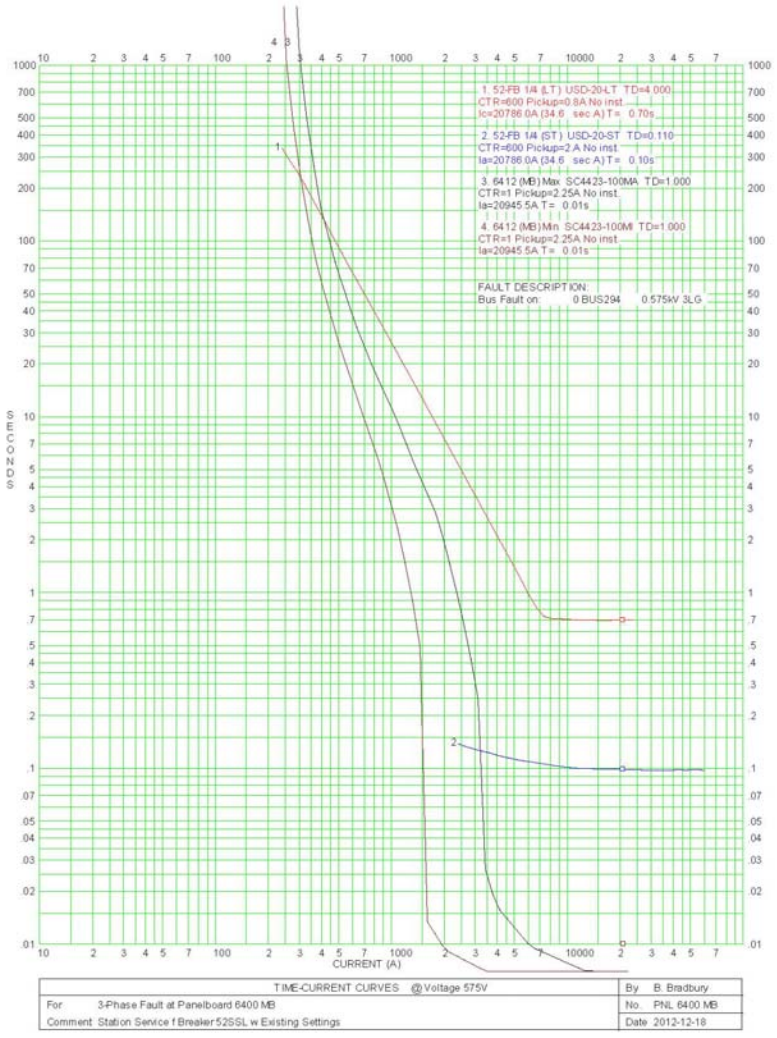
Appendix E

Station Service Panelboard 6400 in Powerhouse No. 1



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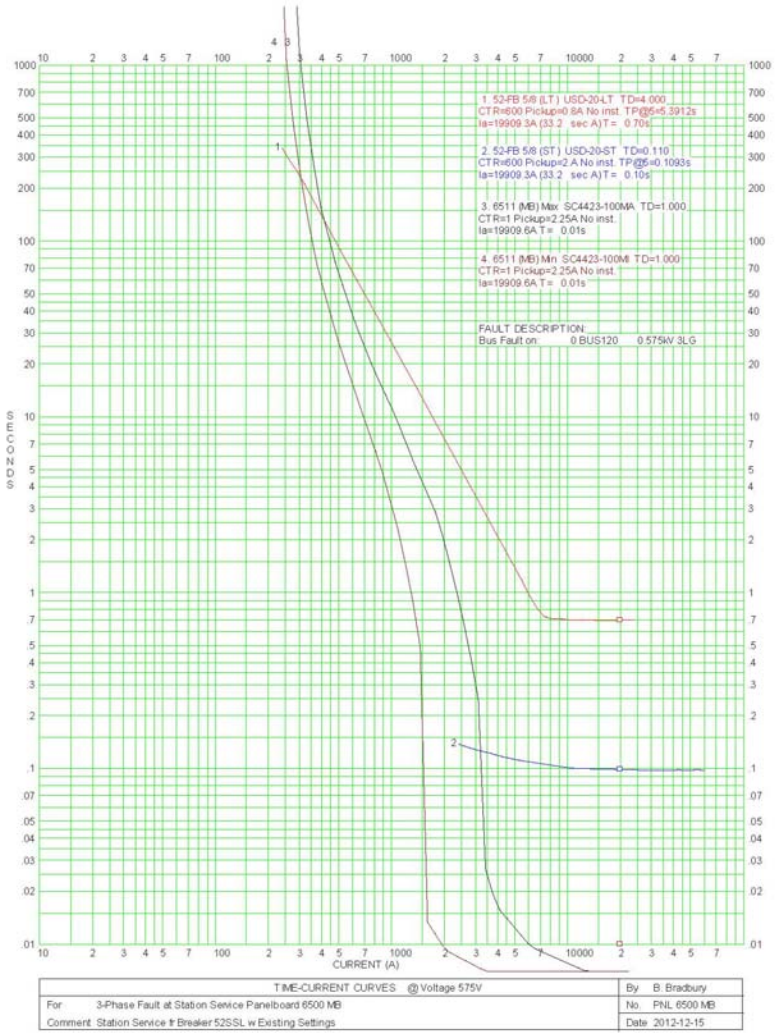
Powerhouse No. 1 & No. 2

Appendix E

Station Service Panelboard 6500 in Powerhouse No. 1



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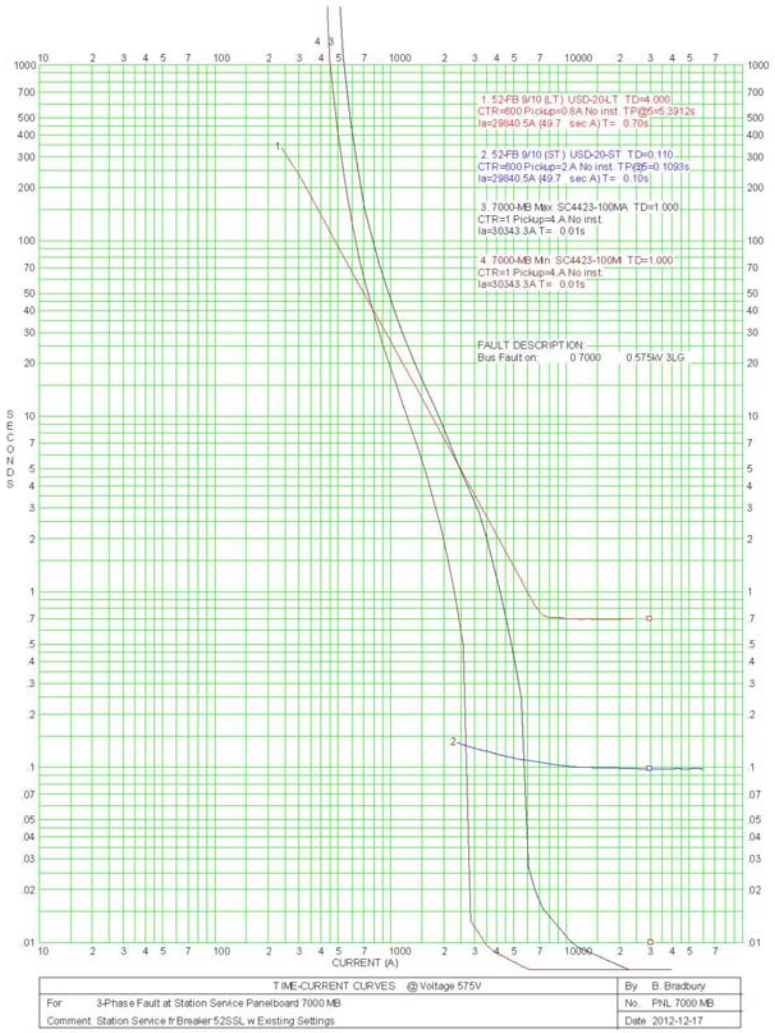
Appendix E

Station Service Panelboard 7000 in Powerhouse No. 1



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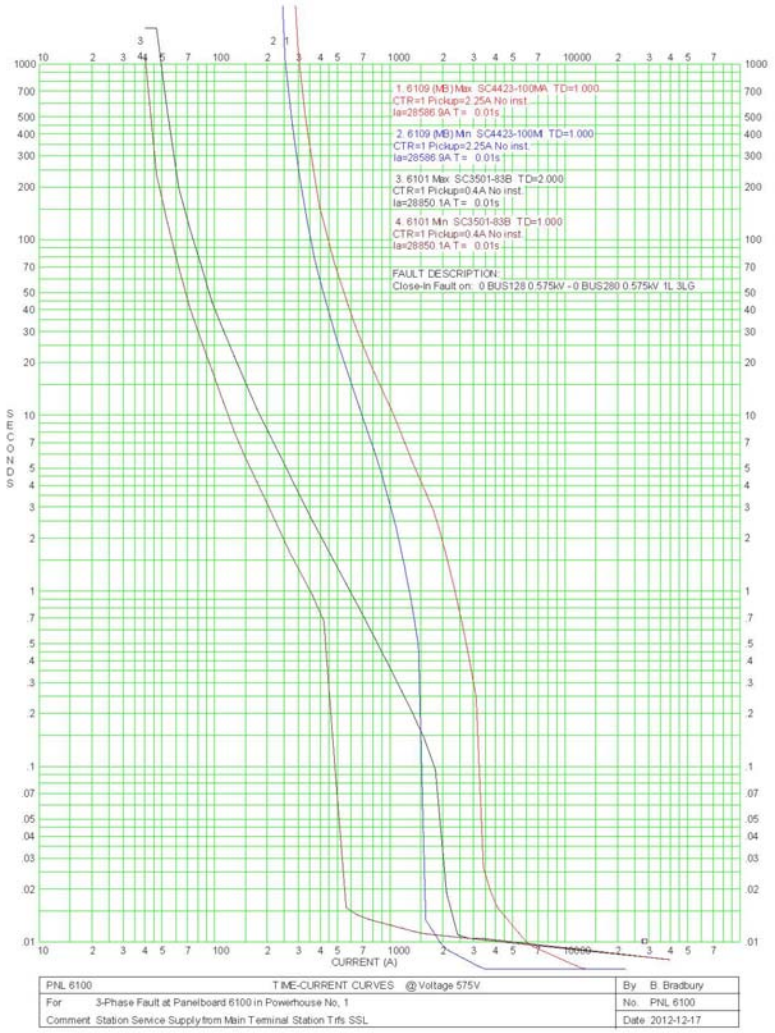
Appendix F

Panelboard 6100 in Powerhouse No. 1



PNL 6100	TIME-CURRENT CURVES @Voltage 575V	By B Bradbury
For 3-Phase Fault at Panelboard 6100 in Powerhouse No. 1		No. PNL 6100
Comment Station Service Supply from Main Terminal Station Trfs SSL		Date 2012-12-17

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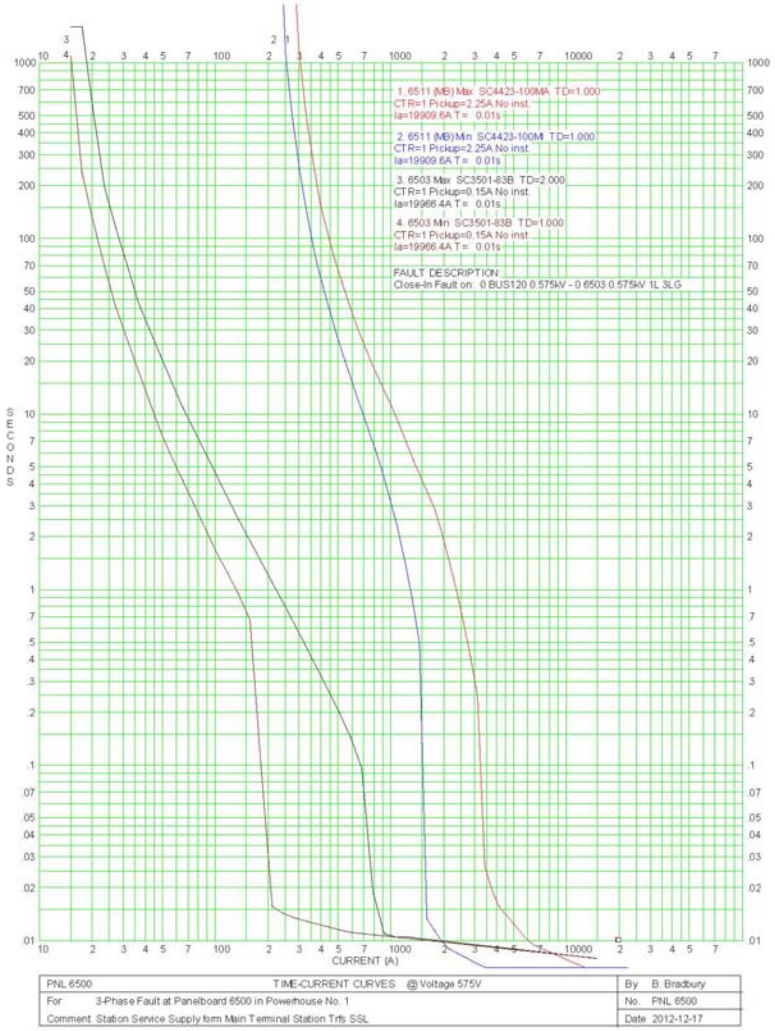
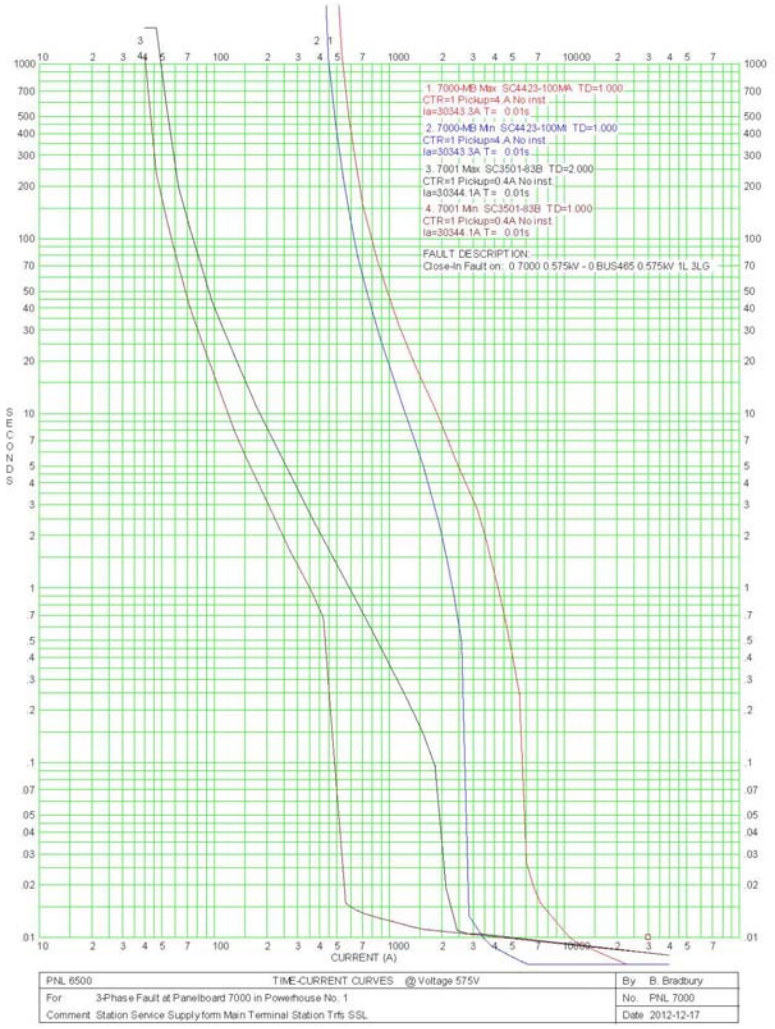
Panelboard 6500 in Powerhouse No. 1



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix F

Panelboard 7000 in Powerhouse No. 1



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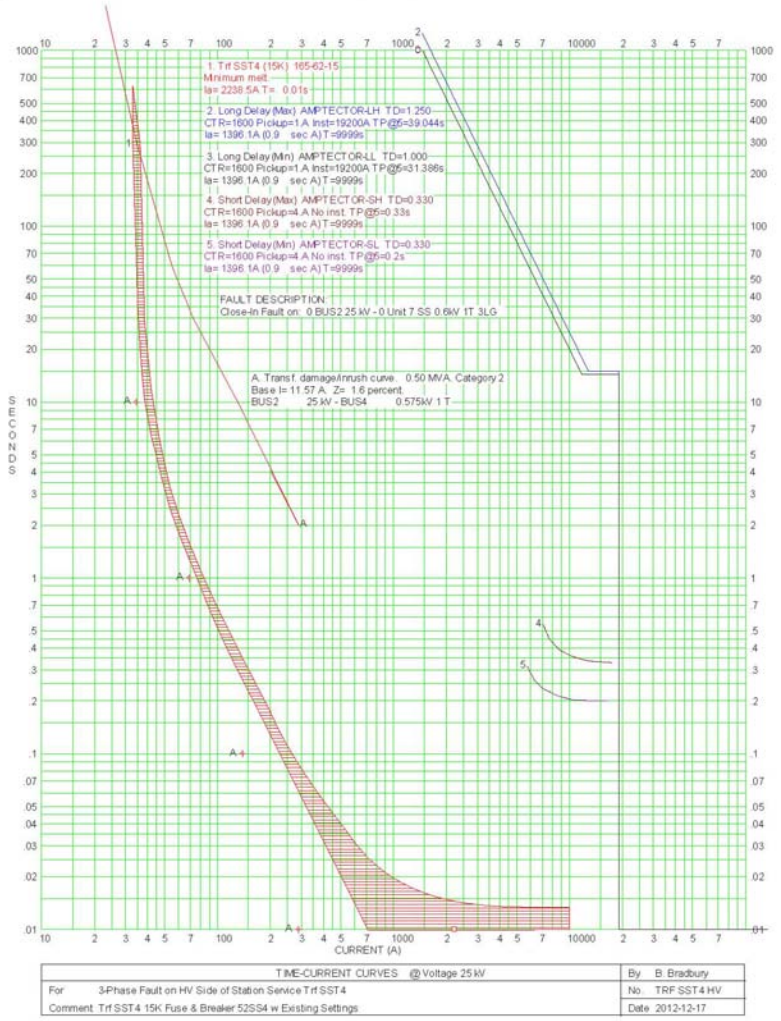
Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix G

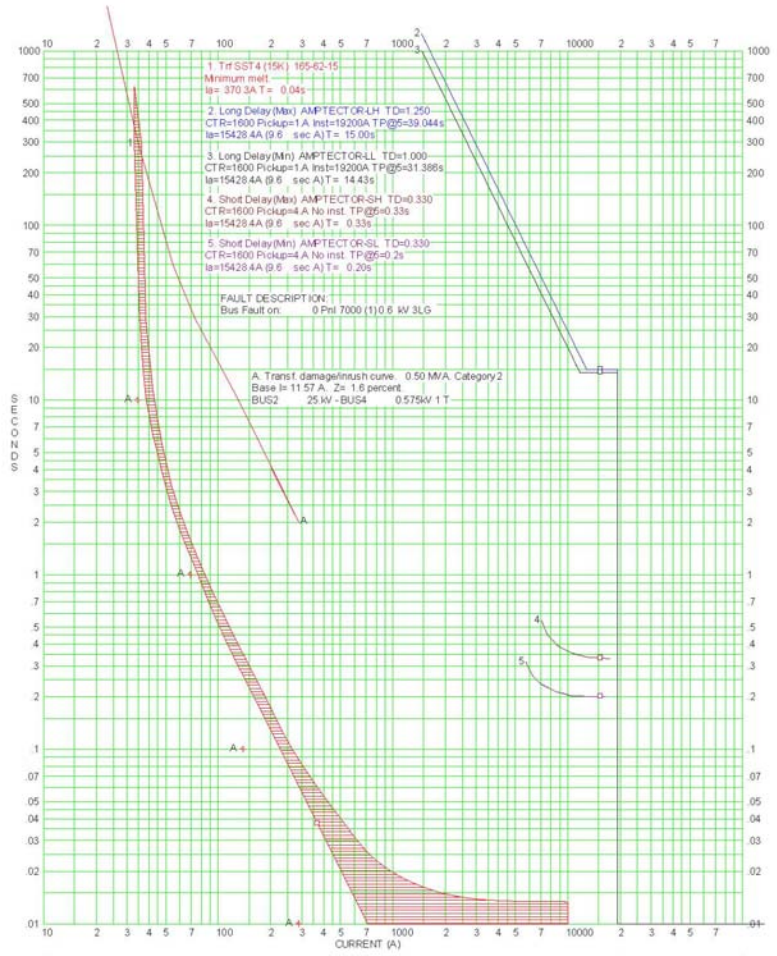
Station Service Transformer SST4 (Existing Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix G

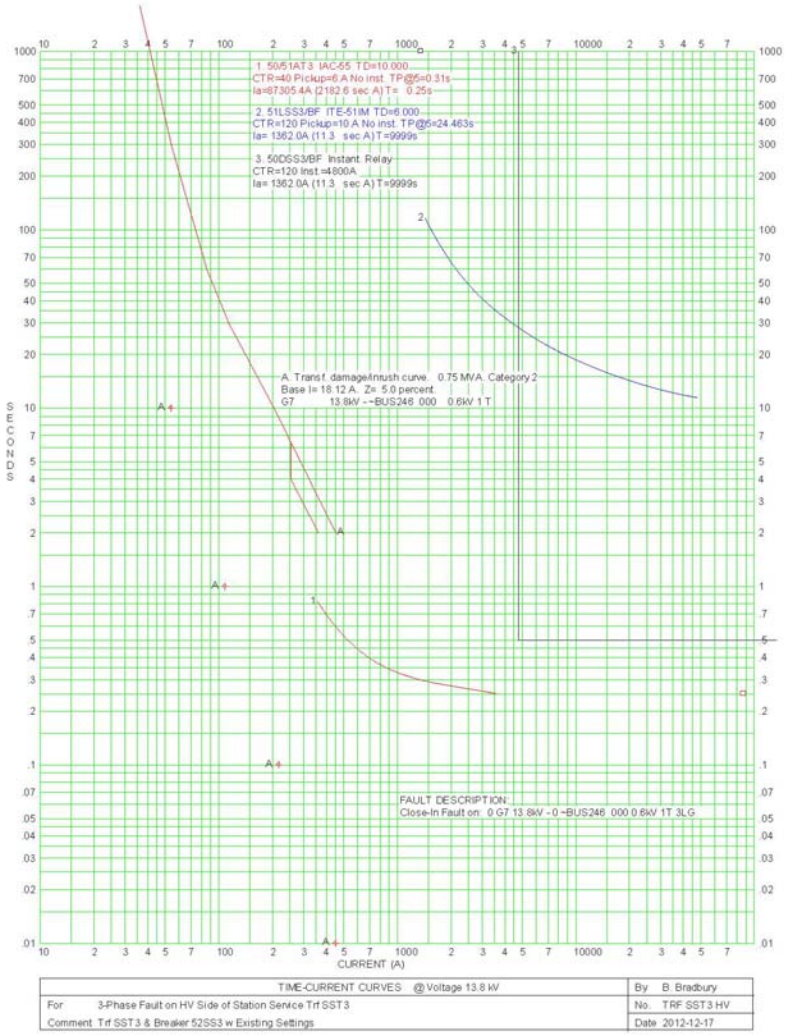
Station Service Transformer SST4 (Existing Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix H

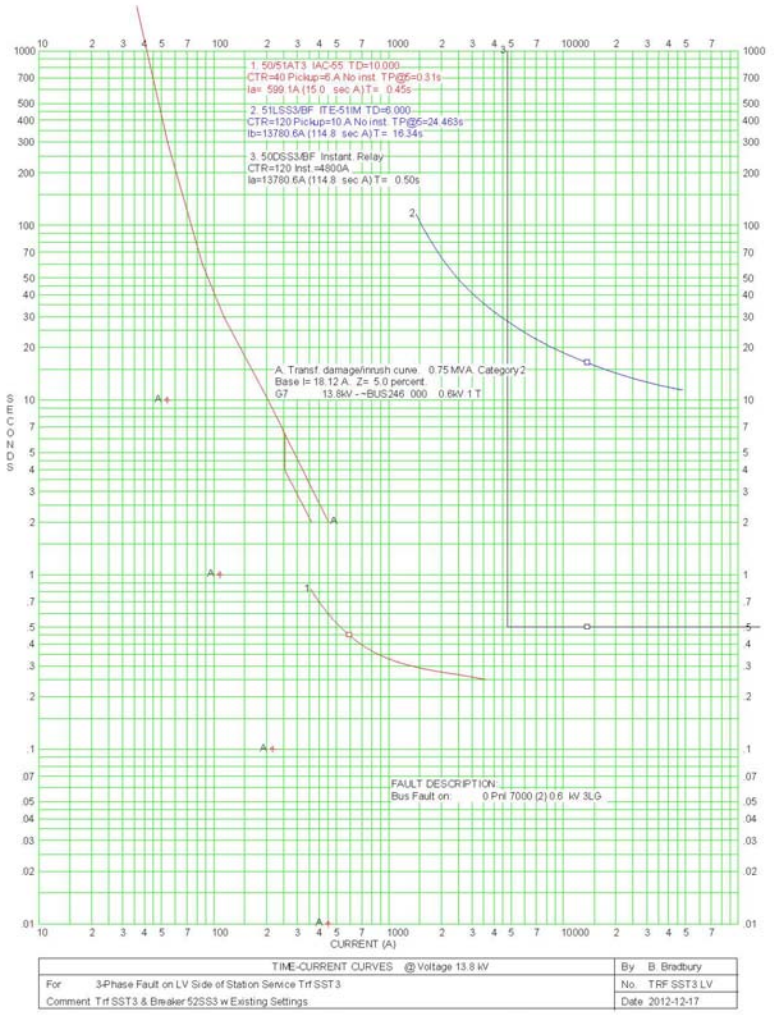
Station Service Transformer SST3 (Existing Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix H

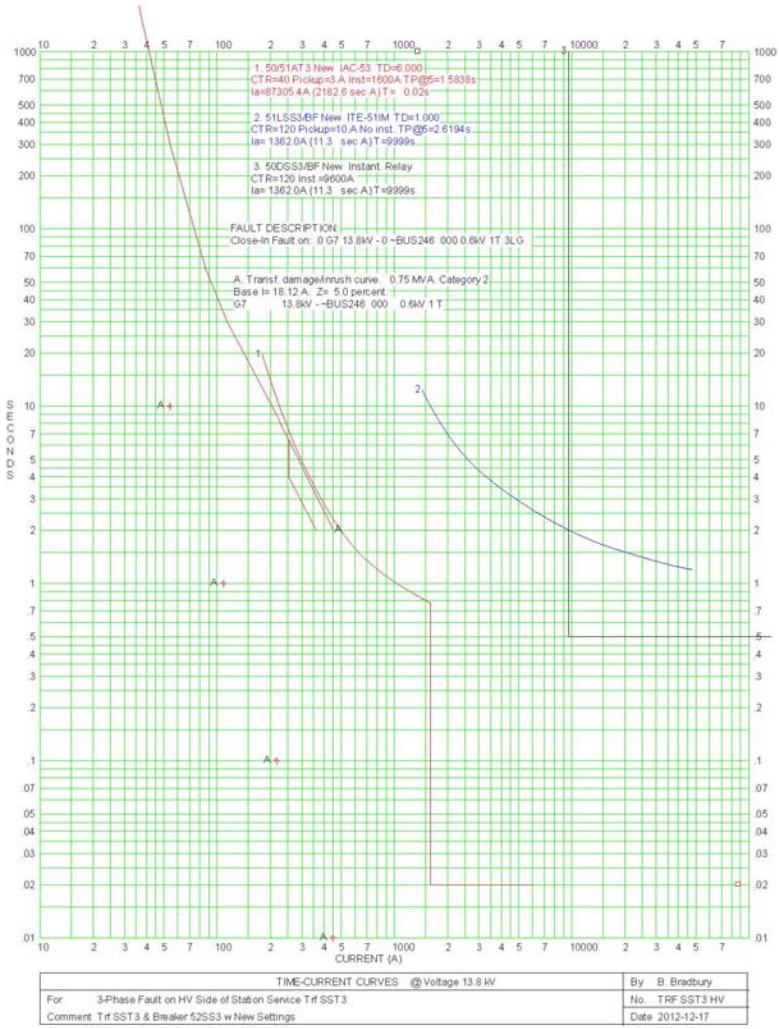
Station Service Transformer SST3 (Existing Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix H

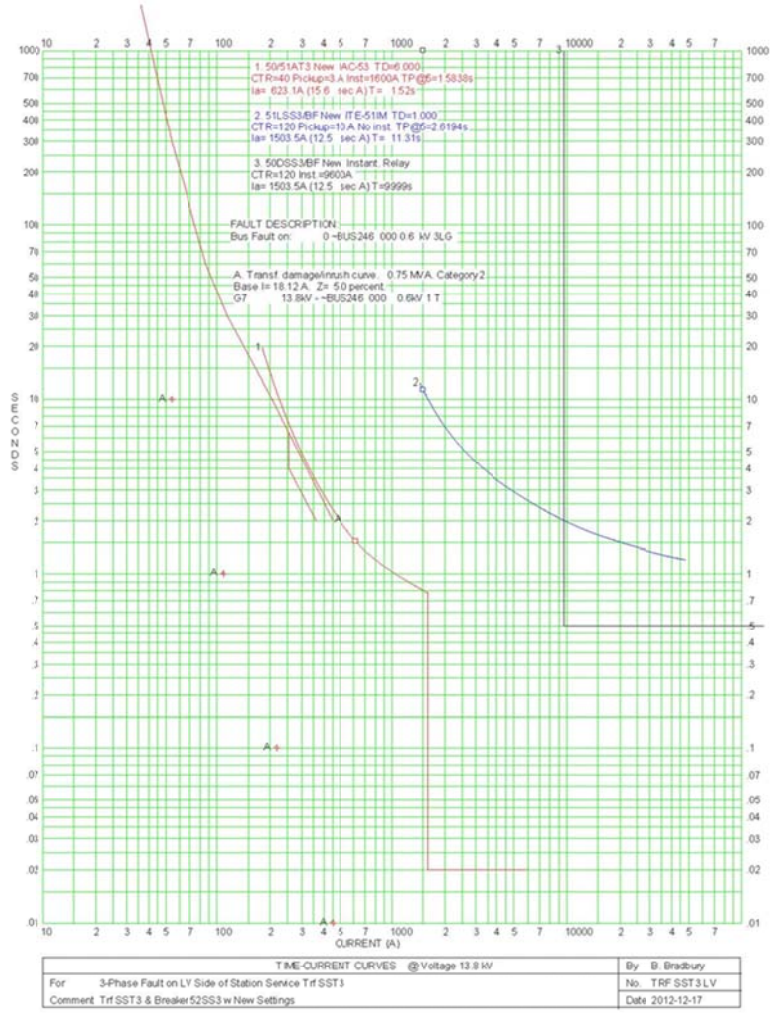
Station Service Transformer SST3 (New Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix H

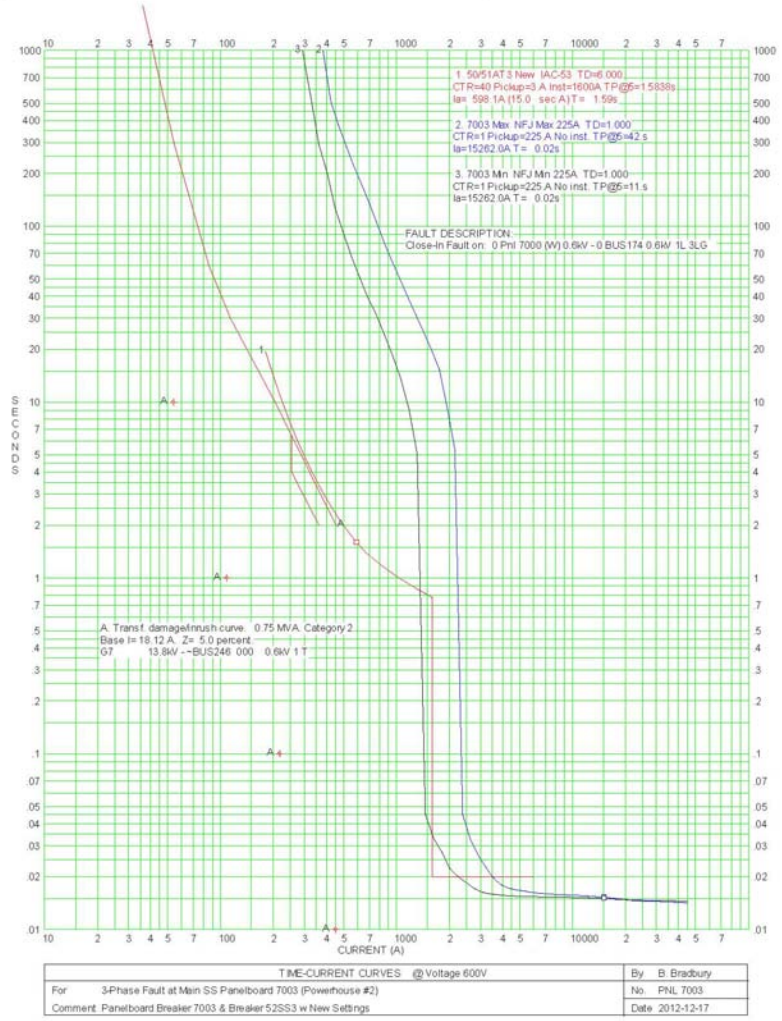
Station Service Transformer SST3 (New Relay Settings)



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix I

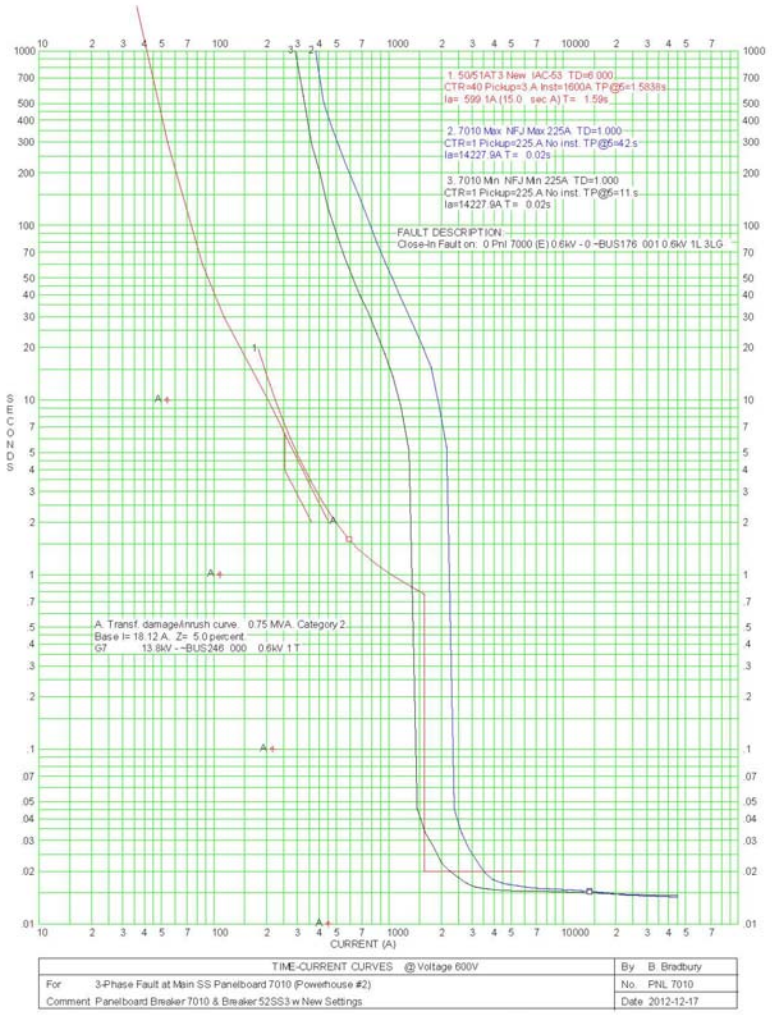
Breaker 7003 in Panelboard 7000 (West) at Powerhouse No. 2



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix I

Breaker 7010 in Panelboard 7000 (East) at Powerhouse No. 2



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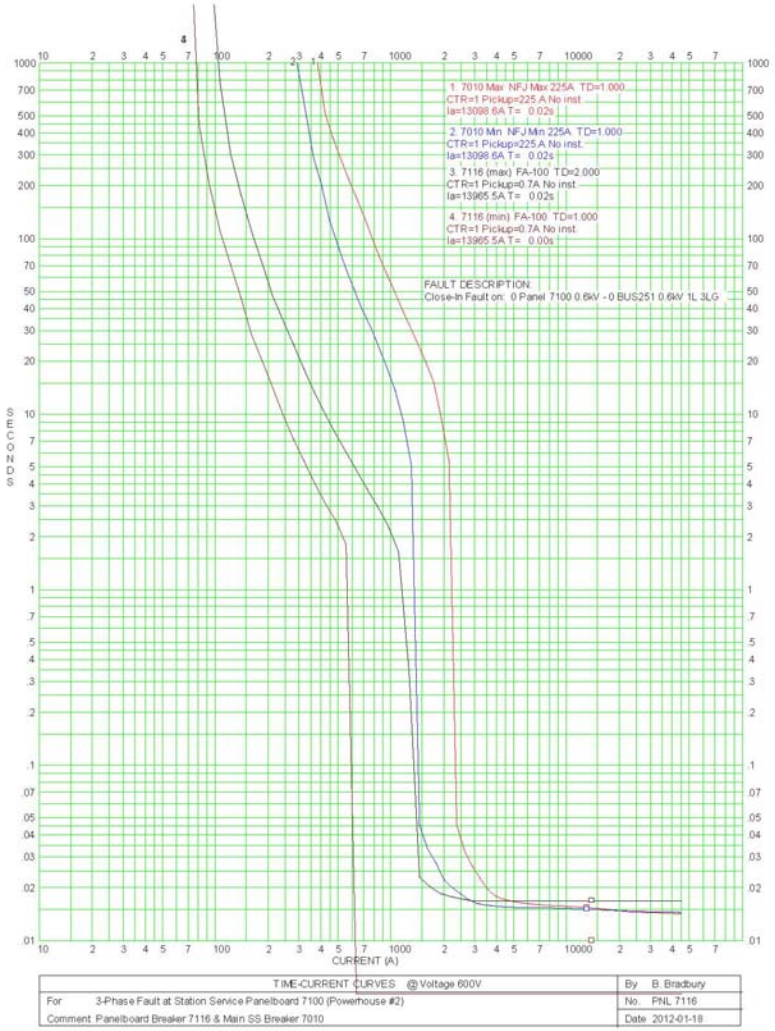
Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix J

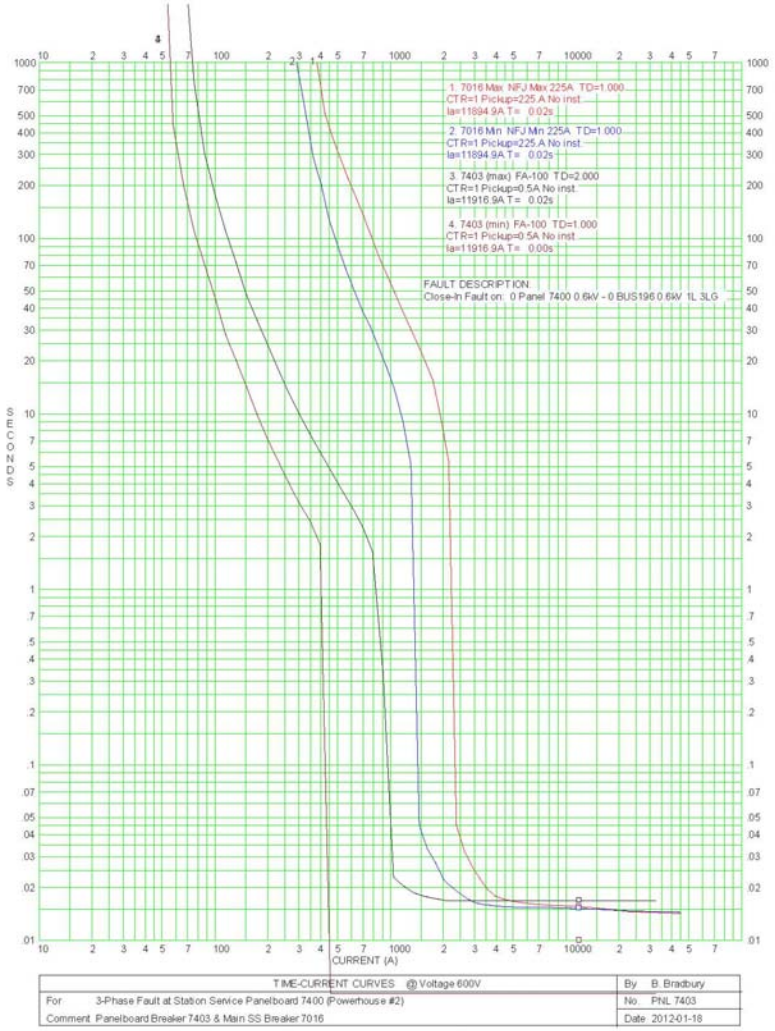
Panelboard 7100 in Powerhouse No. 2



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix J

Panelboard 7400 in Powerhouse No. 2



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Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix K

Cooper RV Recloser Phase Trip Curves

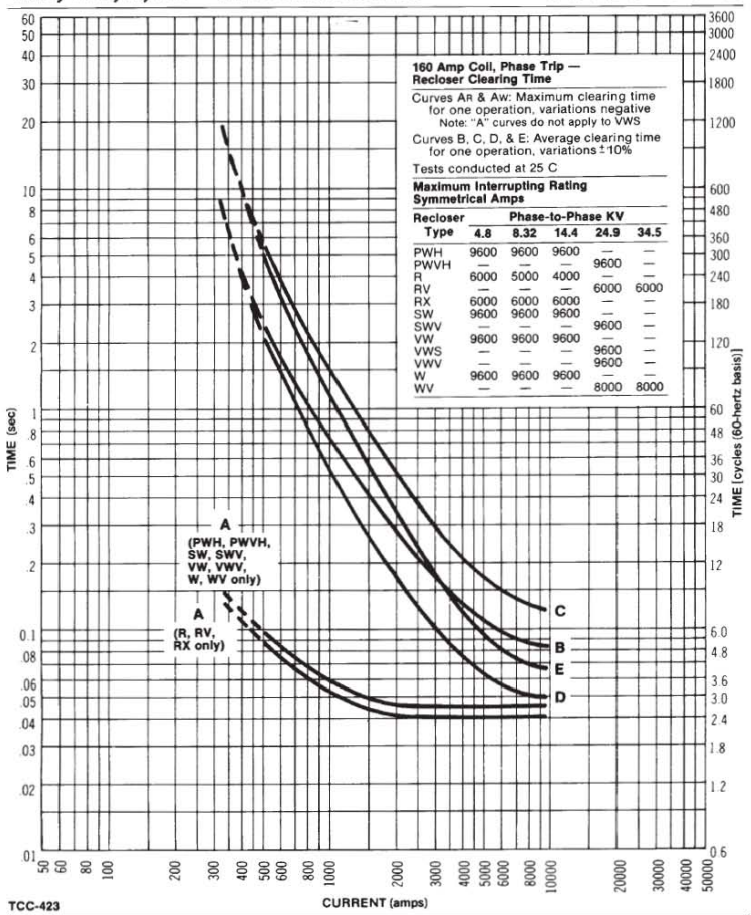
Reclosers

COOPER Power Systems

Reference Data

Types PWH, PWVH, R, RV, RX, SW, SWV, VW, VWS, VWV, W, WV — Time-Current Curves

R280-91-6



TCC-423

June 2002 • Supersedes 7/80

7

Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix K

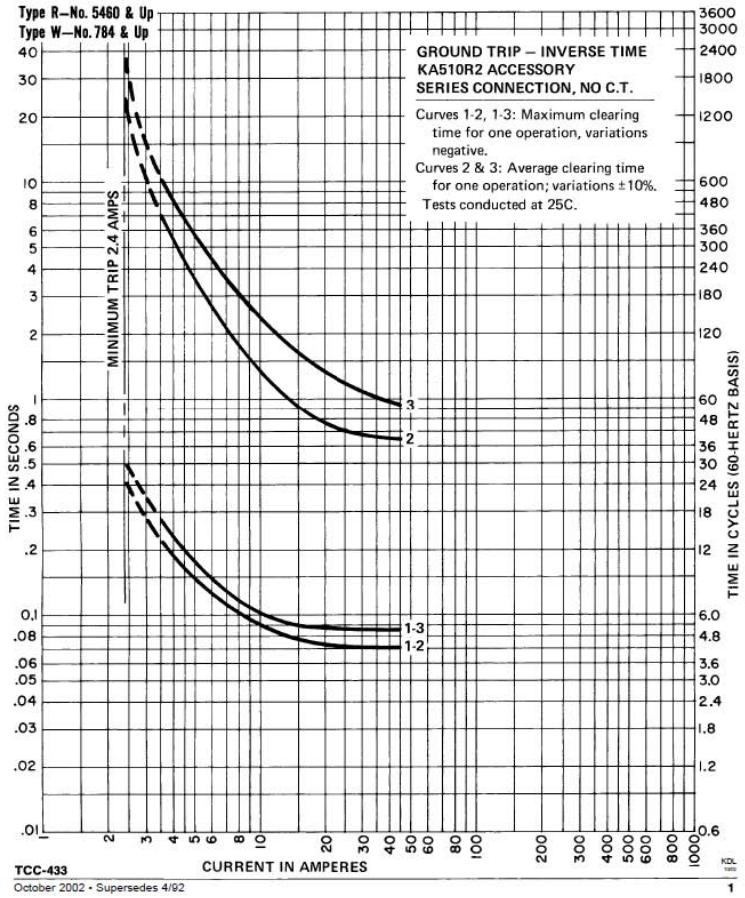
Cooper RV Recloser Ground Trip Curves

Reclosers

COOPER Power Systems

Types R, RV, RX, VW, VWV, W, WV
Time/Current Curves

Reference Data
R280-91-7



TCC-433
October 2002 • Supersedes 4/92

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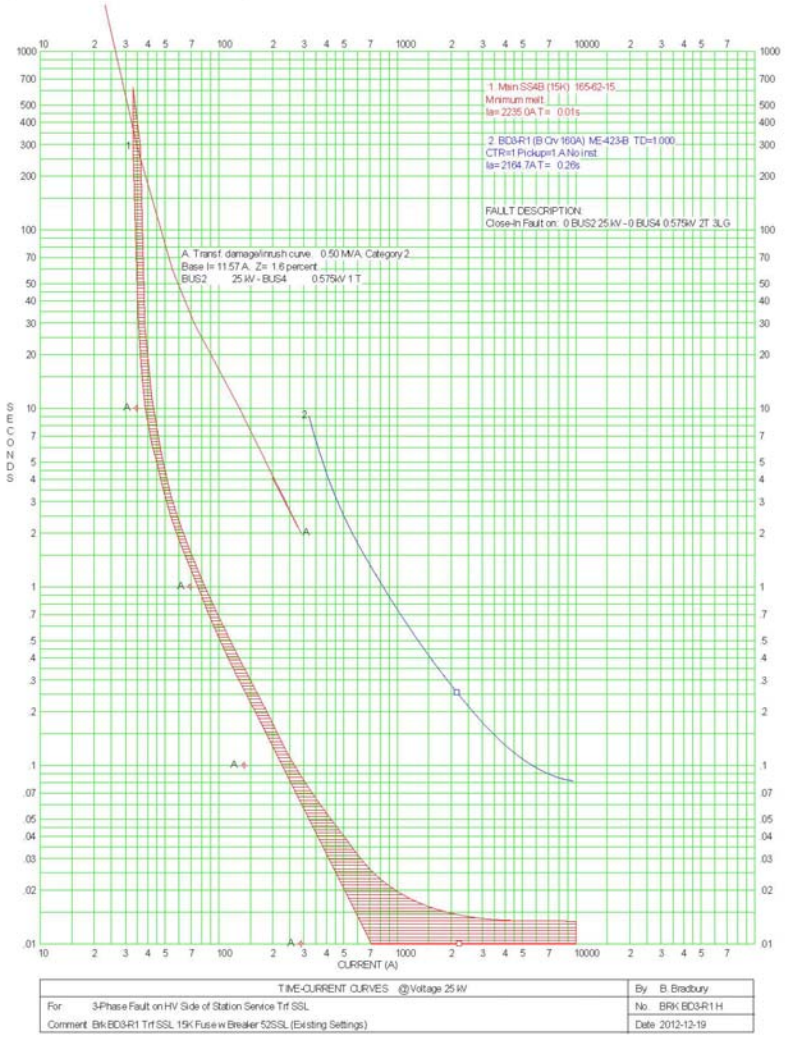
Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix K

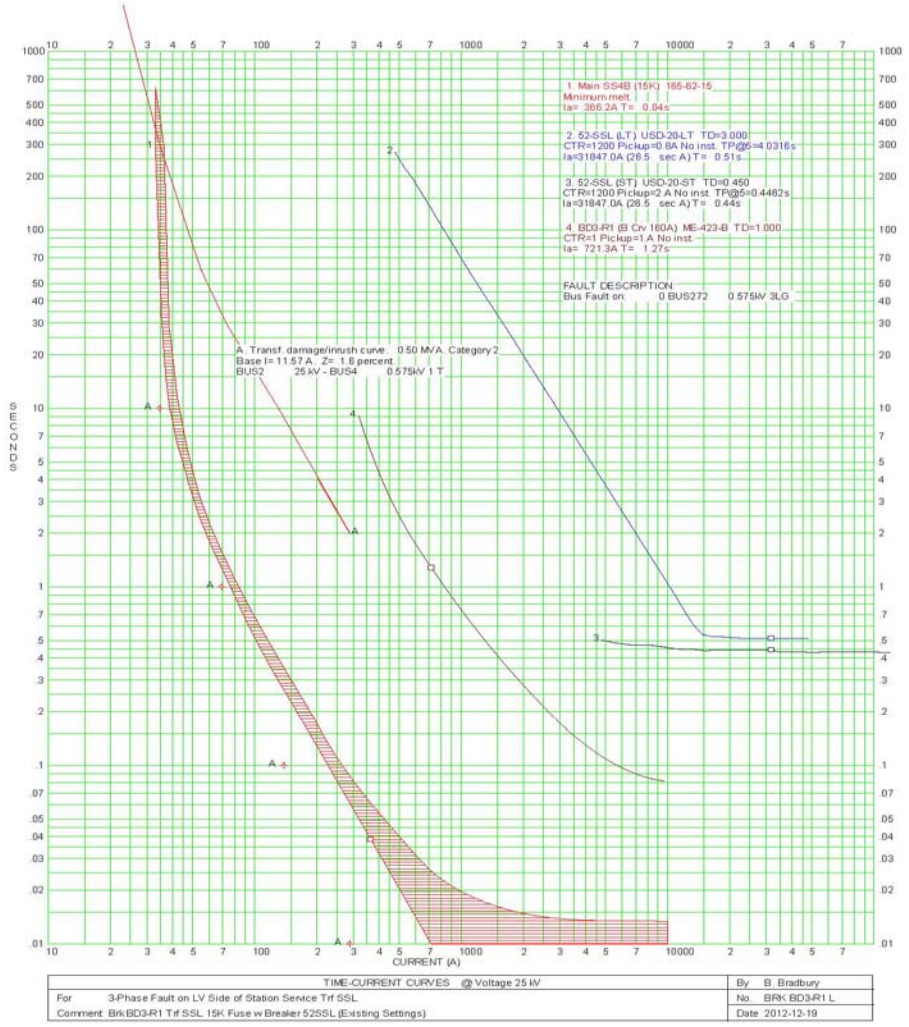
Station Service Breaker BD3-R1



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix K

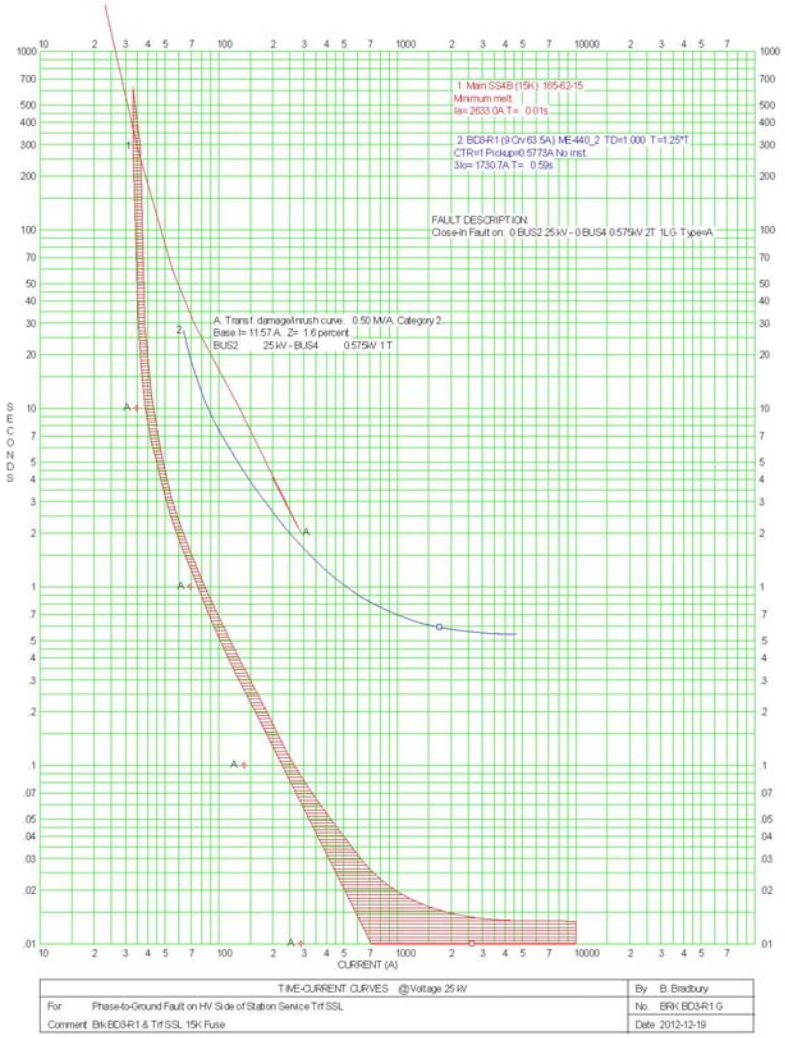
Station Service Breaker BD3-R1



Bay D'Espoir Station Service Review
Powerhouse No. 1 & No. 2

Appendix K

Station Service Breaker BD3-R1



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Project Title: Replace Vibration Monitoring System Unit 7

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project involves the installation of a new vibration monitoring system on Bay d'Espoir Unit 7 including a plant centralized data recording and diagnostics platform. The existing real time vibration monitoring device is obsolete, deficient in its monitoring capacity, and does not provide historical condition monitoring data. The new system will enable continuous monitoring and recording of the vibration levels on Unit 7 to ensure safe operation within normal limits. It will provide useful, long term information and aid in the development of a preventive maintenance strategy to correct undesired conditions, thus improving asset health and reliability. A vibration specialist will be on-site during probe installation and commissioning of the system.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	82.0	0.0	0.0	82.0
Labour	165.0	0.0	0.0	165.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	30.0	0.0	0.0	30.0
Other Direct Costs	8.0	0.0	0.0	8.0
Interest and Escalation	24.0	0.0	0.0	24.0
Contingency	57.0	0.0	0.0	57.0
TOTAL	**366.0**	**0.0**	**0.0**	**366.0**

Justification:

Unit 7 is the largest hydroelectric generating unit on the Island electrical system. The existing monitoring device and number of probes are insufficient in identifying the condition of the unit on an immediate or long term scale. While there are no legislative or regulatory requirements to apply vibration or condition monitoring to hydroelectric generators, it is common practice to do so to identify potential problems in the bearings and shaft of the unit, thus providing a framework for predictive maintenance rather than crisis management.

Vibration Monitoring systems have evolved to Condition Monitoring systems which include speeds and temperatures that provide for a comprehensive analysis of the operating status of a generator. While vibration sensing is the primary objective of such systems, additional data is collected for data correlation and analysis. With the proposed condition monitoring system installed, the vibration, speed, and temperature levels of the unit can be closely monitored, collected and analyzed over the life of the asset. It is anticipated that results can be analyzed and major issues prevented through the use of such systems. Similar vibration monitoring systems installed on other units on Hydro's system have proven to be effective in predicting and identifying high vibration levels before failures or equipment damages occur. A condition assessment was conducted in April, 2015 on Units 1 through 7 by Aker Solutions, a third party contractor with experience in vibration systems. This report identified the existing vibration monitoring components of all units and assessed the need for enhancements throughout in order to bring the systems to present standards. Although all units were observed, this budget proposal focuses on Unit 7 as it has the most antiquated system yet it is the largest generator. The budget proposal is based on the findings and recommendations from this report. The report is provided in Appendix A.

Existing System:

The existing vibration monitoring device is the original equipment and in excess of 30 years old. It consists of an obsolete IRD Mechanalysis vibration monitoring unit which is connected to four Entek vibration probes. Two probes are mounted 90 degrees apart on the generator shaft and two probes are mounted 90 degrees apart on the turbine shaft. This device provides a cycling display of present vibration values of one sensor at a time. It does not have the facility to record values although it can be set up to send an alarm or trip signal on vibration exceeding a predetermined set-point. There have not been any major upgrades done to this system.

The existing vibration monitor is shown in Figure 1. One of the vibration probes and the required electronics package to interface it to the IRD vibration monitor is shown in Figures 2a and 2b.

Figure 1: Existing Vibration Monitoring Device

Figures 2a and 2b – Existing Vibration Probe and Interface Electronics

Operating Experience:

The existing vibration monitoring system on Unit 7 is obsolete and lacking in breadth of monitoring and retention of data. It is not adequate in the representation of vibration levels in that the scales vary and it does not provide any analytical tools to use for predictive maintenance decisions. Data collection is done manually by operations personnel which is only a momentary glimpse of the vibration levels. Unit 7 has had a history of vibration issues, especially during run up, therefore a system that continuously monitors and records the vibration of the unit will be of great benefit in helping to manage these issues.

In July 2010, an internal report was prepared by Hydro's Mechanical Engineering group addressing run-up issues attributed to vibration and balancing on Unit 7. This report is provided in Appendix B.

A vibration and balancing assessment was conducted by HydroExpertise USA from September 26 through October 5, 2014, and a report was provided to Hydro. This report is provided in Appendix C. In April 2015, a condition assessment of vibration monitoring systems on all units was conducted by Aker Solutions. The findings of all reports point to the benefits of accurate, long term vibration monitoring.

Reliability Performance

When the unit is started following annual planned maintenance, the issue of excessive vibration is prevalent leading to many false starts (up to ten or more at times) where vibration has exceeded the limits of the existing vibration monitor. It is not known to what extent the vibration level reached. As Unit 7 is the largest unit in the Hydro Generation fleet, an updated vibration monitoring system is warranted to ensure reliable operation and prevent unnecessary damage to the unit.

Outage Statistics

The vibration system has not been attributed to causing any outages on Unit 7. There has, however, been difficulty in getting the unit to its rated speed and load due to rough zones, which are excessive vibrations at certain speeds, associated with this particular unit.

Industry Experience

An industry standard for condition monitoring of rotating machinery is the API Standard 670 "Machinery Protection Systems", 5th Edition, November 2014. The vibration system assessment conducted on Unit 7 by Aker Solutions Canada Incorporated and subsequent recommendations was based on this standard.

Vendor Recommendations

A condition assessment provided by Aker Solutions identified an array of probes that should be applied to properly monitor the vibration and overall condition of Unit 7. The listing of sensors recommended is as follows:

- X and Y Proximity Probes at the Generator Lower Guide Bearing;
- X and Y Proximity Probes at the Turbine Guide Bearing;
- Dual (Redundant) Thrust Probes observing the position of the Generator Thrust Collar;
- Dual Accelerometer on the scroll case to detect cavitation and other hydrodynamic effects;
- Redundant bearing temperature probes for the Generator Lower Guide Bearing;
- Redundant bearing temperature probes for the Turbine Guide Bearing;

- Redundant bearing temperature probes for the Thrust Bearing; and
- One permanent tachometer probe.

Although Aker Solutions are not a vendor of vibration monitoring systems, they have extensive experience in the assessment of hydroelectric generating units.

Maintenance History

There is no maintenance history for the existing vibration monitoring device or sensors.

Anticipated Useful Life

A vibration monitoring system has an estimated service life of 30 years. Any applicable software and hardware upgrades would be done on the recommendations of the manufacturer throughout the life of the system.

Development of Alternatives

There are no alternatives to a vibration or condition monitoring system, only variations of systems from different manufacturers. Each would have to functionally provide the requirements and be competitive on price and support. A functional specification subject to the Public Tendering Act is intended to be developed for a condition monitoring system for Unit 7.

Conclusion:

This project is necessary to provide an industry standardized version of a condition monitoring system of present day technology for the largest hydroelectric generating unit in Hydro's generation fleet. The existing system is deficient on many levels therefore a new technologically up-to-date and expandable system is needed which will aid the plant personnel responsible for the operation and maintenance of this unit. A new system will not only provide an extensive condition monitoring system for Unit 7 but offer the opportunity to extend the system across both Powerhouses to monitor all units. In time, and based upon the results of the Unit 7 system, the new system can be extended so that all generating units at Bay d'Espoir Plant will have a centralized monitoring system that to assist the operators in reliable operation of the units. The system will also retain the operating conditions to aid in predictive maintenance scheduling.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Site assessment Information collection	January 2016	February 2016
Design	P&C Design Mechanical Design	March 2016	May 2016
Procurement	Tender for Condition Monitoring System Award of Tender Arrival of materials	March 2016 May 2016 July 2016	April 2016 May 2016 July 2016
Construction	Install sensors and system	July 2016	August 2016
Commissioning	Commissioning As-built drawings and documentation	August 2016 September 2016	August 2016 September 2016
Closeout	Closeout	October 2016	October 2016

APPENDIX A

Aker Solutions - Vibration Monitoring Assessment for Bay D'Espoir

AkerSolutions™

REPORT

NL Hydro

Bay d'Espoir Hydro Electric Generating Station Units 1- 7 Vibration Monitoring Equipment Assessment

Document No.: 12031 /2015-61564
Revision No.: A2

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AkerSolutions™

PROJECT NAME:	
Bay d'Espior Hydro Electric Generating Station Unit 1-7 Vibration Monitoring Equipment Assessment	
CLIENT: **NL Hydro**	CLIENT REF.: **Leyon Williams**
ORGANISATIONAL UNIT: **Aker Solutions Canada Inc.** AIM, St. John's	CONTRACTOR REF.: **Stephen Pye**
PROJECT NUMBER: **12007**	CONTRACT NUMBER: **2015- 61564**
INTERNAL DOCUMENT NUMBER:	CLIENT DOCUMENT NUMBER:
DOCUMENT TITLE: **Bay d'Espior Hydro Electric Generating Station Unit 7 Vibration Monitoring Equipment Assessment**	NO. OF PAGES: 47

COMPANY STAMP:	ENGINEERS STAMP:

REV.	DATE	REASON FOR ISSUE	PREPARED	CHECKED	LEAD APPROVAL	MANAGEMENT APPROVAL
A2	27th May2015	Final				
A1	21st May 2015	First Draft	S Pye	G Brown	G Brown	P Hillier

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REVISION STATUS SHEET

Rev. A1

First revision – Issued for comment

Rev A2

Final issue including client comments

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1 INTRODUCTION

1.1 Background

Aker Solutions AIM has been invited to conduct an assessment of the permanently installed vibration monitoring equipment at the Bay d'Espoir Hydro Electric Generating Station. The intention of the assessment is to determine the current condition of the Vibration Monitoring System for Units 1-7 which reside in Power House 1&2 at the Bay d'Espoir (BDE) site and to make recommendations as to what replacements would be required to provide the appropriate level of data acquisition and analysis for Units 1-7, bring the system up to today's standards and allow for better fault detection and monitoring.

The site visit was completed on the 24th April 2015.

This assessment report details the current condition of the vibration equipment installed on Units 1-7 at the Bay d'Espoir Hydro Electric Generating Station and provides recommendations for the improvement of the overall system, based on the site assessment and discussions with site personnel.

1.2 Abbreviations and definitions

API	American Petroleum Institute
DAQ	Data Acquisition Unit
LGB	Generator Lower Guide Bearing
DSA	Dynamic Signal Analyzer
OEM	Original Equipment Manufacturer
TGB	Turbine Guide Bearing

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2 METHOD

The site assessment consisted of a visual inspection of the equipment installed in the Station Control Room, Unit 2 in Powerhouse 1 and Unit 7 in Powerhouse 2. All Units were examined, however, Unit 2 was out of service which allowed for a much more detailed inspection of the installed equipment. Photographs were taken and as much technical documentation collected that was readily available.

The assessment of the equipment has been based on the API Standard 670 "Machinery Protection Systems", 5th Edition, November 2014 along with the extensive experience of the assessor relating to remotely operated hydroelectric stations.

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3 ASSESSMENT

3.1 Findings and Observations

The following section outlined the major findings from the assessment.

Units 1-7 all have similar probes installed, four retrofitted radial proximity probes, located at the Generator Lower Guide Bearing and the Turbine Guide Bearing, Figure 1.

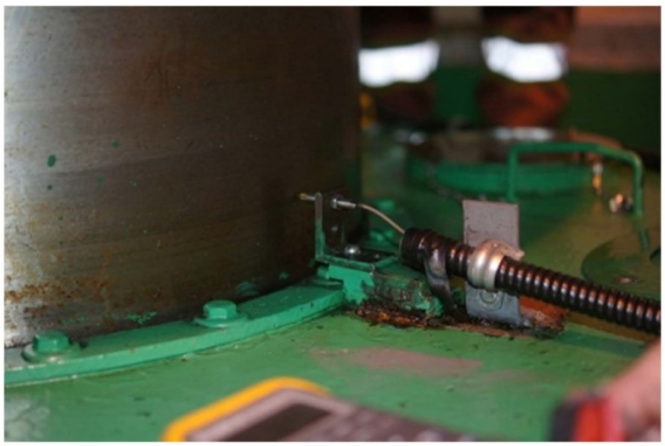

Figure 1 Typical Proximity Probe Installation

Based on the conversations with site personnel the installation of the probes was done in two phases, initially only a single probe was installed at each location, at a later time a second set of probes and a tachometer probe was installed, Figure 2.

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Figure 2 General view of Proximity Probe and Tachometer Installation

For Units 1-6 in Powerhouse 1, this has led to two junction boxes in the turbine pit housing with the proximity probe transmitters and the devices that read them located in both the station control room and in a cabinet in the turbine hall.

The equipment installed in Unit 7 is Entek IDR and only provides a local display of vibration levels as a percentage, Figure 3, it does not indicate absolute vibration levels nor does it have peak hold capabilities to record vibration levels during start-up. Considering today's standards for vibration monitoring systems this is clearly inadequate, however, this equipment is obsolete and will require replacing. Based on the drawing provided and confirmation by site personnel, Unit 7 does not have a keyphasor installed.

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Figure 3 Unit 7 Vibration Monitoring Panel

The manufacturer for the equipment deployed in Units 1-6 is Rockwell Automation and is part of their Condition Monitoring Protection System hardware which has the capability of interfacing with the Odyssey Condition Monitoring software. The Rockwell Automation XM-121 Vibration Module being used is obsolete as is the XM-500 Devicenet to TCP/IP Gateway, Figure 4 and Figure 5.

Figure 4 Rockwell Automation XM-121 Vibration Module

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Figure 5 Rockwell XM-500 Gateway

The probes in use across all units are of various ages, based on their physical appearance, and the units first installed are obsolete. This is not necessarily a problem as these can be readily replaced with current model, however, no calibration records were able to be produced for the probes in service and the probe installations are susceptible to both mechanical and liquid damage from both water and/or oil, Figure 1, Figure 2 and Figure 6.

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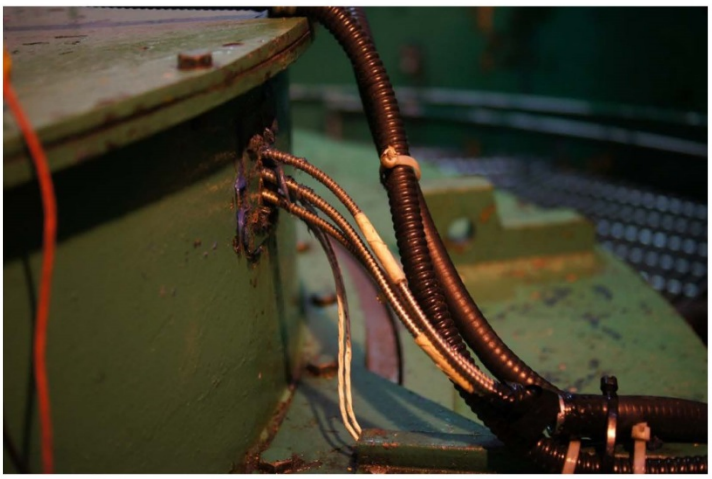

Figure 6 Typical Probe Cable Installation

Additionally there is no cable identification at the Proximitor Junction Box in Unit 2, Figure 7 and it was confirmed that the other unit's junction boxes are in similar condition.

Figure 7 Unit 2 Proximitor Junction Box

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On closer inspection of the turbine probes it was revealed that the attachment method for installing the tachometer reference mark to the shaft was to glue a piece of shim stock to the shaft. This would not be considered a permanent solution and it was mentioned that there have been occasions in the past when the shim stock has come off.

Figure 8 Tachometer Reference Mark

3.2 Assessment General Comments

With the advancement in technology and the development of more sophisticated monitoring systems and standards, the existing system does not conform to the current industry standards for vibration monitoring or as they are referenced in the industry today "Condition Monitoring Systems" as outlined in API standards, API 670 "Machinery Protection Systems", 5th Edition, November 2014. Whilst the standard is for protection systems, it addresses what is required for a condition monitoring system which is the core requirements of any protection system.

Clearly the Vibration Monitoring system installed at the Bay d'Espoir Hydro Electric Generating Station was originally intended as a simple vibration level monitoring system and would have served its purpose at that time. Over the years it has had modifications carried out in an attempt to make improvements, however, these modifications have to a degree been in a rather piecemeal fashion which has resulted in the current fragmented system configuration. As the majority of the individual

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equipment items within each system, Units 1-6 and Unit 7, are obsolete and have no equivalent replacement it is strongly recommended that the current systems are replaced with a system that encompasses today's technology and will also be future-proof to allow improvements and upgrades in a more systematic and integrated manner.

Additionally it is understood, from discussions with plant personnel, that NL Hydro may at some time in the future move to a position of providing its surplus power generation capacity to the electrical distribution system. If or when this occurs there will be required to meet the rigorous ISO Quality Control standards which require traceability of equipment calibration and system standardization that the latest Machinery Health monitoring systems can provide. This further reinforces the recommendation for replacement.

As the main recommendation to install a complete new system that will be compliant with today's standards, it is also recommended that no further modifications are made at this time as they will most likely not be cost effective considering the level of obsolescence within the current system.

All units suffer from a fragmentation of the vibration monitoring systems equipment with some equipment in the control room and other equipment in the turbine power house pits. All of these factors expose the systems to low reliability, poor data quality, poor fault finding capability and poor calibration certification. Replacing each with dedicated DAQ units and integrated data analysis and storage facilities would greatly increase data quality and analysis, improve data reporting and minimize the calibration process across all units and make the system standards compliant.

Finally with an up to date condition monitoring system installed it will provide NL Hydro a predictive tool to forecast maintenance requirements by deferring intrusive PMs based on equipment condition, and provide far greater confidence in the health of its equipment. This becomes a significant benefit should NL Hydro choose to sell surplus power.

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3.3 New System Requirements

A more thorough specification will be required that goes beyond this documents once a suitable concept is agreed. A new condition monitoring system should entail.

Each unit should have installed the following hardware:

- X and Y Proximity Probes at the Generator Lower Guide Bearing
- X and Y Proximity Probes at the Turbine Guide Bearing
- Dual (Redundant) Thrust Probes observing the position of the Generator Thrust Collar
- Dual Accelerometer on the scroll case to detect cavitation and other hydrodynamic effects
- Redundant bearing temperature probes for the Generator Lower Guide Bearing
- Redundant bearing temperature probes for the Turbine Guide Bearing
- Redundant bearing temperature probes for the Thrust Bearing
- One permanent tachometer probe
- One permanent tachometer probe target

During the assessment the current condition of the probes functionality could not establish or verify their calibration certificates, as such replacement probes have been included.

As an option for consideration the unit can have a second tachometer installed to be configured to serve as a creep detector.

Installing a permanent tachometer mark on the shaft can be as simple as drilling a shallow dimple into the shaft surface that complies with API 670 and/or probe OEM standards. If there is reluctance to do this then a split collar can be manufactured that clamps around the shaft with a raised "key" as the target. This collar can also be the machined with the target surface for a creep detection system.

All instruments, including the temperature probes and cabling should be installed in the spirit of API 670 standard to provide mechanical and liquid tight protection, Figure 9.

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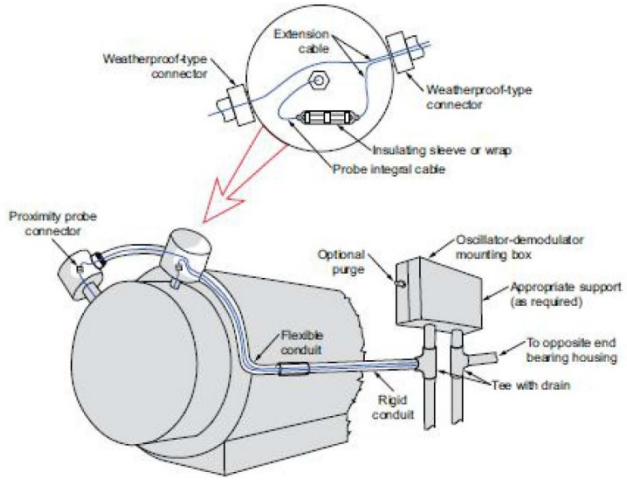

Figure 9 Typical Instrumentation Installation Using Flexible Conduit And Probe Junction Boxes

Changing from panel mounted to DIN rail mounted proximity hardware will allow for a higher channel density within the pit mounted junction box fabrication. It is believed that a single junction box containing both the vibration and temperature probe terminations and the main data acquisition device can be constructed and mounted in the turbine pit making a much smaller footprint what is currently in place.

These vibration and temperature DAQ devices will be connected via a dedicated condition monitoring system network within Powerhouse 1. Connecting Unit 7 to the same network will be achieved by either using spare conductors on the fiber connection to Powerhouse 1 or by a wireless link between the two powerhouses.

The units would communicate with a central server that will provide data storage for all data. It is recommended that data display units are sited within the control room but the system would also be capable of being viewed on smart devices. This would negate the need for a permanent display unit to be housed in Unit 7.

In this manner each unit would have its own DAQ process unit linked to a central server that would have the capability of connecting and sharing data with other NL Hydro sites.

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Figure 10 presents a possible system concept for NL Hydro to consider, this type of system utilizing such DAQ units as National Instruments CompactDAQ range of units and plugin modules, would provide a standard platform that could be adopted as the standard installation configuration across all NL Hydro's sites. This would provide future-proofing of the systems and ultimately a capability of remote interrogation/analysis of systems in addition to centralized analysis and monitoring should that be of interest to NL Hydro now for current un-manned sites or in the future.

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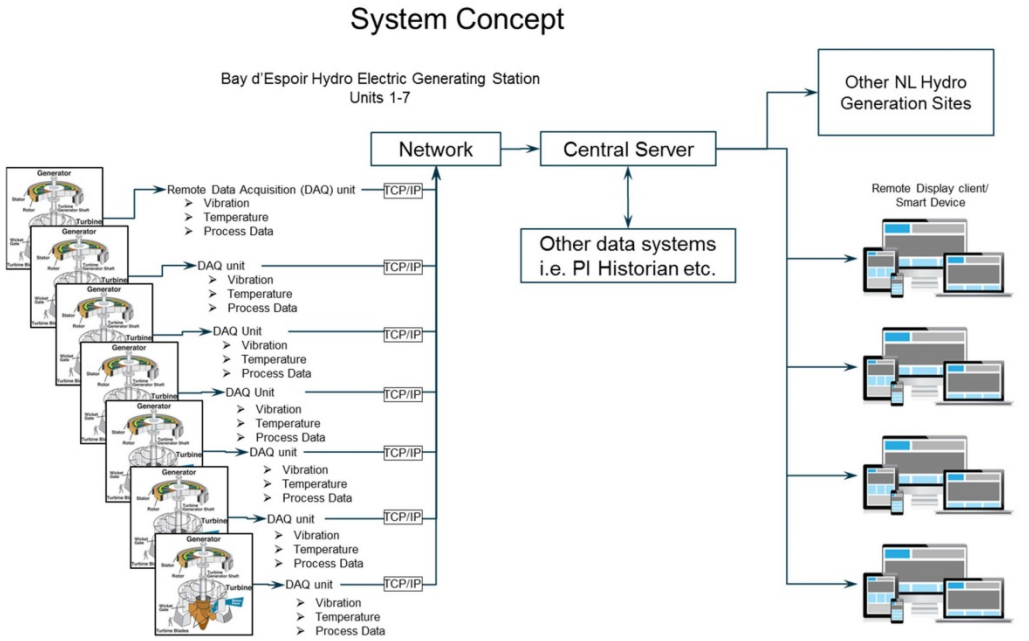

Figure 10 Possible System Concept

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4 ESTIMATED COST

To implement the system proposed or a system with similar capabilities, at this time for Unit 7 only, and one that will comply with API 670, it is estimated the cost would be in the region of Eighty Thousand Canadian Dollars (CAD$80,000). This includes all the probes, data acquisition unit, acquisition modules, acquisition and analysis software and the required configuration.

This estimated prices include:-

- Condition Monitoring Data Acquisition unit
- CM software
- Central Server
- Proximity probes
- Accelerometers
- Stainless Steel wall mounted cabinet
- Software
- Software configuration
- Configuration of Condition Monitoring Data Acquisition unit & Site Installation

Not include in the estimated price:-

- Site preparation work
- Site engineering for probe mounts (mechanical and environmental protection)
- Cabling between data acquisition instruments and central server/DAQ

To further expand the system to Units 1-6 the unit costs would reduce as the initial Unit 7 replacement includes the cost of the main Central Server.

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APPENDIX A. NATIONAL INSTRUMENTS EQUIPMENT BROCHURES

- Compact RIO NI 9068
- NI PS-15 Power SupplyNI-PS-15
- Voltage/Current Analog Input Module – NI 9207
- AC/DC Analogue Input 3 Ch Module – NI 9232
- 16-Channel Isothermal Thermocouple Input Module – NI 9214
- NI InsightCM Data Explorer
- NI Insight Server

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NI cRIO-9068

667 MHz Dual-Core Controller and Artix-7 FPGA

- 667 MHz dual-core ARM Cortex-A9 processor, 1 GB nonvolatile storage, 512 MB DDR3 memory
- 8-slot Artix-7 FPGA chassis for custom I/O timing, control, and processing
- NI Linux Real-Time OS
- Program the onboard processor with LabVIEW Real-Time or C/C++ and the FPGA with LabVIEW FPGA
- 2 Gigabit Ethernet, 1 USB Hi-Speed, and 3 serial ports for connectivity
- -40 °C to 70 °C operating temperature range

Overview

The NI cRIO-9068 combines a dual-core processor, a reconfigurable FPGA, and eight slots for C Series I/O modules within one chassis. Featuring a 667 MHz dual-core ARM Cortex-A9 processor running the NI Linux Real-Time OS and an Artix-7 FPGA, this system is well-suited for advanced embedded control and monitoring applications. The cRIO-9068 offers a -40 °C to 70 °C operating temperature range along with dual 9 VDC to 30 VDC power supply inputs for use in applications that demand a rugged and temperature-tolerant controller. The device features 512 MB of DDR3 memory for embedded operation, 1 GB of nonvolatile memory for data logging, and a wide range of connectivity options including two Gigabit Ethernet, one USB Hi-Speed, and three serial ports.

You can use NI LabVIEW system design software to create, debug, and deploy logic to both the onboard FPGA and the processor running the NI Linux Real-Time OS. The LabVIEW environment includes hundreds of prewritten libraries for analysis, control, and logging. C/C++ developers have the option to reuse existing libraries within LabVIEW Real-Time or develop, debug, and deploy C/C++ applications for the onboard processor. Also included are all necessary I/O drivers and middleware for AXI communication between the FPGA and processor as well as network communication libraries to develop the entire system software with a single tool: LabVIEW.

The ruggedness and temperature range make the cRIO-9068 well-suited for high-volume and OEM applications in harsh environments. OEM discounting is available.

Specifications

Specifications Documents

- Specifications

Specifications Summary

General

Controller Type	Value
CPU Clock Frequency	667 MHz
Operating System / Target	Linux

Nonvolatile Memory	1 GB
System Memory	512 MB
Peripheral Port	
Number of Ethernet Ports	2
Ethernet	1000BaseT
Serial Ports (RS232)	Yes
Serial Ports (RS485)	1
Power	
Input Voltage Range	9 V - 30 V
Reconfigurable FPGA	
FPGA	Artix-7
Chassis	
Number of Slots	8
Physical Specifications	
Length	30.28 cm
Width	8.81 cm
Height	6.23 cm
Weight	1164 gram
Operating Temperature	-40 °C - 70 °C
Shock and Vibration	
Operational Shock	50 g
Random Operating Frequency Range	5 g

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NI PS-15 Power Supply

5 A, 24 VDC

- 1-phase, 115/230 VAC input; 24 to 28 VDC, 5 A output
- Power supply for CompactRIO, Compact FieldPoint, NI Single-Board RIO, NI Smart Cameras, and NI TPCs
- Full 120 W output power between -25 and +60 °C, (derated 3 W/°C from 60 to 70 °C)
- 20 percent power reserve for dynamic loads can be used continuously up to 45 °C
- Tool-less spring-clamp terminals for easy field connectivity
- DIN-rail mounting included and panel/side mount accessories available

Overview

NI industrial power supplies feature long expected life, generous power reserves, and compact size. The 24 V supplies are ideal for powering any NI CompactRIO, NI Compact FieldPoint, NI Single-Board RIO, NI Smart Camera, NI touch panel computer (TPC), or NI CompactDAQ system as well as heavy accessory loads such as DC motor drives. The DIN-rail system and spring-clamp terminals do not require tools, which makes installation fast and easy. Wide range and autoselect input voltages resist user errors. The wide operating temperature range and extraordinary electromagnetic interference (EMI) immunity enable trouble-free operation, even under harsh conditions.

The NI PS-15 industrial power supply guarantees power reserves of 20 percent for fluctuating loads. You can use this extra current continuously for ambient temperatures under 45 °C. With these power reserves, you do not need to oversize for dynamic loads - simply choose a unit that meets your operating requirements. In some cases, you can select a smaller unit, saving both money and space.

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NI 9207

Voltage/Current Analog Input, 500 S/s, 16 Ch Module

- 8 current and 8 voltage inputs, 500 S/s
- ±21.5 mA current inputs, ±10 V voltage inputs, 24-bit resolution
- High-resolution mode with 50/60 Hz rejection
- 60 VDC, CAT I bank isolation
- Industry-standard 37-pin D-SUB connector
- -40 °C to 70 °C operating range, 5 g vibration, 50 g shock

Overview

The NI 9207 combination voltage and current input C Series module has eight channels of ±21.5 mA input and eight channels of ±10 V input with built-in 50/60 Hz rejection for noise rejection.

Designed with industrial systems in mind, the NI 9207 combines the two most common inputs to reduce the overall number of modules you need. A system that uses fewer modules has the benefit of leaving slots open for other measurement types or reducing the overall cost and size of the system. The NI 9207 has a standard 37-pin D-SUB connection for use with cables and connector blocks.

Recommended Accessories

-NI 9923 front-mount D-SUB to screw terminals

Box Contents

-1 NI 9207 C Series module

-1 NI 9207 Operating Instructions and Specifications manual

Specifications

Specifications Documents

- Specifications
- Data Sheet

Specifications Summary

General

Product Family	Industrial I / O
Measurement Type	Current

	Voltage
Form Factor	CompactDAQ CompactRIO
Operating System / Target	Real-Time
RoHS Compliant	Yes
Isolation Type	Ch-Earth Ground Isolation
Analog Input	
Single-Ended Channels	8
Differential Channels	8
Analog Input Resolution	24 bits
Maximum Voltage Range	
Range	-10 V - 10 V
Accuracy	0.05608 V
Available Filters	50 Hz 60 Hz
Simultaneous Sampling	No

Simultaneous Sampling

A property of a measurement system in which each input or output channel is digitized or updated at the same instant. You will need simultaneous sampling for applications where the time relationship between inputs is important, such as phase analysis of AC signals.

Because channel-dedicated analog-to-digital converters (ADCs) are used to sample data simultaneously between inputs, the maximum sample rate is applicable to each channel and is not divided by the total number of channels. Devices that don't have simultaneous sampling capabilities use multiplexing to connect each channel to its ADC.

Interval scanning is a low-cost option to simulate simultaneous sampling for low-frequency signals such as temperature or pressure. This method scans the input channels at one interval and uses a second interval to determine the time before repeating the scan. The input channels are scanned within microseconds, creating the effect of simultaneously sampling the input channels.

Signal Conditioning	0-20 mA current input
Analog Output	
Number of Channels	0
Digital I / O	
Bidirectional Channels	0
Input-Only Channels	0
Output-Only Channels	0

Counters / Timers	
Counters	0
Physical Specifications	
Length	9 cm
Width	9 cm
I / O Connector	37-pin D-Sub
Operating Temperature	-40 °C - 70 °C

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NI 9232

±30 V, IEPE, AC/DC Analog Input, 102.4 kS/s/ch, 3 Ch Module

- 3 channels, 102.4 kS/s per channel simultaneous AI; 41 kHz bandwidth
- ±30 V input, 24-bit resolution, 99 dB dynamic range
- Software-selectable AC/DC coupling; AC coupled (0.1 Hz)
- Software-selectable IEPE signal conditioning (0 or 4 mA); IEPE open/short detection
- Smart TEDS sensor compatibility
- -40 °C to 70 °C operating range, 5 g vibration, 50 g shock

Overview

The NI 9232 is a 3-channel C Series dynamic signal acquisition module for making industrial measurements from integrated electronic piezoelectric (IEPE) and non-IEPE sensors with CompactDAQ or CompactRIO systems.

The NI 9232 delivers 99 dB of dynamic range and incorporates software-selectable AC/DC coupling and IEPE signal conditioning for accelerometers, tachometers, and proximity probes. The three input channels simultaneously digitize signals at rates up to 102.4 kHz per channel with built-in anti-aliasing filters that automatically adjust to your sampling rate.

EMC Performance

To ensure EMC compliance, you must use a ferrite bead, such as part number 782802-01.

Recommended Software

NI sound and vibration analysis software, including the Sound and Vibration Measurement Suite and the Sound and Vibration Toolkit, provides signal processing functionality for performing condition monitoring and machine diagnostics including frequency analysis, order tracking, and display techniques such as orbit plots and shaft centerlines.

Recommended Accessories

-NI 9971 strain relief and operator protection

-EMI suppression ferrite for NI 9232 (part number 782802-01)

Note: To ensure EMC compliance, you must use a ferrite bead, such as part number 782802-01.

Box Contents

-1 NI 9232 C Series module

-1 NI 9232 Operating Instructions and Specifications manual

Specifications

Specifications Documents

- Specifications
- Data Sheet

Specifications Summary

General	
Product Family	Industrial I / O
Measurement Type	Accelerometer Microphone
Form Factor	CompactDAQ CompactRIO
Operating System / Target	Real-Time Windows
RoHS Compliant	Yes
Isolation Type	Ch-Earth Ground Isolation
Product Certifications	C-Tick CE Demko or VDE Ex FCC ISO 9001 / 14001 MIC RoHS UL - Hazardous Locations UL - Product Safety WEEE
Analog Input	
Single-Ended Channels	0
Differential Channels	3
Analog Input Resolution	24 bits
Maximum Voltage Range	-30 V - 30 V
Simultaneous Sampling	Yes

Simultaneous Sampling

A property of a measurement system in which each input or output channel is digitized or updated at the same instant. You will need simultaneous sampling for applications where the time relationship between inputs is important, such as phase analysis of AC signals.

Because channel-dedicated analog-to-digital converters (ADCs) are used to sample data simultaneously between inputs, the maximum sample rate is applicable to each channel and is not divided by the total number of channels. Devices that don't have simultaneous sampling capabilities use multiplexing to connect each channel to its ADC.

Interval scanning is a low-cost option to simulate simultaneous sampling for low-frequency signals such as temperature or pressure. This method scans the input channels at one interval and uses a second interval to determine the time before repeating the scan. The input channels are scanned within microseconds,

creating the effect of simultaneously sampling the input channels.

Excitation Current	4 mA
Dynamic Range	99 dB

Dynamic Range (RF Only)

The ratio of the highest signal level a circuit can handle to the smallest signal level it can handle (usually equal to the noise level), normally expressed in dB.

Maximum Bandwidth	40.96 kHz
Input Impedance	324 kOhm
Analog Output	
Number of Channels	0
Counters / Timers	
Counters	0
Physical Specifications	
Length	9 cm
Width	2.3 cm
I / O Connector	Screw terminals
Operating Temperature	-40 °C - 70 °C
Shock and Vibration	
Operational Shock	50 g
Random Vibration	10 Hz - 500 Hz
Random Operating Frequency Range	5 g

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NI 9214

16-Channel Isothermal Thermocouple Input Module

- Isothermal terminal block (included) for measurement accuracy up to 0.45 °C
- Several cold-junction compensation (CJC) sensors
- 250 Vrms channel-to-earth ground safety isolation
- Autozero channel for offset error compensation
- 24-bit ADC for up to 0.02 °C measurement sensitivity
- J, K, T, E, N, B, R, and S types supported

Overview

The NI 9214 is a high-density thermocouple module for NI C Series carriers designed for higher-channel-count systems that also need higher accuracy than the NI 9213 offers.

The NI 9214 has several features that increase overall accuracy including the following:

- Front-mounting metal terminal block (NI TB-9214)

- Several CJC sensors in the terminal block

- Component layout to minimize thermal gradients

You can use up to eight NI 9214 modules in an NI CompactDAQ chassis or CompactRIO chassis for 128 thermocouple measurements in a single chassis.

Each shipping kit contains the following:

-NI 9214 module with spring-terminal connectivity

-TB-9214 front-mounting terminal block

-Printed manual

Note that the NI 9214 isothermal thermocouple module **does not** work with the legacy NI cDAQ-9172 chassis or any of the legacy 1-slot C Series carriers (NI USB-9162, NI ENET-9163, and NI WLS-9163).

Specifications

Specifications Documents

- Specifications
- Data Sheet

Specifications Summary

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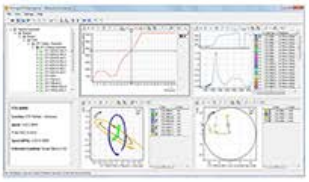
NI InsightCM™ Data Explorer

NI InsightCM Enterprise for Online Condition Monitoring

- Visualization client for maintenance and equipment specialists to view data and results
- Modes for viewing periodically acquired data and transient events
- Support for industry-standard vibration plots
- Interactive user interface to explore raw data, features, and historical trends
- Remote access to data stored on server



Overview

The NI InsightCM Data Explorer offers in-depth, interactive visualization and analysis of real-time and historical offline data to maintenance and equipment specialists. This application runs on a desktop or laptop and allows for convenient, remote access to data and results stored on the server.

For pricing information, request a follow-up with a local sales engineer.

The NI InsightCM Data Explorer provides two modes: one for viewing periodically acquired data and one for viewing previously captured transient events, such as start-ups and coast-downs.

With this software package, maintenance specialists can perform in-depth comparative analytics and detailed data mining to diagnose equipment health. They can:

-Select a server location and navigate the equipment hierarchy

-View multiple channels or features together

-Correlate data to faults and events, and save notes to easily recall diagnoses

-Take snapshots to compare current data to previously recorded data on the same machine

-Compare suspect health issues on one machine to previous fault signatures from other machines

-Track historical trends

-Determine whether harmonics or sidebands are present, and calculate their frequency

-Listen to the time series data that was recorded

Maintenance and equipment specialists can detect imbalances, bent shafts, misalignments, bearing defects, and other faults in rotating machinery based on the visualization and analysis capabilities offered in this application. They then can determine the actions that need to be taken as part of the diagnosis and maintenance procedure.

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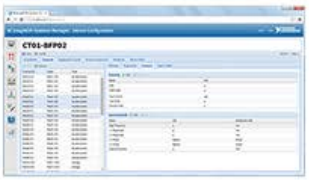
NI InsightCM™ Server

NI InsightCM Enterprise for Online Condition Monitoring

- Deployment-ready server software at the heart of the NI InsightCM Enterprise solution
- Handles data analysis, alarming, notifications, device management, user privileges, and more
- Thin-client web interface for configuring and monitoring devices and server parameters
- Optional NI InsightCM Enterprise Gateway for exporting data as OPC UA or OSIsoft PI tags
- Flexible purchase options available, including lower cost annual licensing options



Overview

The NI InsightCM Server delivers in-motion analytics combined with the management of CompactRIO systems, data, and alarms. The server software manages reliable, lossless communication across the entire architecture and includes a thin-client application called the NI InsightCM Systems Manager to configure, view, and manage remote acquisition systems and server parameters. The optional NI InsightCM Enterprise Gateway allows exporting tags and feature calculations to external software packages.

For pricing information, request a follow-up with a local sales engineer.

NI InsightCM Systems Manager

This thin client is accessible via any web browser to provide a portal to access, view, and configure server capabilities such as:

-Web-based CompactRIO configuration

-Web-based test panels for commissioning systems

-Equipment layout definition

-IT system console with error and message logs

-Alarm and notification management

-Aging of data to automatically reduce data

NI InsightCM Enterprise Gateway (optional)

Integration with third-party data historian, SCADA, CMMS, and other enterprise software packages is offered via the NI InsightCM Enterprise Gateway. With this add-on option, you can communicate calculated results via tags using the OPC UA protocol to a large number of software packages or directly to the OSIsoft PI System server, a database historian commonly used in the energy and oil and gas industries. Aggregation of key calculated features from the NI InsightCM Enterprise software suite with other measurements and business data allows for additional trending and alarming possibilities as well as consolidation with decisions on budgeting, downtime scheduling, spare parts, and maintenance personnel.

APPENDIX B. CASE STUDIES RELATING TO HYDRO POWER GENERATORS

- Monitoring Synchronous Power Generators with LabView and NI CompactDAQ
- Designing an Automatic Fault Monitoring and Diagnostic System for Large Hydro Generators

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NATIONAL INSTRUMENTS

Monitoring Synchronous Power Generators with LabVIEW and NI CompactDAQ

Control Cubicle with NI CompactDAQ Equipment

"We programmed the application using LabVIEW, which provides a real-time view of the entire system on a primary screen and a live view of all analog values displayed as VIs. LabVIEW also provided the flexibility to display all analog signals in a graph and record them on demand and on external trigger. "
- Nemanja Milojčić, Electrical Engineering Institute "NIKOLA TESLA"

The Challenge:
Automating the monitoring and analysis of an excitation system and generator used in thermal power plants.

The Solution:
Using NI LabVIEW software and NI CompactDAQ hardware to develop a flexible, fully functional, and easy-to-use power plant excitation monitoring system.

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Goran Mandić - Electrical Engineering Institute "NIKOLA TESLA"

In modern power systems, the main sources of electrical energy are synchronous generators. The power of the generators ranges from a few kilowatts in small power plants to upwards of 1.5 GW in modern thermal plants. Synchronous generators can be coupled with different types of hydro turbines in hydro power plants or steam turbines in thermal and nuclear power plants.

Excitation winding is connected to an excitation system and at the heart of every synchronous machine. In principle, an excitation system includes the regulated source of direct current needed to form an excitation electromagnetic field, which produces voltage at the generator's terminals, in a synchronous machine. It is crucial for scientists and operators to monitor, record, analyze, and study the transient processes that can occur during power production in these systems.

As a designer and manufacturer of complete excitation systems for synchronous generators, the Electrical Engineering Institute Nikola Tesla implemented a solution to monitor the behavior of our system and generator to determine the precise response of our excitation system and generator during normal operations and when failures occur. Using data acquisition systems that are independent from all control signals in excitation systems allows for experimentation without endangering primary equipment and normal plant processes.

Hardware and Software Configuration

We built the monitoring system with NI data acquisition modules on an NI CompactDAQ platform. The main elements include the NI cDAQ-9172 chassis, an NI 9203 analog input module, an NI 9245 digital input module, an industrial 15 in. touch panel PC, and signal conditioning equipment. In addition, we selected LabVIEW graphical system design software for its ease of use and seamless integration with NI CompactDAQ hardware.

We built our rack with isolated voltage and current sensors for signal conditioning equipment. We also conditioned the voltage and current signals so that output signals would be within voltage levels suitable for NI CompactDAQ analog input modules. The main goals during the application development process were to retain linearity in the range of measurements and acquire signals within 10 kHz bandwidth. We took digital input signals from I/O relays in a relay scheme of the excitation system control cubicle. Figure 1 demonstrates the control cubicle with NI CompactDAQ equipment and Figure 2 presents the software front panel for the system at the Nikola Tesla A plant in Obrenovac, Serbia.

Figure 1

Figure 2

We programmed the application using LabVIEW, which provides a real-time view of the entire system on a primary screen and a live view of all analog values displayed as VIs. LabVIEW also provided the flexibility to display all analog signals in a graph and record them on demand and on external trigger. The system allows the operator to easily review recorded analog signals, adjust the triggering conditions, view all digital inputs in real time, and monitor changes.

We implemented our first monitoring system in the Nikola Tesla A thermal power plant on the new excitation system for generator No. 4 (308 MW). We installed a second monitoring system on a new excitation system for generator No. 1 (348 MW) in the Kostolac B thermal plant in Kostolac and plan to implement a third systems in the Potpeć hydro plant in Priboj for generator B (20 MW).

Continued System Development

The most recent addition to our NI CompactDAQ system involves the ability to monitor two important subsystems in the power plant: the generator synchronizer and a device for automatic reconnection of the power plant 6 kV self-supply. The system ensures that all relevant signals are recorded in every generator synchronization process as well as when changes occur in the 6 kV busbar system.

Future system plans include linking communication of our NI CompactDAQ monitoring system with supervisory control and data acquisition (SCADA) power plant control equipment and the ability to access all measurement data remotely via an Ethernet connection. Overall, the monitoring system based on NI hardware and software proved to be a highly flexible and easy-to-use solution for our application.

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3/4 www.ni.com

Control Cubicle with NI CompactDAQ Equipment

LabVIEW Front Panel of the Cubicle

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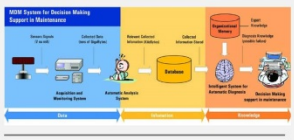
NATIONAL INSTRUMENTS

Designing an Automatic Fault Monitoring and Diagnostic System for Large Hydro Generators



MDM System for Decision Making Support in Maintenance - Flow Chart

"NI technology gives the MDM system superior reliability and flexibility, high performance, and easy maintenance. Another important advantage is its reduced cost compared to the systems that adopt dedicated acquisition units."
- Eliandro Félix, M&D Monitoração e Diagnose LTDA

The Challenge:
Designing a condition monitoring and automatic fault diagnosis and report system for large hydro generators and large industrial machines.

The Solution:
Using NI LabVIEW software and the CompactRIO hardware platform to build an advanced, real-time, online and offline monitoring system that supports a large amount of data, has high data acquisition channel density, is fully automated, and provides accurate information through graphs, reports, and analysis tools.

Author(s):
Eliandro Félix - M&D Monitoração e Diagnose LTDA

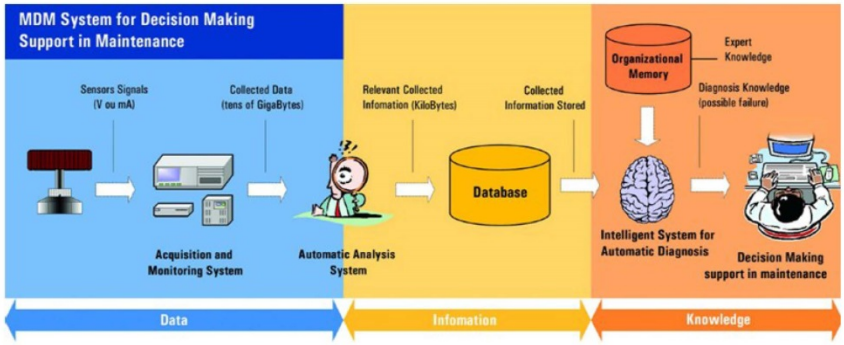
Our MDM system is composed of hardware and software for monitoring, automatic diagnosis, and prognosis of faults in industrial equipment. We based the system on LabVIEW and the CompactRIO platform to perform automatic data acquisition using various predictive techniques, whether online or offline, such as vibration analysis, temperature, and operational parameters.

After acquisition, the system automatically correlates and analyzes the different information acquired to generate a single diagnosis/prognosis of the equipment. Finally, it supplies high-level reports that users can access by e-mail or mobile phone to help them make decisions.

The MDM system offers the following benefits:

- Reduces the operational costs of predictive maintenance through automatic analysis
- Improves the operational safety of the equipment through early fault detection
- Correlates information of various magnitudes by monitoring multiple parameters
- Eases maintenance, progression and expansion with a modular and distributed architecture
- Offers more accurate diagnostics through self-adapting monitoring at the point of operation
- Supports decision making with automatic specialist diagnostics
- Creates diagnostics centers for remote communication via Internet or intranet
- Eases access with Web and mobile phone reports by e-mail and SMS
- Manages knowledge on the diagnosis through knowledge editing

The MDM system is fully configured by the user, from the sensors to the existing knowledge about fault modes for adaptation to any type of industrial equipment. It supports various languages (English, Spanish and Portuguese) as well. The system integrates data coming from different predictive techniques in a single platform for correlation and integrated analysis



The MDM system is fully configured by the user, from the sensors to the existing knowledge about fault modes for adaptation to any type of industrial equipment. It supports various languages (English, Spanish and Portuguese) as well. The system integrates data coming from different predictive techniques in a single platform for correlation and integrated analysis

One of the differences between this system and those used in traditional predictive maintenance practices is its working philosophy: the greater the amount of data accumulated, the less analytical effort necessary to decide the equipment status (automatic analysis). In traditional systems, the opposite occurs, that is, the greater the amount of data accumulated, the more analysis effort is necessary. Another important characteristic is its capacity to accumulate data from different sources of predictive information for integration and centralization.

The MDM system is ideal for monitoring hydro and turbo generators, motors, compressors, winding and cutting machines, shredders, chippers, extruders, and laminators.

In most production units, maintenance is the biggest operational cost of hydro generators. Moreover, bad maintenance in these units can have serious consequences on product quality, equipment availability, and environment, and therefore, on the company's competitiveness.

We created the MDM system to considerably reduce human intervention by using LabVIEW and CompactRIO, a multiparameter approach and current supervisory control and data acquisition (SCADA) trends, providing accurate information through graphs, reports, and other analysis tools.

In addition to serving as an intelligent decision support system, the system is the organizational memory of the company, formalizing the knowledge on maintenance equipment through storage and management of new knowledge. The benefits of the system include reduced maintenance costs, reduced parts inventories, reduced machine downtime and increased productivity.

Data Acquisition

Users can monitor multiple parameters online and offline using the MDM system. The data relative to the principal equipment and its auxiliaries is integrated in a single database, increasing the system's automatic diagnosis capacity.

NI technology gives the MDM system superior reliability and flexibility, high performance, and easy maintenance. Another important advantage is its reduced cost compared to the systems that adopt dedicated acquisition units.

Online Monitoring

The online data acquisition strategy of the system avoids storing irrelevant or repeated information, eliminating uncontrolled data growth through time. The MDM system also reduces the risk of false alarms and nondetection events using spectral signature comparison and decision algorithms that consider the characteristics of the operating point of the equipment.

Offline Monitoring

Meant for noncritical equipment, offline acquisition uses mobile data collectors with simplified and intuitive operating characteristics. During the data acquisition process, the MDM system shows the condition of the equipment and corresponding warning or alarm levels for the parameters monitored.

Analysis Tools

The MDM system has analysis tools and integrated reports that considerably reduce analysis time due to their ease of use. Analysis tools improve the knowledge stored in the system and help identify equipment fault modes. They are integrated into the diagnostics and show data in a graphic form. The MDM system adopts traditional signal processing techniques as well as specially developed techniques such as the following:

- Tendency analysis (parameters and faults)
- Orbit analysis with 3D animation
- Comparative analysis in the time and spectral domains
- Cascade diagrams
- 3D graphics
- Graphic display of temperature profiles
- Correlation analysis
- Operations between signals
- Intelligent assistant for balancing
- Analysis in different domains
- Comparative table for fast analysis
- Fault analysis in bearings (envelope: more than 8,000 prerecorded bearings)

Automatic Diagnosis

With the MDM system automatic diagnosis function, its main differential, any user can obtain a diagnostic of the status of the equipment, as well as understand, insert, and modify the stored knowledge using only a mouse. For this, we used a specialist fuzzy system that handles the uncertainties in a simple and efficient manner. Similar to the other system functions, its interface is friendly and intuitive.

Graphical Knowledge Tracking

The user can track the diagnosis by navigating through interactive and dynamic graphic trees to easily understand the generated diagnosis, as well as its improvement. This function also allows navigation from any concept that exists in the knowledge database (monitored points, rules and faults).

Report Creation and Management

The MDM system can transform hundreds of gigabytes of data into a single-page report daily. It has various report modalities that may be automatically or manually generated. The reports are easy to interpret despite the large amount of content. Through the reports, users learn the current status of the equipment and the system configuration. The MDM system reports may be displayed, exported, and manipulated in any Web browser.

Advanced Study Tools – Data Mining and Automatic Learning

The system has tools for knowledge extraction and refeeding the intelligent system using the data stored throughout time. With data mining techniques, neural networks, and decision trees, the data is transformed into diagnostic knowledge that is sent automatically and transparently to the user. With the tool, the user can perform studies that would be impractical to do manually.

Systems Deployed

Various companies already have MDM systems installed to automatically monitor and diagnose the condition of their equipment. Due to its modularity and connectivity, users can easily integrate the system with other existing monitoring or supervisory software. In the power generation sector alone there are more than 25,000 MW of power installed and monitored by MDM systems.

Some deployed systems and their geographic distribution within Brazilian territory:

Definitions:

UHE stands for *hydroelectric power plant*

PCH stands for *"small" hydroelectric power plant*

UTE stands for *thermoelectric power plant*

01. UHE Sobradinho

02. UHE Tucuruí

03. UHE Paraibuna

04. UHE Jurumirim

05. UHE Capivara

06. UHE Jupiá

07. UHE Ilha Solteira

08. UHE Três Irmãos

09. UHE Porto Primavera

10. UHE Cachoeira Dourada

11. UHE Taquaraçu

12. UHE Promissão

13. UHE Paulo Afonso I

14. UHE Chavantes

15. UHE Monte Claro

16. UHE Passo Fundo

17. UHE Nova Avanhadava

18. UHE Água Vermelha

19. UHE Paulo Afonso III

20. UHE Risoleta Neves

21. UHE Ibitinga/AES Tietê

22. UHE Machadinho

23. UHE Salto Osório

24. UHE Salto Santiago

25. UHE Apolônio Sales

26. UHE Paulo Afonso II

27. UHE Lajeado

28. UHE Quebra-Queixo

29. UHE Santa Clara

30. UHE Jauru

31. UHE Porto Estrela

32. UHE Simplício:

33. PCH Santa Lucia I

34. PCH Santa Lucia II

35. PCH Tucunaré

36. PCH Sapezal

37. Subestação Santo Angelo

38. Subestação Embu Guaçu

39. UTE Uruguaiana

40. UTE Norte Fluminense

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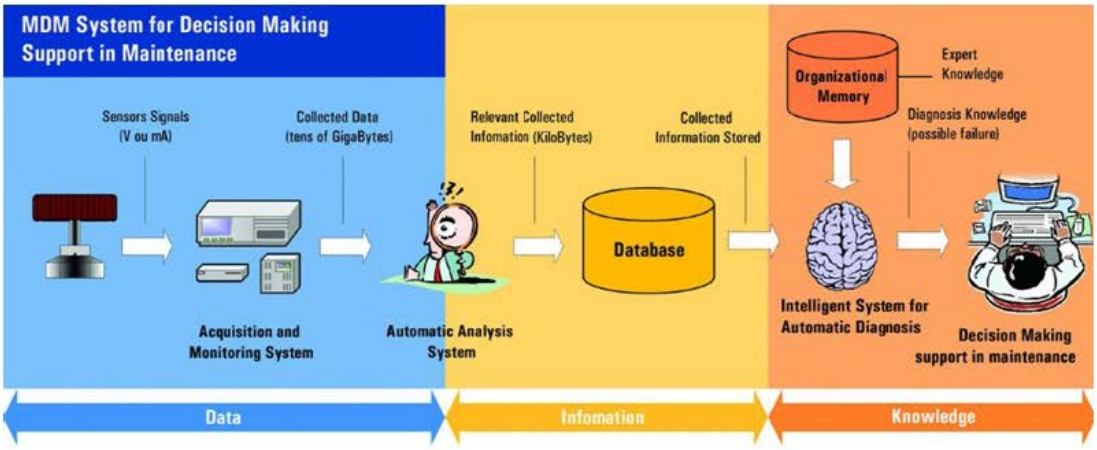
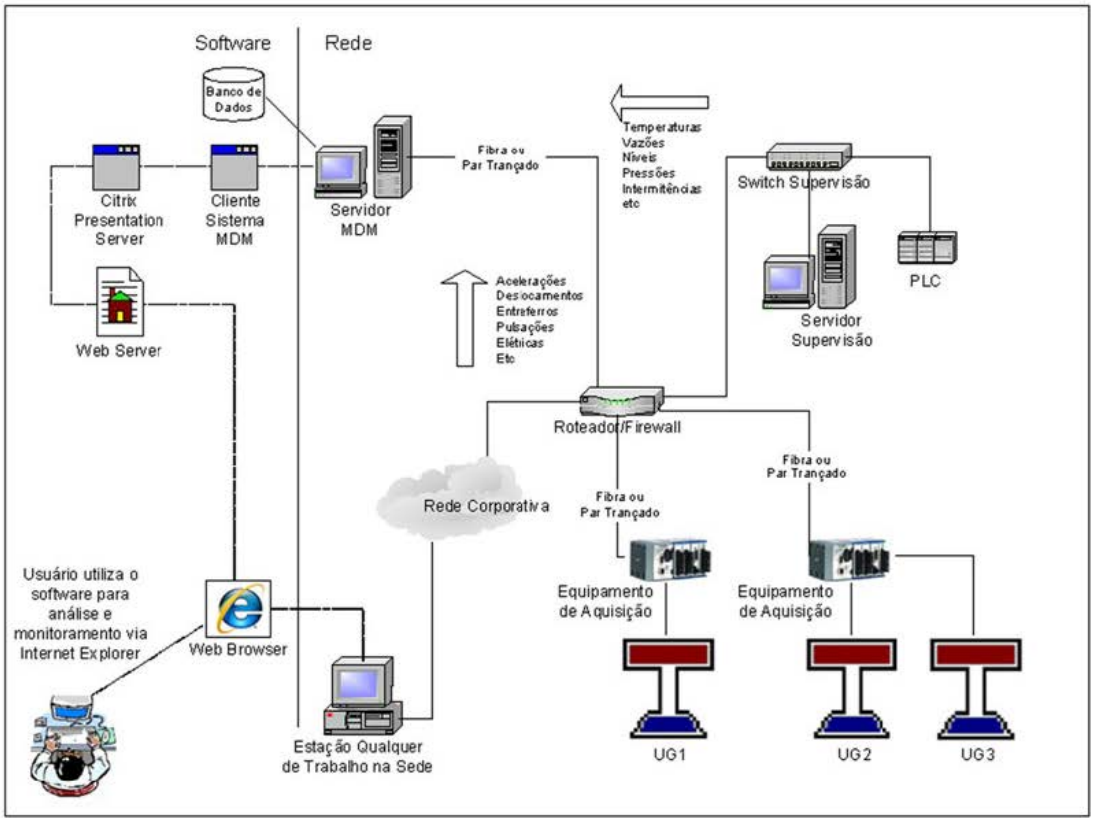
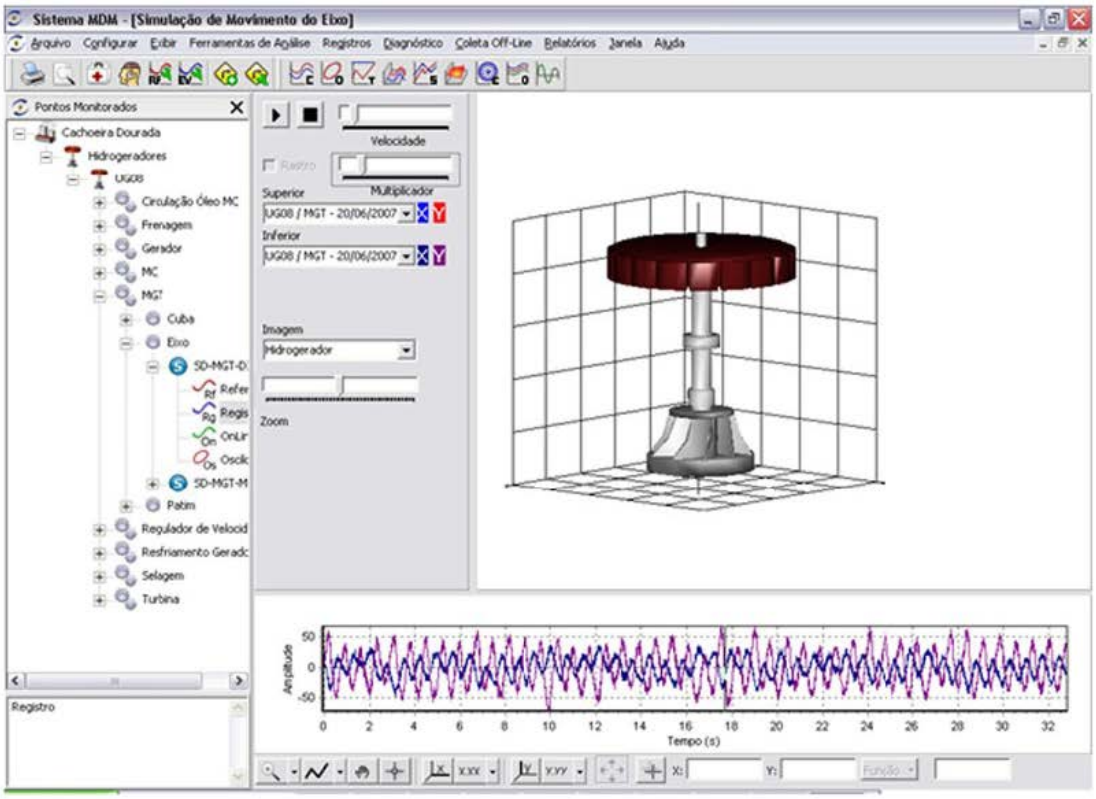


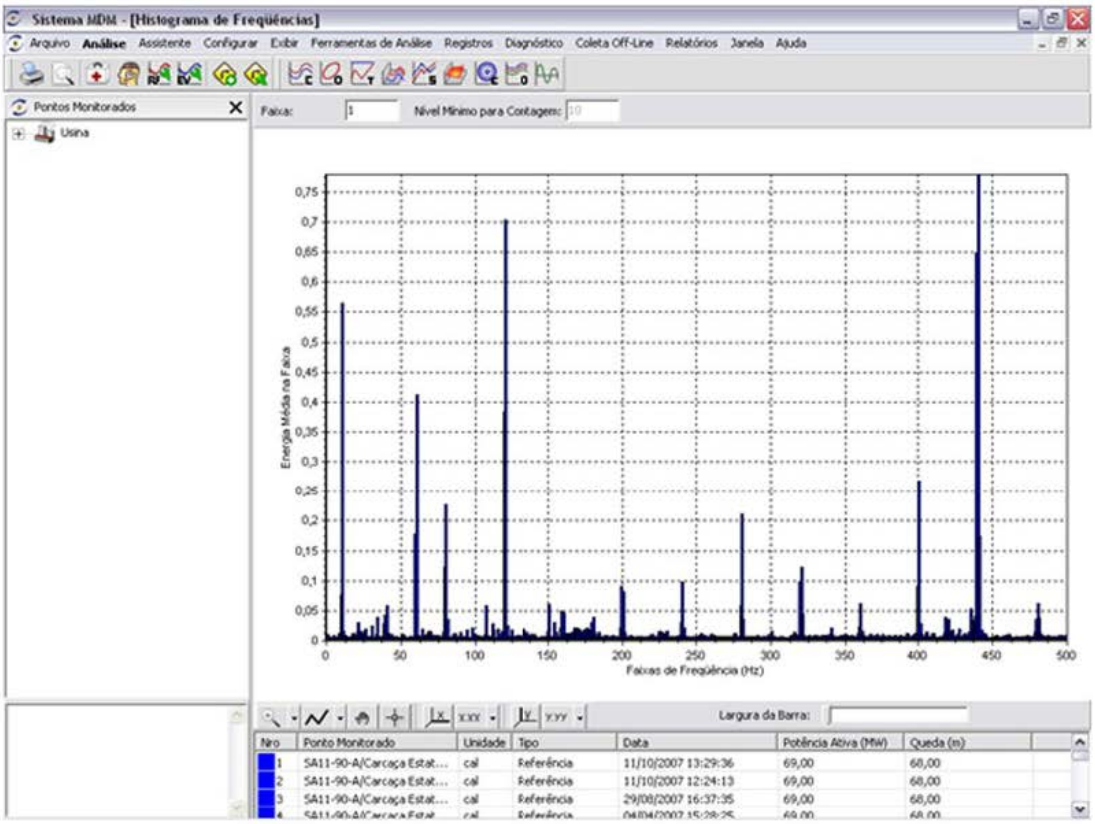
MDM System for Decision Making Support in Maintenance - Flow Chart



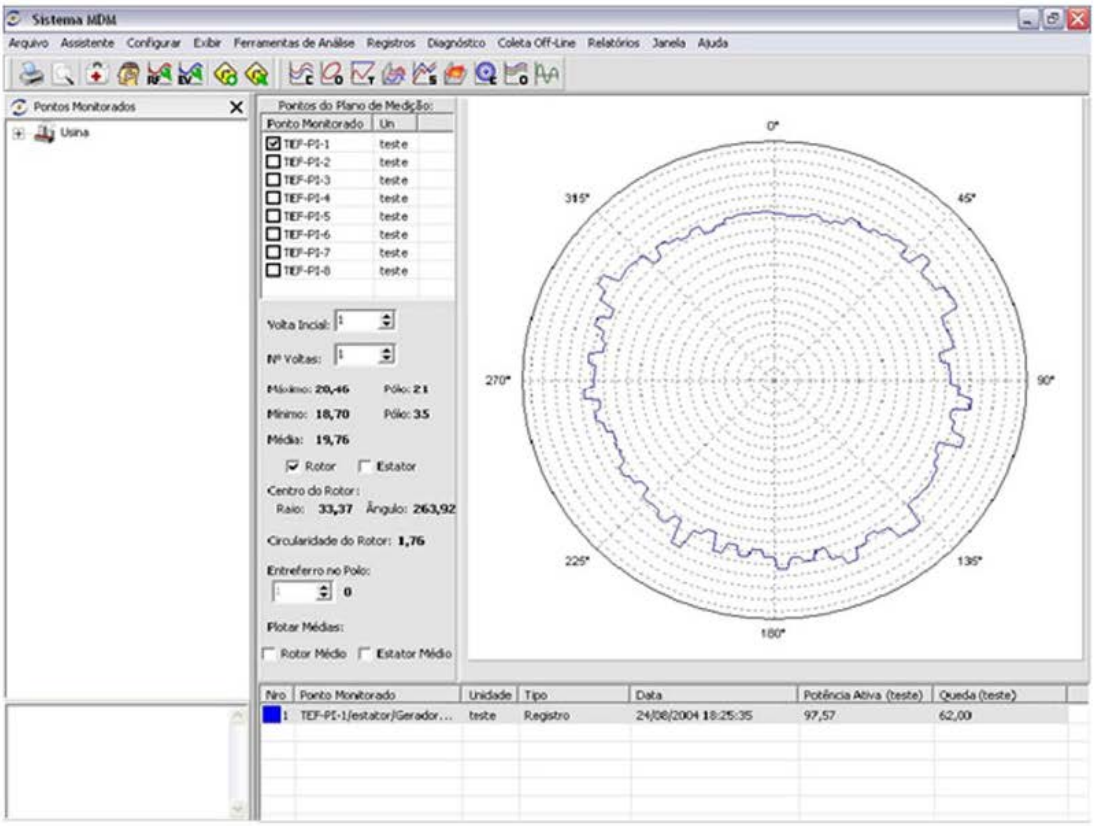
MDM System - Measurement Chain



MDM System - Orbit Analisys, Axis Simulation



MDM System - Frequency Histogram



MDM System - Orbit Analisys

MDM System - Data Acquisition Enclosure with a CompactRIO Controller, Chassis and CompactRIO Modules

MDM Deployed Systems in Brazil

Legal
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APPENDIX B

NLH report - Unit 7 Run-Up Issues 2010

newfoundland labrador hydro
a nalcor energy company

UNIT 7 VIBRATION 2010

Prepared By: Dave Royle
Plant Mechanical Engineer
August 5, 2010

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a nalcor energy company

HISTORY

Unit 7 is equipped with a floating rim guidance system, which makes it difficult for the unit to maintain its balance following shutdowns and startups. Each start/stop disturbs the position of the rotor, throwing the generator out of balance. The unit would balance itself over a few months of continuous operation; however the vibration levels have been so high that the unit could not run at these levels. To remedy this, the unit has to be put through a series of stop/start sequences to disturb the relative position of the rotor and "trim balance" the generator.

EQUIPMENT SPECIFICATIONS

The following specifications are design clearances; the commissioning values as well as the final values for the 2010 annual are located in Appendix 1.

Turbine Bearing:	(Radial) Design min: 0.0100" (Radial) Design max: 0.0145" High Temperature Alarm: 75 degrees Celsius
Upper Primary Seal Clearances:	0.080/0.094" (Diametrical)
Lower Primary Seal Clearances:	0.090/0.104" (Diametrical)
Generator Guide Bearing:	Design in the commissioning manual is 0.012", however this value was reduced to 0.009" by recommendations with GE.

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RUN-UP 2010

On July 11th 2010 unit 7 was ready for a mechanical run of the unit. This was performed and vibration levels seemed alright at 200 rpm, however once the unit was taken to speed no load (snl) the vibration levels went off the chart, i.e.: greater than 20 mils. The unit was taken down to start the procedure of trim balancing. This first attempt at restoring the unit was unsuccessful due to a fault with the new RTU installed during the annual. Once troubleshooting was done (July 13th) on the electrical issue the unit was again prepared for the trim balancing procedure, this again was unsuccessful due to a continuing problem with losing the signal from powerhouse 2 to the control room in powerhouse 1. On July the 14th another attempt at trim balancing unit 7 was attempted and again we lost the signal from the RTU, this was corrected and the procedure continued without success. Once the machine went above 100 MW the vibration levels continued to rise with no indication of this level dropping off. Over the next few weeks the unit was balanced, this took longer due to the new code (only one balance run per day) and the proper orientation of our vibration equipment was in question, this was rectified by contacting Rockwell, the manufacturer of the vibration equipment. The balancing of the unit allowed for better vibration levels at snl and up to 50 MW however the vibration levels increased thru the rough zone (anticipated) but did not drop off after 100MW, the levels actually increased. The final run up after balancing was done on July 28th with similar results, the unit vibration levels would increase after 100 MW with load. It was then decided, with consultation with Dave Cole of Andritz (GE), to center the unit and reset the generator guide bearing clearances to the recommended clearance of 0.009" radial. This was performed on July 29th – 31st; the unit was restored and ran up with lower vibration on Sunday Aug 1st. The unit was released to operations with a vibration level of approximately 11 mils at 120 MW; operations were informed to monitor the vibration and temperature levels for the next 24 hours. On Monday Aug. 2nd, Dave Cole was contacted once again to review the vibration levels and he noted they were high but acceptable for unit 7 considering the history of the unit. He also advised us that there may be a need to center the rotor in the near future. Note all vibration readings during the run-up attempts and balancing is located in appendix 2.

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RUN-UP ISSUES

1. The capital work on unit 7 this year, RTU upgrade, ran in to problems during attempts to bring the unit back on-line. This occurred a few times during the run-up, causing the first delay in the schedule.
2. Unit 7 has had many problems with vibration in the past, the vibration tends to decrease in the winter months and to increase during the summer months. From year to year the levels tend to increase form the previous year possibly indicating the requirement of re-centering the generator guide bearing.
3. During balancing of the unit, the balancing technique came into question as the results obtained were not correcting the vibration levels of the unit.
4. Conflicting data on the standing instruction compared to the engineering directive concerning vibration rough zones for unit 7. Also ECC has different valves for this rough zone.
5. The existing vibration equipment on unit 7 shows a range for the vibration value instead of a numerical value and does not have the capability of measuring phase angles, therefore our portable vibration analyzer is required to measure the phase angles. The question of calibration frequency on our portable analyzer was asked during the balancing of the unit.
6. While performing the balancing procedure, which requires multiple runs on the unit followed by adding balancing weights, the new code added a considerable amount of time to the procedure. With unit 7 having an independent penstock with no need for a spherical valve, it is required to drain the penstock and apply full isolation between each balancing move. On average only one balance run a day was possible.
7. During troubleshooting the vibration problem on this unit the lower primary seal clearances came in to question. The clearances on both the upstream and downstream sections seem to be closing in and are well below the design specifications.

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RECOMMENDATIONS

1. To fully investigate the capital upgrade on unit 7. This will be undertaken by the SPA in conjunction with the project manager and the plant electrical engineer. The purpose of this investigation is to ensure the new RTU configuration is reliable and the signals will not be lost during the critical availability season and to ensure the new system performs as originally proposed.
2. All vibration and temperature trending should continue and the SPA should be informed of sudden jumps in vibration and bearing temperature. Also when any of the generator vibration levels exceed 13 mils or bearing temperatures exceed 75 degrees the SPA should be notified immediately. It has been suggested that the vibrations tend to creep up approximately every five years and is usually fixed by setting the guide bearing.
3. To avoid confusion and to have all personal on the same page, an engineering directive should be created outlining the process of balancing any machine within Hydro Generation; this should be done by the plant mechanical engineer.
4. The plant mechanical engineer should define the actual rough zone for this unit and once determined both the engineering directive and the standing instructions should be updated. This information should also be sent to ECC to update their records.
5. All portable vibration equipment must be calibrated yearly to ensure the use of this vital equipment is accurate. Unit 7's permanent vibration equipment should be replaced with equipment capable of displaying phase angles and numerical values of the vibration analyzed to ensure accurate readings and less reliance on portable equipment. This should be added to the 5 or 20 year plan.
6. Plant operations need to investigate the possibility of a work method or an approved procedure to be put in place to minimize the time required to balance the unit under the new code. With the new code only once balance run per day is possible, and usually while performing this procedure there are no other work groups on unit, so if possible with an approved procedure in place the down time during a balancing run would be minimized.
7. Problems with seal and bearing clearance need to be rectified. Due to an oval effect noted on the lower primary seal this should be checked yearly and the results forwarded to the plant mechanical engineer for review. And due to the tendency of the guide bearing opening up with a reset approximately every five years it is also recommended to check these every year and forwarded to the plant mechanical engineer for review.

newfoundland labrador hydro
a nalcor energy company

8. Prepare for centering the rotor. With consultation with Dave Cole (Andritz) he thinks the rotor may require to be centered in the near future. This is an extensive job that takes approximately 2-3 week and requires an Andritz representative on site such as Dave Cole.
9. For the long term, the vibration problems on unit 7 are not going to change by balancing or trend monitoring and as the unit continues to age the problem may get worse, therefore Engineering Services need to investigate a capital upgrade of the floating rim design on unit 7 with a new rotor assembly including a new rotor with poles and the rotor spider and rim. This upgrade would ensure the reliability of the unit for years after the fact and eliminate the struggle to get the unit back on-line after annual maintenance.

APPENDIX 1

Equipment Specifications

HYDRO

ENGINEERING DESIGN

Subject: Design & Commissioning Values for Unit #7

Made By: _____ Date: _____ Page 1 of 6

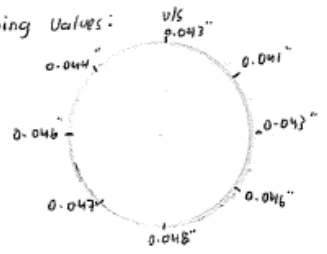
Equipment Specifications

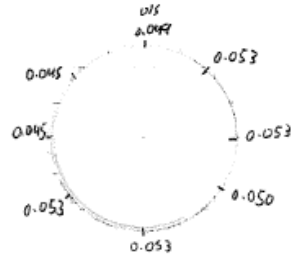
Seal Clearances :

Crown (Periphery)	0.080 / 0.094"	(design)
Crown (Inside)	0.096 / 0.116"	(design)
Band	0.090 / 0.104"	(design)

Commissioning Values:

Upper primary (Crown Seal)

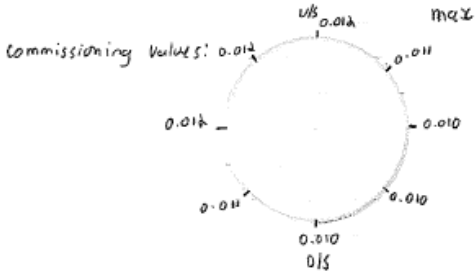




Lower primary (Band Seal)

Turbine Bearing Clearances : (Radial)

	Design	Actual
min	0.0100"	0.012"
max	0.0145"	0.015"



High temp alarm : 75°C

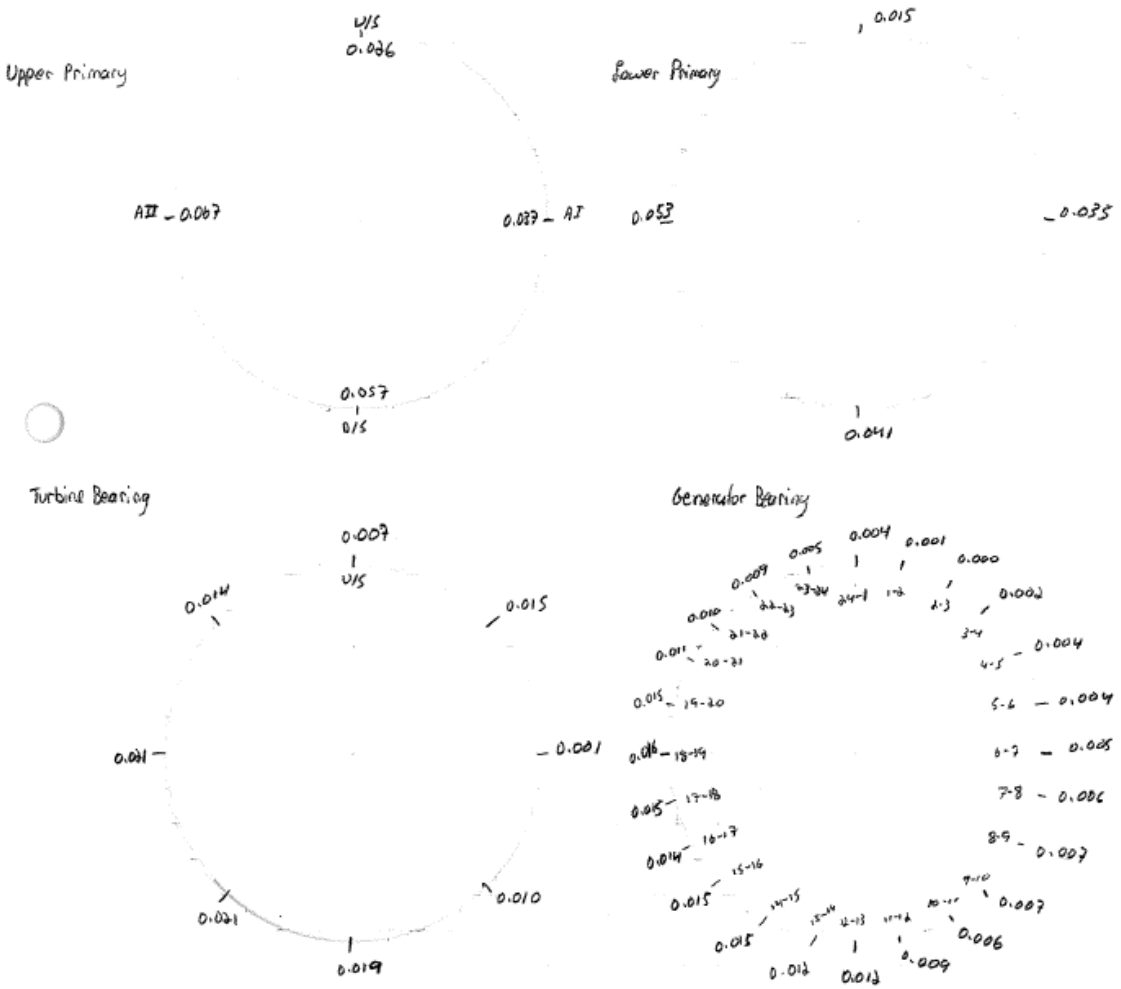
Generator Bearing Clearances : design -> 0.012", however this has been changed to 0.009" which was the value to re-center the bearing in 2010

HYDRO
THE POWER OF COMMITMENT

ENGINEERING DESIGN

Subject: Seal & Bearing Clearances July 4 2010

Made By: _____ Date: _____ Page 2 of 6



Proposed move to center Tur. Bearing was
6↓ + 10←

HYDRO
THE POWER OF COMMITMENT

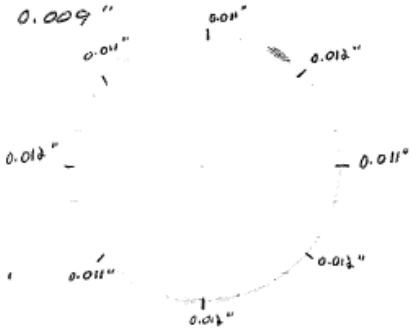
ENGINEERING DESIGN

Subject: Final Clearance Readings for 2010

Made By: _____ Date: _____ Page 3 of 6

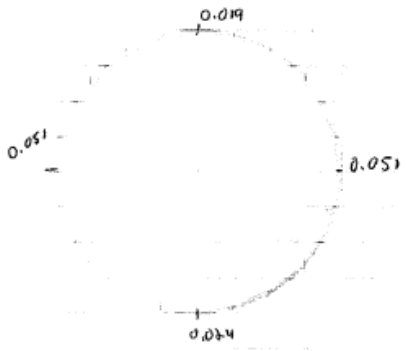
Generator Bearing set @ 0.009"

Turbine Bearing Centered:
(final readings July 30)



Upper Primary Seal

Lower Primary Seal
note another set of
reading were taken
results on next page



HYDRO
THE POWER OF COMMITMENT

ENGINEERING DESIGN

Subject: Lower primary seal clearances (final reading 2010)

Made By: _____ Date: _____ Page 4 of 6

Totals: U/S + D/S = 0.038 + 0.035 = 0.043"

AI + AII = 0.050 + 0.051 = 0.101"

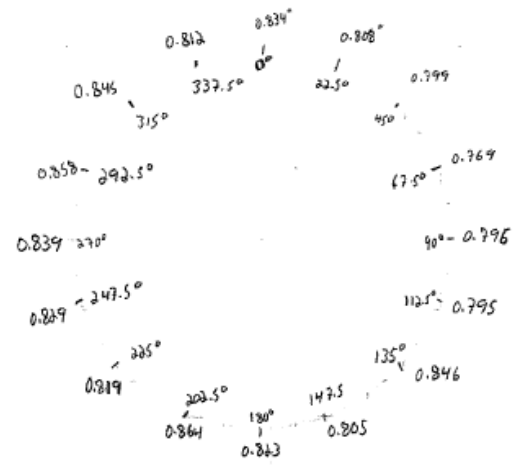
HYDRO
THE POWER OF COMMITMENT

ENGINEERING DESIGN

Subject: Stator Profile - July 2010

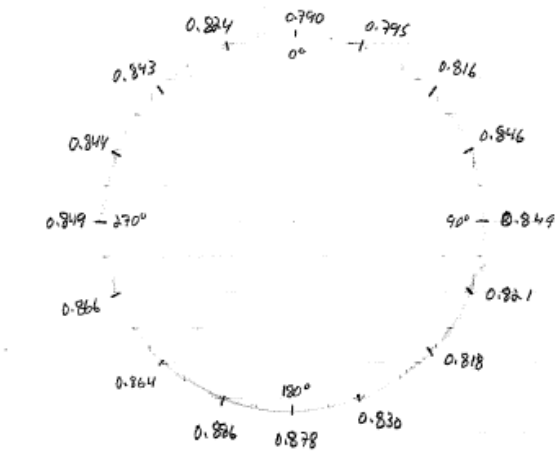
Made By: _____ Date: _____ Page 5 of 6

Stator Top



(360° ~ 0.827")

Stator Bottom



(360° ~ 0.793")

(Readings taken following the same pole number around the stator as the rotor is rotated)

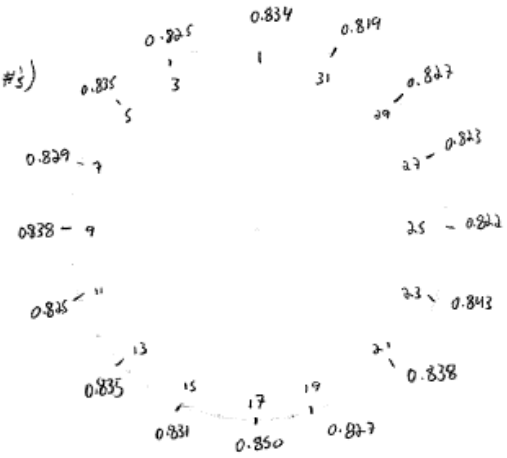
HYDRO
THE POWER OF COMMITMENT

ENGINEERING DESIGN

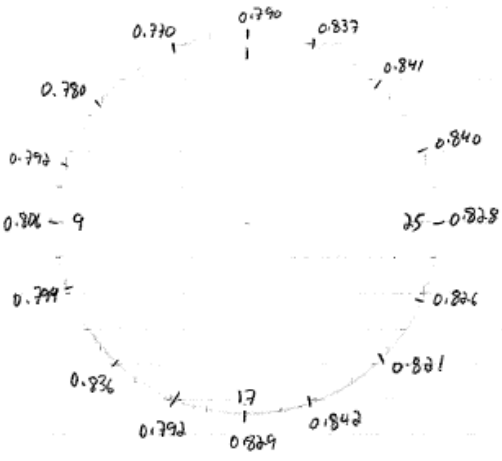
Subject: Rotor Profile - July 2010

Made By: _____ Date: _____ Page 6 of 6

Rotor Top
(reference # in circle are Pole #'s)



Rotor Bottom



(Readings taken from the same U/S position on the stator as the rotor is rotated)

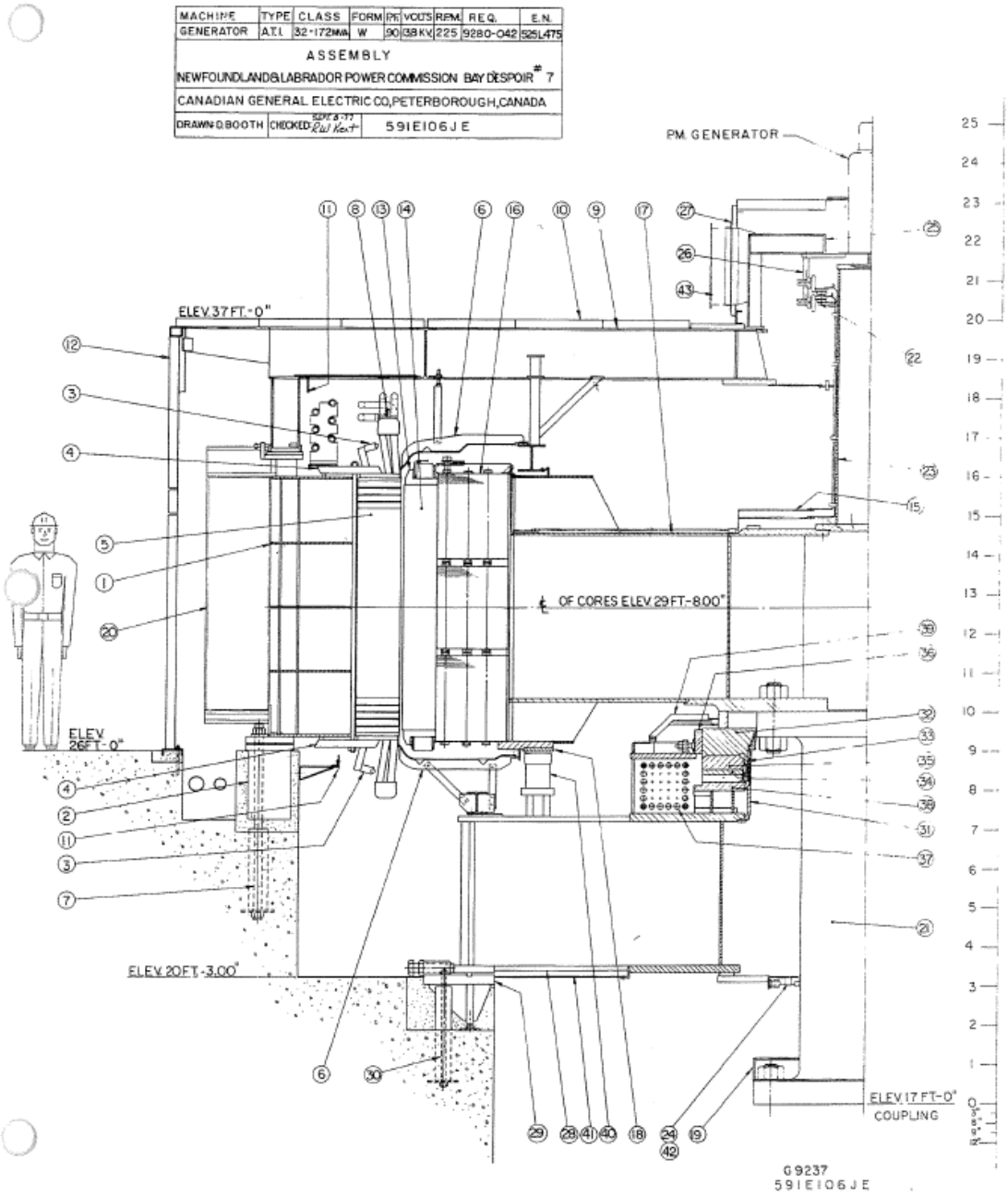


Figure 2-2 Generator Assembly

2-4

1. Stator Frame	23. Collector Support
2. Stator Sole Plate	24. Creep Indicator
3. Stator Coil Support	25. Support for Brush Rigging
4. Stator Flange	26. Brush Rigging
5. Stator Punching	27. Center Housing
6. Shroud Support and Assembly	28. Main Bracket
7. Stator Foundation Bolt	29. Sole Plate (Main Bracket)
8. Stator Winding	30. Foundation Bolt (Main Bracket)
9. Upper Bracket	31. Oil Well Tube
10. Covers	32. Thrust Ring
11. Air Deflectors	33. Rotating Skirt
12. Housing Assembly	34. Stationary Ring
13. Rotor Pole Piece	35. Rotating Ring
14. Rotor Coil	36. Guide Bearing
15. Rotor Connections	37. Cooling Coil
16. Rotor Rim Plate	38. Base Ring
17. Rotor Spider	39. Oil Baffler
18. Brake Plate	40. Brakes and Jacks
19. Coupling Guard	41. Pit Diaphragm
20. Surface Air Cooler	42. Grounding Brush
21. Generator Shaft	43. Fan
22. Collector	

Table 2-1 Assembly Drawing Key

2-3

APPENDIX 2

Vibration and Temperature Readings

2010-07-06

UNIT 2 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 182.42 TAILRACE LEVEL 1.26 TRASHRACK

TIME	LOAD MW	VIBRATION MILS GEN 2	4	TURB 1	3	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS		WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
1055	NSD	-	-	-	-	34	30	35						338	20.8	39	30	16	17/18	
1300						STARTED UP & SHUTDOWN						EXCESSIVE		VIB		OVER 20 MILS.				
1310						STARTED UP & SHUTDOWN						EXCESSIVE		VIB		OVER 20 MILS.				
1321	NSD	-	-	-	-	51	29	40												
1330						STARTED UP & SHUTDOWN						EXCESSIVE		VIB				19 MILS.		
						PUT BRAKES ON AT 70 R.P.M. AND THEN RELEASE. BRAKES														
						CAME ON AGAIN & NORMAL SHUTDOWN.														
1338						STARTED UP & SHUTDOWN						17 - 18		MILS.		APPLIED BRAKES AT				
						80 RPM														
1358	2.0MW SWC					62	47	50.5												
1403	4.0MW SWC					65	48.5	52												
1408	4.0MW SWC					65.5	51	53.5												
14.13	4.0MW SWC					67.5	52	55												
14.33	N20					53.5	48	51.5												
14.38	8.0MW SWC					60.5	49	55												
14.43	12.0MW SWC	15	5			66	51	56.5												

2010-07-16

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 182.42 TAILRACE LEVEL 1.26 TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C								WATER FLOWS LPM				WATER TEMP °C		
		GEN 2	4	TURB		THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS		GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
14:48	F.OU SNC					67.5	52.5	58.5												
14:53	10	17	6 4			67.5	54	59.5												
14:58	20	11	6 4			68	54.5	60.5												
15:03	30	17	7			68	54.5	61												
15:08	40	17	7			68.5	55	61.5												
15:13	50	17	8			68.5	55.5	62												
15:18	55	17				70.5	56	62.5												
15:23	60	17.5	12			71	56	63.5												
15:28	65	16.9				71	56	63.5												
15:33	70	15.8				71	56	63.5												
15:38	71	15				71	56	64												
15:43	77	15				71	56	64.5												
15:48	83	14	8			71	56	64.5												
15:53	87	15	9			71	56.5	65												
15:58	100	15.2	8.4			71	56.5	65.5												
16:05	110	16.4	11			71.5	56.5	66												

2010-07-17

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C								WATER FLOWS LPM				WATER TEMP °C		
		GEN 2	4	TURB 1	3	THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS		GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
0515	80	16 14	7.2	3.6	2.9	70	57	72						340	21.2	40	26			
0525	90	15 14	9.2	3	2.2	70	57	72												

2010-07-19

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 20/

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

TIME	LOAD MW	VIBRATION MILS GEN 2	4	TURB 1	3	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS	T.BRG TRIPS	WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
0820	N.S.D	-	-	-	-	29	20	26				343	21.3	39	90			
0835	F.O.N S.W.C	16	18			UNIT	SHUT	DOWN	HIGH	VIBRATION.								
0900	F.O.N S.W.C	19	8	2	2	UNIT	RESTARTED.											
0905		16 17	6	2	2	62	45	45										
0910						UNIT	SHUT	DOWN										
0929		14 17	6	2	2	UNIT	RESTARTED.											
0931		17	5 6	2	2	59	46	46				342	21.3	39	00			
0937		16 16	5 6	2	2	64	50	50				344	21.3	39	60			
0941						UNIT	SHUT	DOWN	VIB.	OVER	18 MILS.							
10:20						UNIT	RESTARTED.											
10:25	F.O.N S.W.C	18	6 6	2	2	52	46	48.										
10:30	F.O.N S.W.C	16 17	5.2	2	2	63	49	51				343	21.3	39	40			
10:35	"	16 17	5.8	2.2	2.0	66	52	52				342	21.2	39	70			
10:40	"	18	4.8	2.2	2.0	66	52	55										
10:43	"	18 19	4.8	2.2	1.6	66	53	55										
10:45	"	15 19	4.8	2	1.6	66	53	56				338	21.2	39	80			
10:50	"	19	4.8	2	1.6	67	54	57										
10:52	"	19	4.8	2	1.6	67	54	58										

2010-07-19

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2016

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN		TURB		THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G..BRG DISCH.
1055	11					67	54	58											
1057	11	19	4.8	2	1.6	67	54	59					340	21	40	90			
1100	11	19.5	4.8	2	1.4	67	54	59											
1102	11	19.2	4.8	2.2	1.6	67	55												
1105	11	19.0	4.8	2.4	2	67	55	60											
1107	11	20	10	2.6	2.2	67	55	60											
1110	11	20 19	8 6	4	2.8	67	55	60					328	20.5	35	40			
1112	11	18 16	10	4	4	67	55	60											
1115	11	17 16	10	4	4	67	55	60					337	20.9	38	40			
1117	R.P.M 170	10	8	4	4	66	53	60											
1120	R.P.M 150	6.4	6	4	3.2	66	52	59											

2010-07-21

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 182.39 TAILRACE LEVEL 1.47 TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN 2	GEN 4	TURB 1	TURB 3	THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
1255	NSD	-	-	-	-	34	28	27	NOTE:	25	LBS	PLACED	IN	BUC	KET	#6	18	21 / 20	
1322	NSD	-	-	-	-	34	28	27					479	20.5	38	90	16	18 / 18	
1425	100	6	5.2	1.6	2	34	29	29					475	20.4	41	90	16	18 / 16	
1435	140	9	7	2	2	49	37	38					475	20.5			16	18 / 16	
1445	145	9	6.4	2	2	54	41	41					475	20.4			16	18 / 16	
1450	185	13	8	2	2	56	43	44					476	20.5			16	18 / 18	
1452	190	14	9	2	2	58	45	45					478	20.5			16	18 / 18	
1455	225	20	5	2	2	61	46	47					475	20.5			16	18 / 18	
1458	200	14	9	2	2	62	48	49									16	18 / 18	
1500	225	20	6	2	2	62.5	48.5	49					478	20.5			16	18 / 18	
1525	150	7	4.5	2	2	51	44	44					475	20.5			16	17 / 16	
1529	200	13	7.5	2	2	53	44	47					477	20.6			16	17 / 16	
1533	225	16	8	2	2	59	47	50					476	20.5			16	17 / 16	

2010-07-03

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 182 38 TAILRACE LEVEL 1.28 TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C						WATER FLOWS LPM				WATER TEMP °C		
		GEN 2	4	TURB 1	3	THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS	T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
						NOTE:	REMOVE 25 LBS			FROM BUCKET		# 6		ADDED 15 LBS		TO		
							BUCKET # 5.			ALSO ADJUSTED		BAFFLE		SEALS.				
0850		–	–	–	–	30	26	26				476	20.5	44	00	18	18/18	
0900	150	11	8	2	2	41	32	34				473	20.4	45	10	17	18/17	
0905	200	15	11	2	2	49	36	38				472	20.5	44	20	17	18/17	
0913	150	11	8	2	2	53	40	40				473	20.3	44	20	17	18/17	
0918	175	14	10	2	2	57	44	44				473	20.4	44	10	17	18/17	

2010-07-24

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2016

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

TIME	LOAD MW	VIBRATION MILS		BEARING TEMPERATURES ALARMS/TRIPS °C						WATER FLOWS LPM				WATER TEMP °C		
		GEN	TURB	THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS	T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
				NOTE: 15 LBS	4	25 LBS	REMOVED FROM		BUCKET #5					16		
					RESPECTIVELY.											
0845	N50	-	-	30	25	26				480	20.7	40	60			
0855	150	6.4	6.8	32	28	32				481	20.9	40	80			
0902	140	6.6	6.0	49	35	37				479	20.8	41	49			
0906	191	14.4	10.6	52	40	40.5				482	20.8	40	90			
0910	191	13	9	55	42	43				479	20.7	40	90			
0915	191	12.4	9	59	45	45.5				479	20.7	40	50			
0920	210						NOTE: EXCESSIVE			USAGE						
0923	200	13.4	9.6	62	47.5	48.5					20.8	40	40			
0927	225	14.6		63	49	51					20.9	41	00			
0946	225	15.2	4	54.5	46.5	50					20.7	40	80			
				NOTE: AUTO START FIELD OFF.												
1018	230	19	4	52	45	49										
1021	230	17.8		59	45	50.5										
1025	230	17		64	50	52										

2010-07-24

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

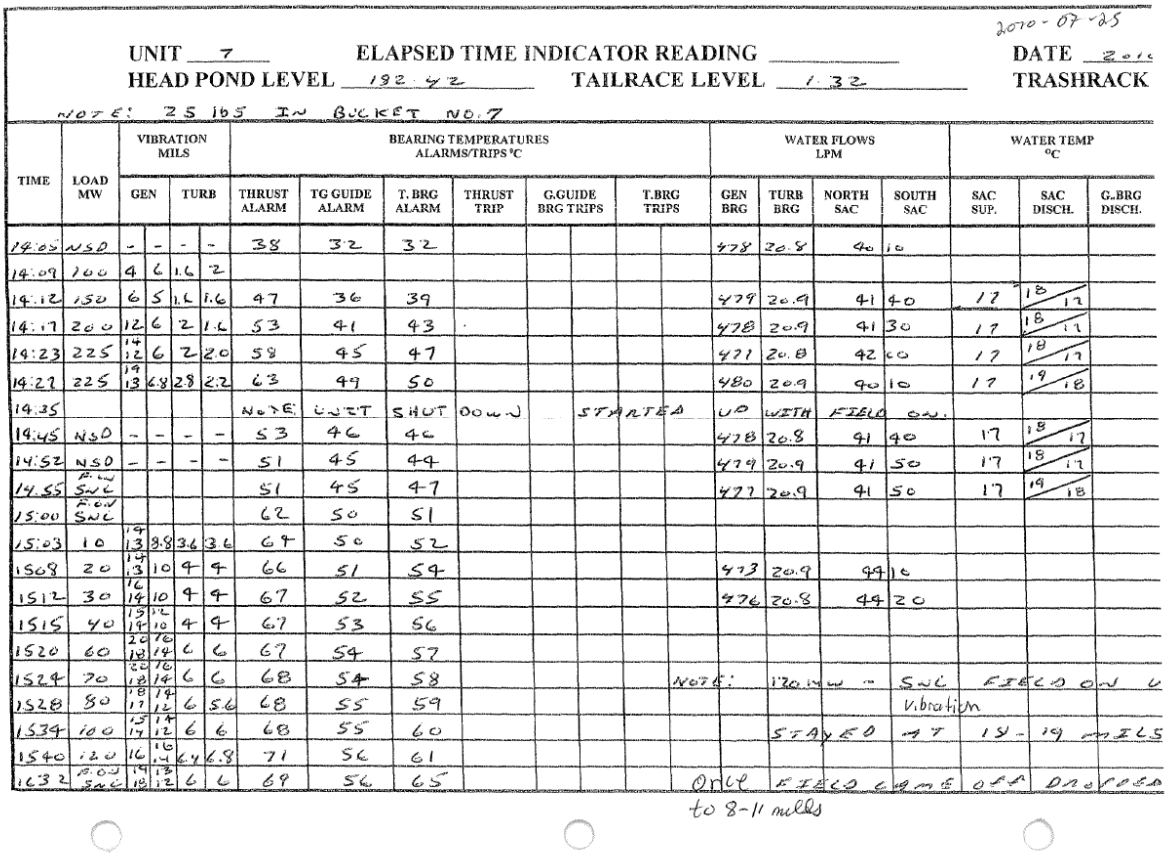
TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN		TURB		THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
						NOTE:	AU70	START	FIELD	ON									
1027	230	16.4	6.0	2	2	64.5	50.5	51.5					478	20.8	40	00			
1035	230	16.8	6.4	2	2	66	53	56					480	20.9	40	60			
1052	230	17.0	6			58.5	49	53.5					476	20.8	41	20			
1057	230	16.2	6			64	51	56					480	20.7	39	20			
1115	230	16.6	5			56	48	54					478	20.7	40	80			
1118	230	15.8	5.2			62	51.5	55					479	20.8	41	20			
1121	230	15.0	5.2			64.5	53	56.5					479	20.8	40	80			
1125	230	15.6	5.2			66.0	53.5	58					479	20.7	40	60			
1130	230	16.8				66.5	54	59.5					479	20.9	38	50			
1150	230	18				55	49	55					478	20.9	41	20			
1155	230	16.2				63	56.5	59					479	20.9	40	90			
1202	20	16.2				66.5	53.5	60.0					478	20.8	41	00			
1206	30	15.6				67	54	60.5					478	20.8	40	30			
1209	40	15.5				67	54.5	60.5					478	20.9	41	50			
1213	50	14.9				67	55	61					479	20.8	40	60			
1219	60	16.4				67.5	55	61					477	20.8	39	50			
1225	70	17.8				68	55.5	63					478	20.9	40	00			
1229	80	18.0				68	55.5	63					477	20.8	39	50			
1234	90	18.4				68	56	63					477	20.9	40	00			

2010-07-24

UNIT 2 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN 2 4		TURB 1 3		THRUST ALARM	?G GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G..BRG DISCH.
1238	100	15				68.5	56	63.5					479	20.9	39	80			
1246	110	16				68.5	56.5	64.5					476	20.8	41	00			
						NOTE:	AUTO	START	FIELD	ON .									
1252	120	16X				69	57	65					477	20.8	38	90			
1254	124	17																	
1258	125	16.5				71	58.5	65					477	20.8	39	80			



2010-07-25

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 192.42 TAILRACE LEVEL 1.32 TRASHRACK

NOTE: 25 lbs IN BUCKET NO. 7

TIME	LOAD MW	VIBRATION MILS GEN		VIBRATION MILS TURB		BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS		WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
14:05	NSD	-	-	-	-	38	32	32						478	20.8	40	10			
14:09	100	4	6	1.6	2															
14:12	150	6	5	1.6	1.6	47	36	39						479	20.9	41	40	17	18/17	
14:17	200	12	6	2	1.6	53	41	43						478	20.9	41	30	17	18/17	
14:23	225	14/12	6	2	2.0	58	45	47						471	20.8	42	20	17	18/17	
14:27	225	19/13	6.8	2.8	2.2	63	49	50						480	20.9	40	10	17	19/18	
14:35						NOTE: UNIT		SHUT	DOWN		STARTED			UP	WITH	FIELD	ON.			
14:45	NSD	-	-	-	-	53	46	46						478	20.8	41	40	17	18/17	
14:52	NSD	-	-	-	-	51	45	44						479	20.9	41	50	17	18/17	
14:55	F.ow SWC					51	45	47						477	20.9	41	50	17	19/18	
15:00	F.ow SWC					62	50	51												
15:03	10	19/13	3.8	3.6	3.6	64	50	52												
1508	20	14/13	10	9	9	66	51	54						473	20.9	44	10			
1512	30	16/14	10	9	9	67	52	55						476	20.8	44	20			
1515	40	15/14	10	4	9	67	53	56												
1520	60	20/18	16/14	6	6	67	54	57												
1524	70	20/18	16/14	6	6	68	54	58						NOTE:	1.20 MW	-	SWC	FIELD ON 6		
1528	80	18/17	14/12	6	5.6	68	55	59									V.bration			
1534	100	15/14	14/12	6	6	68	55	60							STAYED	AT	15 -	19	MILS	
1540	120	16	16/14	6.4	6.8	71	56	61												
1632	F.ow SWC	19/18	18/12	6	6	69	56	65						Only	FIELD CAME		OFF	DOWN	PSD	

to 8-11 mils

2010-07-26

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 182.46 TAILRACE LEVEL 165 TRASHRACK

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN		TURB		THRUST ALARM	ZG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
						NOTE: WE MOVED THE 25 LBS from							BUCKET #7			TO	BUCKET	#6	
2050	N50	-	-	-	-	37	32	31					442	21.2	37	50	17	18/19	
2105	N30	-	-	-	-	37	32	31					476	20.7	40	30	17	18/19	
2125	N50	-	-	-	-	37	32	31					473	20.6	39	80	17	18/17	
2136	140	12		2	2	36	32	33					473	20.6	40	00	17	18/17	
2141	140	11	10	2	2	48	37	38											
2143	190					EXCESSIVE		VIBRATION					470	20.5	39	90	17	18/17	
2146	150	10	8.4	2	2	53	40	41											
2150						NOTE: BRAKES		APPLIED		AT 35		R.P.M.							

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010-07-27

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK I

TIME	LOAD MW	VIBRATION MILS GEN 2	4	TURB 1	2	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS	T.BRG TRIPS	WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
							NOTE: 25 LBS REMOVED FROM					BUCKET NO. 6				AND	26.5	10.5
								PLACED IN BUCKET				#8.						
1948	NSD	-	-	-	-		39	34	33			483	21	38	70	17	18/18	
1955	145	8	8	2	6.4		39	34	35			481	21	38	60	17	18/18	
2000	140	5	6	1	2		44	36	37			479	21.1	38	50	16	18/16	
2003	200	14	10	1.6	2		50	38	40			480	21.1	40	20	16	18/16	
2007	200	12	9	1.2	2		55	41	44			482	21.1	39	10	16	18/16	
2010	225	16	11	1.4	2		59	45	46			481	21.0	39	20	16	18/16	
2015	225	16	5	1.4	2		62	48	50			480	21.0	39	10	16	18/16	
2027	NSD	-	-	-	-		55	46	46			477	21.0	39	20	16	18/17	
2030	225	17	8	2	2		54	46	49			476	21.0	39	00	16	18/17	
2035	225	16	56	2	2.4		58	49	51			478	21.1	38	10	16	18/17	
2057	NSD	-	-	-	-		51	46	46			479	21.0	37	80	16		
						NOTE:	AUTO	START.	FIELD	ON.								
2100	225	14	9	3	4		51	46	48			477	21.0	39	30	16	18 16	
2105	225	13	76	24	4		58	46	51			477	20.9	39	90	16	17 16	
2107	225	12	64	36	2		60	49	52			479	21.1	41	10	16	17 16	
2110	225	11	6	2	3.2		66	51	54			478	21.0	38	30	16	17 16	
2115	225	11	6	2.6	3.2		67	52	56			479	21.0	39	60	16	19 17	

2010-07-27

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK

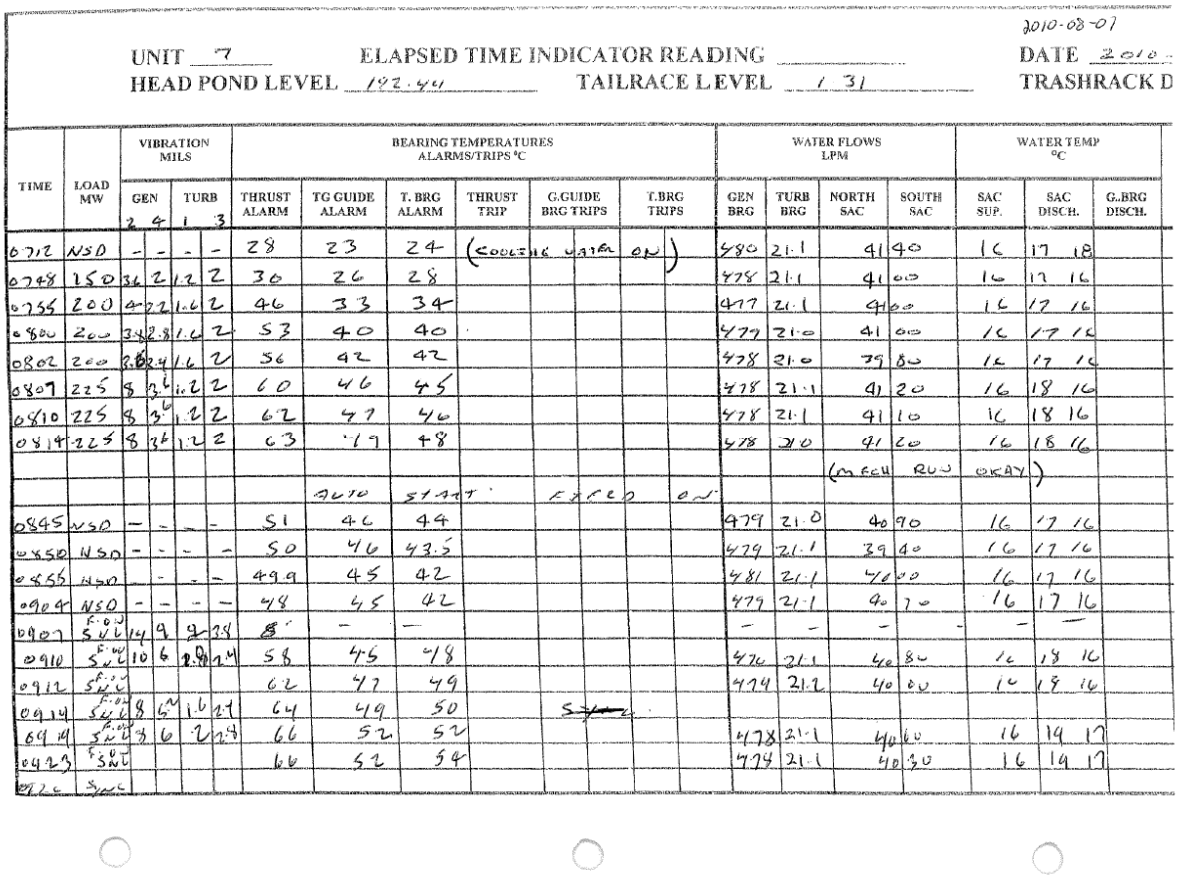
TIME	LOAD MW	VIBRATION MILS GEN 2	4	TURB 1	3	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS	T.BRG TRIPS	WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
						NOTE:	REMOVED		25 LBS	FROM	BUCKET	#6	AND	PLACED		265	LBS	
							IN BUCKET	#8.										
2120	10	12	6.2	3	3.6	67	53	58				478	21	38	50	16	19	18
2125	20	12	6.8	3.2	4	67	53	58				477	21	38	90	16	19	18
2128	30	12	6.4	3.2	4	68	53	59				476	21	39	10	16	19	18
2130	40	12	6.8	3.8	4	68	53	59				477	21	39	80	16	19	18
2134	50	12	8	4	4.2	68	53	60				481	21	38	20	16	19	18
2140	80	15	9.6	5	5	68	54	60				478	20.9	39	20	16	19	18
2145	105	17	11	5	4.4	68	54	61				476	20.9	38	60	16	20	18
2148	120	18	13	5	4.4	68	54	61				477	21.1	39	10	16	20	18
2153	109	18	12	5.2	4.2	69	55	62				476	21.0	39	50	16	20	18
2158	80	17	12	5.0	5.6	70	55	62				477	21.0	39	60	16	20	19
2203	50	17	11	5	5.2	70	55	63				477	21.1	39	90	16	20	19
2208	35	15	11	5	6	70	54	63				474	21.0	39	50	16	20	19

2010-07-28

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010

HEAD POND LEVEL 182.46 TAILRACE LEVEL 1.50 TRASHRACK I

TIME	LOAD MW	VIBRATION MILS GEN 2	GEN 4	TURB 1	TURB 3	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	NG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS		WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G..BRG DISCH.
1045	NSD	-	-	-	-	32	28	31						474	209	38	30	16	18 17	
1047	P.ON SNL					UNIT GIVEN A START DEUSE.														
1052	SD					UNIT GIVEN A STOP DEUSE.									HIGH VIBRATION.					
11 11	P.ON SNL					45	39	41						478	21	38	00	16	18 17	
11 14	SD					UNIT SHUT DOWN				HIGH		VIBRATION.								
1129	P.ON SNL	13	12	8	2.4	3.2	51	42	44						478	20.9	38	60	16	18 16	
1135	SD					TRIED	70	BRING DOWN VIBRATION.						478	20.9	FURTHER. (13-17 DEGS)				
1148	P.ON SNL					53	44	47						478	20.9	38	70	16	18 17	
1152	"					61	48	50						477	21	38	90	16	18 17	
1200	"					66	50	53						475	21.1	38	60	16	19 18	
1205	50					67	52	55						475	21.1	37	50	16	19 18	
1210						UNIT TAKEN OFF GIVE HIGH VIBRATION.														
						NOTE: STARTED ADJUSTING THE GEN. BRG GUIDE CLEA														
						clearances ON JULY 29 2010.														



2010-08-07

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010-
HEAD POND LEVEL 192.46 TAILRACE LEVEL 1.31 TRASHRACK D

TIME	LOAD MW	VIBRATION MILS GEN 2	4	TURB 1	3	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS	T.BRG TRIPS	WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
0712	NSD	-	-	-	-	28	23	24	(COOLING WATER ON)			480	21.1	41	40	16	17 18	
0748	150	36	22	1.2	2	30	26	28				478	21.1	41	00	16	17 16	
0755	200	4.2	2.2	1.6	2	46	33	34				477	21.1	41	00	16	17 16	
0800	200	3.4	2.8	1.6	2	53	40	40				479	21.0	41	00	16	17 16	
0802	200	3.8	2.4	1.6	2	56	42	42				478	21.0	39	80	16	17 16	
0807	225	8	3.6	1.2	2	60	46	45				478	21.1	41	20	16	18 16	
0810	225	8	3.6	1.2	2	62	47	46				478	21.1	41	10	16	18 16	
0814	225	8	3.6	1.2	2	63	47	48				478	21.0	41	20	16	18 16	
														(MECH	RUN	OKAY)		
							ALTO	START	EXCED		ON							
0845	NSD	-	-	-	-	51	46	44				479	21.0	40	90	16	17 16	
0850	NSD	-	-	-	-	50	46	43.5				479	21.1	39	40	16	17 16	
0855	NSD	-	-	-	-	49	45	42				481	21.1	40	00	16	17 16	
0904	NSD	-	-	-	-	48	45	42				479	21.1	40	70	16	17 16	
0907	S.U.C.	14	9	2	3.8	8	-	-				-	-	-	-	-	-	
0910	S.U.C.	10	6	2.8	2.4	58	45	48				476	21.1	40	80	16	18 16	
0912	S.U.C.					62	47	49				474	21.2	40	80	16	18 16	
0914	S.U.C.	8	6	1.6	2.4	64	49	50		S~~TART~~								
0919	S.U.C.	7	6	2	2.4	66	52	52				478	21.1	40	60	16	19 17	
0923	S.U.C.					66	52	54				474	21.1	40	30	16	19 17	
0926	S.U.C.																	

2010-08-01

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010-

HEAD POND LEVEL 182.74 TAILRACE LEVEL 1.31 TRASHRACK I

TIME	LOAD MW	VIBRATION MILS GEN 2	4	TURB 1	3	BEARING TEMPERATURES ALARMS/TRIPS °C THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS		WATER FLOWS LPM GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	WATER TEMP °C SAC SUP.	SAC DISCH.	G.BRG DISCH.
0928	SYNC	8	4.8	2	2.8	67	53	56						478	21.1	41	50	16	19 18	
0934	20	8	4.8	2	3.6	67	54	56						480	21.1	40	60	16	19 18	
0937	30	7.6	5.2	2.4	4	67	54	57						475	21.2	40	50	16	19.9 18	
0942	50	8	6	2.4	4	67.9	54	58						475	21.1	41	00	16	19.9 18	
0945	70	10	8	4.8	4.4	68	54	59						478	21.1	40	50	16	19.9 18	
0952	120	11	10	2.8	3.2	68	54	60						474	21.1	41	40	16	20 18	
0956	130	10.4	10	2.8	2.4	68.5	55	60												
10:04	140	11.7	10	2.8	3.2	72	55.8	61						472	21	40	30	16	20 19.5	
1010	134	11.2	10	3.2	4.2	72	56	61.9						474	21	41	20	16	20 19.5	
11:00	120	9	10	3	3	70	56	62.5						477	21	41	50	16	20	

UNIT 7 ELAPSED TIME INDICATOR READING _____ 2010-03-01 DATE 2
HEAD POND LEVEL 182.45 m TAILRACE LEVEL 210 m TRASHRACK I

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN		TURB		THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G.BRG DISCH.
		2	4	1	3														
1200	121	10.4	9.2	4.0	3.6	72	56	67					470	21.0	– 4020 –				
1300	122	10.8	9.6	4.0	4.0	72	57	68					471		3990				
1400	115	10.8	9.2	3.6	3.6	72	57	69					470		4040				
1500	117	10.8	9.6	4.0	4.0	72	57	69					470		4060				
1600	111	10.3	8.8	3.6	3.6	71.5	57	70					474		3990				
1700	110	10.8	9.6	4.0	3.6	71.5	57	70.5					472		4080				
1800	110	10.2	8.8	4.0	4.0	71.5	58	71					475		4100				
1900	105	10.3	8.8	4.0	4.0	71	60	71					473		4040				
2000	110	10.3	9.2	4.0	4.0	72	60	72					475		4010				
2100	115	10.8	9.2	4.0	4.0	72	60	72					475		3980				
2200	108	11.2	9.2	4.0	4.0	72	60	71					474		4000				
2300	90	10.8	9.0	4.0	4.0	71	60	72					475		4030				
2400	87	10.8	9.2	4.0	4.0	70	60	71					473		4010				

UNIT 7 ELAPSED TIME INDICATOR READING _____ DATE 2010-08-02 2011

HEAD POND LEVEL _____ TAILRACE LEVEL _____ TRASHRACK I

TIME	LOAD MW	VIBRATION MILS				BEARING TEMPERATURES ALARMS/TRIPS °C							WATER FLOWS LPM				WATER TEMP °C		
		GEN 2	GEN 4	TURB 1	TURB 3	THRUST ALARM	TG GUIDE ALARM	T. BRG ALARM	THRUST TRIP	G.GUIDE BRG TRIPS		T.BRG TRIPS	GEN BRG	TURB BRG	NORTH SAC	SOUTH SAC	SAC SUP.	SAC DISCH.	G..BRG DISCH.
0100	77	10.8	9.6	4.8	4.8	70	59	71					477	21	3980				
0200	81	11.2	9.6	4.8	4.8	70	59	72					473	21	4060				
0300	80	11.2	9.2	4.8	4.8	70	59	72					474	21	4016				
0400	78	11.2	9.6	4.8	4.8	70	59	72					476	21	3990				
0500	80	10.8	9.2	4.4	4.4	70	59	72					474	21	4000				
0600	81	11.2	9.6	4.4	4.4	70	59	72					475	21	4030				
0700	82	10.8	9.6	4.4	4.4	70	59	72					476	21	4000				
0800	95	11	9.6	4.2	4.2	70	59	72					476	21	4000				
0900	115	11	9.6	4.0	4.0	71	59	72					477	21	4080				
1000	125	11	9.6	4.0	4.0	72	60	72					472	21	4040				
1100	125	11	9.6	4.0	4.0	72	60	72					473	21	4020				

APPENDIX C

HydroExpertise USA - Bay D' Espoir Unit 7 Vibration Assessment & Balance Report

Hydro Expertise USA

Technical Report

Newfoundland and Labrador Hydro

Bay D' Espoir

Unit 7

TECHNICAL REPORT:

Vibration Assessment and Balance Report

September 2014

Prepared by
Douglas Leubner, MSME
2014-11-13

Hydro Expertise USA

Technical Report

1. INTRODUCTION

Load was restricted below 110 MW on Unit 7 due to excessive generator bearing vibration at higher load. Vibration tests were conducted at various operating conditions in August in an effort to determine a cause for excessive generator vibration. Generator bearing clearances were believed to have opened up due to generator vibration exceeding design bearing clearances whenever transitioning through the 55 to 75 MW rough zone. Misalignment was also expected due to vibration increase with load. Bearing clearances were close to design, a thrust bearing inspection revealed nothing unusual and alignment checks revealed nothing other than a 5 mil shaft run out during Unit 7's excitation transformer replacement outage in early September.

August vibration tests indicated generator vibration was repeatable at similar load points and during a stop and restart test and a 3 mil vibration step change was observed when excitation was applied. The decision was made to install temporary vibration and power measuring instrumentation to separate electrical from mechanical vibration causes and to enable accurate comparison of vibration with load, excitation voltage and stator current for additional vibration analysis during September balance efforts. Starting and stopping Unit 7 several times during its return to service revealed balance vectors were stable enough for balancing. Although difficult, Unit 7 generator vibration was able to be reduced sufficiently for unrestricted 155 MW full load operation by balancing. Several contributing factors to elevated generator vibration were identified. This report discusses the balancing performed and the identified elevated vibration contributing factors along with some recommendations for a long term fix.

2. SUMMARY

One contributing factor to elevated generator bearing vibration is excessive rotor pole eccentricity evidenced by a vibration step change when excitation is applied and by the difference required to balance the generator mechanically versus electrically. 2010 air gap readings indicated rotor pole eccentricity was 0.013" which is greater than the recommended tolerance of 0.010". Suspect rotor pole eccentricity may change between starts at times due to floating rim design based on operating procedure to perform multiple startups to reduce vibration when excessive but we did not observe any significant vibration changes when the unit was started and stopped several times prior to balancing. Magnetic flux readings showed minimal rotor pole eccentricity and did not indicate any poles with shorted turns.

Another contributing factor is a rotor critical near the 225 rpm operating speed that was identified during balance efforts. 1X running speed vibration increased 8 mils from 150 to 225 rpm and would increase or decrease with only +/- 2 rpm changes around the 225 rpm running speed. A rotor critical near running speed makes balancing more difficult due to significant changes in 1X amplitude and phase with minor changes in speed.

A 5 mil pk-pk shaft run out was identified during alignment rotation checks and a 10 mil pk-pk run out was observed during slow roll rotation readings during balance efforts. The fact that balancing was nonlinear indicates excessive shaft run out. Excessive shaft run out complicates balancing since changes in shaft vibration are used to determine balance weight location and

weight amounts. Balance calculations will be inaccurate when shaft vibration change due to balancing is less than the existing shaft run out. Balance using low frequency velocity transducers instead of proximity probes for balancing would eliminate shaft run out errors inherent to proximity probes.

Generator vibration increases 6 mils when load increases from 3 to 100 MW. Vibration increases due to load effects is indicative of bearing centerline concentricity misalignment and/or excessive shaft run out. Nonlinear balance results also indicate excessive shaft run out and/or bearing centerline concentricity misalignment. Although difficult due to nonlinearity of balance results, balancing was effective in reducing full load vibration to acceptable levels without increasing synchronous condense and rated speed unexcited vibration to unacceptable vibration levels.

3. RECOMMENDATIONS

1. Start generator with excitation in auto. Vibration was lower without excitation before balance weights were installed. Latest balance weights are compensating for an electrical imbalance instead of a mechanical imbalance so vibration is now lower with excitation than without excitation.

2. If vibration is elevated but below the 18 mil shutdown limit allow generator to run 15 minutes to give time for bearings to warm up before performing generator restarts to lower vibration. Vibration decreases approximately 4 mils as the generator warms up from a cold start. We did not observe much change in vibration other than thermal effects when the generator was restarted three times before balancing was performed.

3. Identify and correct shaft run out if feasible. Record shaft run out using X-Y dial indicators at four turbine/generator shaft vertical locations, two points above the turbine/generator coupling and two points below. Determine if shaft run out is due to coupling offset and/or coupling angularity or thrust block angularity. Determine feasibility of correcting source of run out.

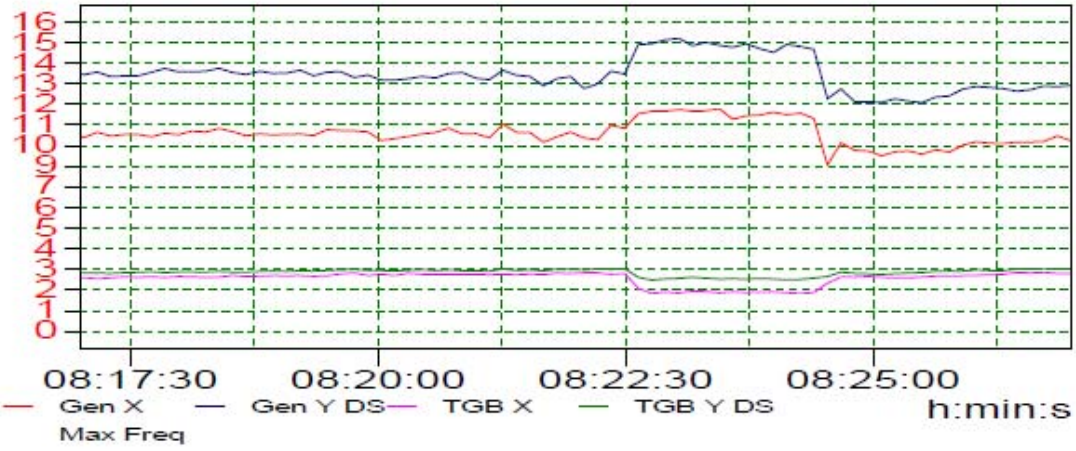
4. Perform a complete set of alignment readings including verticality measurements. Taking into account shaft run out amount and angular location, adjust generator guide shoe clearances to improve bearing centerline concentricity between generator and turbine bearing. Improved bearing centerline concentricity should reduce load effect vibration.

5. If not feasible to reduce shaft run out, perform additional balancing to further reduce full load vibration. The last balance weight installed reduced full load vibration and did not increase vibration during speed no load and synchronous condense mode above acceptable limits.

6. Use two low frequency velocity transducers when balancing to eliminate balance calculation errors caused by excessive shaft run out when proximity probes are used. Recommend Bently-Nevada low frequency horizontal velocity transducers model number 330505 for balancing.

4. ANALYSIS

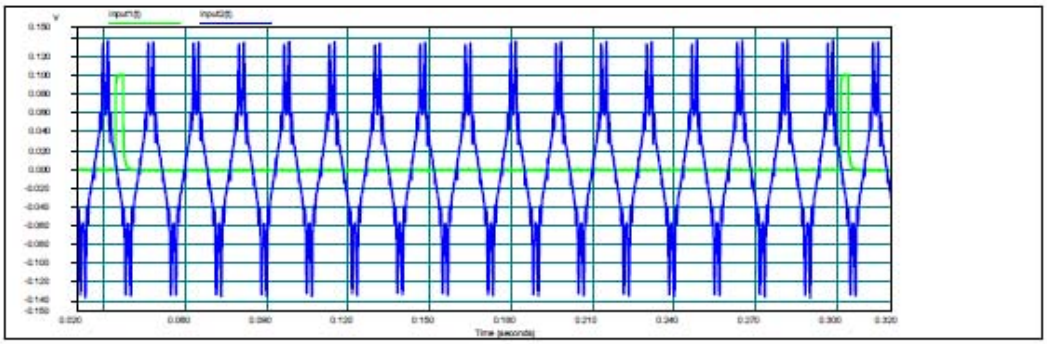
Vibration step changes with excitation indicates rotor pole eccentricity. The plot below illustrates the vibration step increase observed when excitation was applied before balancing.



9/28/14 Vibration Increase With Excitation

The attached stator and rotor air gap profile charts (See attached QCR 140) developed from 2010 air gap readings indicated rotor pole eccentricity of 0.013" which is above the recommended 0.010" eccentricity tolerance.

Magnetic flux probe data did not indicate any poles with shorted turns as shown below:

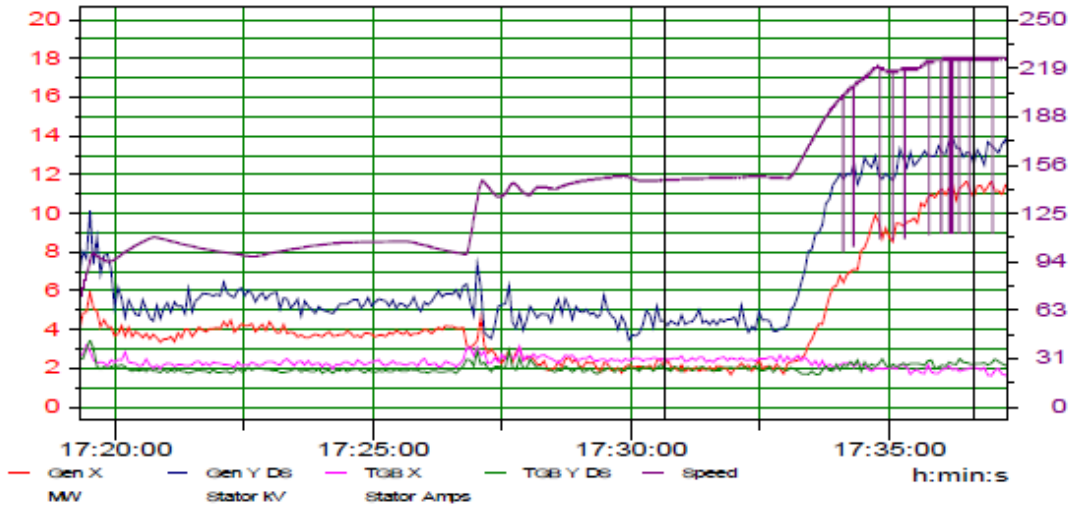


Flux Data Shows All Poles @ Same Height

Hydro Expertise USA

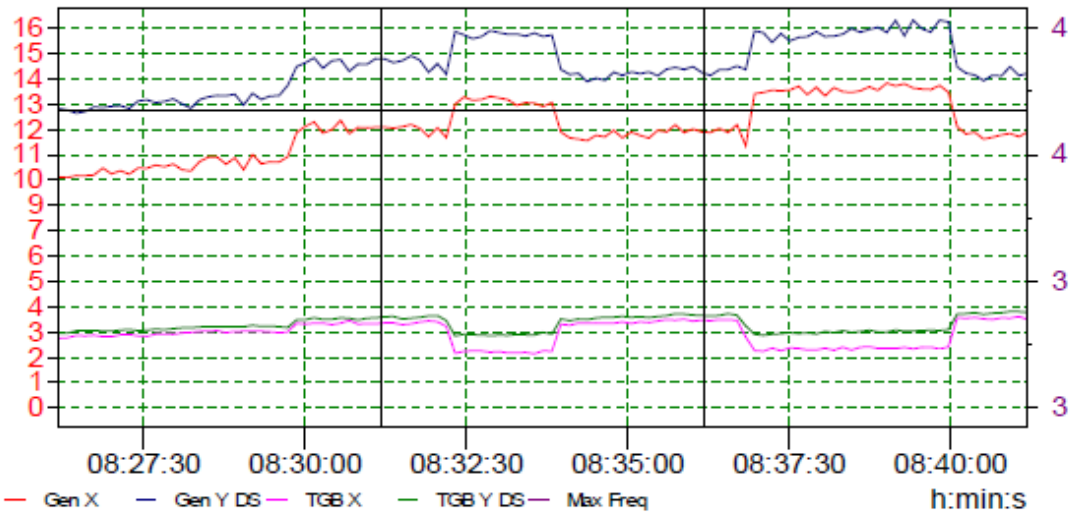
Technical Report

Rotor critical is evident during startup due to 8 mil increase in generator bearing vibration as speed increases from 150 to 220 rpm as shown in vibration v.s. speed trend plot below.



9/27/14 Slow Roll Vibration Test

Rotor critical is also evident by 2 mil step changes in 1X vibration with speed changes of +/- 2 rpm above and below its 225 rpm running speed as shown below:



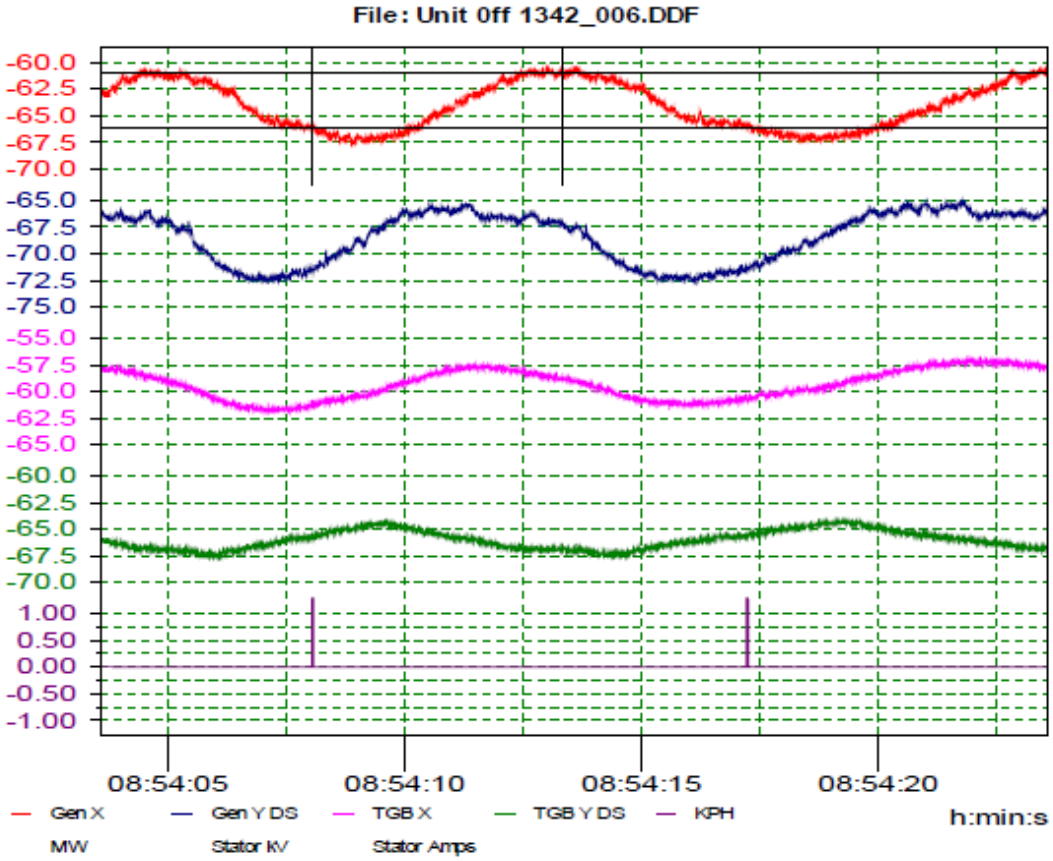
9/28/14 1X Vibration Step Changes During +/- 2 rpm Speed Changes

Hydro Expertise USA

Technical Report

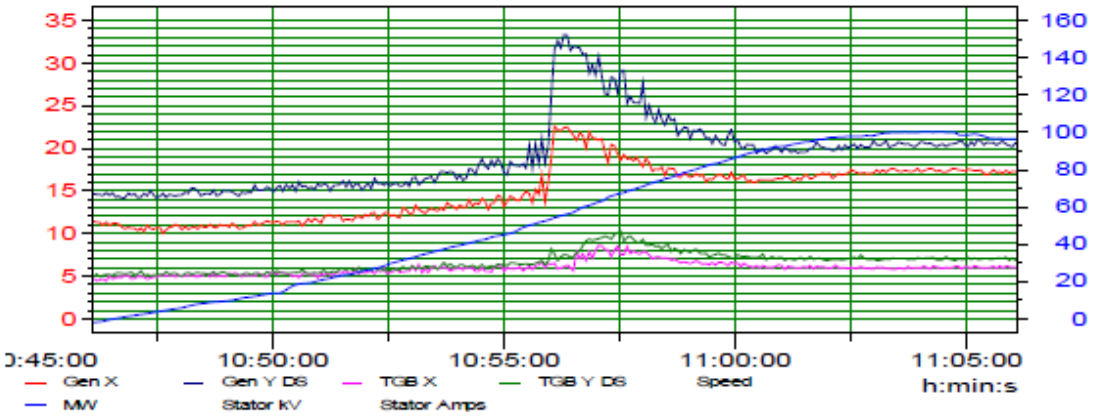
Alignment readings taken during the excitation transformer replacement outage indicated bearing clearances had not increased but there was a 5 mil shaft run out (See attached QCR 104) that was not taken into account during bearing adjustments to improve generator/turbine bearing centerline. Slow roll shaft run out taken at 4 rpm indicate a 10 mil shaft run out when normalized at the generator bearing as shown below:

092914 Slow Roll During Unwatering @ 4.2 RPM

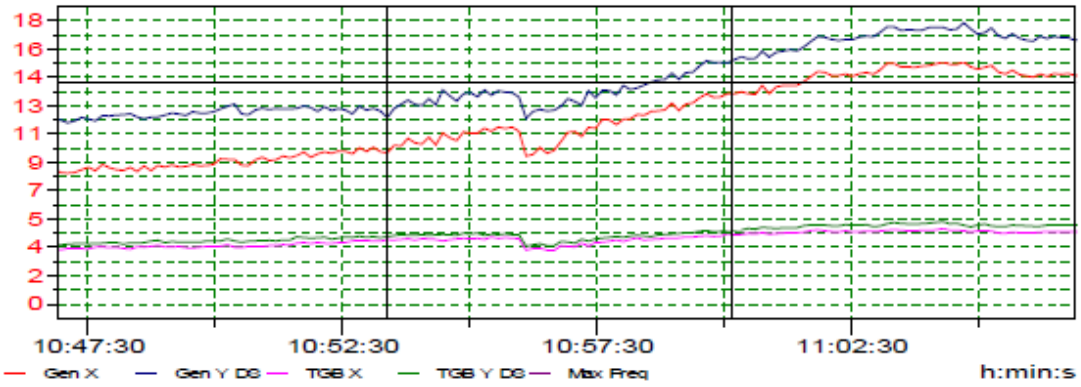


Bay D' Espoir Unit 7 Runout @ 4.2 RPM 9/29/14						Nornalized to Gen	
	Max	T_{max}	Min	Pk-Pk	Φ	Pk-Pk	Φ
Gen X	-60.1196	7.8	-67.2943	7.1747	385	0	#DIV/0!
Gen DS	-65.2313	4.578	-72.1802	6.9489	226	0	#DIV/0!
TGB X	-57.077	4.996	-60.73	3.653	246	10.19	218
TGB DS	-64.2761	2.068	-67.3584	3.0823	102	9.03	62

Generator bearing vibration increases 6 mils when load increases from 3 to 100 MW and generator downstream overall vibration increased from 17 to 32 mils when traveling through the 55 to 75 MW rough zone. Overall and 1X vibration trend plots are shown below:



9/28/14 Overall Vibration Trend During Load Increase From 3 to 100 MW



9/28/14 1X Vibration Trend During Load Increase From 3 to 100 MW

Determined balance calculations were nonlinear when vibration would increase significantly when balance weight was placed at calculated location. Suspect excessive shaft run out caused nonlinear balance results since needed to use the same pole 15 weight location to reduce full load vibration even though balance results predicted pole 14. Balance results were verified to be acceptable at rated speed no excitation, rated speed excited, full load and synchronous condense. A polar plot of generator bearing downstream balance results at all four operating modes and a table of all balance vectors are attached. Generator bearing downstream vibration was reduced from 18 mils at 100 MW to 10 mils at 155 MW.

The table below indicates generator downstream vibration was 14 mils at 135 MW during an August 2012 start up.

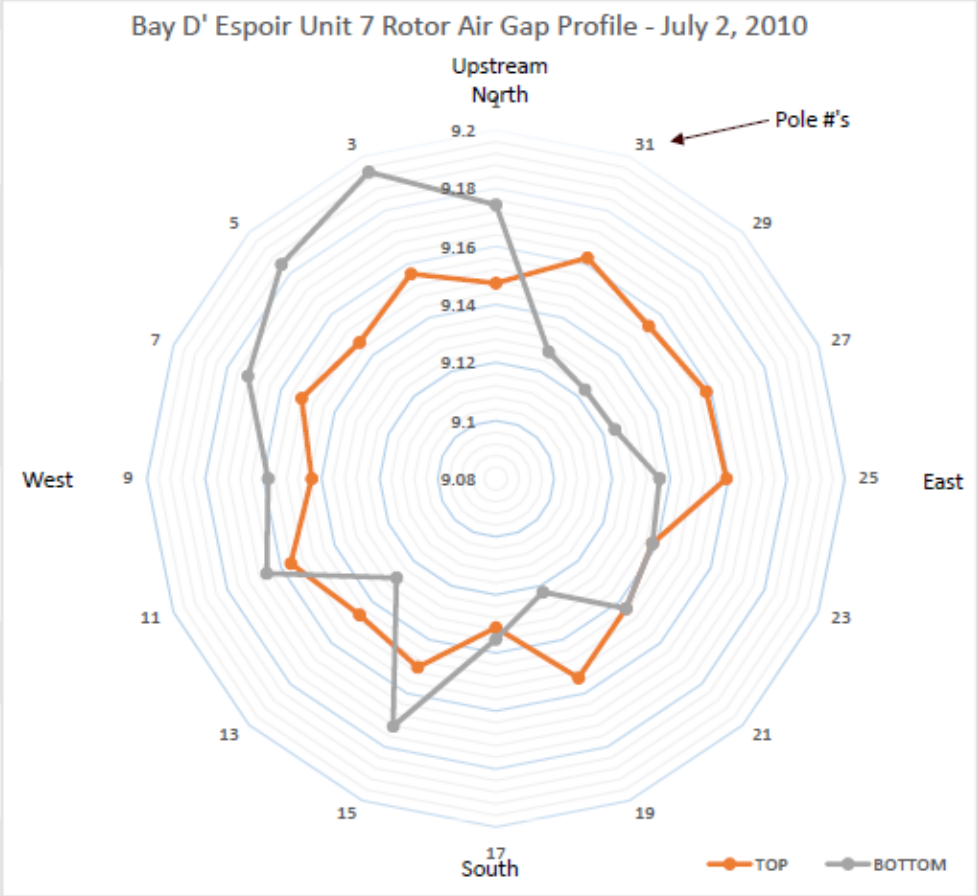
Bay D' Espoir Unit 7 Startup 8/15/12

		Temperature °C			Vibration mils pk-pk			
Time	Condition	GTB Thrust	GGB Generator Guide	TGB Turbine Guide	1 Turbine Downstream	2 Generator Downstream	3 Turbine X- Axis	4 Generator X-Axis
10:50	SNL	58	49	52	2.4	7.6	2.8	6.0
10:55	Synch	65	51	54	2.4	7.2	3.2	5.2
	5 MW	70	53	56	2.4	8.0	3.2	6.0
	10 MW	71	53	57	2.4	8.0	3.2	5.2
	20 MW	72	56	58	2.4	8.0	3.2	5.6
	30 MW	73	56	59	2.8	7.2	3.2	6.4
	40 MW	73	57	59	3.2	8.0	3.2	6.0
	50 MW	73	57	59	3.2	8.0	3.2	7.2
	60 MW	73	57	59	4.8	14.0	3.6	10.0
	70 MW	74	57	59	4.8	12.0	4.0	8.0
	80 MW	74	57	60	4.0	10.0	4.0	8.8
	90 MW	74	58	60	3.6	10.0	3.2	10.0
	100 MW	74	58	60	3.2	11.2	3.2	11.2
	110 MW	75	58	61	3.6	13.2	3.6	12.8
	120 MW	75	58	61	3.6	14.0	3.6	13.6
	130 MW	75	58	61	3.6	14.0	3.6	14.0
11:38	135 MW	75	59	61	3.8	14.0	3.6	14.0

Manual logs of vibration and bearing temperatures that were taken during each balance shot for all four operating modes are attached. Bearing temperatures remained the same before and after balancing and vibration was reduced from over 16 mils before balancing to 10 mils after balancing.

A daily work log that provides a summary of instrumentation setup, all measurements taken, balance activities and operating lineups with time durations is attached.

Portland General Electric	QUALITY CONTROL RECORD	Document #: QCR-140 Project: Bay D' Espoir Unit 7
	Rotor Sweep	Hydro Expertise USA



Rotor Sweep Results				
	BEST CENTRE		Eccentricity	Circularity
	X	Y		
TOP	-0.021	0.011	0.024	0.055
BOTTOM	0.002	0.005	0.006	0.023
AVERAGE	-0.010	0.008	0.013	0.029
CEA Tolerance (on Avg.)			0.010	0.049

TOOLS #: Parallels MEASURED BY: _____ DATE: _____

_____ _____ DATE: _____ P.1

REVIEWED BY: Leubner DATE: 11/11/2014

U-CQF001
Revision: 01
Issue date: 2014-07-22

Portland General Electric

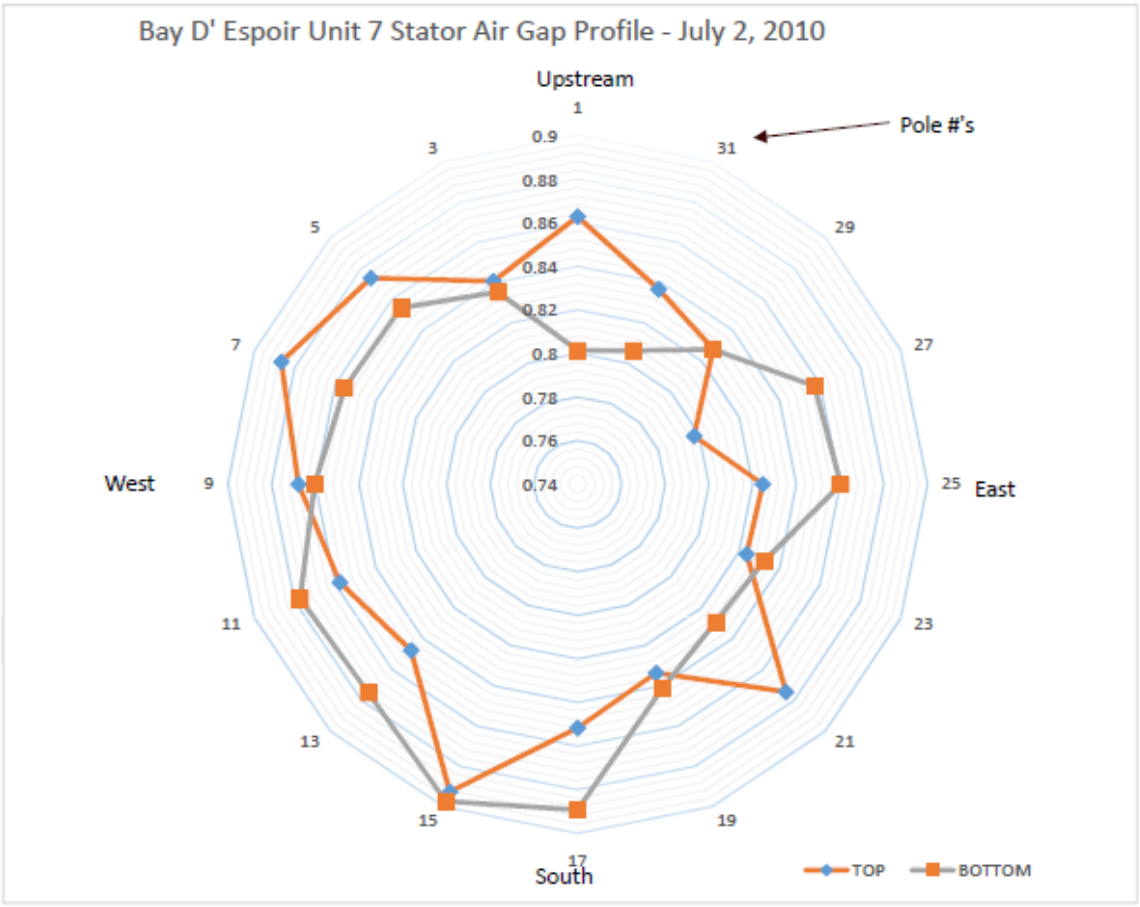
QUALITY CONTROL RECORD

Stator Sweep

Document #: QCR-140

Project: Bay D' Espoir Unit 7

Hydro Expertise USA



Stator Sweep Results				
	BEST CENTRE		Concentricity	Circularity
	X	Y		
TOP	-0.024	-0.006	0.025	0.065
BOTTOM	-0.015	-0.024	0.029	0.057
AVERAGE	-0.020	-0.015	0.025	0.042
CEA Tolerance (on Avg.)			0.042	0.066

TOOLS #: Parallels

MEASURED BY: _____ DATE: _____

DATE: _____

REVIEWED BY: Leubner DATE: 11/11/2014

P. 2

U-CQF001
Revision: 01
Issue date: 2014-07-22

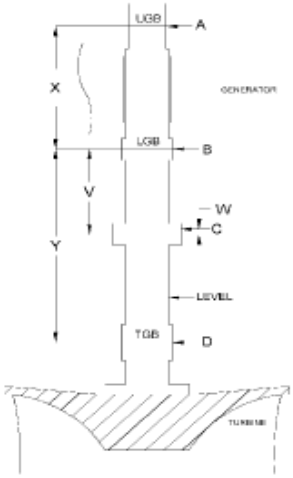
newfoundland labrador hydro
a nalcor energy company

QUALITY CONTROL RECORD

Runout Readings (4 dials)

Document #: QCR-104
Project: Bay D' Espoir #7

Hydro Expertise USA



NOTES: There is no upper guide bearing (UGB)

The runout at the TGB is calculated as if there was no movement at the LGB

Turbine packing still installed and 4 generator bearings hand tight against generator shaft.

Unit rotated with chainfall and high pressure lift pump on.

Calculations modified to account for only one dial indicator at US LGB & TGB locations instead of X & Y indicators.

1st Rotation

Pole #1 Position	LGB				TGB			
	US South	3o'clk West	DS North	9o'clk East	US South	3o'clk West	DS North	9o'clk East
0°	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90° cw	0.0025	0.0000	0.0000	0.0000	0.0015	0.0000	0.0000	0.0000
180°	0.0090	0.0000	0.0000	0.0000	0.0030	0.0000	0.0000	0.0000
270°	0.0060	0.0000	0.0000	0.0000	0.0035	0.0000	0.0000	0.0000
360°	0.0015	0.0000	0.0000	0.0000	-0.0010	0.0000	0.0000	0.0000

Pos.	Results		Tolerance
Pos.	US & 3 O'clk	DS & 9 O'clk	Tolerance
UGB	n/a	n/a	n/a
LGB	n/a	n/a	n/a
TGB	0.005	na	0.008
Ave	0.005		n/a
Straightness	n/a	n/a	n/a

2nd Rotation

Pole #1 Position	LGB				TGB			
	US South	3o'clk West	DS North	9o'clk East	US South	3o'clk West	DS North	9o'clk East
0°	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
90° ccw	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
180°	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
270°	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
360°	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Pos.	Results		Tolerance
Pos.	US & 3 O'clk	DS & 9 O'clk	Tolerance
UGB	n/a	n/a	n/a
LGB	n/a	n/a	n/a
TGB	0.000	0.000	0.008
Ave	0.000		n/a
Straightness	n/a	n/a	n/a

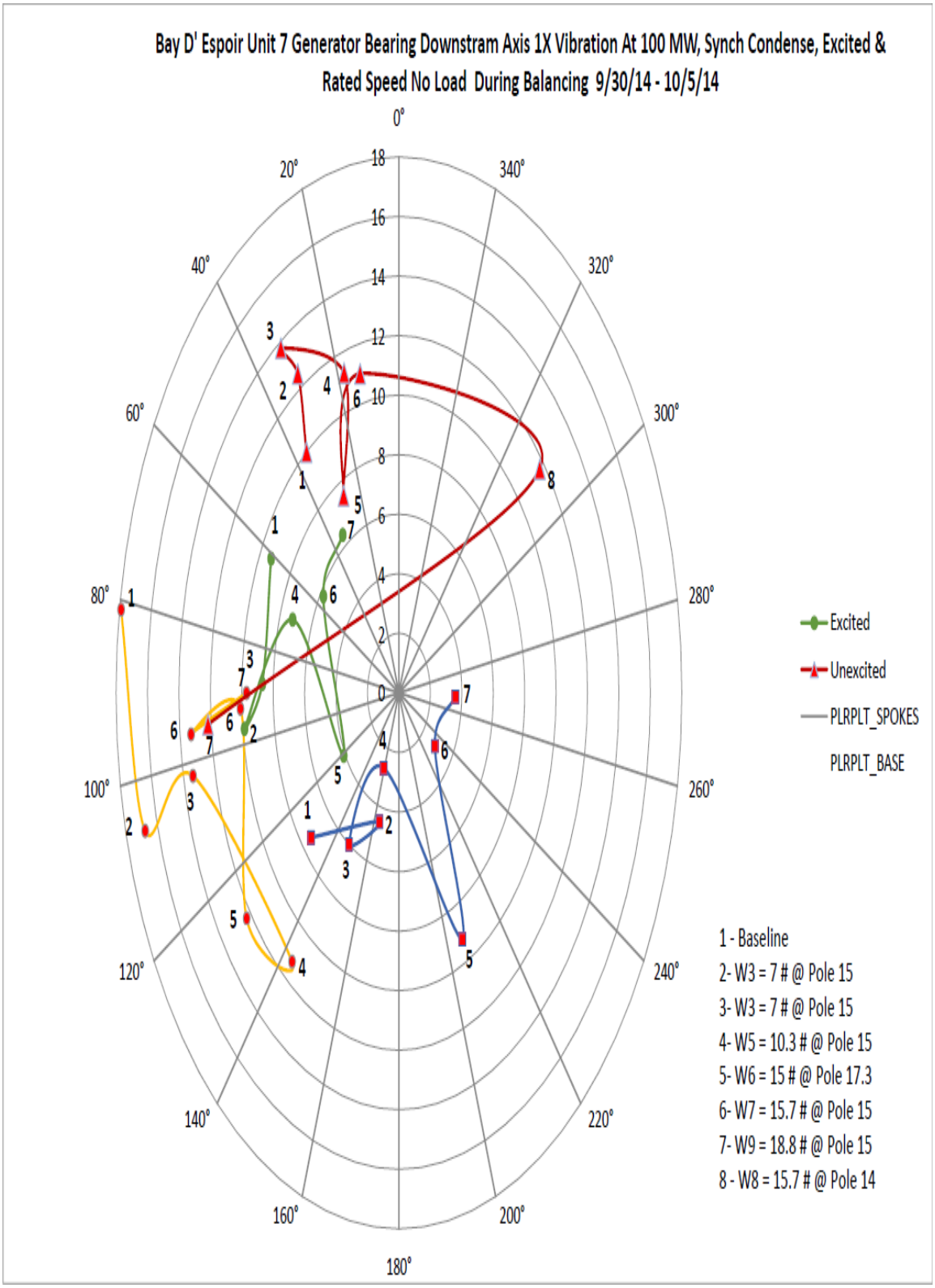
TOOLS #: dial indicators

MEASURED BY: _____ DATE: _____

DATE: _____

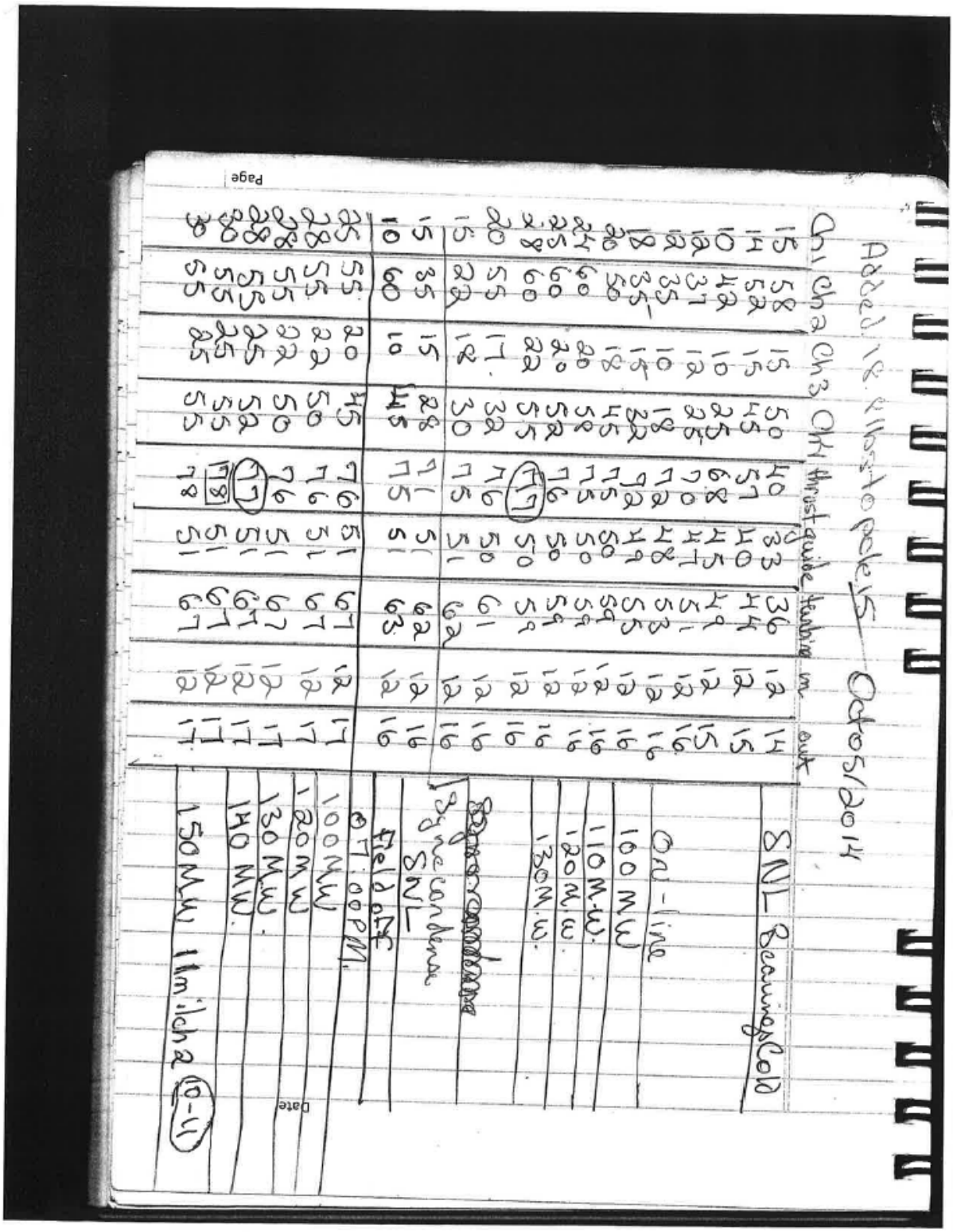
REVIEWED BY: Leubner DATE: 2014-09-19

U-CQF060
Rev 00
Issue date: 2014-07-14


Bay D' Espoir Unit 7 Generator Bearing Downstram Axis 1X Vibration At 100 MW, Synch Condense, Excited & Rated Speed No Load During Balancing 9/30/14 - 10/5/14
0°
20°
340°
40°
320°
60°
300°
80°
280°
100°
260°
120°
240°
140°
220°
160°
200°
180°
18
16
14
12
10
8
6
4
2
0
Excited
Unexcited
PLRPLT_SPOKES
PLRPLT_BASE
1 - Baseline
2- W3 = 7 # @ Pole 15
3- W3 = 7 # @ Pole 15
4- W5 = 10.3 # @ Pole 15
5- W6 = 15 # @ Pole 17.3
6- W7 = 15.7 # @ Pole 15
7- W9 = 18.8 # @ Pole 15
8 - W8 = 15.7 # @ Pole 14

Bay D' Espoir Unit 7 Vibration At Various Conditions During Balancing 9/27/14 to 10/5/14												
Unit 7 Vibration At Rated Speed, No Load, No Excitation												
	Gen X			Gen Y DS			TGB X			TGB Y DS		
Condition	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ
9/27/14 17:51 Startup, 15 Min at SNL	12.0	10.8	73°	14.6	13.3	8°	2.5	1.1	180°	2.7	1.7	88°
9/27/14 18:16 Startup, 1 Min at SNL	14.7	13.6	87°	16.6	15.2	10°	3.0	1.8	169°	3.0	2.1	82°
9/27/14 18:29 SU from 117 RPM, 9 Min @ SNL	9.6	8.1	62°	12.4	11.0	350°	2.3	0.9	204°	2.4	1.4	91°
9/28/14 13:33 S/D, 33 Min @ SNL	11.1	7.4	94°	15.5	10.0	36°	5.4	1.9	208°	5.9	2.6	112°
9/30/14 8:29 W2= 9.3# @ Pole 23 (113°) 3 Min	11.7	9.6	152°	13.8	10.9	76°	3.6	2.4	212°	3.4	2.5	124°
9/30/14 9:31 W2= 9.3# @ Pole 23 (113°) 7 Min	12.1	9.7	166°	13.3	10.5	83°	4.9	3.4	226°	4.7	3.5	136°
9/30/14 19:00 ,W3= 7# @ Pole 15 (191°), 3 Min	13.3	11.3	100°	16.6	14.2	29°	3.0	1.6	188°	3.1	2.0	98°
9/30/14 19:55,W3= 7# @ Pole 15 (191°), 5 Min	11.8	10.1	98°	14.5	12.9	30°	3.5	2.2	195°	3.7	2.7	103°
9/30/14 20:04,W3= 7# @ Pole 15 (191°), 4 Min	11.2	9.7	99°	14.5	12.5	31°	3.5	2.2	196°	3.7	2.7	105°
10/2/14 8:35,W3= 7# @ Pole 15 (191°), 2 Min	13.7	12.5	94°	15.1	13.9	27°	3.4	2.2	185°	3.7	2.8	95°
10/2/14 9:39,W3= 7# @ Pole 15 (191°), 10 Min	12.9	11.4	98°	15.5	13.8	33°	3.7	2.4	195°	4.1	3.1	103°
10/2/14 18:57,W5= 10.3# @ Pole 15 (191°), 10 Min	11.8	9.0	85°	14.8	11.3	18°	3.2	1.7	188°	3.5	2.2	96°
10/3/14 15:44 W6=15#@Pole 17.3 (165°). 10 Min	5.9	4.2	91°	9.6	7.5	28°	3.0	1.7	227°	3.0	1.9	122°
10/4/14 12:50 W7=15.8#@Pole 15 (191°). 10 Min	9.8	8.1	75°	13.1	11.0	13°	3.0	1.4	200°	3.0	2.0	96°
10/4/14 22:00 W8=15.7#@Pole 14 (202°). 2 Min	8.6	7.1	36°	13.0	11.7	310°	2.3	0.9	241°	2.2	1.1	87°
10/5/14 14:18 W9=18.8#@Pole 15 (191°), 1 Min	10.3	8.7	66°	13.8	12.2	95°	2.4	1.2	193°	2.8	1.9	89°
Unit 7 Vibration At Rated Speed, No Load, With Excitation 13.8 to 14.4 kV												
	Gen X			Gen Y DS			TGB X			TGB Y DS		
Condition	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ
9/27/14 19:40 Startup, 1 Min @ 225 RPM Exc	14.2	11.6	160°	16.8	13.5	77°	4.3	2.8	217°	3.9	2.8	128°
9/27/14 20:53 Startup, 56 Min @ 225 RPM Exc	12.6	10.8	132°	15.0	13.3	59°	4.5	3.2	209°	4.5	3.6	118°
9/28/14 9:19 Startup, 16 Min @ 225 RPM Exc	9.7	7.9	133°	13.3	11.3	57°	4.1	2.8	215°	3.9	3.1	119°
9/28/14 11:56 Startup, 6 Min @ 225 RPM Exc	8.4	6.7	143°	11.6	9.3	61°	4.0	2.8	224°	4.0	3.0	129°
9/28/14 12:45 S/D, 2 Min @ 225 RPM Exc	11.2	8.4	164°	13.2	10.0	82°	5.0	3.3	227°	5.0	3.5	136°
9/29/14 8:37 W1= 29.7# @ Pole 12 (225°)	36.4	34.6	88°	42.1	38.8	5°	5.1	3.5	126°	4.6	3.3	40°
9/29/14 8:37 W2= 9.3# @ Pole 23 (113°)	19.2	16.6	234°	19.5	16.5	155°	4.9	3.5	254°	4.2	3.0	170°
9/30/14 8:24 W2= 9.3# @ Pole 23 (113°)- Run 2	17.1	15.2	231°	17.3	14.9	155°	4.6	3.2	249°	3.9	2.8	165°
9/30/14 8:39 W2= 9.3# @ Pole 23 (113°)- Run 2	14.1	11.8	221°	14.5	11.7	143°	4.8	3.2	248°	4.3	2.9	161°
9/30/14 9:22 W2= 9.3# @ Pole 23 (113°)- Run 2	15.9	14.5	229°	17.2	14.5	148°	6.1	4.6	261°	5.7	4.4	172°
9/30/14 18:56 SU,W3= 7# @ Pole 15 (191°), 5 Min	12.3	9.9	191°	13.6	10.5	104°	4.1	2.7	236°	3.6	2.5	146°
9/30/14 19:08,W3= 7# @ Pole 15 (191°), 7 Min	8.7	7.1	184°	10.5	8.1	91°	3.9	2.7	236°	3.6	2.6	142°
9/30/14 19:47,W3= 7# @ Pole 15 (191°), 2 Min	9.8	8.1	183°	11.6	9.4	92°	4.9	3.5	237°	4.6	3.4	146°
9/30/14 19:59,W3= 7# @ Pole 15 (191°), 2 Min	9.3	7.3	178°	11.2	8.7	88°	4.6	3.4	233°	4.4	3.2	142°
10/1/14 14:10, W4=15.65 @ Pole 8 (270°)	36.3	34.3	135°	40.0	38.1	52°	5.4	4.0	176°	5.2	3.9	89°
10/2/14 8:35,W3= 7# @ Pole 15 (191°), 36 Min	9.5	7.6	174°	11.6	9.2	93°	4.3	3.2	235°	4.2	3.2	141°
10/2/14 8:43,W3= 7# @ Pole 15 (191°), 4 Min	9.6	7.7	173°	11.9	9.4	91°	4.7	3.3	232°	4.3	3.3	139°
10/2/14 9:28,W3= 7# @ Pole 15 (191°), 10 Min	10.5	8.5	181°	12.3	9.9	97°	5.0	3.6	238°	4.9	3.7	146°
10/2/14 17:52,W5= 10.3# @ Pole 15 (191°), 47 Min	7.5	5.7	136°	9.7	7.6	53°	3.7	2.3	222°	3.4	2.4	126°
10/2/14 18:46,W5= 10.3# @ Pole 15 (191°), 5 Min	7.9	5.2	159°	10.6	7.2	70°	4.3	2.6	232°	4.0	2.6	138°
10/3/14 14:05 W6=15#@Pole 17.3 (165°). 32 Min	6.7	5.0	255°	4.6	2.6	171°	3.5	2.2	257°	3.0	1.8	164°
10/3/14 15:32 W6=15#@Pole 17.3 (165°). 9 Min	6.2	5.0	226°	5.9	4.1	121°	4.1	2.8	255°	3.6	2.5	163°
10/4/14 10:43 W7=15.8#@Pole 15 (191°). 27 Min	4.0	2.0	111°	8.0	5.9	26°	3.1	1.8	229°	2.7	1.7	123°
10/4/14 12:39 W7=15.8#@Pole 15 (191°). 2 Min	5.5	3.5	154°	8.0	5.8	56°	3.7	2.3	237°	3.5	2.3	139°
10/4/14 20:35 W8=15.7#@Pole 14 (202°). 2 Min	19.5	17.8	125°	21.6	20.2	46°	4.0	2.7	192°	3.7	2.8	104°
10/4/14 21:11 W8=15.7#@Pole 14 (202°). 3 Min	10.3	8.3	99°	14.4	12.1	31°	3.4	2.0	199°	3.6	2.4	101°
10/4/14 21:38 W8=15.7#@Pole 14 (202°). 10 Min	8.1	6.6	60°	12.8	11.1	2°	2.4	1.1	215°	2.5	1.4	92°
10/4/14 21:57 W8=15.7#@Pole 14 (202°). 3 Min	8.1	6.5	62°	12.9	11.2	2°	2.4	1.1	218°	2.5	1.4	93°
10/5/14 13:15 W9=18.8#@Pole 15 (191°), 22 Min	4.6	2.9	99°	8.2	6.3	23°	2.9	1.7	227°	2.6	1.6	123°
10/5/14 14:16 W9=18.8#@Pole 15 (191°), 3 Min	4.8	3.1	121°	8.2	6.4	34°	3.3	2.1	229°	3.1	2.0	127°

Bay D' Espoir Unit 7 Vibration At Various Conditions During Balancing 9/27/14 to 10/5/14												
Unit 7 Vibration At Load												
	Gen X			Gen Y DS			TGB X			TGB Y DS		
Condition	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ
9/28/14 9:50 ~1 Min @100 MW	17.8	15.6	167°	21.0	18.0	81°	5.9	4.6	230°	6.7	4.9	137°
9/28/14 11:04 ~1 Min @ 99 MW from - 4 MW	17.4	15.3	168°	20.5	17.6	83°	6.0	4.7	230°	7.0	5.2	138°
9/28/14 12:19 ~6 Min @ 101 MW	16.4	13.9	159°	20.1	16.8	77°	5.5	3.9	229°	6.4	4.4	137°
9/30/14 8:54 W2= 9.3# @ Pole 23 @ 77 MW	23.1	19.3	215°	27.9	20.1	135°	6.9	4.8	258°	7.9	4.8	169°
9/30/14 19:26,W3= 7# @ Pole 15 (191°), 100 MW	17.0	15.1	193°	19.5	16.8	106°	5.6	4.3	247°	6.3	4.4	154°
10/2/14 9:02,W3= 7# @ Pole 15 (191°), 101 MW	17.9	16.5	200°	20.0	17.9	114°	6.4	5.3	254°	7.0	5.2	161°
10/2/14 18:11,W5= 10.3# @ Pole 15 (191°), 100 MW	14.4	12.3	189°	16.4	13.4	102°	5.4	4.1	249°	6.2	4.2	156°
10/2/14 18:26,W5= 10.3# @ Pole 15 (191°), 135 MW	18.3	16.1	184°	20.1	17.3	96°	6.1	4.9	238°	7.1	4.8	147°
10/3/14 14:29 W6=15#@Pole 17.3 (165°). 99 MW	12.2	10.9	225°	13.0	11.3	143°	5.0	3.9	269°	5.5	3.7	178°
10/3/14 14:35 W6=15#@Pole 17.3 (165°). 131 MW	16.1	15.2	221°	17.5	16.4	135°	6.3	5.3	263°	7.3	5.4	171°
10/3/14 15:11 W6=15#@Pole 17.3 (165°). 100 MW	13.2	11.7	212°	14.1	12.3	128°	5.4	4.4	261°	6.0	4.3	173°
10/4/14 10:56 W7=15.8#@Pole 15 (191°). 100 MW	11.8	9.8	182°	13.2	10.2	95°	4.4	3.3	245°	5.1	3.2	153°
10/4/14 11:06 W7=15.8#@Pole 15 (191°). 130 MW	13.4	11.8	193°	14.7	12.4	103°	5.3	4.2	247°	6.2	4.1	155°
10/4/14 11:30 W7=15.8#@Pole 15 (191°). 150 MW	16.2	14.3	181°	17.6	15.0	92°	6.3	4.5	236°	7.3	4.6	146°
10/4/14 12:20 W7=15.8#@Pole 15 (191°). 100 MW	14.4	12.1	181°	16.7	13.4	94°	5.6	4.3	248°	6.6	4.5	153°
10/5/14 13:29 W9=18.8#@Pole 15 (191°), 100 MW	10.5	8.4	179°	12.6	9.7	89°	4.2	3.0	243°	4.8	3.0	149°
10/5/14 13:37 W9=18.8#@Pole 15 (191°), 120 MW	13.2	11.2	181°	14.6	12.1	92°	4.9	3.7	243°	5.7	3.8	149°
10/5/14 13:56 W9=18.8#@Pole 15 (191°), 129 MW	12.7	10.8	187°	14.0	11.7	99°	5.3	4.1	247°	6.3	4.2	154°
10/5/14 14:51 W9=18.8#@Pole 15 (191°), 100 MW	10.9	8.8	166°	12.9	9.9	79°	4.5	3.3	243°	5.2	3.4	149°
10/5/14 19:15 W9=18.8#@Pole 15 (191°), 100 MW	11.0	8.6	164°	13.1	10.1	76°	4.6	3.2	244°	5.2	3.3	148°
10/5/14 19:23 W9=18.8#@Pole 15 (191°), 130 MW	11.5	10.0	177°	13.2	10.7	87°	5.2	4.0	246°	6.0	4.0	153°
10/5/14 19:39 W9=18.8#@Pole 15 (191°), 140 MW	12.1	10.3	179°	12.8	10.3	89°	5.9	3.7	239°	6.2	3.6	150°
10/5/14 19:47 W9=18.8#@Pole 15 (191°), 150 MW	12.6	10.8	178°	13.4	10.8	88°	5.9	4.0	238°	6.6	3.9	149°
Unit 7 Vibration During Synchronous Condense ~ -4 MW												
	Gen X			Gen Y DS			TGB X			TGB Y DS		
Condition	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ	OA	1XA	1Xϕ
9/28/14 10:43 ~34 Min @ -4 MW	8.4	6.5	200°	10.8	7.6	119°	7.7	4.6	216°	7.6	4.2	123°
9/28/14 11:29 ~9 Min @ -4 MW	8.5	6.5	201°	11.5	7.6	125°	8.2	4.6	217°	8.0	4.2	125°
9/28/14 12:39 ~5 Min @ -4 MW	8.6	6.5	204°	11.6	7.4	131°	8.2	4.4	218°	7.8	4.1	128°
9/30/14 9:13 W2= 9.3# @ Pole 23 @ -4.1 MW	16.1	14.2	242°	20.4	16.0	176°	7.8	4.6	242°	7.5	3.9	160°
9/30/14 19:45,W3= 7# @ Pole 15 (191°),-4 MW	8.1	6.1	244°	8.0	4.5	164°	6.8	3.6	227°	6.2	2.9	133°
10/2/14 9:16,W3= 7# @ Pole 15 (191°), -4 MW	8.0	6.1	230°	10.1	6.0	148°	7.6	3.9	225°	7.2	3.3	133°
10/2/14 18:39,W5= 10.3# @ Pole 15 (191°), -4 MW	7.0	4.8	246°	6.6	2.7	159°	7.2	3.7	223°	6.8	3.0	126°
10/3/14 15:00 W6=15#@Pole 17.3 (165°).-4 MW	13.7	11.0	264°	13.8	9.2	206°	7.0	3.6	239°	6.0	2.5	155°
10/4/14 12:32 W7=15.8#@Pole 15 (191°). -4 MW	7.7	5.0	275°	7.7	2.9	232°	7.3	3.4	226°	6.5	2.5	128°
10/5/14 14:12 W9=18.8#@Pole 15 (191°), -4 MW	7.7	5.0	294°	8.2	3.6	268°	6.6	3.0	229°	5.9	2.2	127°


Added 18 wires to pole 15 — Oct 05/2014
Ch1 Ch2 Ch3 CH1 thrust guide bearing temp out
SNL Bearings Cold
OU-line
100 MW
110 M.W.
120 M.W.
130 M.W.
Reservoir drawdown
Bypass condenser
SNL
Field off
01:00 PM
100 MW
120 MW
130 MW
140 MW
150 MW 11m ich 2 10-11
Date
Page

8:30 Added 15 lbs 1½oz on pole 14. Oct 04/2014.

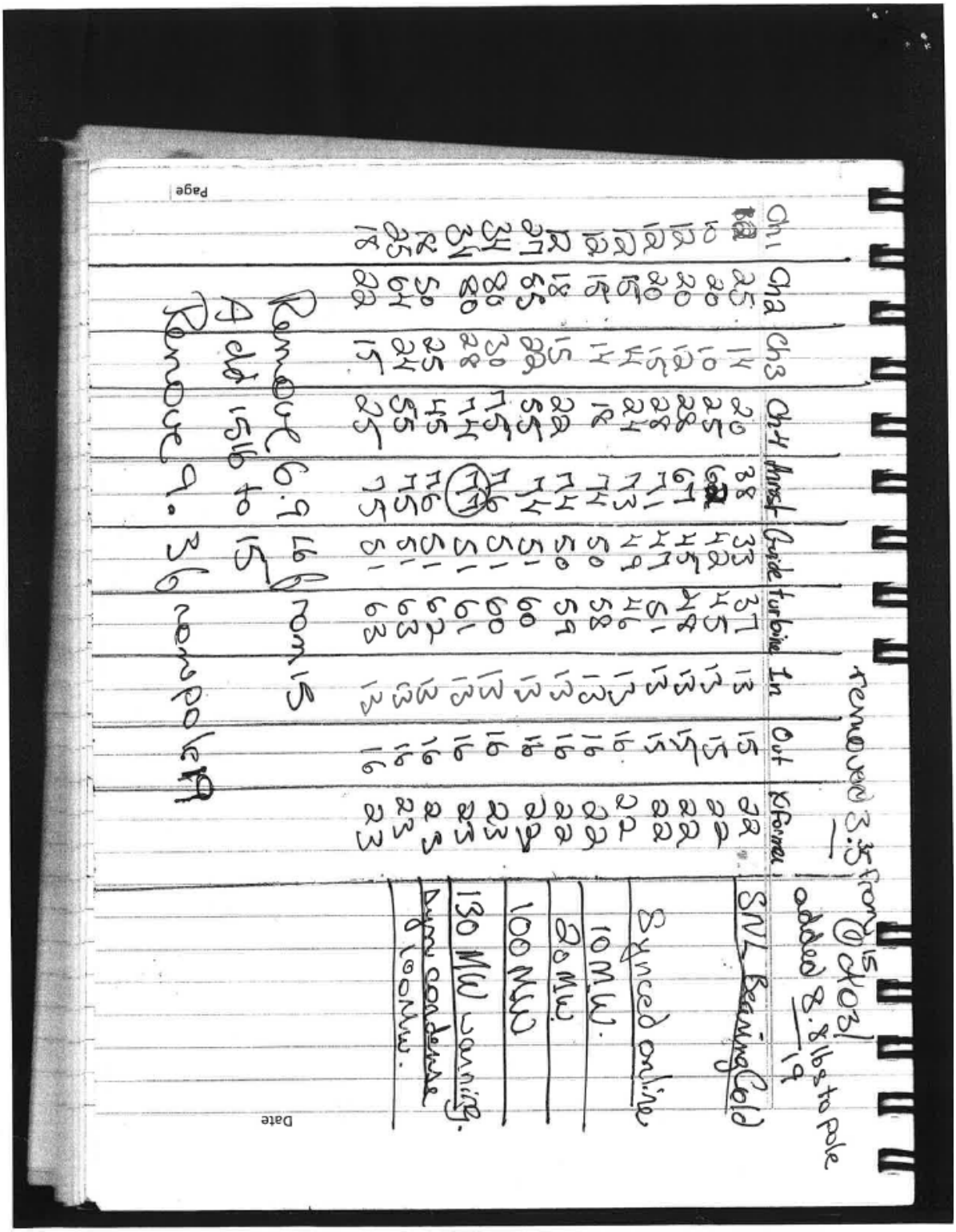
Ch1	Ch2	Ch3	Ch4	Christ guide turbine	In	Out	
18	80	18	80	46	38	43	12	14	Cold
15	90	12	70	66	44	50	12	15	10MW
18	75	15	60	68	47	51	12	15	34MW -
18	70	15	50	78	49	55	12	16	20 MW
18	75	15	55	73	50	57	12	16	SNL
16	60	15	45	73 Shut down	50	59	12	16	SNL
12	55	12	33	64	46	57	12	16	SNL
12	55	12	35	71	45	59	12	16	Shutdown -

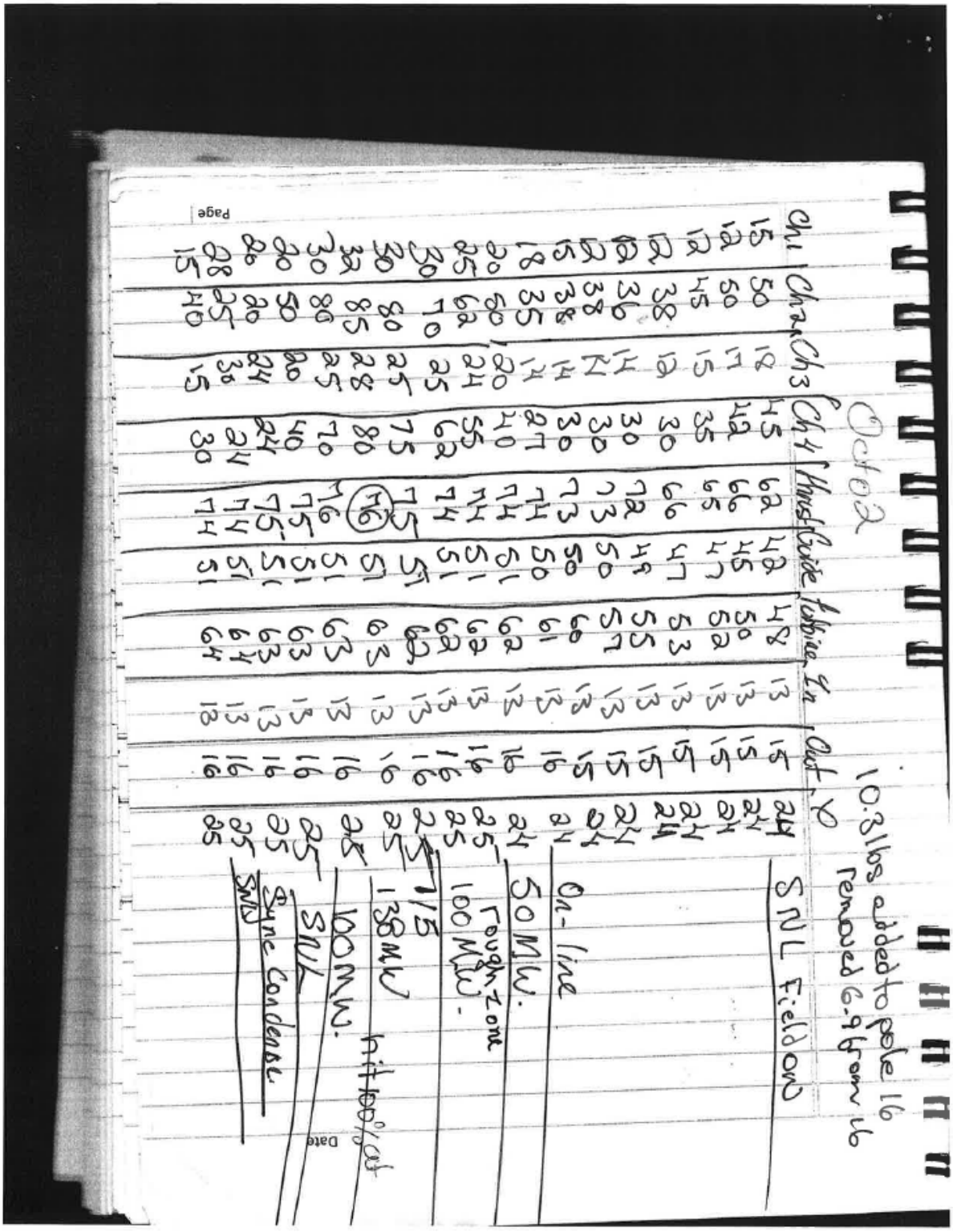
Page

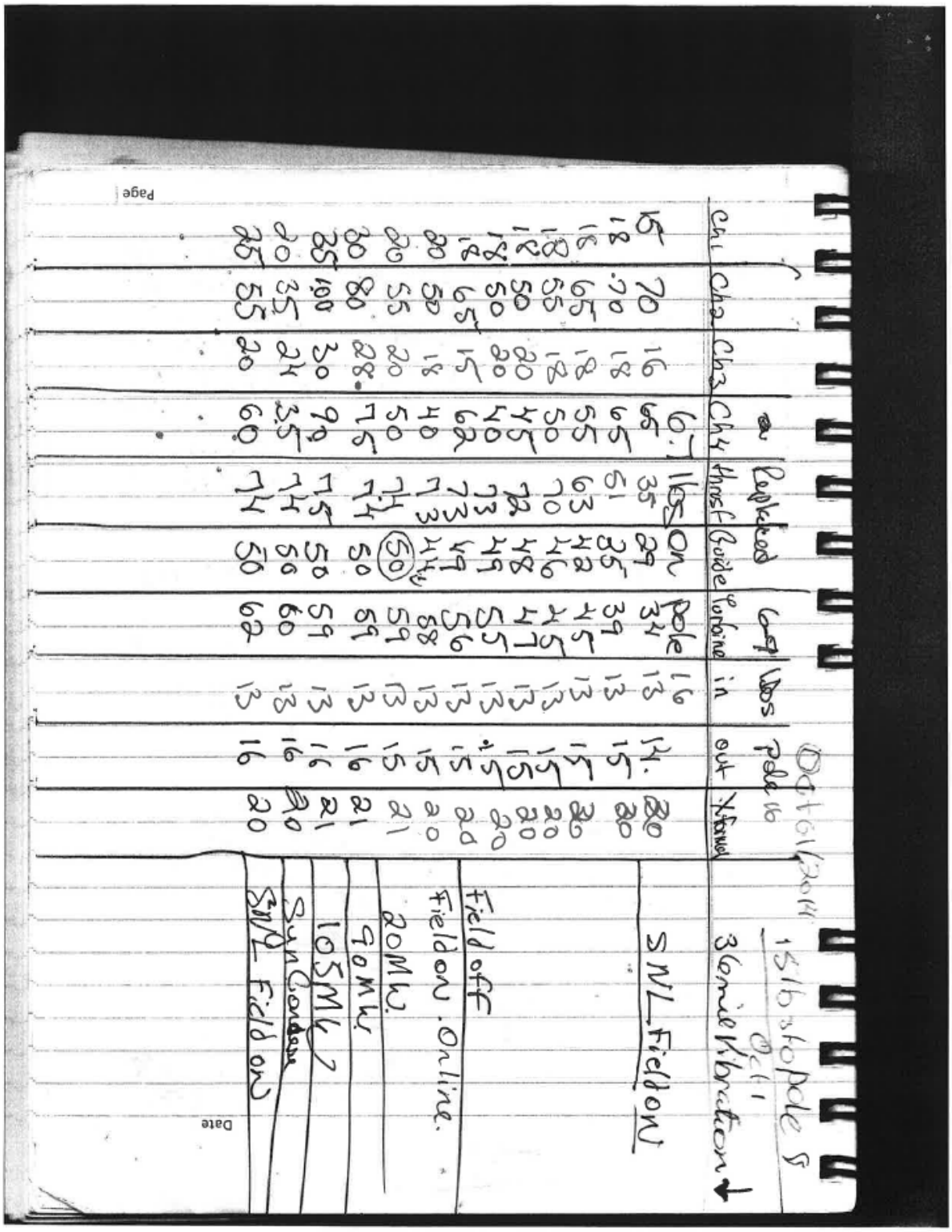
Date

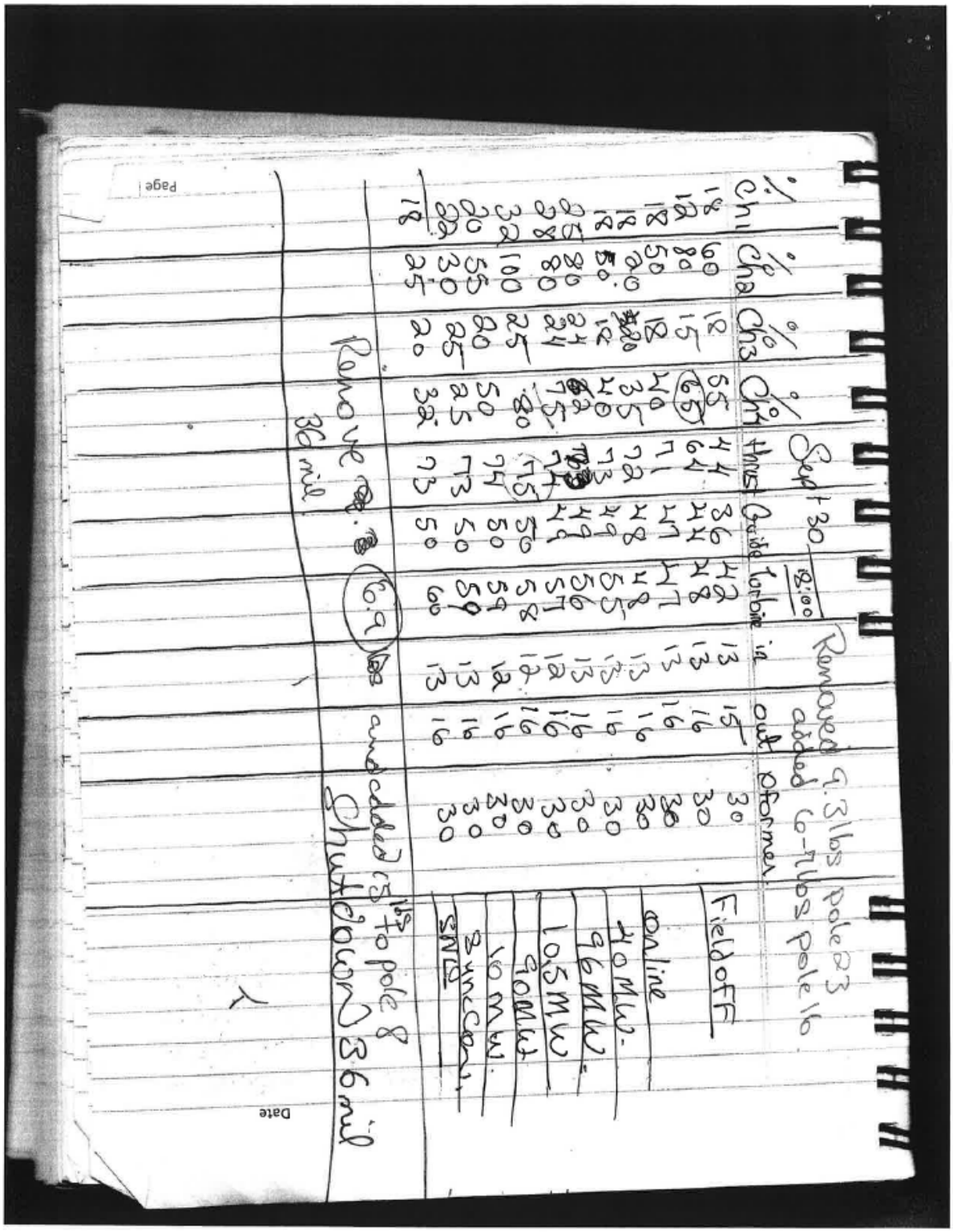
13

Added 15. 8 pole 15
Oct 01/2004 Removed 1
Page
Date
BNL Fieldon
On-Line.
75 MW.
100 MW.
110 MW.
130 MW
140 MW.
147 MW.
150 MW.
151 MW.
132 MW.
100 MW.
100MW.
Sync Condense
Sync Condenser

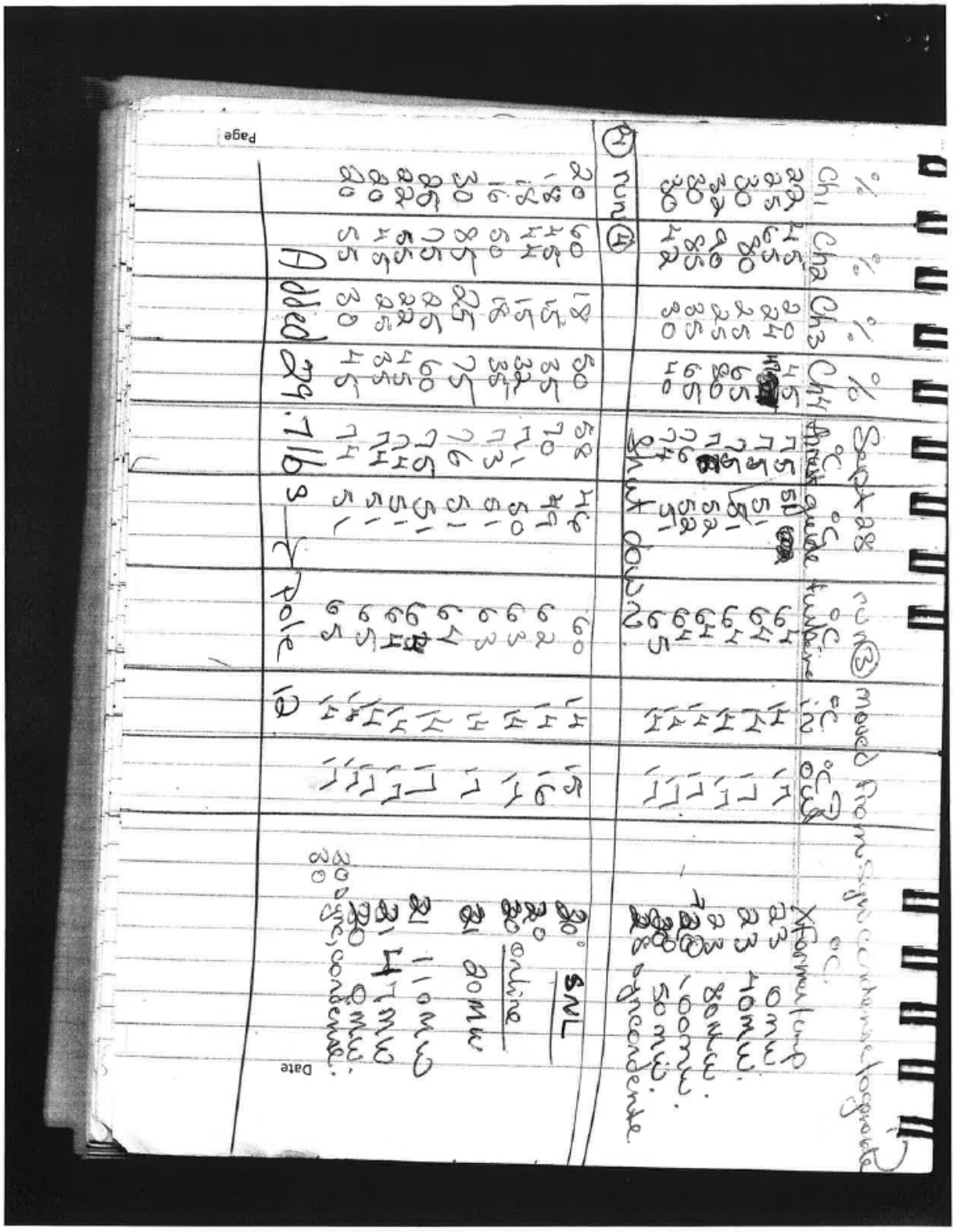


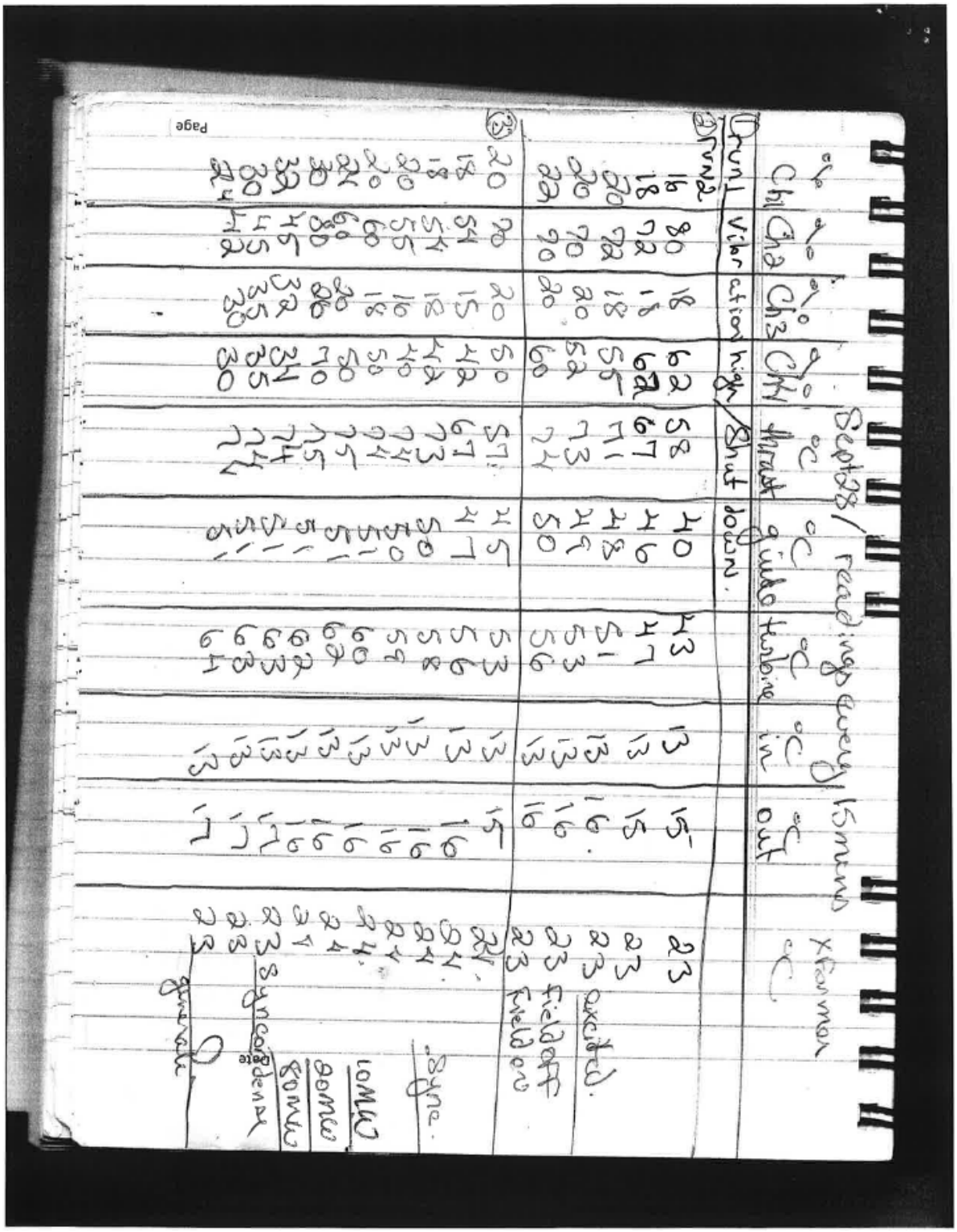

Oct 03
10:31 hrs added to pole 16
removed 6-9 from 16
SNL Field and
On-line
50 MW.
Rough zone
100 MW.
1/5
138 MW
hit 100% at
100 MW.
SNL
Skyne Condense
SNL


Page
Date
Field off
Field on - Online.
20MW
40MW
105MW
Sync Condor
SWL Field on
SWL Field on
36 miles/bration
15 lb stop/pole
Pole 16
Ch1 Ch2 Ch3 Ch4 Ch5 Ch6 Ch7 Ch8 Ch9 Ch10 Ch11 Ch12 Ch13 Ch14 Ch15 Ch16 Ch17 Ch18 Ch19 Ch20 Ch21 Ch22 Ch23 Ch24 Ch25 Ch26 Ch27 Ch28 Ch29 Ch30 Ch31 Ch32 Ch33 Ch34 Ch35 Ch36 Ch37 Ch38 Ch39 Ch40 Ch41 Ch42 Ch43 Ch44 Ch45 Ch46 Ch47 Ch48 Ch49 Ch50 Ch51 Ch52 Ch53 Ch54 Ch55 Ch56 Ch57 Ch58 Ch59 Ch60 Ch61 Ch62 Ch63 Ch64
Reflected
Thrust Guide
Loss in Pole
Loss in Turbine
Pole out
Pole Xfmed


Sept 30
Removed 9.3 lbs Pole 23
added 6-7 lbs Pole 16
Field OFF
Saline
40 MW-
96 MW-
105 MW
60 MW
10 MW
Remove 9.3 lbs and added 6.9 lbs to pole 8
Shutdown 336 mil
336 mil

Sept 24/2014.
3.3 lbs on pole 23.
Ch1 Ch2 Ch3 Ch4 thrust guide turbine in out Frames
① 18 80 50 38 40 13 15 29
20 75 Shut down
② 20 80 75 53 41 13 15 29
20 65 63 44 53 13 15 29
22 60 71 49 55 13 15 29
22 60 72 50 13 15 30
23 60 73 13 15
10 MW ↔
Page
① 18 15 70 60 18 75 55 47 63 36 13 15 29
15 60 60 15 50 67 43 13 15 29
20 70 20 65 70 72 46 13 15 29
22 60 20 70 73 48 13 15 30
25 75 25 70 73 47 13 15 30
28 80 24 70 73 49 13 16 30
24 64 60 74 50 59 13 16 30
25 51 60 17 30
Sept 30 morning
SVC locked
Regen online
50MW / in the rough
20m had to reduce load.
Shut down




Sept 28 / reading every 15 mins
Ch1 Ch2 Ch3 CH4 Thrust Shut down
Vibration high
Guide turbine
in
out
Xformer
Page
Synchronized
Synchronized
Synchronized

Unit 1 Flashed before shutdown
Sept 27
Ch1 Ch2 Ch3 Ch4 thrust & guide turbine 66°C
thrust guide turbine cooling inlet
15 shutdown
Flashed.
Page
Date

Canadian Instrumentation Services Group Ltd.

Description: LOG
OCT 5, 2014

Project

SUNDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	ARRIVE AT SITE
~~8:00~~	THE UNIT IS DEWATERED UP
8:12	FINISH & APPLY THE PERMIT
7:30	TAIL BOARD MEETING
8:00	REMOVE SEARCH COIL & REINSTALL THE AIR
—	DUCT COVERS
9:00	INSTALL BALANCE WEIGHT #9
9:28	REMOVE THE PERMIT
10:00	WATER UP THE UNIT
12:15	REMOVE AIR FROM THE BEARING & SAC COOLERS
12:40	TEST OPERATOR ARRIVED
12:50	START THE UNIT AND SET RATED ARMATURE VOLTS
13:14	PUT THE UNIT ON LINE
13:22	SET 100 MW LOAD
13:40	MAX MW 130
	REDUCE THE LOAD
14:07	SYN CONDENSER MODE
14:12	RATED VOLTAGE - OFF LINE
	REMOVE EXCITATION & POWER METER
~~14:27~~	PUT THE UNIT BACK ON LINE
14:40	SET 100 MW LOAD
~~14:35~~	FA 905.4
17:00	INCREASE LOAD TO 130 MW - 15 MVARS
17:24	INCREASE THE LOAD TO 140 MW -15 MVARS
	FA = 936.5
17:41	INCREASE THE LOAD TO 150MW -15 MVARS
	FA = 964.6
17:50	TURN THE UNIT OVER TO ECC
17:55	FINISH PACKING THE TEST EQUIPMENT

Originator	Date	Checker	REFERENCE	Page	Of
BRUCE DUPLESSIS	OCT 5/14				

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Canadian Instrumentation Services Group Ltd.

Description: LOG
OCT 4, 2014

Project
SATURDAY
[redacted]

TIME	BAY D'ESPOIR - UNIT 7
7:45	ARRIVE AT SITE
7:45	STARTED TO WATERUP THE UNIT
9:50	TAILBOARD MEETING
10:00	TEST OPERATORS ARRIVE
9:27	TURN ON WATER SYSTEM & REMOVE AIR
—	FROM THE BEARING & SAC COOLERS
10:13	START THE TURBINE
10:14	SET RATED SPEED AND ARMATURE VOLTS
10:42	PUT UNIT ON LINE & ~~100~~ SET 100 MW LOAD
11:25	MAX MW ~~140~~ 150 Iwave File 39
11:50	100 MW POINT TO Check Repeatable
12:28	SYN CONDENSER MODE
—	~~LOAD UNIT BACK UP TO MAX MW~~ CANCEL
12:30	RATED VOLTAGE - OFF LINE
12:40	DROP THE HEADGATE & START TO DEWATER THE UNIT
17:00	INSTALL BALANCE WEIGHT #8 (20lbs)
18:00	REMOVE THE ELECTRICAL & MECHANICAL CLEARANCE
	~~REMOVE THE CLEARANCE~~
18:22	WATER UP THE UNIT
7:58	REMOVE AIR FROM THE BEARING & SAC COOLERS
20:23	TEST OPERATOR ARRIVE
20:30	START THE UNIT AND SET RATED ARMATURE VOLTS
20:34	PUT UNIT ON LINE
20:35	SET ~~100~~ 40 MW LOAD POINT
—	MAX MW ———
—	100 MW POINT TO CHECK REPEATABLY
—	SYN CONDENSER MODE
21:06	RATED VOLTAGE - OFF LINE
21:15	SHUTDOWN THE UNIT
21:25	RESTART THE UNIT & SET RATED ARM VOLTS
21:40	SHUT DOWN THE UNIT
21:51	RESTART THE UNIT & SET RATED ARM VOLTS
21:55	DROP THE HEADGATE & START TO DEWATER THE UNIT

Originator	Date	Checker	REFERENCE	Page	Of
Bruce Dykstra					

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Canadian Instrumentation Services Group Ltd.

Description: LOG
OCT 3, 2014

Project
FRIDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	AIRRIVE AT SITE
	THE UNIT IS DEWATERED & THE CLEARANCE APPLIED
7:50	TAILBOARD MEETING
8:32	INSTALL BALANCE WEIGHT # 6 (9-10 LBS)
9:15 - 12:51	WATER ED UP THE UNIT & REMOVE CLEARANCE
13:15	TEST OPERATORS ARRNE
13:05	REMOVE AIR FROM BEARING & SAC COOLERS
13:30	START THE UNIT AND SET RATED ARMATURE VOLTS
8:30	ELECTRIAN TO VERIFY THE LOCKOUT
14:06	PUT UNIT ON LINE (-.184 MW) Power File 26
14:32	MAX MW ~~130.065~~ ~~-14.328~~ MVARS ~~45.571~~ FA 911.42
14:37	REDUCE MW
14:41	100 MW LOAD POINT
14:51	SYN CONDENSER MODE
—	~~RATED VOLTAGE - OFFLINE~~
15:13	LOAD UNIT BACK UP TO 100 MW
	RATED VOLTAGE - OFFLINE
15:21	LOW FREQUENCY ALARM 57.161 HZ
	RESET THE FREQUENCY TO 60HZ
15:36	DROP THE HEADGATE & START TO DEWATER THE UNIT
	INSTALL BALANCE WEIGHT #7 (15.8 LBS)
	REMOVE THE ELECTRICAL & MECHANICAL CLEARANCE
	READY TO BE WATERED UP

Originator	Date	Checker	REFERENCE	Page	Of
Bruce Duplessis		OCT 3/14			

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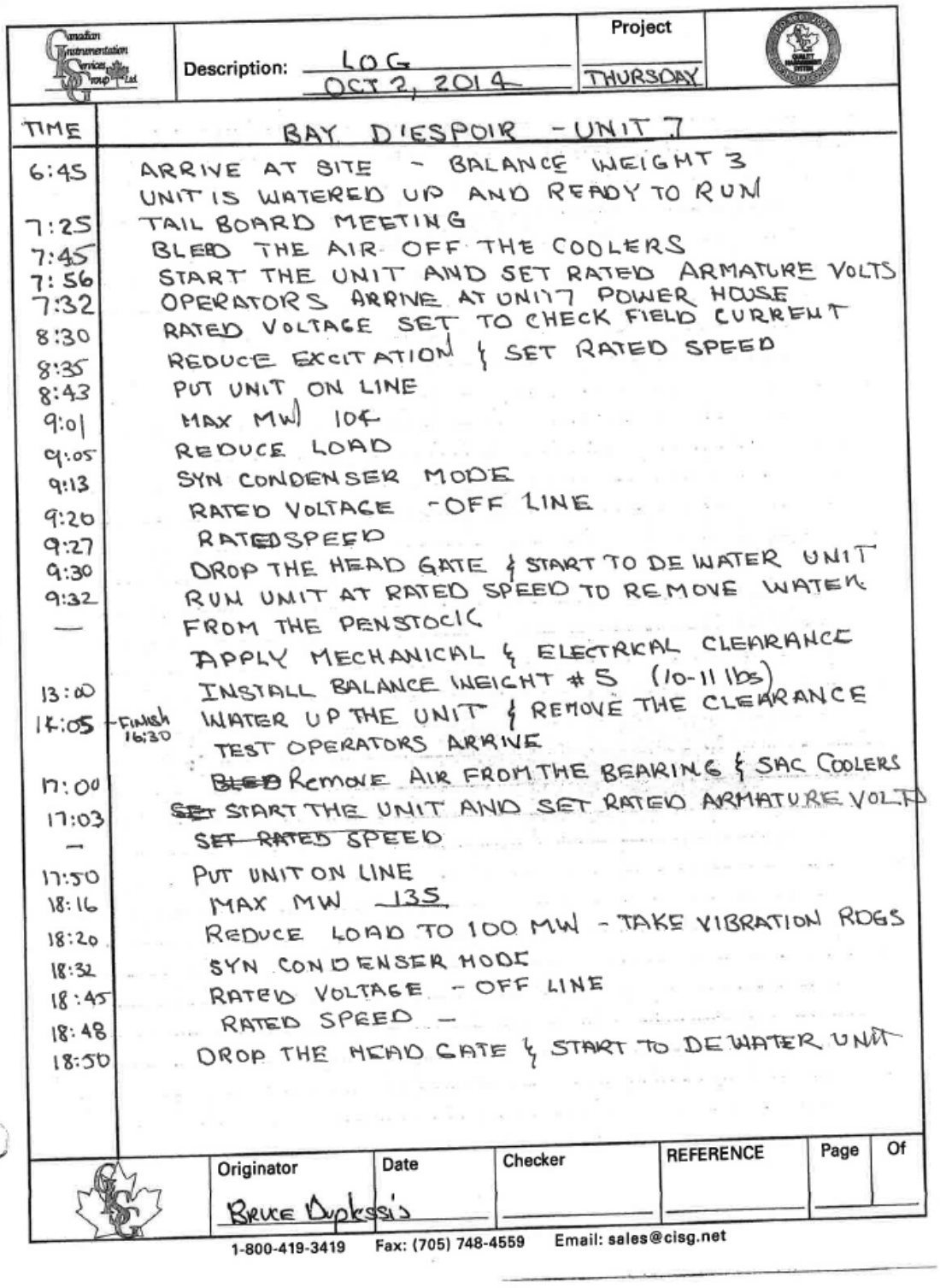

Canadian Instrumentation Services Group Ltd.

Description: LOG
OCT 2, 2014

Project

THURSDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	ARRIVE AT SITE - BALANCE WEIGHT 3
	UNIT IS WATERED UP AND READY TO RUN
7:25	TAIL BOARD MEETING
7:45	BLEED THE AIR OFF THE COOLERS
7:56	START THE UNIT AND SET RATED ARMATURE VOLTS
7:32	OPERATORS ARRIVE AT UNIT7 POWER HOUSE
8:30	RATED VOLTAGE SET TO CHECK FIELD CURRENT
8:35	REDUCE EXCITATION & SET RATED SPEED
8:43	PUT UNIT ON LINE
9:01	MAX MW 104
9:05	REDUCE LOAD
9:13	SYN CONDENSER MODE
9:20	RATED VOLTAGE - OFF LINE
9:27	RATED SPEED
9:30	DROP THE HEAD GATE & START TO DE WATER UNIT
9:32	RUN UNIT AT RATED SPEED TO REMOVE WATER
—	FROM THE PENSTOCK
	APPLY MECHANICAL & ELECTRICAL CLEARANCE
13:00	INSTALL BALANCE WEIGHT #5 (10-11 lbs)
14:05 FINISH 16:30	WATER UP THE UNIT & REMOVE THE CLEARANCE
	TEST OPERATORS ARRIVE
17:00	~~BLED~~ Remove AIR FROM THE BEARING & SAC COOLERS
17:03	~~SET~~ START THE UNIT AND SET RATED ARMATURE VOLTS
—	~~SET RATED SPEED~~
17:50	PUT UNIT ON LINE
18:16	MAX MW 135
18:20	REDUCE LOAD TO 100 MW - TAKE VIBRATION RDGS
18:32	SYN CONDENSER MODE
18:45	RATED VOLTAGE - OFF LINE
18:48	RATED SPEED —
18:50	DROP THE HEAD GATE & START TO DE WATER UNIT

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Bruce Dupkess					

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Canadian Instrumentation Service Group Ltd.

Description: LOG
OCT 1, 2014

Project

WEDNESDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	ARRIVE AT SITE. UNIT IS DEWATERED & THE CLEARANCE APPLIED
8:20	TAILBOARD MEETING
9:00	INSTALL BALANCE WEIGHT # 4 (15 lbs)
13:30	WATERED UP THE UNIT & REMOVED THE CLEARANCE BLEED THE AIR OFF THE COOLERS
14:08	START THE UNIT AND SET RATED ARMATURE VOLTS
14:09	~~PUT UNIT ON LINE~~ VIBRATION TOO HIGH SHUT THE UNIT DOWN (> 30 MILS)
14:15	DOUG REVIEWED THE TEST DATA
14:28	DROP THE HEAD GATE & START TO DEWATER THE UNIT
15:00	RAN UNIT AT 100 RPM TO REMOVE WATER FROM PENSTOCK TOOK VIBRATION READINGS AT 25, 50, 75, 100, 150, 200
16:30	CUSTOMER REVIEW MEETING
	• INSTALL BALANCE WEIGHT Number 3 (7 lbs)
21:00	REMOVED THE CLEARANCE WATERED UP THE UNIT

Originator	Date	Checker	REFERENCE	Page	Of
Bruce Dykstra					

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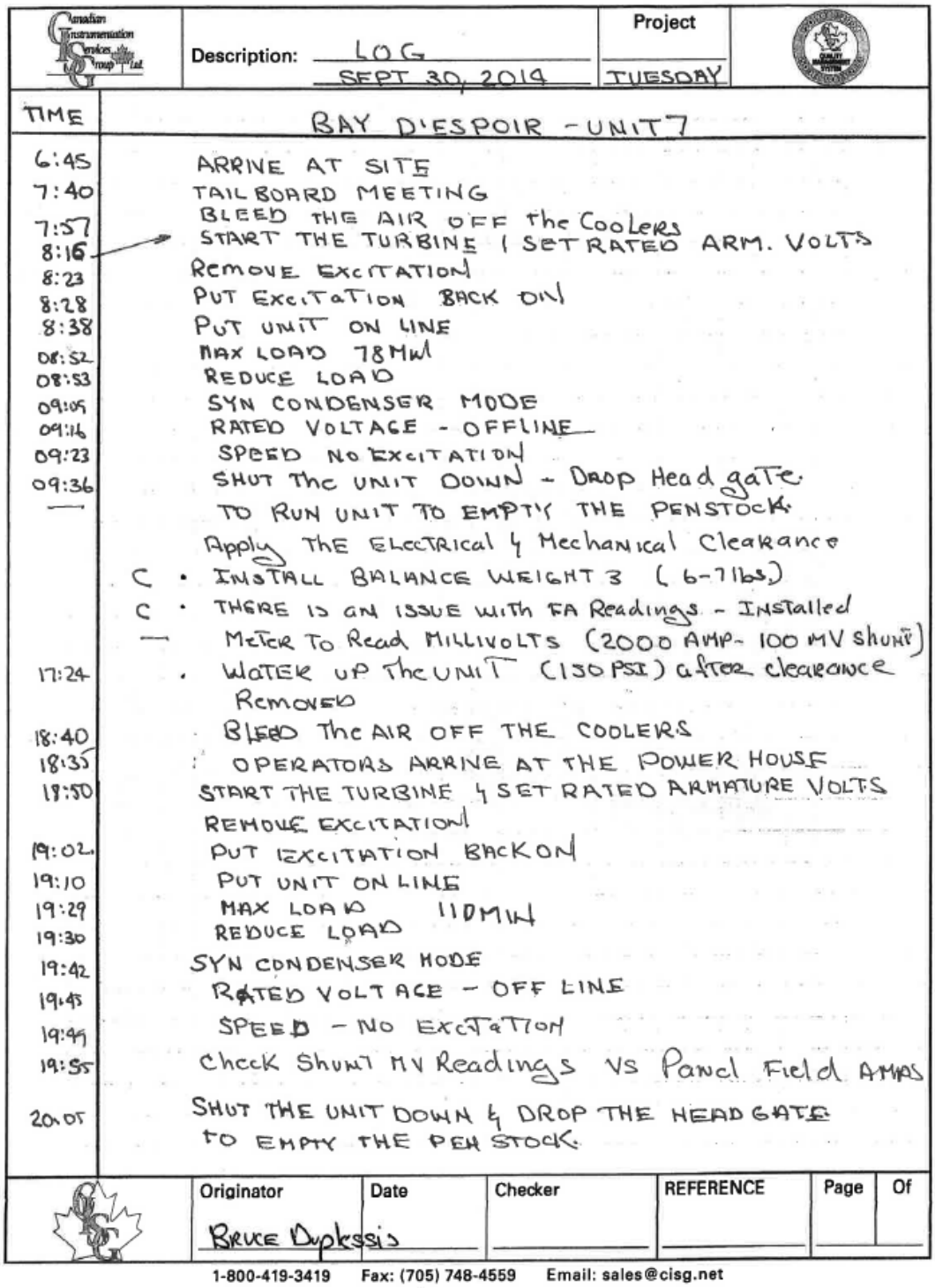

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Description: LOG SEPT 30, 2014

Project: TUESDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	ARRIVE AT SITE
7:40	TAILBOARD MEETING
7:57	BLEED THE AIR OFF the COOLERS
8:16	START THE TURBINE & SET RATED ARM. VOLTS
8:23	REMOVE EXCITATION
8:28	PUT EXCITATION BACK ON
8:38	PUT UNIT ON LINE
08:52	MAX LOAD 78MW
08:53	REDUCE LOAD
09:05	SYN CONDENSER MODE
09:16	RATED VOLTAGE - OFFLINE
09:23	SPEED NO EXCITATION
09:36	SHUT the UNIT DOWN - DROP Head gate.
—	TO RUN UNIT TO EMPTY THE PENSTOCK.
	Apply THE ELECTRICAL & Mechanical Clearance
	C • INSTALL BALANCE WEIGHT 3 (6-7lbs)
	C • THERE IS AN ISSUE WITH FA Readings - Installed
	— Meter To Read MILLIVOLTS (2000 AMP - 100 MV shunt)
17:24	• WATER UP the UNIT (130 PSI) after clearance Removed
18:40	BLEED the AIR OFF THE COOLERS
18:35	OPERATORS ARRIVE AT THE POWER HOUSE
18:50	START THE TURBINE & SET RATED ARMATURE VOLTS
	REMOVE EXCITATION
19:02	PUT EXCITATION BACK ON
19:10	PUT UNIT ON LINE
19:29	MAX LOAD 110MW
19:30	REDUCE LOAD
19:42	SYN CONDENSER MODE
19:43	RATED VOLTAGE - OFF LINE
19:49	SPEED - NO EXCITATION
19:55	Check Shunt MV Readings vs Panel Field AMPS
20:05	SHUT THE UNIT DOWN & DROP THE HEAD GATE TO EMPTY THE PEN STOCK

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Canadian Instrumentation Services Group Ltd.

Description: LOG SEPT 29, 2014 | Project: MONDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	ARRNE AT SITE
8:00	TAIL BOARD MEETING
8:00	MARK shaft in collect or Housing & one brush box
8:25	bleed the water coolers - bearing & SAC.
	• Normal START • Rated Speed
	• MAX LOAD
	• SYN Condenser
	• Rated VOLTS
8:34	START the TURbine & SET RATED ARMATURE voltage
8:36	SHUT UNIT DOWN DUE TO HIGH VIBRATION (35 mil)
	DOUG REVIEWED the TEST DATA
8:50	DE WATER the UNIT AFTER HEAD GATE HAS BEEN DROPPED.
9:30	RAN UNIT AT 138 RPM TO REMOVE WATER FROM PENSTOCK
15:00	INSTALL Balance Weight number 2 (9.3 lb)
16:00	Fixed the brush Rigging Spacing as it was Too close.
16:15	START TO Remove the Mechanical & Electrical clearance
18:00	WATER UP the UNIT - Finished @ 19:30
20:15	bleed the air off the Coolers
20:10	OPERATOR ARRIVE AT the POWER HOUSE
20:32	START the TURBINE & check the brush box SPACING
20:35	Restore UNIT back for NORMAL START
20:40	START THE TURBINE & SET RATED ARMATURE VOLTAGE
	RATED SPEED
20:46	Shutdown UNIT
20:59	START THE TURBINE & SET RATED ARMATURE VOLTAGE
~~21:10~~	~~Shutdown UNIT FOR THE NIGHT~~
21:13	PUT UNIT ON LINE SET 10 OR 11 MW
	File 658 10.53 MVI [- 29.653] MVARS 60.020 FA 662-8
21:25	Shutdown UNIT FOR THE NIGHT

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Bruce Dykstra					

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Canadian Instrumentation Services Group Ltd.

Description: LOG Sept 28

Project: SUNDAY

TIME	BAY D'ESPOIR UNIT 7
13:00	· SHUT THE UNIT DOWN · DE WATER THE UNIT · Apply the clearance (Mechanical & Electrical)
16:48	The customer Ready to install the FIRST TRAIL WEIGHT
17:00	Customer installs the balance weight #1 (30lbs)
17:45	Remove the clearance (Mechanical & ELECTRICAL)
21:00 →	WATER THE UNIT & ~~bleed Air off coolers~~ ~~START THE UNIT (balance weight #1)~~

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BRUCE Dupkssis					

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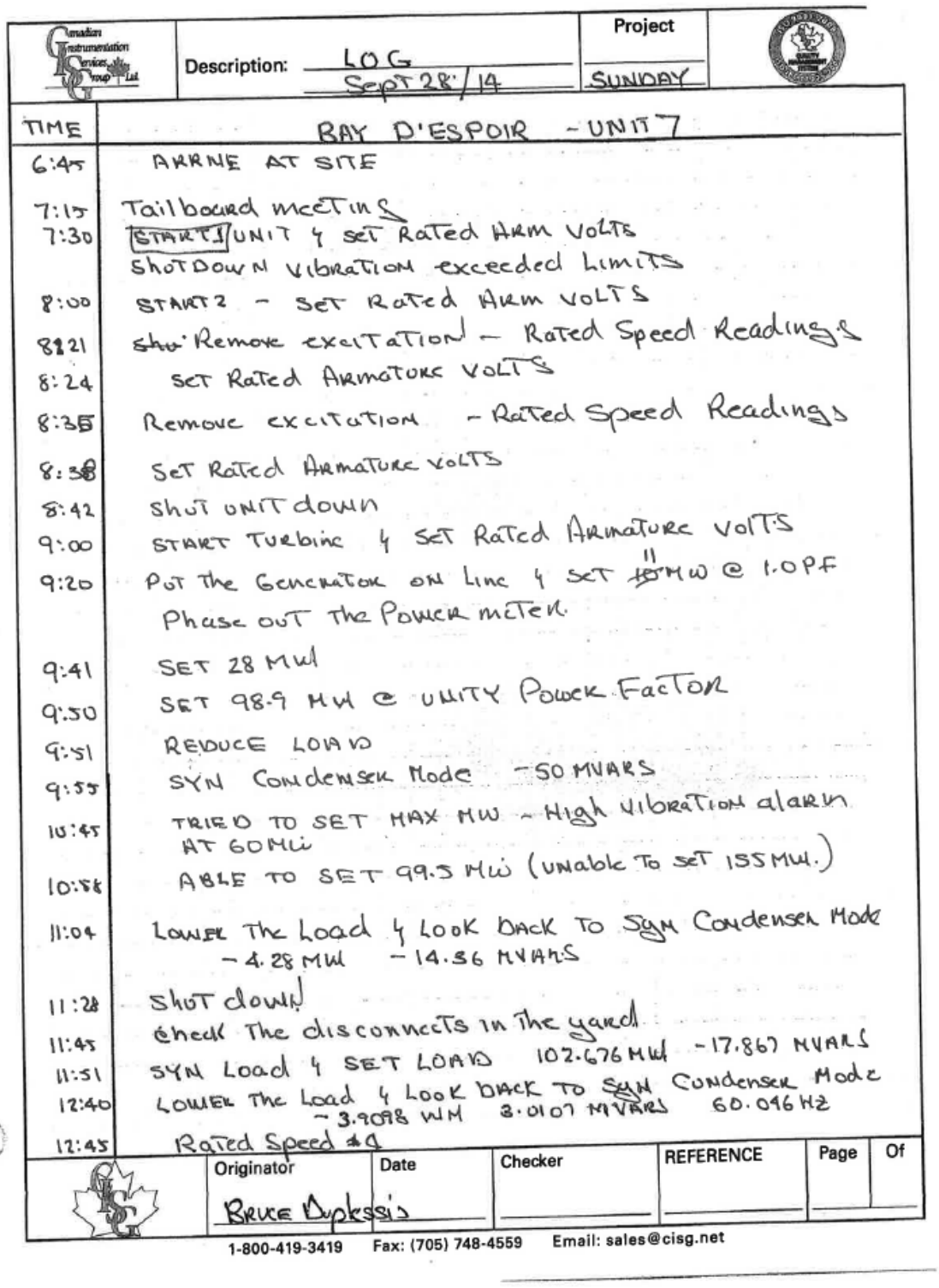

Canadian Instrumentation Services Group Ltd.

Description: LOG Sept 28/14

Project: SUNDAY

TIME	BAY D'ESPOIR - UNIT 7
6:45	ARRIVE AT SITE
7:15	Tailboard meeting
7:30	START UNIT 4 SET Rated ARM VOLTS
	SHUTDOWN VIBRATION exceeded LIMITS
8:00	START 2 - SET Rated ARM VOLTS
8:21	Shu Remove excitation - Rated Speed Readings
8:24	SET Rated ARMATURE VOLTS
8:35	Remove excitation - Rated Speed Readings
8:38	SET Rated ARMATURE VOLTS
8:42	SHUT UNIT down
9:00	START Turbine 4 SET Rated ARMATURE VOLTS
9:20	PUT the GENERATOR ON Line 4 SET 11 MW @ 1.0PF
	Phase OUT the POWER METER
9:41	SET 28 MW
9:50	SET 98.9 MW @ UNITY POWER FACTOR
9:51	REDUCE LOAD
9:55	SYN CONDENSER Mode -50 MVARS
10:45	TRIED TO SET MAX MW - High VIBRATION alarm AT 60MW
10:58	ABLE TO SET 99.3 MW (UNable TO SET 155 MW.)
11:04	LOWER The Load 4 LOOK BACK TO SYN CONDENSER Mode -4.28 MW -14.56 MVARS
11:28	SHUT down
11:45	Check The disconnects IN The yard
11:51	SYN Load 4 SET LOAD 102.676 MW -17.867 MVARS
12:40	LOWER The Load 4 LOOK BACK TO SYN CONDENSER Mode -3.9098 WM 3.0107 MVARS 60.096 HZ
12:45	Rated Speed #4

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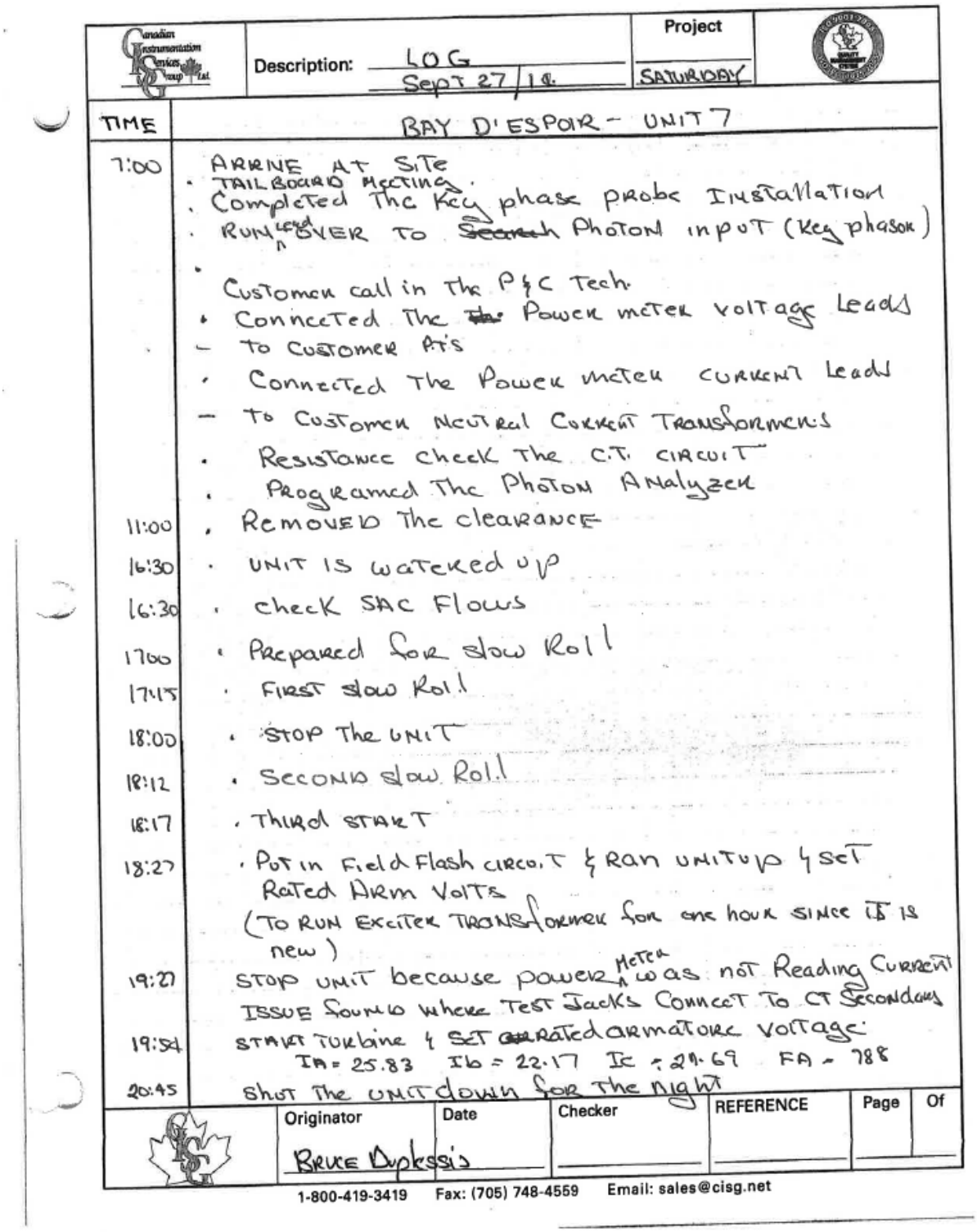

Canadian Instrumentation Services Group Ltd.

Description: LOG
Sept 27/18.

Project: SATURDAY

TIME	BAY D'ESPOIR - UNIT 7
7:00	ARRIVE AT SITE • TAILBOARD MEETING. • Completed The Key phase probe INSTALLATION • RUN LEAD OVER TO ~~Secrech~~ PHOTON input (Key phasor) • Customer call in the P&C Tech. • Connected The ~~the~~ Power meter voltage Leads – To Customer PT's • Connected The Power meter current Leads – To Customer Neutral Current Transformers • Resistance check The C.T. circuit • Programed The Photon Analyzer
11:00	• Removed The clearance
16:30	• UNIT IS watched up
16:30	• check SAC Flows
1700	• Prepared for slow Roll
17:15	• First slow Roll
18:00	• STOP The UNIT
18:12	• Second slow Roll
18:17	• Third START
18:27	• Put in Field Flash circuit & Ran UNIT up & set Rated ARM Volts (To RUN Exciter TRANSformer for one hour since it is new)
19:27	STOP UNIT because power meter was not Reading Current ISSUE found where Test Jacks Connect To CT Secondaries
19:54	START Turbine & SET ~~GENERATED~~ armature voltage: IA = 25.83 IB = 22.17 IC = 21.69 FA = 788
20:45	Shut The UNIT down for the night

Originator	Date	Checker	REFERENCE	Page	Of
Bruce Dupkess					

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Canadian Instrumentation Services Group Ltd

Description: LOG
Sept 26/14

Project: FRIDAY

TIME	BAY D'ESPOIR - UNIT 7
14:17	ARRIVE AT SITE. Job Review meeting with customer ~~UNLOADED~~ UNLOADED The Test Equipment Setup Two Test Tables Bench checked The INSTRUMENTS • SIGNED ON The clearance permit • Installed The Search Coil • RUN INSTRUMENT cable To Vibration panel In TURBINE P.I. • WIRED up the V-A-W Package • PROGRAMED The POWER METER • Completeted Power INSTRUMENT & Vibration Setup - except did not Connect P.T. OR C.T. Leads as customer was not sure where To Connect
21:00	• Completed FINAL INSPECTION

Originator	Date	Checker	REFERENCE	Page	Of
Bruce Dupkess					

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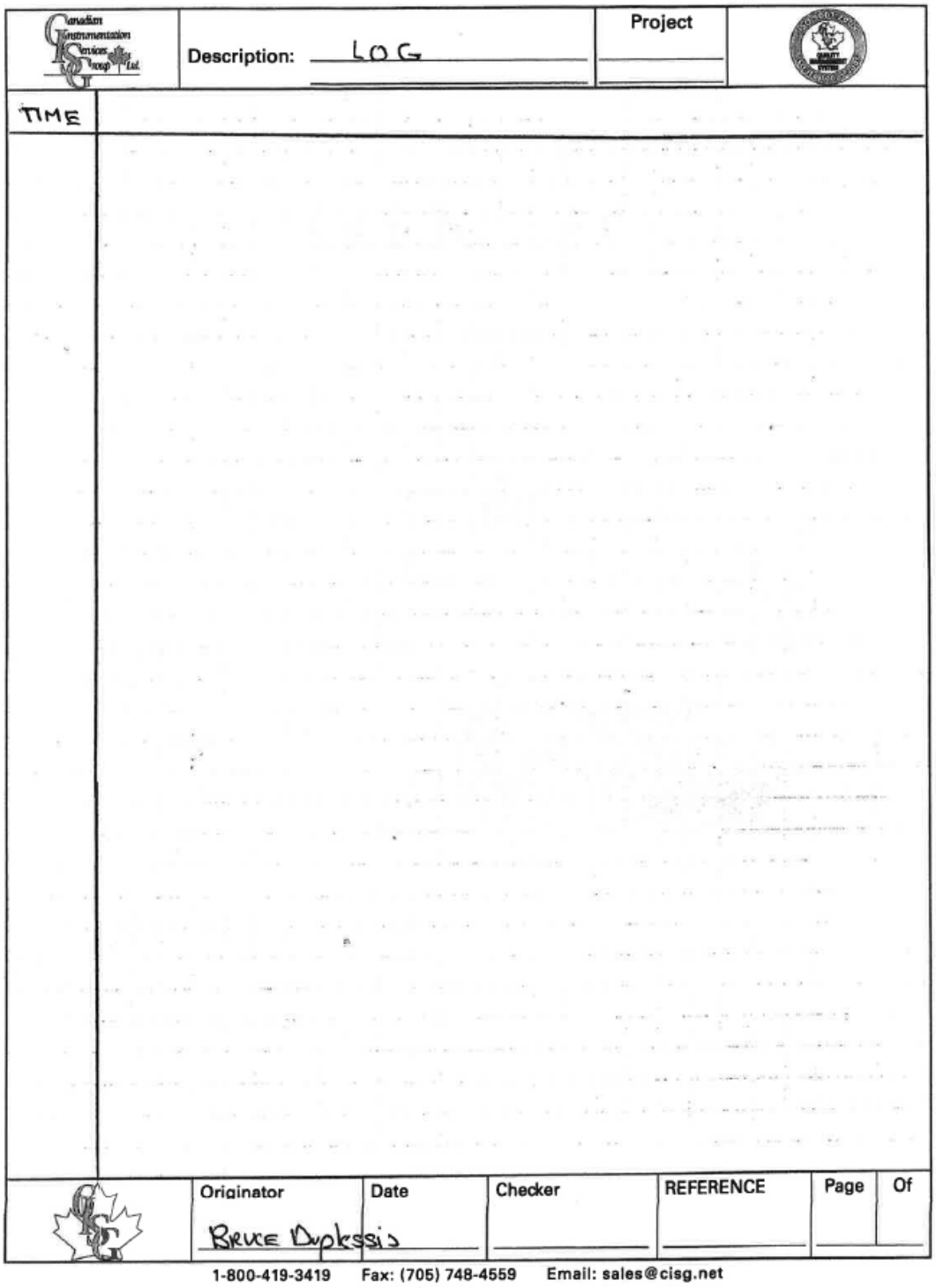

Description: LOG

Project

TIME

Originator	Date	Checker	REFERENCE	Page	Of
Bruce Dykstra					

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Bruce Duplessis

From: Bob Jameson <bob.jameson@cisg.net>
Sent: Monday, September 22, 2014 9:21 AM
To: Bruce Duplessis; 'Doug Leubner'
Subject: FW: Balance work on Unit 7

I will call you guys and set it up. It is a go!!!

R. G. (Bob) Jameson C.E.T.
President
Canadian Instrumentation Services Group Ltd. (CISG)
Accredited by A2LA to ISO/IEC 17025-2005
1091 Monaghan Road, Peterborough, Ontario K9J 5L4
705-748-5225 ext. 223
F: 705-748-4559

bob.jameson@cisg.net
www.cisg.net

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From: BWoodman@nlh.nl.ca [mailto:BWoodman@nlh.nl.ca]
Sent: Sunday, September 21, 2014 9:08 PM
To: Bob Jameson
Cc: MatthewLambert@nlh.nl.ca; KInkpen@nlh.nl.ca
Subject: Re: Balance work on Unit 7

Bob,

We decided to proceed. Sorry for not getting back to you sooner.

I asked Matt to prepare the PO documentation on Monday morning. Karl will work with you on timing.

I am on the road for work this week so I am not as close to the work on Unit 7.

Have a great week.
Bob
Sent from my BlackBerry 10 smartphone on the Bell network.

From: Bob Jameson
Sent: Sunday, September 21, 2014 10:23 PM
To: BWoodman@nlh.nl.ca
Subject: Balance work on Unit 7

Bob

I hope and trust you had a good weekend.

1

Bruce Duplessis

From: Doug Leubner HE <doug.leubner@hydroexpertise.com>
Sent: Monday, September 22, 2014 10:59 AM
To: 'Bob Jameson'; 'Bruce Duplessis'
Subject: RE: Balance work on Unit 7

Hi Bob,

I just spoke with Karl Inkpen, Work Execution Manager about Unit 7 readiness for testing. He does not think Unit 7 will be ready until this Fri or Sat but wanted to have a meeting with Rod Fudge and others working on Unit 7. Something about cables are too short for a new transformer that they are putting in that may delay them for a day or so. He does not think it will be later than Saturday but wanted to have a meeting with all involved in an hour to discuss. I told him we would need the unit tagged out to install the power meter equipment. We should have an answer on when we need to travel after their meeting. It looks like Thursday will be the day but will confirm after their meeting.

Doug

From: Bob Jameson [mailto:bob.jameson@cisg.net]
Sent: Monday, September 22, 2014 9:21 AM
To: Bruce Duplessis; 'Doug Leubner'
Subject: FW: Balance work on Unit 7

I will call you guys and set it up. It is a go!!!

R. G. (Bob) Jameson C.E.T.
President
Canadian Instrumentation Services Group Ltd. (CISG)
Accredited by A2LA to ISO/IEC 17025-2005
1091 Monaghan Road, Peterborough, Ontario K9J 5L4
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bob.jameson@cisg.net
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Subject: Re: Balance work on Unit 7

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Have a great week.
Bob
Sent from my BlackBerry 10 smartphone on the Bell network.

From: Bob Jameson
Sent: Sunday, September 21, 2014 10:23 PM
To: BWoodman@nlh.nl.ca
Subject: Balance work on Unit 7

Bob

I hope and trust you had a good weekend.

Can you please let me know as soon as possible if you will need us to work on unit 7. I need to make arrangements for both the guys and the equipment and time is running out if you want it done this week.

Thanks once again and look forward to hearing from you soon.

R. G. (Bob) Jameson C.E.T.
President
Canadian Instrumentation Services Group Ltd. (CISG)
Accredited by A2LA to ISO/IEC 17025-2005
1091 Monaghan Road, Peterborough, Ontario K9J 5L4
705-748-5225 ext. 223
F: 705-748-4559

bob.jameson@cisg.net
www.cisg.net

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Project Title: Replace Spherical By-Pass Valve Units 1 and 2

Location: Bay d'Espoir

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is required to replace the spherical valve (SV) by-pass assemblies on Generating Units 1 and 2 located in Powerhouse 1 at Bay d'Espoir Hydroelectric Generation Station (BDE). A similar multi-year project was approved by the Board of Commissioners of Public Utilities (Board) as part of Hydro's 2014 capital program, Board Order No. P.U. 42(2013), but due to outage constraints related to the generating Units 1 and 2, the approved project could not take place as planned. Generating Units 3 and 4 were substituted for the Generating Units 1 and 2. All four generating units are the same age and design. They each have the same by-pass valve arrangement and are in a similar state of deterioration.

Removal of the old by-pass assemblies and installation of new will be performed by Hydro personnel. The project will be completed over a two year period due to the estimated 24 week lead time required for procuring the valves and the limited construction window for completing the installations due to available outage schedules.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	120.0	0.0	0.0	120.0
Labour	23.8	88.9	0.0	112.7
Consultant	29.6	0.0	0.0	29.6
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.8	1.6	0.0	2.4
Interest and Escalation	9.4	24.5	0.0	33.9
Contingency	0.0	52.9	0.0	52.9
TOTAL	**183.6**	**167.9**	**0.0**	**351.5**

Justification:

The spherical valve by-pass assemblies including piping and valves are 48 years old. They are

deteriorated and at the end of their life expectancy.

In the past five years, there have been times when the by-pass assemblies have not been operating in compliance with the basis of design for the spherical valve control system. Hydro personnel were required to manually open and close by-pass valves that were designed for remote control.

The by-pass valves have to be actuated in order for the large spherical valve to be opened/closed properly. The spherical valve is considered a critical isolation point of the turbine and is a generating unit protection device in case of emergency. Complete failure of the by-pass valves to be actuated results in improper operation of the large spherical valves thereby creates a high risk to incur damage.

In order to ensure reliable operation of Generating Units 1 and 2, the aged and deteriorated spherical valve by-bass assemblies are required to be replaced.

Existing System:

The spherical valve by-pass valves and associated components (see Figure 1) are original plant equipment installed in 1967.

The spherical valve is approximately seven feet in diameter and, is used to isolate the flow of water to the turbine generator when the turbine is taken out of service. The by-pass assembly includes an eight inch remotely activated motorized valve, manual valve, and associated piping. It controls the water flow around the spherical valve from the upstream side to the downstream side. Proper operation of the by-pass assembly is vital to safe operation of the large spherical valve. Essentially, the by-pass assembly allows both sides of the spherical valve to reach approximately equal pressure prior to operating the spherical valve. If there is an imbalance in pressure between the upstream and downstream sides of the spherical valve, risks include spherical valve seal damage and pressure shock in the scroll cage. The by-pass assembly routes penstock water to the scroll case, located on the discharge side of the spherical valve. The scroll case is a large spiral waterway wrapped circumferentially around the turbine. It delivers water along the perimeter of the turbine runner at the proper distribution. The scroll case has to be flooded and pressurized, close to that of the penstock pressure feeding the supply side of the spherical valve, before the spherical valve is opened. A pressurized scroll case is required to prevent damage to the spherical valves seals during

its opening and closing motion. Using the by-pass assembly to prime the scroll case before opening the spherical valve prevents damage to the seals of the spherical valve when it goes through its opening/closing motion and minimizes the pressure shock experienced by the scroll case when the spherical valve is activated.

Figure 1: Spherical Valve By-Pass Assembly

Operating Experience:

Operation of the spherical valve is originally designed to be fully automatic and remotely activated from the control room with a set of logic controls in place. The control system requires several conditions to be met before the generating unit is allowed to start up.

Priming of the scroll case is a critical step in the operation of the generating unit and is the first condition that must be met for safe operation of the spherical valve. The set value of scroll case pressure, by engineering design, is 100 pounds per square inch (psi), while the penstock pressure is 250 psi. In the last five years, it has been difficult to attain the proper pressure of 100 psi in the scroll cases due to by-pass valve malfunctions (see Figure 2). If the operation of the by-pass assembly does not meet the designed activation pressure, technicians have to manually manipulate the valves in order to open or close them, as internal components may have become jammed or seized. If the technicians are unable to open the valves, this could lead to a forced generating unit outage until the issue is resolved. If a jammed by-pass valve occurred during a critical time of the year, it is possible to circumvent the priming process and operate the spherical valve; however, in doing so, the spherical valve would be at high risk of incurring seal damage.

Figure 2: By-Pass Valve with Disk Jammed in Half Open Position

Water is present in the housing of the motorized by-pass valve on Generating Unit 2 which indicates that the internals of the valve are damaged. Along with the valves, the pipe lines in these assemblies also show signs of erosion. The passing of high pressure water around the spherical valves over the past 48 years has caused erosion in the by-pass pipe lines such that they need to be replaced.

The generating units 1 to 6 at Bay d'Espoir are each fitted with spherical valves. The generating units 3 and 4 will be completed in Fall 2015. Completion of Units 1 and 2 with this capital proposal will complete the replacement of all original by-pass assemblies for Units 1-6 by 2017.

Maintenance or Support Arrangements

Routine maintenance such as greasing and annual checks is carried out by Hydro personnel.

Maintenance History

No major maintenance has taken place on the by-pass assemblies for Generating Units 1 and 2 since they were originally installed.

Anticipated Useful Life

The anticipated useful life for the spherical valve by-pass assembly is approximately 45 years.

Development of Alternatives

There are no viable alternatives to this project.

Conclusion:

This project will replace the deteriorated spherical valve by-pass assemblies on Generating Units 1 and 2 located in Powerhouse 1 at Bay d'Espoir. The by-pass assemblies are critical to the proper operation of the large spherical valves and the reliable operation of the generating units.

The by-pass valves and associated components are original plant equipment, installed in 1967. The valves are not functioning properly and are at the end of their life expectancy. The presence of water inside the housing indicates internal component damage. In addition the by-pass pipe lines have deteriorated due to erosion.

In order to ensure reliable operation of Generating Units 1 and 2, the spherical valve by-pass assemblies need to be replaced.

Project Schedule:

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open Project in JDEdwards	March 2016	March 2016
	Prepare scope statement	March 2016	March 2016
	Review schedule and budget	March 2016	March 2016
Design	RFP and award consultant contract	March 2016	April 2016
Procurement	Prepare material requisitions	April 2016	April 2016
	Evaluate bids	May 2016	May 2016
	Issue materials purchase orders	May 2016	May 2016
Construction	Shop piping prefabrication	June 2017	June 2017
	Installation (Generating unit 1)	June 2017	June 2017
	Installation (Generating unit 2)	June 2017	July 2017
Commissioning	Commissioning (Generating unit 1)	June 2017	June 2017
	Commissioning (Generating unit 2)	July 2017	July 2017
Closeout	Prepare close out package	September 2017	September 2017

Future Plans:

There are no plans to perform similar work at Bay d'Espoir in the foreseeable future. When replacing the spherical valve by-pass assemblies on Generating Units 1 and 2 is complete, all spherical valve by-pass assemblies will have been replaced at Bay d'Espoir. Unit 7 is not fitted with a spherical valve.

oject Title: Perform Condition Assessment of Control Structure

Location: Hinds Lake

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is for the detailed condition assessment of the Hinds Lake Control Structure including both gates 1 and 2. The assessment is to be performed by a qualified consultant familiar with this type of equipment. The assessment will include a thorough inspection of all critical components.

To complete the detailed inspection there will be a need for a diving crew to inspect the emergency gate gains and trash rack before the emergency gates are put in place. Before the gate inspection begins Hydro personnel will install the emergency gates both up and down stream and dewater the internal area. To access the sill, gate gains, and embedded parts a swing stage will be taken from the warehouse in Bay d'Espoir and installed for the inspection, safety anchors are required for this installation.

The consultant will provide a report on the Control Structure identifying short, medium and long term required upgrades as well as cost estimates for the repairs. The report will also provide the current life expectancy of the Control Structure. It is anticipated that the Hinds Lake Control Structure, shown in Figure 1 and located on the map in Figure 2, will be in a condition to operate safely and reliably for an additional 25 years after the recommended upgrades are complete.

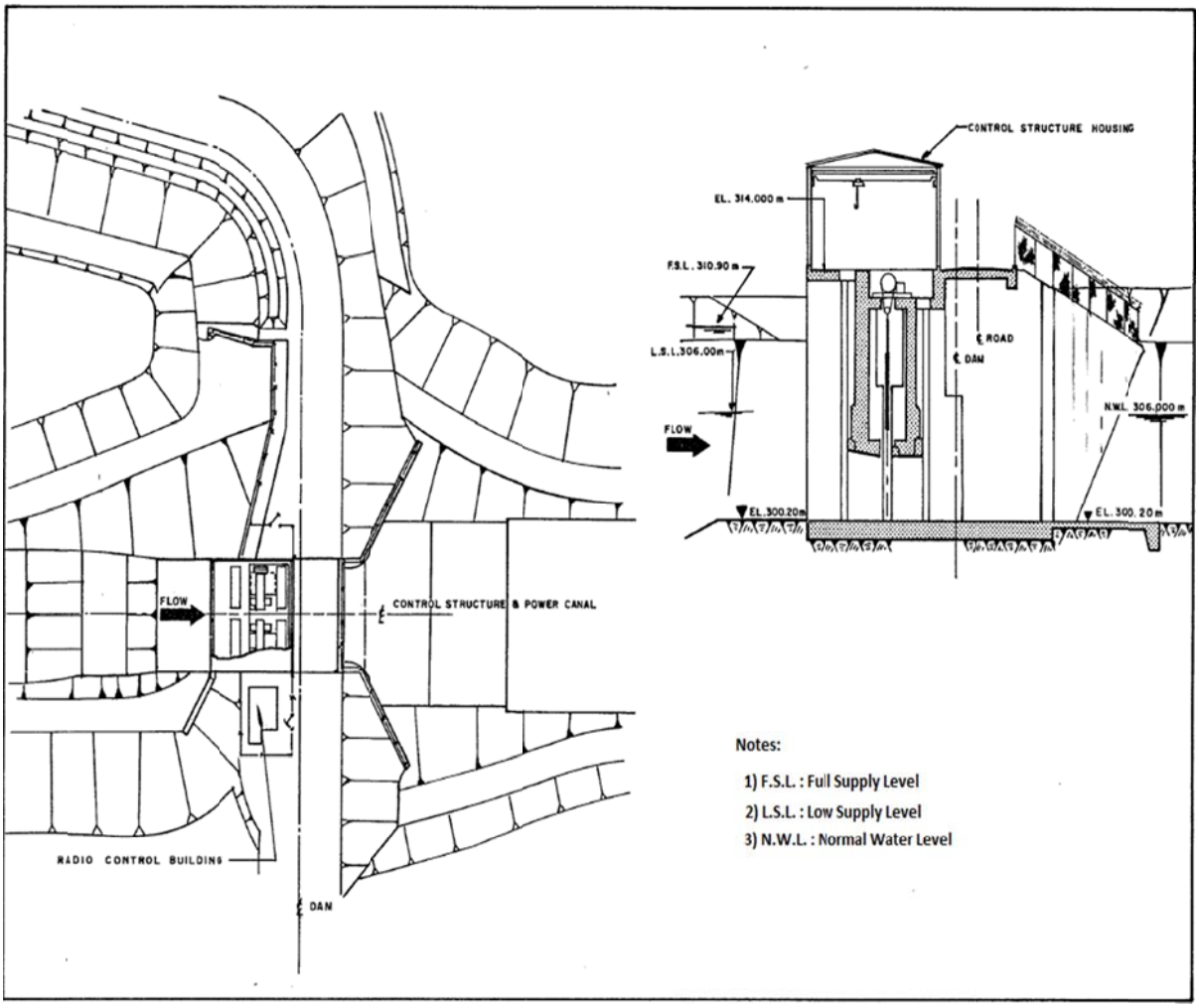

Figure 1: Control Structure – Hinds Lake

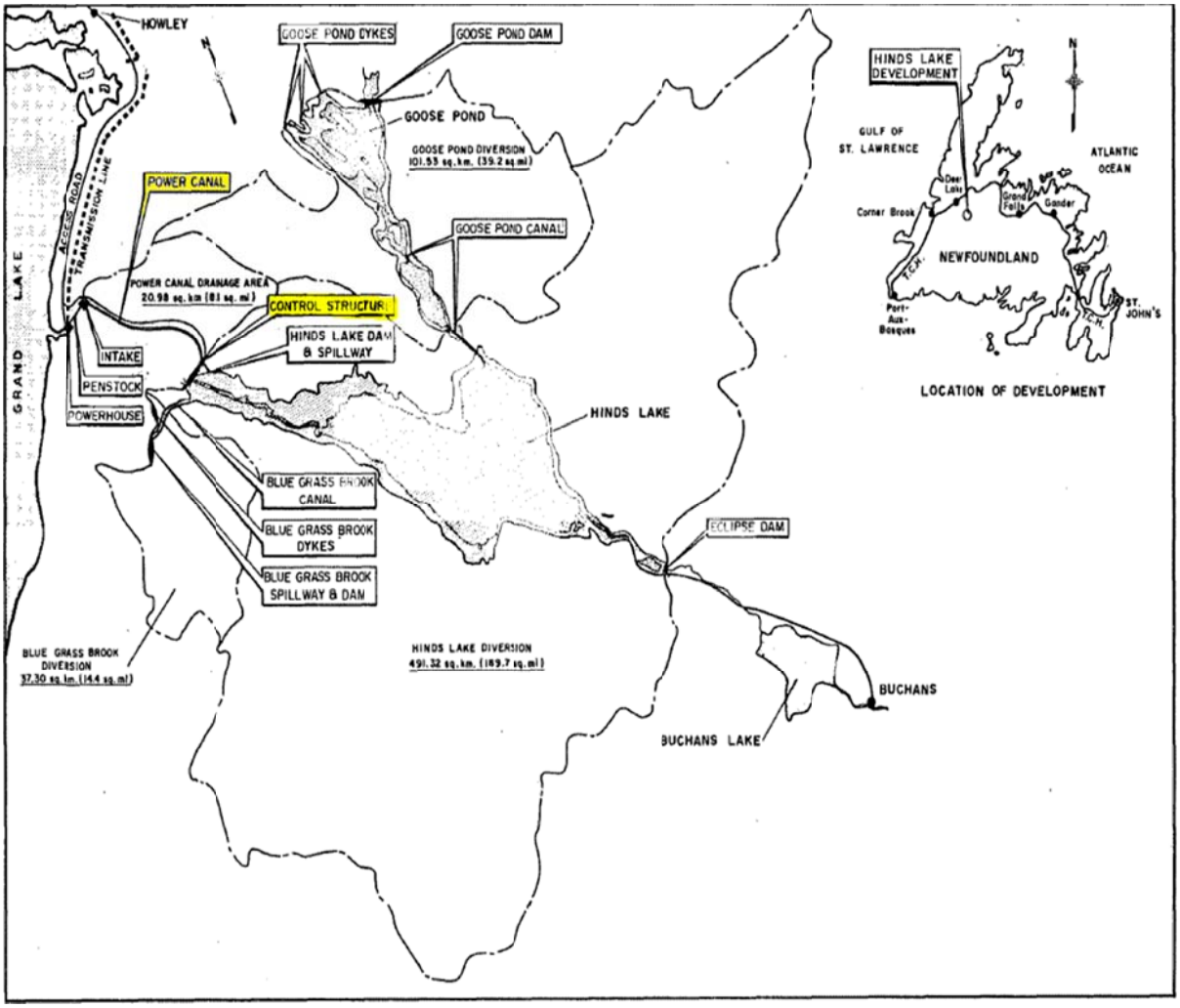

Figure 2: Hinds Lake Development

The project estimate is shown in Table 1:

Table 1: Project Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	5.0	0.0	0.0	5.0
Labour	78.0	0.0	0.0	78.0
Consultant	140.6	0.0	0.0	140.6
Contract Work	12.0	0.0	0.0	12.0
Other Direct Costs	19.5	0.0	0.0	19.5
Interest and Escalation	17.3	0.0	0.0	17.3
Contingency	51.0	0.0	0.0	51.0
TOTAL	**323.4**	**0.0**	**0.0**	**323.4**

Justification:

This project is justified on the requirement to replace or refurbish failing or deteriorated infrastructure in order for Hydro to provide safe, reliable, and controlled water supply to the Hinds Lake Generating Station. In order to control water levels in the Power Canal (Figure 2), the gates in the Control Structure have to be frequently operated. To ensure the reliability of these gates into the future, a detailed assessment is required to identify all required upgrades for the Control Structure. Once the upgrades are identified, short and long terms plans can then be completed.

In 2008, condition assessments were performed by a professional engineering firm, HATCH, on the Bay d'Espoir development structures. The report assessed the structures (Bay d'Espoir Intake; Burnt Dam; Victoria Control; Salmon River Spillway; and Ebbegunbaeg Control) and provided short, medium and long term recommendations with cost estimates. The age of the Hinds Lake Control Structure is approaching the age of the structures in the Bay d'Espoir development when they were assessed in 2008. The assessment in 2008 showed that after approximately 40 years of service, structures of this nature require upgrades to ensure continued reliable operation.

Existing System:

Hinds Lake Control Structure was placed in service in 1979, is therefore 36 years old. It controls the flow from Hinds Lake Reservoir to the Power Canal which leads to the intake of the Hinds lake Generating Station. The Control Structure consists of two submerged wheeled gates approximately 3 m (10 ft.) wide that are operated by a remote controlled cable hoist assembly. A single pair of emergency slide gates is available to provide dewatering around either of the control gates for maintenance. The emergency gates are stored in an insulated housing which covers the complete operating area of the control structure and the gates are maneuvered by means of an overhead gantry crane which can also be used for the removal of the main gates when required.

Operating Experience:

At times when Hinds Lake Reservoir provides water at Full Supply Level, the water can be controlled by using one opening, however during times when the reservoir provides water at Low Supply Levels (figure 2) then both openings are required. Over the past five years, there have been instances where the gates have had problems being closed and the gates stuck in place. In 2011, Gate 2 became stuck in an open position and could not be closed. The gate was isolated and inspected, and repairs had to be performed to be able to return the gate back to service. Currently, Gate 1 is out of

service and has been visually inspected by the Long Term Asset Planning (LTAP) department in Bay d'Espoir and the gate is not anticipated to be back in service until the fall of 2015. The visual inspection picked up on many deficiencies at the Control Structure and has recommendations for the rehabilitation of the Control Structure as seen in Appendix A. The inspection from the consultant will further explore the items that LTAP pick up on and will further explore these issues and provide dimensional data.

Reliability Performance

The Control Structure at Hinds Lake is a critical asset that controls the water flow in the power canal. During the design of the Hinds Lake development, it was determined more economical to have this structure at the upstream end to limit the operating water level in the power canal to about 306 m than to build a deeper power canal to manage the wide range of fluctuation of the water levels. Therefore, to keep control of the flows in the power canal leading to the intake of the generating station, this structure needs to be reliable.

Outage Statistics

A review of the work order history over the last five years indicates that there have been five occasions when Gate 1 could not be closed and six instances of when Gate 2 could not be closed due to becoming jammed in the gains while the gates were being lowered.

Safety Performance

Hinds Lake Control Structure has been designed to control the flow of water in the Power Canal. On the upstream end, if the flow is not able to be managed due to unreliable of operation of the gates, uncontrolled flows could backup to the reservoir, potentially damaging the dam. On the downstream end, if this flow is left to uncontrolled to the Power Canal due to unreliable operation of the gates, then the canal can over flow which can cause damage and water spillage. Failure of the Control Structure can lead to unsafe management of water for the Hinds Lake Generating Station.

Industry Experience

Throughout North America, as hydraulic structures age the requirement for refurbishment is undertaken by most utilities including the largest, Hydro Quebec. Churchill Fall Labrador Corporation whose spillways, intakes and control structures are approximately 40 years old, are also presently involved in a rehabilitation program.

Maintenance or Support Arrangements

Routine preventive and corrective maintenance is performed by Hydro personnel.

Maintenance History

The five-year maintenance history for the entire Control Structure and auxiliary equipment is shown in Table 2:

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.2	0.0	0.2
2013	1.6	0.5	2.1
2012	1.3	1.8	3.1
2011	0.9	27.7	28.6
2010	4.6	3.1	7.7

Late in 2011, Gate 2 would not completely close. An inspection was performed and excessive movement of the rollers was found. At this time, the gate was fully removed from the gate opening to carry out an extensive inspection. The inspection found the stationary holes supporting the eccentric pins were severely worn. The locking plates for the eccentric pins were badly worn allowing the pins to rotate, causing misalignment. Hydro, in conjunction with an external consultant, developed a repair procedure. This procedure was then implemented on site and the gate was released for service in January of 2012. The gate was out of service for approximately four weeks and during this time to maintain proper water levels in the power canal Gate One had to be operated more frequently.

Historical Information

A program to upgrade all structures on the original Bay d'Espoir water control system started with Burnt Dam Spillway in 2011 and the upgrades are still ongoing. Victoria Control Structure was the second structure in the Bay d'Espoir water control to be upgraded starting in 2014. Upgrades also started on Salmon River Spillway in 2015. Several modifications to various structures have been completed in the past as follows:

1. Victoria Spillway; converted to an overflow spillway in 1988;
2. Salmon River Spillway; increased height of gates in 1988; and

3. Ebbegunbaeg; replaced screw hoists on Gate 2 with cable hoist in 2004.

Anticipated Useful Life

It is anticipated that the service life of Hinds Lake Control Structure will be extended by 25 years when the upgrade program is completed.

Conclusion:

Hinds Lake Control Structure is a critical asset for flow water regulation at the Hinds Lake Generating Station. The structure controls the water levels in the Power Canal which leads to the Intake to the generating station that provides the water essential for the operation of the hydroelectric unit. This project will help provide Hydro employees the assessment required to be able to maintain the structure for the next 25 years.

Project Schedule:

The anticipated schedule for this project is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Project Kick-off Meeting, Open project in JDE, develop project scope document for approval, develop WBS.	February 2016	February 2016
Design	Anchor point required for swing stage, consultant specification for gates developed.	February 2016	March 2016
Procurement	Award contract for anchor point and gate inspection and dates set for diver inspection	February 2016	April 2016
Construction	On site for anchor point assessment, on site for gate inspection and diver inspection	March 2016 August 2016	March 2016 August 2016
Report	Report issued based assessment/inspections	September 2016	September 2016
Closeout	Lessons learned meeting, contract close out certificate.	September 2016	September 2016

APPENDIX A

Hinds Lake Control Structure Gate #1 Inspection

Hinds Lake Control Structure – Gate #1 Condition Assessment

During the week of February 16th, 2015, the mechanical department was sent to the HLK control structure to disassemble the control structure gate for the purposes of completing a mechanical inspection. Two members from the Long Term Asset Planning group travelled to site later in the week to assist in the assessment. It was anticipated that this gate would have some of the same issues that were found on gate #2, which was overhauled in 2013.

During the inspection of gate #1 the following conditions were noted:

- The holes for supporting the roller's eccentric pins were worn in the structural steel on the sides of the gate. Some of the eccentric pins were tack welded to the structural steel. (Figure 1)
- Gate seal was worn with Teflon missing (Figure 2). The wear marks were not even which indicated that the gate was not plumb. Bolts were missing on the clamps that hold the j-seal.
- Roller bushings are worn as well as the side spacers (thrust washers). (Figure 3)
- Gains are worn were the rollers are making contact. This appears to get worse as you move down the gains (tapered wear). (Figure 4)
- Seal mating surface in the gains appears to be in good condition. We were unable to check the bottom seal due to ice build-up and water.
- Mini-trashrack appears to be in good condition.
- Sheaves in the lower block are severely worn. (Figure 5)
- Lift cable for the gate is frayed and has broken strands. (Figure 6)
- The pin has been corroded away in the operating stem for the watering up valve (Figure 7) . This prevents us from operating the valve.
- Watering up valve is extremely corroded. (Figure 8)
- Rollers have been hard faced in the past and have been machined so that they are flat (no radius).
- Eccentric pins appear to be in good condition; however they need to be measured to ensure they still meet specs. (Figure 9)
- A bushing has backed out of one of the rollers. (Figure 10)
- Gate well access ladder was very corroded; the fall arrest slider was not in usable condition.

Measurements:

The following measurements were recorded on the roller wear plates in the gains. This measurement represents the amount of wear caused by the rollers on the gain guide surface. Any indication of wear is unfavourable.

	Upstream (inches)	Downstream (inches)
Right Side	.065	.075
Left Side	.085	.110

Note: These measurements will increase as we travel down the gain. Readings were unable to be taken due to ice buildup.

Short Term Recommendations:

Similar issues were experienced on gate #2 and a procedure (Appendix I) was developed to repair these issues. Since the repair, this gate has been operating adequately and this procedure should be repeated on this gate. The following recommendations are required to bring this gate up to good operating condition.

- Line boring and welding of the holes on the side of the gates
- Measure the roller bushings, side spacers (thrust washers), and roller eccentric pins. Compare these measurements to the drawings and replace components if necessary.
- Replace the sheaves in the lower block.
- Replace the lifting cable for gate #1.
- Install new pin in the stem of the watering up valve and shim the shaft if necessary.
- Remove the inspection cover on gearbox and perform a detailed inspection. This includes checking the bearings for play.
- Take an oil sample from the gearbox.
- Inspect brakes and drum.
- Meggar the motor.
- Check and record motor amperage while under load to ensure we are within specs.
- Replace bushings as per the procedure attached in Appendix I.
- Install fall arrest anchor above the gate well access ladder.

Long Term Recommendations:

Although not causing immediate concerns, these actions should be addressed in the future either through capital structure upgrades or with operating projects.

- Replace/refurbish the roller contact plate in the gains.
- Replace the lower lift block.
- Replace the watering up valve and stem.
- Replace the J-seals on the gate.
- Recoat and paint the gate.
- Remove "Hard Facing" from rollers and re-machine to return to original specifications. Replacement is also an option.
- Replace gate well access ladder with a galvanized ladder.

Pictures

Figure 1 - Wear on the hole supporting the eccentric pin

Figure 2 - Teflon Worn on J-Seal

Figure 3 - Thrust Washer Damage (cupping and pinch)

Figure 4 - Wear in the Gains

Figure 5 - Wear on Lower Block Sheaves

Figure 6 -Frayed Lifting Cable

Figure 7 - Pin Corrosion on Watering Up Valve

Figure 8 - Severe Corrosion on Watering Up Valve

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Figure 9 - Eccentric Pin

Figure 10 - Bushing "Backed Out"

Figure 11 - Thrust Washer Wear and Tacked Eccentric Pin

Figure 12 - Corrosion on Gate Well Access Ladder

Figure 13 - Full view of Gate

Project Title: Install Hydrometeorological Equipment

Location: Various Sites

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

Hydro uses hydrometric (water level and flow) and meteorological (temperature, precipitation, 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 direction, and distance 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 to provide accurate information about precipitation and therefore runoff into each reservoir.

The 2016 project is the continuation of a program to improve the hydrometeorological network in Hydro's reservoir basins, providing data for improved management and control. The program was started in 2008 and seven stations, either hydrometric, meteorological, or both, are currently in operation.

The proposed 2016 program is to broaden the coverage of Hydro's hydrometeorological program to better predict the inflow into Hydro's watersheds through the installation of four new snow water equivalent sensors in the Victoria, Hinds Lake, Granite and Cat Arm watersheds. The proposed equipment will monitor snow water equivalent only – temperature and precipitation gauges will be installed in the watersheds in 2015 under Hydro's approved 2015 capital program.

Hydro currently has one snow water equivalent sensor, installed on the Cat Arm reservoir in 2008/2009 program. The Cat Arm snow sensor has sensors that weigh the snow as it accumulates on a set of gauged metal plates. The sensors proposed for the new sites are a different technology; they monitor snow water equivalent in real time by measuring the natural emissions by the soil and

their absorption by the snow.

The 2016 project involves installing the measurement equipment and the means of returning the data to Hydro's Energy Control Centre. Table 1 provides the budget estimate for this project.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	141.1	0.0	0.0	141.1
Labour	53.3	0.0	0.0	53.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	51.9	0.0	0.0	51.9
Interest and Escalation	18.5	0.0	0.0	18.5
Contingency	49.3	0.0	0.0	49.3
TOTAL	**314.1**	**0.0**	**0.0**	**314.1**

Justification:

This project is justified on Hydro's requirement to effectively manage its water resources. Failure to properly prepare for the spring runoff can result in spillage. By installing remote meteorological stations, Hydro will obtain critical information about snow pack around the reservoirs, which will help ensure that the reservoirs are operated in such a fashion to be well-positioned in advance of the spring runoff. Maximizing the use of Hydro's water resources minimizes the use of thermal generation.

A spill of one million cubic meters at Cat Arm represents 900 MWh of production. Using a Holyrood cost[1] of approximately $180/MWh, 900 MWh of production represents a Holyrood fuel cost of $164,000. One million cubic meters of water could be spilled in one day at Cat Arm if the water level were above the crest of the spillway.

Minimizing spill is also important from safety and property damage perspectives as spill is typically discharged in channels that are normally dry.

The traditional method of snow water equivalent monitoring involves manual snow surveys; these surveys must be done by helicopter and can therefore only be done safely in good weather. Remote, automatic sensing will, therefore, also improve reliability of data and operator safety.

[1] Based on 2007 test year fuel conversion rate of 630 kWh/bbl and the average fuel cost of $115/bbl.

Meteorologic data would also provide an early indication of dry conditions, and assist operations in making the best use of available inflows, again minimizing the required use of thermal generation. Implementing this project supports Hydro's goals of being an environmental leader and maintaining operational excellence.

Existing System:

Hydro operates eight reservoirs in three main reservoir systems. These reservoir systems supply Granite, Upper Salmon, Bay d'Espoir, Hinds Lake and Cat Arm Hydroelectric Generating Stations. The Hinds Lake and Cat Arm systems are single reservoir systems. The Bay d'Espoir system is a multi-reservoir system comprised of the following six reservoirs:

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

The watersheds associated with these systems cover vast, variable terrain comprised of 7200 square kilometers that have a variable and unpredictable climate. This leads to uncertainty in predicting inflows, making management of these complex reservoir systems difficult.

As an example, the Cat Arm watershed encompasses 651 square kilometers of mountainous terrain on the Great Northern Peninsula. The climate in the area is influenced by weather systems from the Canadian mainland as well as the maritime systems from over the North Atlantic. The resulting climate tends to be unstable and characterized by rapid changes in weather conditions. There can be variations in the weather patterns experienced in various portions of the watershed as a result of the proximity of part of the watershed to the ocean, while other portions are affected by their altitude and inland location. As in the other two reservoir systems, inflows into the Cat Arm reservoir are heavily influenced by snowmelt, with inflows during the spring runoff (May and June) accounting for about half of the annual inflows for the reservoir. Snowmelt inflows tend to take place in a two week period within the runoff season. Inflows can increase rapidly from a typical 20 cubic meters per second to 200 cubic meters per second within this period. The Cat Arm plant only consumes 40 cubic meters per second at maximum generation. Accordingly, when the runoff starts,

sufficient reservoir storage must be available to accommodate the rapid change in inflow. Currently, Hydro performs snow core sampling only two to three times throughout the winter; real time information will improve the information on how the snow pack changes throughout the season significantly.

Meteorological data is currently collected by Hydro at the:

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

Additional sites are operated by Environment Canada but are funded by Hydro.

Hydro uses the Vista Decision Support System (Vista) to optimize hydraulic and thermal power production, water storage releases and flood handling. Vista is comprised of three primary modules including long term generation forecasting (weekly, monthly and yearly schedules), short term generation forecasting (hourly to multi-hourly schedules) and inflow forecasts for the purposes of generation scheduling and flood management. The installation of additional snow monitoring meteorological stations will provide Hydro access to real time data which, used in conjunction with the Vista model, will enhance decision making pertaining to optimizing hydraulic power production and, therefore, minimize thermal power production at Holyrood.

Operating Experience:

Hydro first installed its own hydrometeorological gauges as part of this program in 2008. Data from the existing sites are transmitted automatically to Hydro's databases and used in load and inflow forecasting models. Hydro's experience with the existing gauges has been positive; the harsh conditions the gauges are exposed to means that there are sometimes missing or erroneous data points but these are addressed through routine quality control. Similarly, communications are sometimes interrupted but in those instances, the data is still collected and is available once communication is restored.

Historical Information

The first year of meteorological station deployment was 2008. Four meteorological stations were installed at Long Pond, Meelpaeg and Cat Arm (two sites) as approved by Board Order P.U. 30(2007).

One of the two sites at Cat Arm Reservoir included the installation of Hydro's first snow water equivalent sensor. The gauge has been in place since 2008, but in the first few years there were various problems both with the sensor equipment and with the satellite communications. Reliable data was received from 2010 through 2014. Data has been received in 2015 but its reliability is uncertain since field staff indicates that some maintenance is required.

In 2009, the second year of the program, meteorological stations were installed at the Burnt Dam Spillway and the Hinds Lake Control Structure according to Board Order No. P.U. 36(2008). Installation of a third station, at Victoria Reservoir, was postponed because it was to include a second snow water equivalent sensor. It seemed prudent to ensure that the first station was giving satisfactory results prior to further investment. The 2010 program was to include additional snow sensors and was therefore postponed because of experience with the Cat Arm equipment in the earlier years following its installation.

The 2011 program was to install equipment required to take over several hydrometric stations currently operated on Hydro's behalf by the provincial Department of Environment and Conservation and Environment Canada. Work was approved by Board Order No. P.U. 38(2010) but was cancelled because of concerns expressed by the Provincial Department of Environment and Conservation about taking the existing gauges out of the provincially operated network. Hydro continues to pay for these gauges to be maintained.

No budget request was made for new hydrometeorological stations in 2012 to 2014. A budget of $378,000 was approved by the Board for 2015 for the installation of four new meteorological stations, measuring temperature and precipitation only. The vendor of the equipment for the 2015 program has offered to provide one snow water equivalent sensor as a demo. The demo sensor will be installed in the Victoria watershed at the same time as the other meteorological equipment in 2015; the sensor will then be purchased in 2016, together with three additional sensors, if the 2015/2016 operation is satisfactory and the budget is approved.

Anticipated Useful Life

The equipment used in meteorological stations has different life expectancies. Remote sites are powered by solar panels and batteries; these batteries have a life expectancy of three to five years. Other components of the station including radios, data loggers and sensor have life expectancy of seven to ten years.

Development of Alternatives

There are various types of sensors for obtaining snow water equivalent measurements; Hydro has chosen this type of gauge because the Government of Newfoundland and Labrador has had positive experience with it. The snow sensors were developed by Hydro Québec for use in its watersheds, but the production is now licensed to Campbell Scientific.

The use of remote sensing to supplement climate data is an emerging technology that has been identified, but it cannot yet replace the need for in situ equipment.

Conclusion:

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

Project Schedule:

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

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity	Date
Project Initiation	January 2016
Complete Design Transmittal	February 2016
Develop Equipment Specifications	March 2016
Procure Equipment and Materials	June 2016
Installation and Commissioning	August 2016
Project Completion and Close Out	December 2016

Project Title: Replace Fuel Piping

Location: Hardwoods and Stephenville

Category: Generation - Gas Turbines

Type: Other

Classification: Normal

Project Description

This project will replace the fuel piping (supply, return and drain lines) including fittings, valves and filters inside engine modules A and B at Hardwoods gas turbine (Hardwoods) and Stephenville gas turbine (Stephenville). The fuel filters will be upgraded from a filtration level of 5 micron to 2 micron.

The project will be executed in two years due to the estimated delivery period of four months for the pressure regulating valves.

The project budget estimate is provided in Table 1.

Table 1: Project Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	24.8	38.4	0.0	63.2
Consultant	14.8	0.0	0.0	14.8
Contract Work	0.0	171.8	0.0	171.8
Other Direct Costs	2.5	3.5	0.0	6.0
Interest and Escalation	2.7	23.1	0.0	25.8
Contingency	0.0	30.2	0.0	30.2
TOTAL	**44.8**	**267.0**	**0.0**	**311.8**

Justification:

The fuel piping, fittings and valves inside the gas turbine engine modules at Hardwoods and Stephenville have been in service for over 39 years.

The current fuel filtration level of 5 microns has likely caused two forced outages during the operating season of 2014-2015, due to debris entering the fuel control valves causing them to jam in an open or closed position. The upgrade of the fuel filters to a filtration level of 2 micron is recommended by the manufacturer of the fuel control valves currently installed at Hardwoods.

The existing fuel pressure regulating valves are obsolete and require replacement as they have been the cause of fuel delivery issues at both Hardwoods and Stephenville.

Existing System:

The fuel is pumped from the storage tank using the fuel forwarding pumps through a piping system including strainers, flow meters, pre-filters, heaters and fuel temperature and pressure controls. There are three fuel forwarding pumps; two AC powered and one DC powered. The three pumps are arranged in parallel, and each one is capable of supplying the required amount of fuel at a positive and constant pressure to the engines.

The fuel flows to the engine passing through a fuel filter and pressure regulating valve (see Figure 1). The pressure regulating valve regulates the fuel supply pressure to the inlet of engine mounted pumps to 20 psi. Engine and final filter drains are collected in a fuel drain tank located outside the engine module.

The fuel pipes from the storage tank to the engine modules were replaced in 2007 at both Hardwoods and Stephenville. While components of the fuel systems inside the engine modules have been replaced, the majority of the components have not been replaced since commissioning. The flexible fuel lines within the engine modules which deliver fuel to the engines are being replaced in 2015. The remaining fuel system components within the engine modules are slated for replacement in this project, proposed for 2016 and 2017.

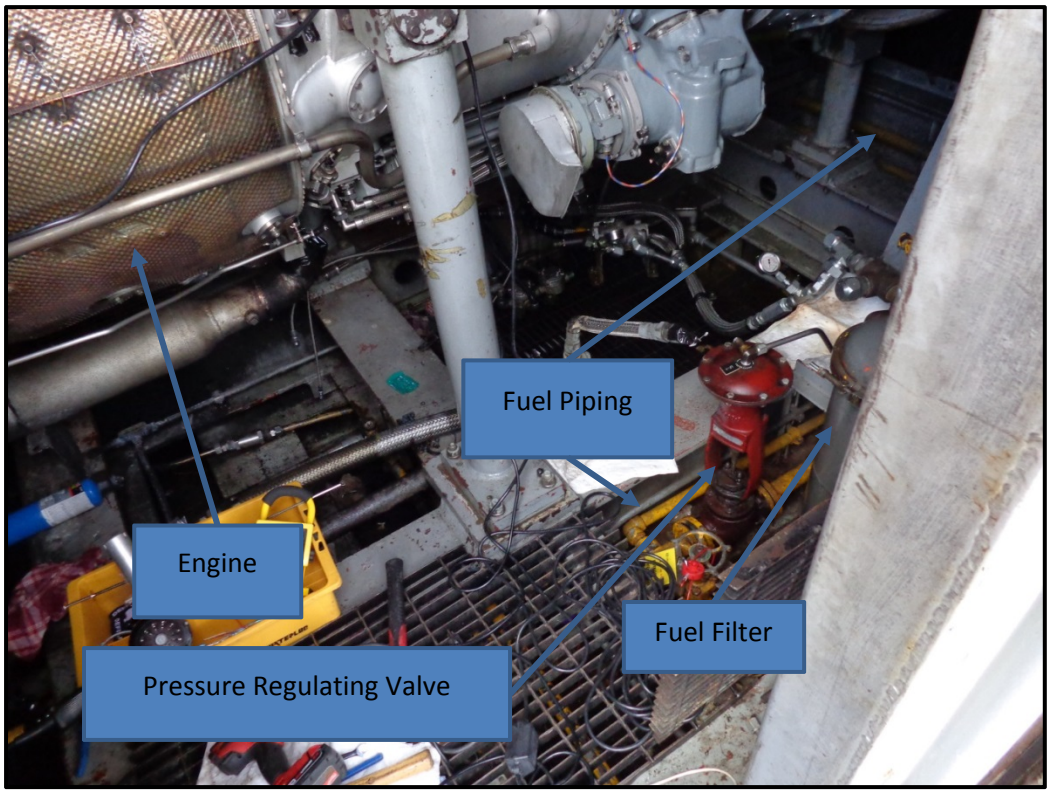


Figure 1: Typical Fuel Piping Inside the Engine Modules

Operating Experience:

Stephenville gas turbine (50 MW) was commissioned in 1975. Commissioning of Hardwoods Gas Turbine (50 MW) followed a year later in 1976. The piping, valves, pressure regulating valves, and fuel filters inside the engine modules are all original and have been in operation since commissioning of both gas turbines. Components of the fuel piping inside the engine modules have failed and required replacement in recent years.

Reliability Performance

It is anticipated that the proposed project will improve the Hardwoods and Stephenville gas turbines' reliability by reducing the potential for forced outages due to failure of components on the fuel piping system inside the engine modules.

Outage Statistics

Tables 2 and 3 below list the 2009 to 2014 operating data, average Capability Factor, Utilization Forced Outage Probability (UFOP) and Failure Rate for Hardwoods and Stephenville gas turbines compared to all of Hydro's gas turbine units and the latest Canadian Electrical Association (CEA) average (2009 to 2013).

Table 2: Hardwoods and Stephenville Operating Data (2009-2014)

Year	Total Operating Hours		Peaking/Emergency Hours		Synchronous Condenser Hours		Available Hours	
	Hardwoods	Stephenville	Hardwoods	Stephenville	Hardwoods	Stephenville	Hardwoods	Stephenville
2014	6,121	6,853	354	381	5,767	6,472	6,502	7,043
2013	156	4,234	81	66	75	4,169	6,604	4,500
2012	3,893	0	103	0	3,790	0	8,260	0
2011	3,226	8,110	38	13	3,187	8,096	8,115	8,438
2010	6,093	6,484	150	51	5,943	6,433	7,375	8,103
2009	3,562	6,430	104	10	3,458	6,421	8,464	8,315

Table 3: Hardwoods and Stephenville Five Year Average (2009-2013 Reliability Data) All Causes

Unit	Capability Factor (%)[2]	UFOP (%)[3]	Failure Rate[4]
Hardwoods	82.04	23.99	146.98
Stephenville	37.03	45.39	188.14
All Hydro Gas Turbine Units	74.89	18.31	145.17
CEA (2009-2013)	86.67	13.07	22.39

Legislative or Regulatory Requirements

There are no specific legislative or regulatory requirements related to this project.

Safety Performance

There is a potential of leakage from the aged fuel piping, fittings and valves inside the engine modules. This leakage could lead to a fire and therefore a safety risk to workers and damage to equipment. This project will improve the safety performance by replacing the fuel piping, fittings and valves inside the engine modules.

Environmental Performance

This project will improve the environmental performance by minimizing the probability of leakage

[2] 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.

[3] 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.

[4] 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.

from fuel piping components inside the engine modules which could have an impact on the environment.

Maintenance or Support Arrangements

Hydro personnel perform routine maintenance at Hardwoods and Stephenville on structures, auxiliary systems and parts of the major equipment. Major work and refurbishment of the engines and generators are performed by external contractors or original equipment manufacturers specializing in engine and generator repairs.

Maintenance History

The five-year maintenance history for Hardwoods and Stephenville is provided in Tables 4 and 5, respectively.

Table 4: Five-Year Maintenance History (Hardwoods)

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	20	925	945
2013	8	196	205
2012	15	262	277
2011	32	299	330
2010	37	191	228

Table 5: Five-Year Maintenance History (Stephenville)

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	18	1,188	1,206
2013	33	224	257
2012	10	159	169
2011	24	123	147
2010	27	141	168

Anticipated Useful Life

The anticipated useful life of fuel oil piping is approximately 35-40 years.

Development of Alternatives

There are no viable alternatives to this project.

Conclusion:

This project will replace the fuel piping, fittings, valves and filters inside the four engine modules at Hardwoods and Stephenville gas turbines. The fuel filters will be upgraded from a filtration level of 5 micron to 2 micron.

Components of the piping have failed while operating at full load resulting in a fire on March 1, 2015. The status quo is not acceptable due to the potential of fuel leakage from piping, fittings and valves inside the engine modules. Fuel leakage inside the engine modules could lead to a fire; and therefore presents a risk to worker safety, damage to equipment and interruption to operation. In addition, this leakage could have an environmental impact.

It is anticipated this project will improve the reliability, safety and environmental performance at Hardwoods and Stephenville gas turbines.

Project Schedule:

The anticipated project schedule is provided in Table 6.

Table 6: Project Schedule.

Activity		Start Date	End Date
Planning	Open Job and prepare scope statement.	January 2016	January 2016
Design	Prepare technical conditions.	March 2016	March 2016
Procurement	Prepare and issue request for proposal (RFP) for technical conditions preparation;	February 2016	February 2016
	Award consultant contract;	March 2016	March 2016
	Prepare and issue tender for supply and installation;	April 2016	April 2016
	Award supply and installation contract; and	June 2016	June 2016
	Deliver new piping, fittings, valves and filters.	October 2016	October 2016
Construction	Install new piping, fittings, valves and filters.	July 2017	July 2017
Commissioning	Test piping.	July 2017	July 2017
Closeout	Prepare closeout documents.	September 2017	September 2017

Project Title: Refurbish Station Water System

Location: Upper Salmon

Category: Generation - Hydraulic

Type: Other

Classification: Normal

Project Description:

This project is for the replacement of the piping within the service water system and the domestic water system at the Upper Salmon (USL) Hydro Generation Plant. The replacement of the service water piping and valves includes sections from the generator supply and the auxiliary cooling water lines. The replacement of the domestic water system includes piping and valves supplying the water starting from the domestic water pump. The piping will be replaced with stainless steel pipe to reduce corrosion and fouling of the piping. The system will also be equipped with Victaulic couplings to allow ease of inspection and maintenance. The project will be managed and executed with Hydro's internal labour forces. The estimate for the project is shown in Table 1.

Table 1: Project Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	65.5	0.0	0.0	65.5
Labour	24.2	117.2	0.0	141.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.6	14.3	0.0	15.9
Interest and Escalation	5.3	21.4	0.0	26.7
Contingency	0.0	44.6	0.0	44.6
TOTAL	**96.6**	**197.6**	**0.0**	**294.2**

Justification:

The piping and its components, as confirmed in preventive maintenance inspections, is extensively fouled and corroded (Figure 1) to the extent that the only option is to replace the piping system with new components. This has to be done to avoid forced unit outages or capacity de-rating of the units.

A service water system study was performed in 2002 for all hydroelectric generating stations (Appendix A for USL). This study concluded that all piping four inch in diameter and smaller should be replaced with stainless steel schedule 10 for corrosion and fouling protection. This reduces future maintenance costs of cleaning the piping every year because of fouling. Changing the piping material

from mild steel to stainless steel eliminates the corrosion fouling problem, thereby improving the efficiency of the cooling system. This lowers the risk of having to de-rate the unit or take a forced outage because of high temperatures. Only the service water piping less than four inches in diameter will be replaced with stainless steel and due to its large size (6 and 12 inches) the supply headers will be inspected during the installation of the piping to determine if replacement is required.

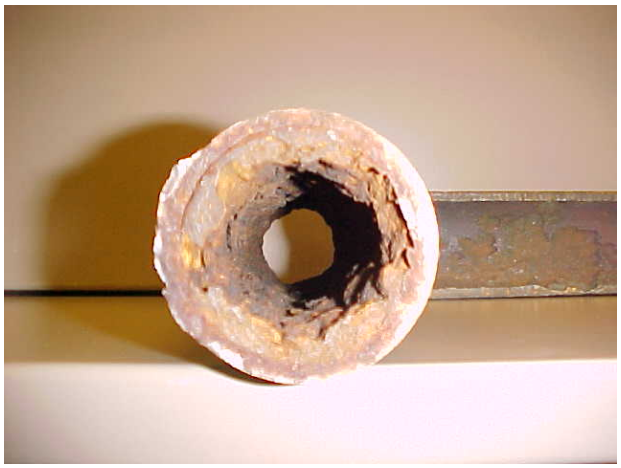


Figure 1: Corroded and fouled pipe

Existing System:

The cooling water supply is gravity fed off the penstock head pressure from the spiral case at the draft tube gallery using a common header with the fire protection water and domestic water supply. System water is provided via a six-inch supply header and passed through an automatic rotary strainer. The water is then distributed to the generator coolers, thrust bearing, turbine shaft seal and low pressure air compressors. As the station is unmanned, the six inch Adams strainer is provided with an automatic backwash cycle controlled by pressure differential and a timed cycle. The strainer is designed to remove particles larger than 0.010 inch. There is a by-pass line around the automatic strainer, with an in-line basket type strainer, to permit maintenance and servicing to the automatic strainer without requiring shutdown of the unit.

The domestic water is supplied through a pumping system, the main header is connected to the cooling water system in order to provide a boost to the more critical cooling water system if required. The water in this system provides the water for all the washrooms, showers, and lunchrooms in the facility.

Operating Experience:

The service water and domestic water system in Upper Salmon has had fouling problems since it's opening in 1983. At first this was thought to be caused by the unsettled organic materials within the water reservoir and should be washed through the system in three to four years. Since the plant's first opening the rotary strainer had to be cleaned twice a year. Every two or three years since the early 1990's a scheduled outage is performed on the unit to clean the strainer and surface air coolers that become clogged with debris. This maintenance is required to prevent the unit from overheating during the summer months. The service water and domestic water system pipe becomes clogged with organic slime and hardened organics that attach themselves to the corroded pipe walls.

Maintenance or Support Arrangements

The maintenance on both the service water and domestic water systems are maintained by staff in Bay d'Espoir.

Maintenance History

The five-year maintenance history for both the service and domestic water systems is shown in Table 2:

Table 2: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.3	0.0	0.3
2013	0.0	0.6	0.6
2012	0.7	1.2	1.9
2011	0.3	10.3	10.6
2010	0.0	1.3	1.3

Anticipated Useful Life

The service water system has an estimated service life of 25 years and has been in service since 1983.

Development of Alternatives

Back in 2002, an internal assessment of the service water system was developed and options were explored, in the report titled "Upper Salmon Generating Station Service Water System" in Appendix

A. The explored options included:

1. Do nothing;
2. Replace the piping with stainless steel and PVC piping;
3. Closed Loop System; and
4. Chemical Injection.

Replace Piping

Currently the piping material is mild steel schedule 40. Two different piping materials have been considered for replacement of the mild steel pipe, they are 316 stainless steel pipe schedule 10 and polyvinyl chloride (PVC) pipe schedule 80.

The 316 stainless steel schedule 10 pipe is considered because of its corrosion resistance and mechanical properties. The stainless steel pipe will be placed in high traffic areas or in areas where the piping is likely to be hit to prevent damage.

The PVC schedule 80 pipe is considered because of its corrosion resistance, mechanical properties, and thermal properties. Schedule 80 will be more durable when compared with schedule 40. Due to PVC's excellent thermal properties there will be no need to insulate the pipe as compared to stainless steel. The PVC pipe will be placed in low traffic areas where the probability of the pipe being damaged is remote.

At the time of this study there were no Hydro facility that used PVC piping and there were questions if this type of pipe could be used in an industrial setting like a hydro plant. This replace option was put on hold but a small section of PVC piping was installed on the surface air cooler discharge line, outside the generator housing. There was little success with this PVC piping and this section of pipe was replaced with carbon steel piping in 2007.

Closed Loop System

By adding another heat exchanger to the existing service water system one can create a closed system. There are various heat exchangers that can be implemented into the system such as water-to-water, air-to-water, or chemical-to-water.

Water-to-water would be the most practical in this situation due to the amount of heat that is being

transferred through the exchanger. An air-to-water heat exchanger would have a very large surface area in order to remove the quantity of heat within the system, making this solution not practical. Using a chemical within the closed circuit system is not necessary considering the temperatures that we are dealing with.

This additional heat exchanger will require pumps, piping and valves in order to be incorporated into the service water system. In addition the style and location of this new heat exchanger will be incorporated into the design of the new system so that maintenance will be easier. Also this system will have 100% capacity back up so that cleaning of the heat exchanger will not require any unit outages.

The use of a cooling pond to supply water to the service water system can be considered a closed loop system because you are reusing the existing water that is in the cooling pond. The water in the cooling pond can be chemically treated to ensure that it remains neutral and does not become acidic. Again, space would be a restriction with this type of solution.

Chemical Injection

The water can be chemically treated to reduce the acidity of the water by raising the ph level and also help keep all organic materials in a suspended state. The existing service water system is a 'once through' operation and will require large amounts of chemical.

Recommendations

It is recommended to replace the piping with corrosion resistant pipe for Upper Salmon. The pipe's life expectancy within the service water system is coming to an end and will need to be replaced in the near future. Also this solution will result in lower up front and maintenance costs for the system. Another benefit is that no new design work has to be done in order for this solution to be implemented.

Conclusion:

With many years of fouling pipes in the history for the Upper Salmon facility due to high levels or organic matter in the water, this issue is not going to go away as initially thought during the early 1980s. Now that the piping has surpassed its life expectancy and needs to be replaced, the addition of stainless steel piping will help alleviate the corrosion and fouling problems at this facility.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Project kick off meeting, safety plan, risk assessment, open project in JDE, and complete WBS.	April 2016	April 2016
Design	Site visit, review of system drawings, review of JDE history	April 2016	August 2016
Procurement	Order of parts and fittings for project completion.	August 2016	September 2016
Construction	Remove old piping and fittings, install new piping and fittings.	July 2017	July 2017
Commissioning	Commission new piping arrangement, checking for leaks.	August 2017	August 2017
Closeout	Asset Assignment Forms, PIR Form, Lessons Learned Meeting, and Contract Close Out Certificate	September 2017	October 2017

APPENDIX A

Upper Salmon Generating Station

Service Water System

Newfoundland & Labrador Hydro

Upper Salmon Generating Station

SERVICE WATER SYSTEM

Piping
Strainer
Control Valves
Heat Exchangers

UPPER SALMON GENERATING STATION

SERVICE WATER SYSTEM

CONCLUSIONS AND RECOMMENDATIONS

From the material presented there were four different solutions that could be taken to resolve the problem. To recap the four alternative solutions were to continue to operate as we have: 'do nothing approach', replace the piping with corrosion resistant material, inject chemical into the service water for treatment, or install a closed loop system with treated water to cool the units. Each solution has it's benefits and draw backs.

The NPW analysis calculated the following dollar figures for each solution;

Table 1:

Do Nothing	$86,210
Replace the Piping with s.s & PVC	$73,806
Closed Loop System	$98,075
Chemical Injection	$340,501

The "continue to operate as we have" will mean scheduled outages for cooler and pipe cleaning. There is an uncertainty with this solution when it comes to forced outages due to cooling problems during the summer months. If a maintenance program for cleaning and maintaining the cooling water system is not implemented forced outages due to cooling problems during the summer months, in the height of the maintenance season, will occur. In order to prevent this a fouling monitoring program for the cooling water system has to be put in place.

The service water system currently has all of its original piping that was installed when the plant was first came on-line in 1983. This life expectancy of this pipe is near its end. The cooling water pipe will have to be replaced in the near future. Already the SAC piping inside the generator housing has been replaced with stainless steel sch 10 pipe. Also the shaft seal piping inside the turbine pit has been replaced with copper pipe. The SAC discharge six-inch line outside the generator housing is scheduled for replacement with PVC pipe before the end of 2001.

The other alternative of replacing the piping with corrosion resistant pipe has an initial capital investment with a low operating cost associated with it. The labour cost of replacing the pipe in the cooling water system is going to be the same regardless of what type of pipe you use to replace it.

One of the benefits of having the corrosion resistant pipe like stainless steel and PVC is lower maintenance. Unit outages for cleaning service water piping will be less frequent, hence will free up more manpower for other tasks during the maintenance season.

Another benefit to corrosion resistant piping is the reduced likely hood of the pipe becoming clogged with debris. Since the pipe is resistant to corrosion from the service water it is not likely that enough organic material will be able to adhere to the pipe wall to impend flow to the point of stagnation. It is believed that only a small layer of organics will adhere to the inner pipe wall and once that layer is in place the rest of the organics will be washed through the system. Cleaning of the coolers and piping will still have to be done to optimize the efficiency of the system but the frequency of cleanings will be drastically reduced from the current operation.

Another benefit to the replace piping with corrosion resistant pipe solution is that no new equipment or design changes have to be made to the existing system, just replace the existing pipe.

As can be seen from the NPW analysis replacing the piping with corrosion resistant pipe has a NPW of $73,806 and the other solution of continuing to operate like we have in the past has a NPW of $86,210. The NPW of the solution to replace the piping with corrosion resistant pipe has a lower NPW.

The closed loop system has a NPW of $98,075. The problem with this solution is that it is add on to the existing cooling water system. Seeing that the service water piping is almost at its life expectancy the cost of replacing that piping has to also be considered. A quick calculation of labour costs just to replace the piping not including the pipe is around $26,000.

With the closed loop solution the piping inside of the generator housing can be mild steel sch 40 pipe and the piping outside of the generator housing can be PVC to help reduce costs. The SAC piping inside of the generator housing has already been replaced with stainless steel. This solution will use treated water for recirculating through the unit and use the existing service water to cool the heat exchangers.

The closed loop solution will have more components with the extra two recirculating pumps and heat exchangers. This increases the chances of more problems within the system.

The maintenance of the unit's coolers and piping will be non-existent but the outside heat exchanger will have to be cleaned. The frequency of this clean will have to be determined from operating the system. These outside heat exchangers should be positioned for easy cleaning.

The chemical injection solution has a NPW of $340,501 which makes this solution not feasible compared to the other alternative solutions. Also any solution that doesn't impact the environment is always a better alternative.

It is recommended that we go with the solution of "replacing the piping with corrosion resistant pipe" for Upper Salmon. The pipe's life expectancy within the service water system is coming to an end and will need to be replaced in the near future. Also the SAC piping inside of the generator housing has already been replaced and this section of piping is the most costly. With this alternative we still have the ability of replacing sections of the existing system year by year until it is all changed over, reducing the overall capital expenditure for that year. Also this solution will result in lower maintenance costs for the system. Another benefit is that no new design work has to be done in order for this solution to be implemented.

Project Title: Upgrade Terminal Station for Mobile Substation

Location: Cow Head

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project involves construction of an extension to the Cow Head Terminal (CH) Station yard. The yard will be increased approximately 30m x 15m on the South side (Left) of the terminal station and will include a three meter high chain link fencing with two double gates, station and fence grounding, yard grading and yard topping. Also included is the installation of a silt/sand fence on the ocean side of the station to help secure the terminal station against sand and snow building up along the chain link fence. A 1.2-1.5m high silt/sand fence will be placed between 5m to 10m away from the existing and the new yard extension chain link fence. This silt/sand fence will be a barrier to prevent the sand from building up against instead of the chain link fence. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	34.0	72.7	0.0	106.7
Consultant	0.0	27.0	0.0	27.0
Contract Work	0.0	219.0	0.0	219.0
Other Direct Costs	4.0	16.7	0.0	20.7
Interest and Escalation	2.0	34.8	0.0	36.8
Contingency	0.0	74.6	0.0	74.6
TOTAL	**40.0**	**444.7**	**0.0**	**484.7**

Justification:

This project is required due to:

a) The Cow Head Terminal Station yard was not originally designed large enough to accommodate a mobile substation. An extension to the yard is required to provide a secured and properly grounded space to locate the mobile substation within the terminal station. This extension will ensure that the mobile unit can be used to minimize the security risk to the general public and increase reliability of the terminal station while completing planned work and in the event of sustained outages.

b) The existing, 3.0m high chain link fence in Cow Head develops sand build up near the top rail thereby reducing security and creating a public safety reliability concern. This accumulation of sand and the added snow could allow access to the energized terminal station. This is a recurring issue for this particular terminal station. For example, sand was removed from around the chain link fence in March 2011. Measurements taken in October 2011 indicated that the sand had built up again near the top rail again. Also, the sand drifting into the terminal station can decrease reliability and the impact of blowing sand on insulators can compromise their integrity as well as the integrity of other equipment within the yard.

Existing System:

The terminal station in Cow Head was constructed in 1970 and provides 69kV service to areas along the west coast of Newfoundland which includes Sally's Cove, Berry Hill and Rocky Harbour. A secure, grounded area inside the yard to position the mobile substation was not included in the original design of the terminal station. Preventive maintenance (PM) on the terminal station is completed approximately every six years. To minimize customer impact during this PM work and periodic other planned project work, the mobile substation is transported to site, maneuvered into place, grounded, enclosed in temporary fencing, road/access upgraded (as required) and 24 hour security watch established to prevent public access to the energized mobile substation.

Figure 1: Cow Head Terminal Station

The existing chain link fence at Cow Head Terminal Station allows sand to build up near the fence as the location of this terminal station is located on a sandy beach. Sand is required to be cleaned out from along the fence line throughout the year. The existing chain link fence was extended in the past and is currently 3.0m in height. The purpose of the chain link fence is to prevent the general

public access to the energized terminal station. At times, the sand has built up quickly along the fence. During winter months with the added snow, members of the public or wildlife could step over the fence and access the yard. Entry into a terminal station is a significant safety risk for members of the public. Industry experience shows people access terminal stations to steal copper, putting themselves at risk, and putting equipment and reliability at risk. Further, animals can wander into a terminal station if access is easy and also interact with equipment, causing outages to equipment, affecting equipment reliability.

Table 2: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2013	Cow Head TS Fence Height Extension	Extended Fence height to 3.0m

Operating Experience:

When lengthy emergency outages are anticipated or scheduled outages occur at Cow Head Terminal Station, the mobile would be deployed. The terminal station would be taken out of service and electrical connectivity would be established to the transmission lines, thus by-passing the terminal station. In order to connect to the mobile substation, this unit needs to be located in a specific location; under the transmission line entering the terminal station. Having a dedicated upgrade to the yard to accommodate the mobile substation will mean that during planned maintenance/repairs and lengthy emergency outages there will be improved grounding safety, decrease setup cost and time and reduced requirement for security watch while the mobile is on site.

Preventative maintenance and various planned work include having the mobile substation brought to site. The mobile setup usually takes between three to five day that includes earthwork upgrades, installation of grounding and installation of security fencing, maneuvering the mobile correctly into place and interconnecting to the transmission lines. This setup time is in addition to the time to complete the required work.

The current yard area of the terminal station is not adequate to allow a mobile substation into the yard in the event the mobile is required. The size of this mobile substation unit is approximately 16m (length) x 5.2m (width) x 4.1m (height) and requires space around it to work. Expansion of the terminal station would help ensure that a mobile substation would have the required area to be properly connected to the terminal station. Use of the mobile substation allows work to occur at the terminal station while still providing service to the customers.

Reliability Performance

Currently, when the substation is required during lengthy emergency outages or major equipment failures, as per the emergency preparedness procedure, delays to service occur while the mobile is transported and set-up. This additional time is attributed to upgrades to the ground for the mobile unit laydown area, installation of temporary fencing and ground mats, properly grounding the mobile and additional time/material to safely connect a mobile substation. In the past, this work has taken between three to five days to get everything in place prior to interconnection of the mobile unit.

Safety Performance

When unexpected issues arise and the mobile substation is available for deployment, workers are required to complete this additional set up work for the mobile substation and restore service to customers. Working under these time constraints, can lead to workers rushing to complete the work and possibly result in unsafe work practices.

Industry Experience

In recent years Hydro has completed minor operating upgrades to terminal stations within Newfoundland and Labrador to include an area to support a mobile substation in the yards. These areas have included South Brook, Bottom Waters, Farewell Head and Hawkes Bay.

Most recently in 2014 a terminal station replacement was completed in Wiltondale. During design and construction of this terminal station additional area to accommodate a mobile substation within the yard was included. The additional area within the yard allows for safe and efficient connection for the setup of a mobile substation when planned or emergency outages occur.

Maintenance History

Preventative Maintenance

The regular maintenance occurs to complete upgrades to equipment and to perform regular maintenance on the equipment. At these times, the terminal station can be down for as much as a week during the outage.

Historical Information

In Hydro's 2015 Capital Budget Application, the Board of Commissioners of Public Utilities approved

a similar project for Barachoix, in Board Order No. P.U. 50(2014). Table 3 shows recent upgrades at Hydro's Terminal Stations.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2015	489.3	-	Barachoix TS – 2015 Construction
2011-2012	794.9	1,043.6	Rocky Harbour – Additional scope included in Upgrades

Anticipated Useful Life

The anticipated useful life for the expansion to the Cow Head Terminal Station would be in excess of 40 years. Once the area, fencing, grounding is in place there would be no further upgrades required to accommodate a mobile substation.

Conclusion:

During unplanned outages or scheduled maintenance work at Cow Head Terminal Station, the mobile substation unit would be deployed to the terminal station to minimize the resulting outage. The mobile would be connected such that electricity would flow through the unit while the terminal station is bypassed and repaired. The Cow Head terminal station is currently too small to properly accommodate the mobile unit within the yard. Extending the station yard will allow adequate room to maneuver the mobile unit into the correct position as well as provide a permanently grounded, fenced and safe area for the mobile unit to be placed during preventative maintenance and planned project work. Having a properly grounded and secure will minimize the time required to correctly locate the mobile unit, thus reducing the personnel and material required and decrease the overall set up time. These upgrades will ensure that the customers of Sally's Cove, Berry Hill and Rocky Harbour continue to have dependable service.

Also, the inclusion on the silt/sand fence will help mitigate the sand developing along the chain link fence and further secure access to the terminal station by the general public or wildlife.

Project Schedule:

The anticipated project schedule is shown in Table 4.

Table 4: Project Schedule

Activity		Start Date	End Date
Planning	Review Project Scope/Design Transmittal	January 2016	April 2016
Design	Design/Specification Development	April 2016	September 2016
Design	Complete Tender Documentation	October 2016	February 2017
Procurement	Tender/Award Contract	Mar 2017	May 2017
Construction	Upgrade to Terminal station and Extension to Chain link fence	July 2017	August 2017
Commissioning	Final inspection	August 2017	September 2017
Closeout	Closeout project	September 2017	October 2017

Project Title: Upgrade Transformers

Location: Cartwright and Postville

Category: Transmission and Rural Operations - Generation

Type: Other

Classification: Normal

Project Description

This is a one year project that will address the growing electrical demand in the isolated communities of Cartwright and Postville. It is forecasted that the growing demand on the Cartwright and Postville systems will result in an overload on the substation transformers by the summer of 2015 and winter of 2015/2016, respectively. The total estimated capital cost is approximately $465,200. The budget estimate for the total project is shown in Table 1.

Table 1: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	184.2	0.0	0.0	184.2
Labour	140.2	0.0	0.0	140.2
Consultant	14.8	0.0	0.0	14.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	23.5	0.0	0.0	23.5
Interest and Escalation	29.8	0.0	0.0	29.8
Contingency	72.6	0.0	0.0	72.6
TOTAL	**465.2**	**0.0**	**0.0**	**465.2**

Cartwright

In Cartwright, the scope will include the procurement and installation of three single phase 500 kVA transformers (0.6 kV/2.4 kV–14.4 kV) and the procurement of a fourth transformer to be stored on site as a spare.

The existing transformer bank in Cartwright consists of three single phase 333 kVA pole-mounted transformers[5] and must be replaced with three new 500 kVA units (0.6kV/2.4kV–14.4kV). The new transformers will be installed on the existing foundations and structures. A pole will be added underneath the existing transformer platform to increase the strength of the substation platform to support the larger transformers. No other foundation modifications are expected to be required.

[5] The existing 333 kVA transformers in Cartwright are 28 years old and their anticipated useful service life is 30 years. As a result, it is recommended that they are not salvaged and reused in Postville.

Postville

In Postville the scope will include the procurement and installation of three single phase 333 kVA transformers (0.6 kV/2.4 kV–14.4 kV) and the procurement of a fourth transformer to be stored on site as a spare.

The existing transformer bank in Postville consists of three single phase 167 kVA pole-mounted transformers and must be replaced with three new 333 kVA units (0.6 kV/2.4 kV–14.4 kV). The new transformers will be installed on the existing foundations and structures. The existing transformer platform can currently support the weight of three single phase 333 kVA transformers and therefore an additional pole for support is not required.

Justification:

This project is justified on the requirement to meet growing electricity needs of Hydro's customers serviced by the Cartwright and Postville systems. The existing electrical equipment in Cartwright and Postville must support the forecasted peak as the integrity of the equipment is jeopardized once it becomes overloaded beyond its capacity, which poses a higher risk of failure and potentially increases operating and maintenance costs. When the load exceeds the equipment capacity ratings, a power outage may result which would reduce the overall reliability of the system.

Existing Systems:

Cartwright

The Cartwright diesel plant was commissioned in 1987 and currently houses four diesel generating units. The facility is the sole source of power for the community of Cartwright and, as such, it is required to provide the electrical supply to approximately 350 customers on a continuous basis. The current plant arrangement consists of four diesel generators rated at 600 kW, 720 kW[6], and two at 450 kW. The total installed capacity of the facility is currently 2,220 kW giving a firm capacity of 1,500 kW. Table 2 provides the ages and other pertinent information for the four installed generating units at Cartwright.

[6] A 2016 Capital Budget Application is being submitted to replace Unit 2052 with a 925 kW Unit.

Table2: Cartwright Installed Generation (December 31, 2014)

Unit #		Engine Model #	Capacity (kW)	Year Built	In-Service Date	Unit Age YTD	Unit Hours	Number of Overhauls
G1	2036	Cat. D-3412	450	1992	1992	23	37,821	3
G2	2086	Cat. C-27	600	2009	2009	6	19,474	0
G3	2045	Cat. D-3412	450	1993	1993	22	31,113	4
G4	2052	Cat. D-3512	720	1998	2002	17	89,054	3

Note: Hydro is proposing to replace Unit 2052 (720 kW with a 925 kW unit) in the 2016 Capital Budget Application.

Three single phase step-up transformers are responsible for converting the voltage from a generation voltage of 600 V to a distribution voltage of 4.16 kV. These existing pole-mounted substation transformers are 28 years old and are each rated for 333 kVA, providing a total transformation capacity of 989 kW[7]. The main bus in the Cartwright diesel plant is rated for 2,400A (2,245 kW). The connection between the diesel plant and substation consists of four runs (per phase) of 535 kcmil copper RW90 service cables. There is a single fuel storage tank located onsite with a total capacity of 46,200 L to supply the diesel plant. Table 3 summarizes the ratings of equipment found in the Cartwright diesel plant. See Appendix A for a single line diagram of the Cartwright diesel plant.

Table 3: Cartwright Diesel Plant - Equipment Ratings

	Equipment Rating	Equipment Rating (kW)
Installed Capacity	2,220 kW	2,220
Firm Capacity	1,500 kW	1,500
Transformation Capacity	333 kVA/Phase	989
Main Bus	2400 A	2,245
Main Breaker	N/A	N/A
Service Conductors	1,427 A/Phase	1,335
Fuel Storage	46,200 L	N/A

Table 4 shows the major works and upgrades that have occurred at the Cartwright diesel plant over the past ten years.

[7] This is assuming a power factor of 90% and an allowable overload of 10%.

Table 4: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2009	New switchgear	All units and main
2009	New cable trenching	
2009	Replacement of power and control cables	
2009	Installation of a new recloser	Including controls
2009	Installation of Unit 2086	
2009	New fuel storage tank	

Postville

The Postville diesel plant was commissioned in 1975 and currently houses three diesel generating units. The facility is the sole source of power for the community of Postville and, as such, it is required to provide the electrical supply to approximately 127 customers on a continuous basis. The current plant arrangement consists of three diesel generators rated at 365 kW, 252 kW[8], and 275 kW. The total installed capacity of the facility is currently 892 kW giving a firm capacity of 527 kW. Table 5 provides the ages along with other pertinent information for the three installed generating units at Postville.

Table 5: Postville Installed Generation (December 31, 2014)

Unit #		Engine Model #	Capacity (kW)	Year Built	In-Service Date	Unit Age YTD	Unit Hours	Number of Overhauls
G1	2084	Cat. C15	365	2009	2009	6	21,847	1
G2	577	6063TK35	252	2001	2001	14	66,221	4
G3	573	6063MK35	275	2000	2000	15	78,045	4

Three single phase step-up transformers are responsible for converting the generation voltage of 600 V to a distribution voltage of 4.16 kV. These existing pole-mounted substation transformers are 27 years old and are each rated for 167 kVA, providing a total transformation capacity of 496 kW[9]. The main bus in the Postville diesel plant is rated for 800A (748 kW). The connection between the diesel plant and substation consists of two runs (per phase) of 300 kcmil copper RW90 service cables. There is a single fuel storage tank located onsite with a total capacity of 638,388 L to supply the diesel plant. Table 6 summarizes the ratings of equipment found in the Postville diesel plant. See Appendix A for a single line diagram of the Postville diesel plant.

[8] A 2016 Capital Budget Application is being submitted to replace Unit 577 with a 450 kW Unit.
[9] This is assuming a power factor of 90% and an allowable overload of 10%.

Table 6: Postville Diesel Generating Station – Equipment Ratings

	Equipment Rating	Equipment Rating (kW)
Installed Capacity	892 kW	892
Firm Capacity	527 kW	527
Transformation Capacity	167 kVA/Phase	496
Main Bus	800 A	748
Main Breaker	N/A	N/A
Service Conductors	590 A/Phase	552
Fuel Storage	638,388 L	N/A

Table 7 shows the major works and upgrades that have occurred at the Postville diesel plant over the past ten years.

Table 7: Postville Major Works or Upgrades

Year	Major Work/Upgrade	Comments
2011	Two new bulk fuel storage tanks	300,000 L installed, with new dyke
2009	Installation of unit 2084 (G2)	Included new Jacket, water radiator, air to air after cooler, exhaust stack, power cables, control wire, and switch gear.

Operating Experience:

Cartwright

Substation upgrades at the Cartwright diesel plant are required to prevent overloading on the substation transformers. The forecasted net peak in Cartwright is growing and will be 997 kW by the summer of 2015. At which time the peak load will exceed the rated capacity of the substation transformers.

This proposed project will not be completed until the summer of 2016 and therefore there will be a slight overload on the transformers for up to two summer seasons. The expected summer peak demand in 2016 is 1,005 kW, which translates into an 11.8% overload on the substation transformers. Hydro's planning criteria for diesel plant substation transformer replacements is to replace them once the load forecast exceeds 110% of their rated capacity.

An 11.8% overload on the transformers is acceptable on an interim basis. However, with more load growth, the overload will become more severe and may eventually have an adverse effect on system reliability.

Table 8 summarizes the existing and proposed capacity ratings for the substation transformers in Cartwright.

Table 8: Cartwright Substation Transformer Capacity Summary[10]

Equipment	Existing		Proposed	
	Configuration	Rating (kW)	Configuration	Rating (kW)
Substation Transformers	3 x 333kVA	989	3 x 500kVA	1,485

With the replacement of the three 333kVA with three 500kVA, the transformer capacity will increase from 989 kW to 1,485 kW. Based on the current load forecast, this will ensure that there is sufficient transformer capacity available in the Cartwright system to maintain a reliable electrical supply for the beyond the year 2035.

Postville

Substation upgrades at the Postville diesel plant are required to prevent overloading on the substation transformers. The forecasted net peak in Postville is growing and will be 507 kW by the winter of 2015/2016. At which time the peak load will exceed 110% of the rated capacity of the substation transformers.

This project will not be completed until the fall of 2016 and therefore there would be a slight overload on the substation transformers for one winter season. As previously mentioned, the expected peak demand for the winter of 2015/2016 is 507 kW, which would translate into a 12.4% overload on the substation transformers. Hydro's planning criteria for diesel plant substation transformer replacements is to replace them once the load exceeds 110% of their rated capacity. However, the review carried out in 2014 indicated that this transformer bank would not need to be replaced until 2016[11]. As noted in the Forecast Customer Growth section, demand has since increased in Postville due to the construction of a recreation center, fire hall and hydrant heat tracing system.

A 12.4% overload on the transformers, especially during the winter, is acceptable on an interim basis. However, with more load growth the overload will become more severe and may eventually

[10] Ratings (kW) are based on a 90% power factor. Diesel plant substation transformers can be overloaded up to 110% of the nameplate continuous rating at any time.
[11] Based on the 2014 Operating Load Forecast.

have an adverse effect on system reliability.

Hydro is pursuing potential conservation and demand management (CDM) programs to reduce the system, and therefore transformer demand in the longer term in its isolated diesel systems. To date, electricity conservation programs throughout the province have been designed with a focus on reducing energy consumption (kWh) and not peak demand (kW). In the case of Postville, Hydro is installing a direct load control pilot to reduce maximum system demand. The exact impact of the CDM program in Postville is not yet quantifiable, therefore, Hydro is planning for the transformer replacement in parallel to the CDM pilot program. Hydro expects positive results from the program, and the results of the CDM program will inform the timing of future transformer upgrade projects for other communities.

Table 9 summarizes the existing and proposed transformer configuration, nameplate rating, and planning rating.

Table 9: Cartwright Substation Transformer Capacity Summary[12]

Equipment	Existing		Proposed	
	Configuration	Rating (kW)	Configuration	Rating (kW)
Substation Transformers	3 x 167 kVA	496	3 x 333 kVA	989

With the replacement of the three 167 kVA with three 333 kVA, the transformer capacity will increase from 496 kW to 989 kW. Based on the most recent load forecasts, this will ensure that there is sufficient transformation capacity available in the Postville system to maintain a reliable electrical supply for the beyond the year 2035.

Reliability Performance/Outage Statistics

One of the intents of the isolated generation planning criteria is to avoid outages as a result of the load exceeding the capacity ratings of specific equipment. The planning criteria is intended to maintain at least a minimum level of system reliability by ensuring that equipment is properly rated for the load, and does not specifically target to improve the reliability of the existing equipment within a given system. However, there may be reliability improvements achieved if the equipment

[12] Ratings (kW) are based on a 90% power factor. Diesel plant substation transformers can be overloaded up to 110% of the nameplate continuous rating at any time.

being replaced has a history of being unreliable.

Similar to distribution systems, the reliability of a diesel plant is tracked using the industry standard service continuity indexes; System Average Interruption Frequency Index (SAIFI), and System Average Interruption Duration Index (SAIDI). Hydro uses the *Loss of Supply* category to track interruptions originating in the diesel plants. The indices are described as follows:

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

SAIDI - Indicates the average length of time a customer is without power in the respective distribution system per year.

Table 10 provides the 2010 to 2014 average SAIFI and SAIDI data for Cartwright and Postville for all causes as compared to Loss of Supply outages. The table also lists the 2010 to 2014 regional and corporate indices and the latest CEA five-year average (2009 to 2013) for comparison.

Table 10: Five-Year Average Outage Statistics (2010-2014)

SYSTEM	All Causes		Loss of Supply	
	SAIFI	SAIDI	SAIFI	SAIDI
Labrador Isolated	10.89	14.74	6.60	3.61
Cartwright System	7.25	4.61	5.20	2.21
Postville System	8.23	3.47	7.39	2.19
Hydro Corporate	5.25	13.78	2.27	4.02
CEA Region 2 (2009-2013)	2.94	9.83	0.67	0.71

According to the five-year outage statistics, the Cartwright and Postville systems generally have less and shorter outages than other systems in the Labrador region. However, Cartwright and Postville are less reliable compared to the CEA Region 2[13] statistics. Comparing outages in the loss of supply

[13] The Canadian Electricity Association (CEA) publishes average outage statistics for utilities across Canada. The CEA Region 2 has mostly rural utilities which is comparable to Hydro.

category to outages from all causes, it is noted that a large portion of outages in Cartwright and Postville are due to loss of supply. In comparison to Hydro's corporate performance, customers in the Labrador region experience more frequent outages at longer durations. It is the limited accessibility to the remote locations in Labrador that primarily accounts for high SAIDI statistics.

Maintenance or Support Arrangements

The maintenance of the Diesel Generating Stations at Cartwright and Postville are performed by Hydro Operations personnel stationed in Happy Valley Goose Bay. Maintenance at diesel plants consist of scheduled preventative maintenance such as changing the oil and oil filters, annual electrical and mechanical preventative maintenance, and required corrective maintenance to repair failed components or correct operational problems. Replacement parts are readily available for the diesel generating sets and associated auxiliary equipment. Hydro maintains a spare substation transformer on site in the event of a failure.

Historical Information

Cartwright is a summer peaking system as the local shrimp plant is in full operation during this time. The Cartwright system currently serves about 350 customers and has historically experienced steady growth in peak load and electricity sales. Postville is a winter peaking system and has historically experienced steady growth in peak load and electricity sales. The distribution system currently serves about 127 customers.

Figure 1 and Figure 2 are graphs that summarize historical annual demand and production data for the Cartwright and Postville diesel plant since the year 2004.

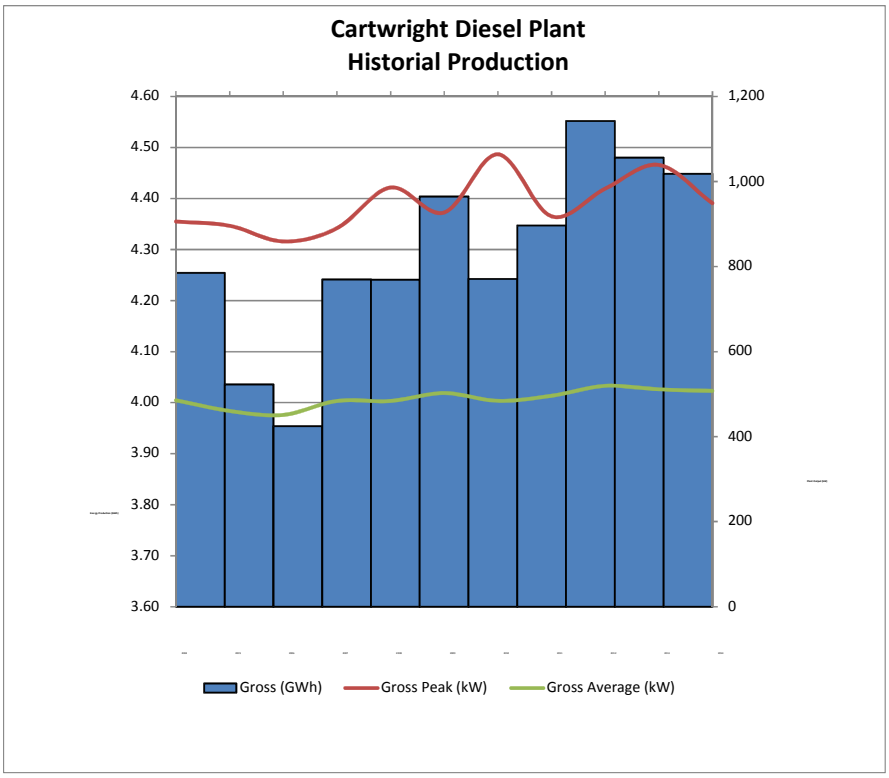


Figure 1: Cartwright Load History 2004-2014

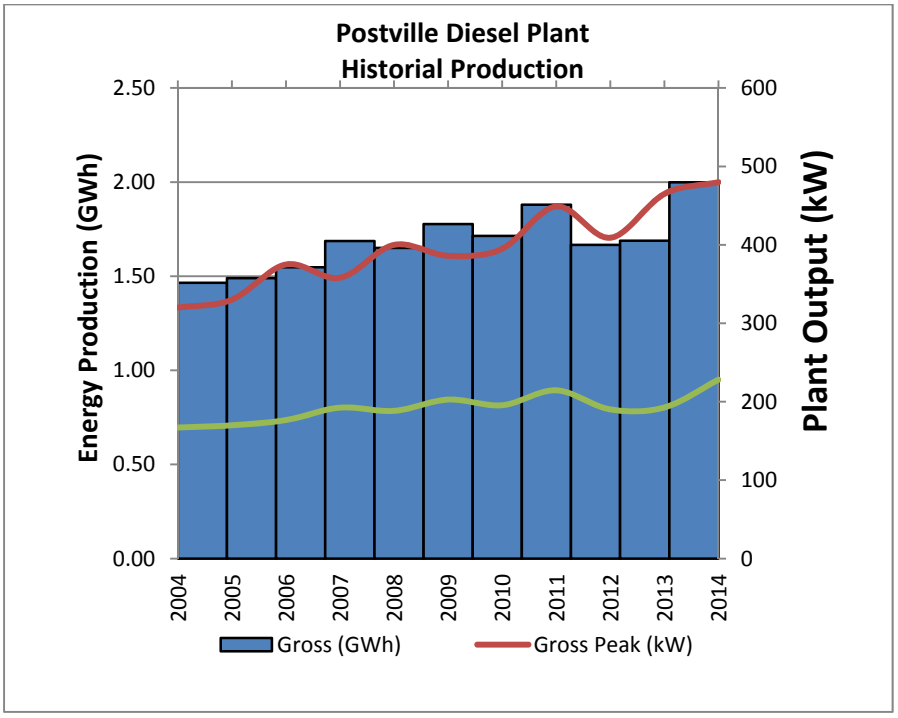


Figure 2: Postville Load History 2004-2014

Forecast Customer Growth

A key input to the planning process is the load forecast. The load forecast allows Hydro to determine timing of criteria violations, so that potential issues can be addressed before they occur. Hydro prepares a forecast of the anticipated loads for all of their distribution systems on an annual basis including Cartwright and Postville. The forecast projects the peak demands and energy requirements for each system from 2015 to 2020. The peak demand forecast is used to determine the required amount of capacity that a plant or piece of equipment within the plant must have in order to meet that demand. The energy forecast is used to determine the amount of fuel the system will require in a given year. The forecast includes new customers from both Domestic Service Customers (new homes) and General Service Customers (new businesses, and government facilities). The new residential customers (domestic services) added to the system are assumed to have the same energy consumption as the average of the existing customers in that system. A winter season spreads over two separate calendar years and therefore the winter peak of a system could occur in one of those two years. For a winter peaking system like Postville, the 2016 peak includes the winter of 2016/2017 which ranges between November 2016 and March 2017. Therefore, to meet the 2016 peak, it is necessary that work be completed before November 2016.

Cartwright

In Cartwright there is slight growth forecasted in the small general service class, but the majority of the growth is expected due to residential customers switching to electric heat. The 2014 operating load forecast for Cartwright is presented in Table 8.

Table 8 - Cartwright Load Forecast 2015-2020

Year	Gross Peak (kW)	Net Peak (kW)	Gross Energy (MWh)	Net Energy (MWh)	Total Sales (MWh)	Company Use (MWh)
2015	1,032	997	4,701	4,500	4,297	0
2016	1,040	1,005	4,739	4,536	4,331	0
2017	1,050	1,015	4,784	4,580	4,372	0
2018	1,059	1,024	4,823	4,617	4,408	0
2019	1,069	1,034	4,869	4,661	4,450	0
2020	1,078	1,043	4,912	4,702	4,489	0

Postville

As previously mentioned, there has been an increase in the load forecast since the release of the

2014 operating load forecast. The sudden forecasted growth can be attributed to three new relatively large customers including, a recreation center, a fire hall and hydrant heat tracing system. Beyond 2015, there is slight growth forecasted in the small general service class, but the majority of the growth is expected due to residential customers switching to electric heat.

The revised 2014 operating load forecast for the Postville System is presented in Table 8.

Table 8: Postville Load Forecast 2015-2020

Year	Gross Peak (kW)	Net Peak (kW)	Gross Energy (MWh)	Net Energy (MWh)	Total Sales (MWh)	Company Use (MWh)
2015	528	507	2,322	2,207	2,038	5
2016	531	511	2,337	2,221	2,051	5
2017	534	514	2,351	2,234	2,063	5
2018	537	517	2,365	2,248	2,076	5
2019	540	520	2,379	2,261	2,087	5
2020	543	523	2,392	2,274	2,099	5

Development of Alternatives

There are no alternatives as each set of substation transformers at the Postville and Cartwright diesel plants are being replaced with the next size up[14]. Given the forecast, replacing the existing transformers with anything larger would be excessive.

Energy Efficiency Benefits

There is potential for energy efficiency benefits with the purchase of a new transformer with less power losses, but this benefit cannot be accurately quantified at this time. The cost of losses versus the capital cost of the transformers is taken into account in the purchase of the new transformers.

Conclusion:

This project is required to meet growing electricity needs, and to ensure the current level of electrical service reliability received by Hydro's customers in the Cartwright and Postville Systems is maintained to at least the standard set by the planning criteria.

14 Based on Hydro's standard sizes

In the long term the status quo is not technically viable for the operation of these systems. The rated capacities of the substation transformers are not adequate to support future system growth. The system net peak has already exceeded 110% of the transformers' rating. Although there will be a temporary minor overload on the transformers, this is deemed acceptable in the short-term. However, future load growth is anticipated on these systems which will correlate into more severe overloads on the transformers. The greater the overload on the transformers, the more likely system reliability will become jeopardized.

If upgrades to the Cartwright and Postville substation transformers are not performed in 2016, the result will be reduced system reliability due to potential outages caused by overloaded equipment.

Based on the 2014 Operating Load Forecast, this project will ensure that the substation transformers are properly sized in the Cartwright and Postville substations to ensure that no overloads occur beyond the year 2035.

Project Schedule:

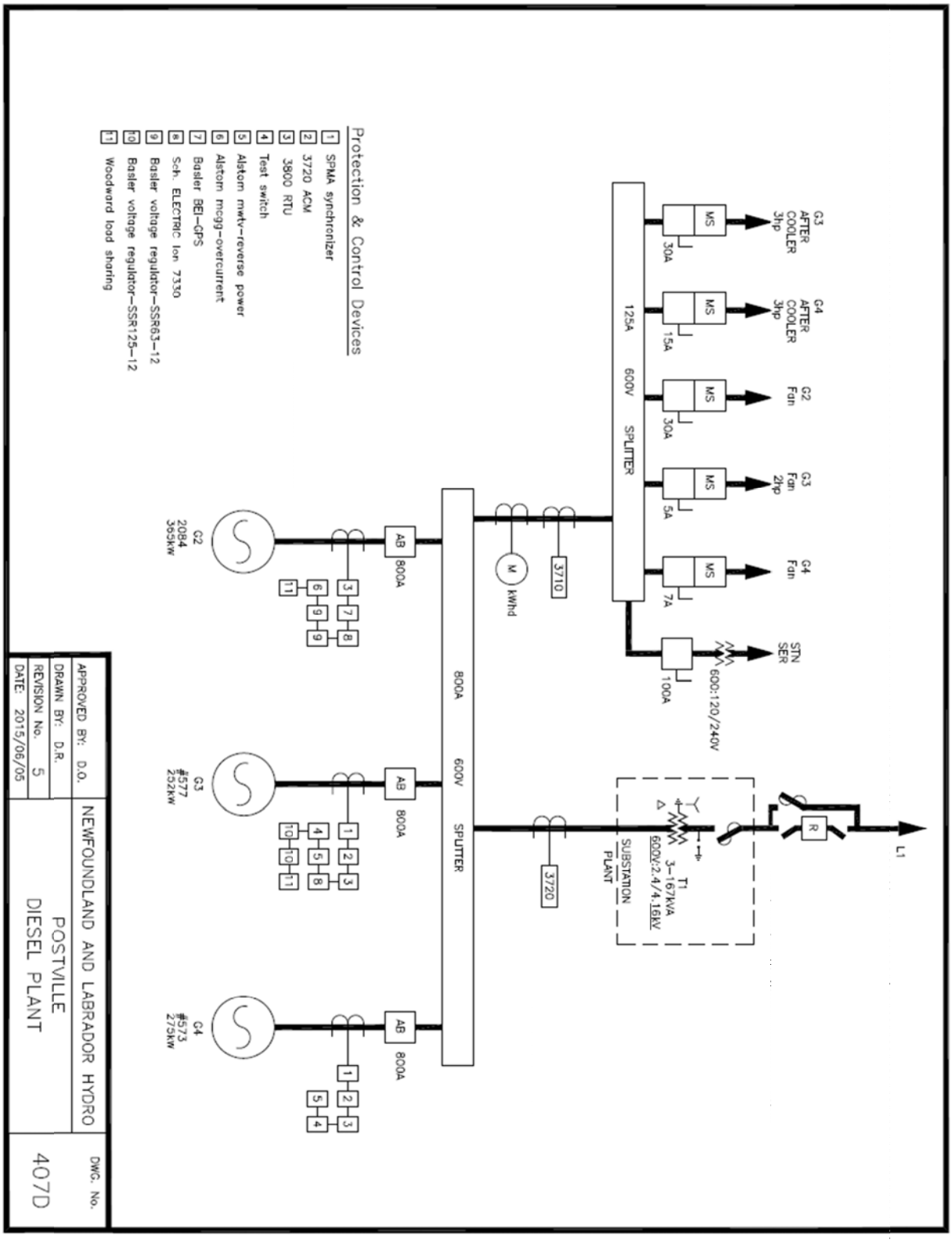
The anticipated project schedule is shown in Table 9.

Table 9: Project Schedule

Activity		Start Date	End Date
Planning	Scope, schedule, cost, risk, quality and communication planning. Also involves monitoring and controlling project activities.	January 2016	February 2016
Design	Site visits, engineering and design to upgrade substation transformers.	January 2016	February 2016
Procurement	Complete transformer technical specification, and requisition for miscellaneous materials. (Delivery lead time of 10-12 weeks for transformer)	February 2016	May 2016
Construction	Install substation transformers	August 2016	August 2016
Commissioning	Complete technical specification.	August 2016	August 2016
Closeout	Project Closeout	August 2016	Sept 2016

APPENDIX A

Single Line Diagrams – Cartwright and Postville Diesel Plants


Protection & Control Devices
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2 3720 ACM
3 3800 RTU
4 Test switch
5 Alstom rmetv-reverse power
6 Alstom mcgg-overcurrent
7 Basler BEI-GPS
8 Sch. ELECTRIC Ion 7330
9 Basler voltage regulator-SSR63-12
10 Basler voltage regulator-SSR125-12
11 Woodward load sharing
G3 AFTER COOLER 3hp
G4 AFTER COOLER 3hp
G2 Fan
G3 Fan 2hp
G4 Fan
STN SER
MS
30A
15A
5A
7A
100A
125A 600V SPLITTER
600:120/240V
M kWhd
3710
3720
800A 600V SPLITTER
AB 800A
G2 2084 365kw
G3 #577 252kw
G4 #573 275kw
T1 3-167kVA 600V:2.4/4.16kV
SUBSTATION PLANT
R
L1
APPROVED BY: D.O.
DRAWN BY: D.R.
REVISION No. 5
DATE: 2015/06/05
NEWFOUNDLAND AND LABRADOR HYDRO
POSTVILLE
DIESEL PLANT
DWG. No.
407D

Project Title: Replace Human Machine Interface

Location: Various Sites

Category: Transmission and Rural Operations – Generation

Type: Other

Classification: Normal

Project Description:

This project consists of the replacement of the existing Human Machine Interface (HMI) systems at the following four diesel plants: Port Hope Simpson, Hawke's Bay, St. Anthony and Ramea. The existing HMI software is obsolete and will be replaced by the latest HMI software, as per the defined standard for Hydro diesel plants. In order to execute the software upgrade, a new server, monitor and miscellaneous hardware will also be installed at each site. This project will upgrade the HMI systems at the four diesel plants over the period of two years 2016-2017.

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	44.5	75.0	0.0	119.5
Labour	52.5	129.9	0.0	182.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	9.5	44.4	0.0	54.0
Interest and Escalation	7.5	35.1	0.0	42.6
Contingency	0.0	35.6	0.0	35.6
TOTAL	**114.0**	**320.0**	**0.0**	**434.0**

Justification:

This project is justified on the requirement to replace obsolete technology and equipment in order for Hydro to provide safe, least-cost, reliable electrical service. The current HMI software used in Port Hope Simpson, Hawke's Bay, St. Anthony and Ramea diesel plants is obsolete and must be replaced in order to continue operational functionality. The functionality of the current HMI system is restricted by its limited capacity to accept changes as diesel plant upgrades occur.

Diesel System Representatives (DSR) at the above mentioned sites use the HMI daily to control and monitor the power system along with some auxiliary systems of the diesel plant. The DSR relies on the HMI as the primary point of control, and the HMI is therefore critical to controlling and

monitoring the diesel systems, notifying of any alarms and/or issues, and the troubleshooting of these issues. The current HMI software in these four diesel plants is Monitor Pro, which is a legacy product from Schneider Electric. They are no longer supported by the vendor, therefore no external support would be provided should one of these systems fail.

Existing Systems:

The HMIs utilized in all four diesel plants are different legacy versions of Monitor Pro and all these versions are no longer supported by the vendor. This lack of support means that the software cannot run on newer versions of Windows. Due to this inability to operate on newer versions of Windows, laptops used by Hydro technicians and engineers cannot run or modify this software. Therefore, any changes in the diesel plant's power system that would require new additions or modifications to the HMI screens cannot occur. Table 2 lists the existing system at each plant and when each system was bought and installed.

Table 2: Existing HMI systems

Location	Installed	Years in Service	HMI Type	Server and Software
Port Hope Simpson	1994	21	Monitor Pro (Double Legacy)	2006
Hawke's Bay	1996	19	Monitor Pro (Single Legacy)	2006
Ramea	1998	17	Monitor Pro 7.2	2006
St. Anthony	1992	23	Monitor Pro 7.2	2006

There is one HMI per site and every site will require a server and software upgrade in order to upgrade to the new standard, VTScada.

Operating Experience

The existing HMI is performing as needed, with the exception of some minor loss of control and inaccurate alarming on new installations. For example, for the Arc Flash Remediation project in Port Hope Simpson, the project team completed upgrades to the site protection but were unable to program and show the new alarms for the additional protection in the current HMI. Problems like these will continue to occur with future capital projects and maintenance. Currently, if any complications or issues arise affecting the HMI, Hydro cannot get any support from the OEM Schneider Electric, as the HMIs at each of these sites are obsolete.

Vendor Recommendations

The vendor recommends a migration or upgrade from the current obsolete system. The current systems are no longer supported by the OEM, Schneider Electric. (See Appendix A for the list of support and availability of Monitor Pro HMIs.)

As a result of the issues outlined above, Monitor Pro HMIs have been replaced as part of various larger capital projects. The first of these projects that occurred was at L'Anse au Loup where the decision was made to migrate away from Schneider Electric and upgrade to VTScada by Trihedral Engineering. This option was chosen due to the cost and ease of use and support offered. This is now considered to be the standard for HMIs in Hydro's diesel plants.

Maintenance or Support Arrangements

The new HMI software standard for diesel plants is VTScada. An annual operating maintenance and support agreement will be entered into and includes all software upgrades and support. This strategy is in line with other diesel plants that have undergone this replacement such as L'Anse au Loup.

Anticipated Useful Life

The anticipated useful life for the server hardware is 8-10 years.

Conclusion:

A reliable and supported HMI system is necessary at the diesel plants to allow the operators to monitor and control the automation systems. The HMI systems for the Port Hope Simpson, Hawke's Bay, Ramea and St. Anthony diesel plants are beyond the end of their useful lives and are obsolete. This budget proposal supports the only viable option which is the replacement of these assets.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Scope, schedule, cost, risk, quality and communications planning	January 2016	April 2016
Design	Design for 1st site in 2016	March 2016	April 2016
	Design for 2nd site in 2016	July 2016	August 2016
	Design for 3rd site in 2017	March 2017	April 2017
	Design for 4th site in 2017	July 2017	August 2017
Procurement	Develop RFP for all 4 sites	February 2016	March 2016
	Engage IS to specify and purchase server and software.	February 2016	April 2016
Construction & Commissioning	Construction Site #1—2 weeks	April 2016	April 2016
	Construction Site #2—1 week	August 2016	August 2016
	Construction Site #3—2 weeks	April 2017	April 2017
	Construction Site #4—3 weeks	August 2017	August 2017
Closeout	Final Billing, Interest Cut-Off, Project Closeout	October 2017	December 2017

APPENDIX A

Monitor Pro –Current System

Monitor Pro

Product Support Lifecycle

Product Release	Release Date	Lifecycle Phase	Support
Monitor Pro V2.0	Apr 1998	Retired Functionally stable and obsolete	Product no longer sold. Authorization codes to upgrade to Monitor Pro V2.1 are available for free until 31/12/2012. No fix maintenance. Recommend upgrade to V2.1 or later.
Monitor Pro V2.1	Feb 1999	Retired Functionally stable and obsolete	Product no longer sold. Authorization codes are available for free until 31/12/2012 and then **at a cost** until 31/12/2017. Fixes available **at a cost** until 31/12/2017. Authorization codes and fixes will no longer be available after 31/12/2017. Recommend switch to Vijeo Citect. Limited support available (switch to Vijeo Citect assistance only).
Monitor Pro V7.0	Aug 2001	Retired Functionally stable and obsolete	Product no longer sold. Authorization codes are available for free until 31/12/2012 and then **at a cost** until 31/12/2017. Fixes available **at a cost** until 31/12/2017. Authorization codes and fixes will no longer be available after 31/12/2017. Recommend switch to Vijeo Citect. Limited support available (switch to Vijeo Citect assistance only).
Monitor Pro V7++	Mar 2002	Retired Functionally stable and obsolete	Product no longer sold. Authorization codes are available for free until 31/12/2012 and then **at a cost** until 31/12/2017. Fixes available **at a cost** until 31/12/2017. Authorization codes and fixes will no longer be available after 31/12/2017. Recommend switch to Vijeo Citect. Limited support available (switch to Vijeo Citect assistance only).
Monitor Pro V7.2	Jan 2004	End-of-Sale date Functionally stable and mature	Product is no longer for sale after 31/12/2012. Authorization codes and fixes available for free until 31/12/2012. Authorization codes and fixes available **at a cost** until 31/12/2017. Authorization codes and fixes will no longer be available after 31/12/2017. Recommend switch to Vijeo Citect.
Monitor Pro V7.6	Feb 2006	End-of-Sale date Functionally stable and mature	Product is no longer for sale after 31/12/2012. Authorization codes and fixes available for free until 31/12/2012. Authorization codes and fixes available **at a cost** until 31/12/2017. Authorization codes and fixes will no longer be available after 31/12/2017. Recommend switch to Vijeo Citect.

Note: **Limited Support** consists of the following:
> Answering customers' questions
> If possible, providing work arounds and fixes that are available for known problems but not hotfixes for new issues
> Providing customers with migration path information

Note: **Fixes** will be supplied for the following:
> Safety issues

Schneider Electric

Publication date: 18/06/2012
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Project Title: Upgrade Aluminum Support Structure

Location: Holyrood

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project is the first year of a three year program to upgrade aluminum support structures at the Holyrood Terminal Station. The proposed upgrades will focus on all Priority 'A' and 'B' structures as identified by Hatch Engineering (Hatch) in their 2015 report titled, *"Re-Assessment of Aluminum Structures"*, see Appendix A. The scope of work, generally, includes: the engagement of a third party consultant to complete the detailed engineering design; the installation of temporary support bracing; removal of existing nuts; lifting of structure baseplates; removal and disposal of aluminum oxide deposits; cleaning of the concrete foundation surface; completion of foundation refurbishment; replacement of damaged structure baseplates; replacement of broken anchor bolts; application of a coating system to the bottom of aluminum baseplates; and installation of new nuts and washers. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	115.8	0.0	0.0	115.8
Consultant	40.0	0.0	0.0	40.0
Contract Work	149.0	0.0	0.0	149.0
Other Direct Costs	10.8	0.0	0.0	10.8
Interest and Escalation	22.4	0.0	0.0	22.4
Contingency	63.1	0.0	0.0	63.1
TOTAL	**401.1**	**0.0**	**0.0**	**401.1**

Justification:

Corrosion of the aluminum baseplates, for the high voltage support structures at the Holyrood Terminal Station, has resulted in the accumulation of aluminum corrosion byproducts between the baseplate and the surface of the concrete foundation, see Figure 1.

Figure 1: Aluminum Oxide Formation between Concrete Surface and Aluminum Baseplate

With time, the voluminous exfoliated aluminum oxide has swelled and expanded, creating tremendous stress on both the support structures and their associated anchor bolts.

As a result of these stresses, aluminum structural members have deformed and a number of anchor bolts have failed. This damage has jeopardized the integrity of the support structures, see Figures 2 and 3.

Figure 2: Deformation of Baseplate Due to Aluminum Oxide Uplift

Figure 3: Deformation of Aluminum Structure Legs as Result of Uplift Stresses

These structures support high voltage electrical equipment. This equipment is critical to the Island Interconnected System and its continued operation is required to ensure the delivery of safe, reliable power to Hydro's customers. To ensure their ability to perform as originally designed, the proposed upgrades must be completed. Failure to complete the necessary upgrades could result in a catastrophic failure causing outages, personal injury or death.

Existing System:

The Holyrood Terminal Station was constructed in two stages. Stage I was completed in 1965, with Stage II following in 1975.

The use of aluminum support structures is unique to the Holyrood Terminal Station. These structures formed a part of the original station construction and range in age from forty to fifty years. They have not received any major work or upgrades since their original installation.

Operating Experience:

The aluminum structures are utilized to support high voltage electrical equipment within the Holyrood Terminal Station. The continuous operation of this equipment is required to maintain energy supply to the Island Interconnected System.

In 2012, the failure of anchor bolts on a 23 0kV bus structure required the enactment of emergency

repairs to restore the structure's integrity, See Figure 4.

Figure 4: Anchor Bolt Failure on Tension Side of B11 Bus Structure

Following the incident, Hydro engaged Hatch to conduct an investigation into the mode of failure. The investigation revealed that the failure was the result of overstressing, induced via the accumulation of aluminum oxide between the base plate and concrete foundation surface. The aluminum oxide is a byproduct of a corrosive reaction, resulting from the direct contact of the aluminum baseplate and concrete foundation. The results of the investigation are contained in the attached report titled, *"Newfoundland and Labrador Hydro Holyrood Thermal Generation Plant Sub Station Aluminum Structure Inspection",* See Appendix B.

Safety Performance

Given the sudden nature of the 2012 anchor bolt failure, the completion of the proposed upgrades is required to ensure the safety of personnel working in and around the terminal station. These structures support high voltage electrical equipment and failure to complete the necessary upgrades could result in a catastrophic failure causing personal injury or death.

Maintenance or Support Arrangements

Maintenance of terminal station infrastructure is completed by Hydro Operations personnel. Major upgrades and repair work is typically completed by external contractors.

Maintenance History

The only maintenance of record for the aluminum support structures involves the emergency

structure upgrades completed in 2013. Four structures were upgraded at a cost of $91,747. The aluminum steel support structures are, generally, self- sufficient and do not require any maintenance. Any general maintenance which may have been completed on the structures is not available. Individual structures are not assigned an asset number but are rather grouped under the asset number, assigned to the piece of electrical equipment they support. Consequently, any maintenance completed on the structures would have been tracked under the equipment asset, making it difficult to isolate the maintenance history for each respective structure.

Historical Information

In 2012, three of four anchor bolts on the tension side of a high voltage bus structure, located at the Holyrood Terminal Station, failed and emergency repairs were required to restore the structure's integrity. As a result of this failure, Hydro commissioned Hatch to assess the condition of the remaining support structures and complete an investigation into the root cause of the anchor bolt failure. Based on the assessment findings, Hatch recommended that emergency repairs be enacted on four structure bases. It was also recommended that continued monitoring of the remaining structure bases be completed.

As per the 2012 assessment recommendation to implement continued monitoring of the structures, Hatch was again consulted to complete a re-assessment of the structure bases in 2014. The re-assessment constituted a visual inspection of the structure bases to determine whether or not their condition had changed since the original assessment; the completion of "wrench" removal tests on a select sample of anchor bolts; and the completion of ultrasonic thickness[15] (UT) tests on sample fabricated anchor bolts to determine the effectiveness of UT tests for establishing the magnitude of damage to remaining bolts. The information garnered through the completion of the "wrench" and UT testing aided in the development of a repair strategy.

While minimal change was noted in the condition of the structure bases, when cross-referenced with the 2012 assessment findings, it is recognized that the process of aluminum oxide build-up is continual. Failure to mitigate this process will inevitably result in the failure of the structure bases and/or the anchor bolts. The only means of eliminating its continued progression is to eliminate contact between the aluminum base plates and concrete foundations. Consequently, the 2015

[15] ultrasonic thickness is a method of performing non-destructive measurement (gauging) of the local thickness of a solid element (typically made of metal, if using ultrasound testing for industrial purposes) basing on the time taken by the ultrasound wave to return to the surface. This type of measurement is typically performed with an ultrasonic thickness gauge.

Hatch report recommends that upgrades be enacted for all priority A and B bases as soon as possible, with continued monitoring implemented for priority C bases.

Anticipated Useful Life

The anticipated useful life of terminal station support structures is 45 years.

Development of Alternatives

The support structures, at the Holyrood terminal station, are subject to overstressing as a result of an aluminum corrosion byproduct which is accumulating at the aluminum-concrete interface. A number of structures have already failed and it is inevitable that others will fail if left and not rehabilitated. There are no viable alternatives outside of the completion of the proposed upgrades.

Conclusion:

The aluminum support structures are subject to a build-up of aluminum oxide, which is occurring between the baseplate and the concrete foundation. The progressive accumulation of this byproduct is generating a tremendous amount of stress on both the aluminum structures and their associated anchor bolts. The magnitude of the stress, and its potential impact on the structures, became evident after the sudden failure of a structure in 2012.

The structures support high voltage electrical equipment. This equipment is critical to the Island Interconnected System and its continued operation is required to ensure the delivery of safe, reliable power to Hydro's customers. To ensure their ability to perform as originally designed, upgrades to the structures must be completed. Failure to complete the necessary upgrades could result in a catastrophic failure causing outages, personal injury or death.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Scheduling, Risk Management, Scope Statement	February 2016	February 2016
Consultant Engagement	Select Third Party Consultant	February 2016	February 2016
Detailed Engineering	Technical Specification and Drawing preparation	March 2016	April 2016
Tender	Tender and Award Support Structure Upgrade Contract	April 2016	May 2016
Construction	Complete Support Structure Upgrades	June 2016	August 2016
Commissioning	Final Inspection and Acceptance	-	August 2016
Closeout	Project Closeout, Final Billing, PIR	-	October 2016

APPENDIX A

Re-Assessment of Aluminum Structures

Newfoundland and Labrador Hydro

Final Report

For

Re-Assessment of Aluminum Structures

H347862-0000-35-124-0001
Rev. 0
February 16, 2015

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Newfoundland and Labrador Hydro

Final Report

For

Re-Assessment of Aluminum Structures

H347862-0000-35-124-0001
Rev. 0
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HATCH

Newfoundland and Labrador Hydro
Re-Assessment of Aluminum Structures
H347862

Final Report

Re-Assessment of Aluminum Structures

H347862-0000-35-124-0001

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Permit No. as issued by PEG D0090
which is valid for the year 2015

REGISTERED PROFESSIONAL ENGINEER
J.E. SNOOK
SIGNATURE
Feb 16/15
DATE
NEWFOUNDLAND & LABRADOR

			L. McPhail	J. Snook	J. Snook
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Appendix A **Legend**

Appendix B **Checklists**

Appendix C **Map – Priority A Structure Bases**

Appendix D **Map – Priority B Structure Bases**

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1. Introduction

In 2014, Hatch Ltd. was engaged by Newfoundland and Labrador Hydro (NL Hydro) to re-assess the aluminum structures at the substation of the Holyrood Thermal Generating Station (HTGS). This re-assessment serves as a follow-up to the 2012 Aluminum Structure Investigation and subsequent repair recommendations completed by Hatch.

A visual inspection of the piers, baseplates and anchors was once again completed to determine if the condition of any structure bases had changed since the 2012 investigation. Using the new site observations, the 2012 recommendations have been revised to address the current state of the HTGS aluminum structure bases.

Additionally, in an effort to determine a methodology for future detailed anchor rod condition assessments, the following trial tests were performed:

- Hydraulic Systems carried out hydraulic wrench removal tests of sample anchor rod nuts at site. The purpose of these tests was to determine whether the nuts can be removed efficiently without damaging the anchor rods.
- TEAM Industrial services carried out trial Ultrasonic Thickness (UT) tests on sample fabricated anchor rods to determine the effectiveness of UT for measuring deformation or damage to anchor rods. If effective, UT could be recommended as a means for detailed in-situ assessment of the anchors at critical locations.

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2. Background

In 2012, Hatch assessed the HTGS aluminum structures. An inspection was completed to evaluate the damage at the structure bases and to provide recommendations on a phased approach for completing repairs. The structure supports were sorted into five categories based on the damage to the piers and connection components. Using this classification and the relative importance of each structure, Hatch identified which structure bases were to be given immediate attention (Priority A), which were to be addressed within the next 12 months (Priority B), and which were not of pressing concern (Priority C).

In total, four structures were identified as requiring immediate repairs, which were completed in early 2013. These structure bases were D1, D3, J1, and R2, of Section I (a legend for the structure base numbering scheme can be found in Appendix A). The 2012 prioritization of the remaining structure bases is summarized in Table 2-1.

Table 2-1: 2012 Structure Base Prioritization

Priority A		Priority B		Priority C
Section I	Section II	Section I	Section II	Sections I & II
A4, B1, J2, J7, J11, J12, O3, P2, R6, R11, R12, W2	R7	C5, F2, H1, J9, K1, K2, P1, R5, S3, U5, V1, X3	H2, X1	All remaining structure bases

**Note: Section I consists of older aluminum structures, constructed circa 1965. Section II consists of newer aluminum structures, constructed in 1975.*

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3. Trip Report Summary

On November 13, 2014, Jacob Tucker and Elizabeth McPhail of Hatch, accompanied by Matthew Leonard of NL Hydro, carried out a follow-up inspection of the aluminum structures at the HTGS substation. Any changes in the overall conditions of the structure bases observed during the 2012 inspection were noted.

Checklists summarizing the 2012 observations were used to facilitate the inspection. The following information about each structure base, where applicable, was included in the checklists (included in Appendix B):

- Baseplate: incorrect anchor bolt hole diameter, corrosion build-up, deformed or cracked
- Bolts: incorrect size, corroded or missing
- Washers: corroded, cupped or missing
- Nuts: corroded or missing
- Welds: cracked
- Concrete and grout: spalled or cracked
- Structural damage of aluminum members

A total of 201 structure bases (105 in Section I and 96 in Section II) were inspected. Some general observations from the inspection include:

- Little to no change was noted at the majority of the support bases inspected.
- The structure bases in Section I remain in poorer condition than those in Section II.
- The structure bases J1, R2, D1 and D3, which were repaired in early 2013, all appear to be in good condition.
- Several structures have been replaced or are in the process of being replaced, therefore the associated structure bases were not inspected, including H1-H4, N1 and N2 of Section I and M1-M3 and N4-N6 of Section II.

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4. Investigation Results

The 2012 rating system used to classify the severity of damage was once again applied to each structure base. The rating categories are as follows:

0. No corrosion product or damage to the pier
1. Minimal corrosion present OR minor concrete cracks
2. More than 6 mm but less than 15 mm of corrosion build-up OR corroded bolts OR cupped/missing washers OR deformed baseplate
3. More than 15 mm of corrosion build-up OR missing bolt/nut OR cracked baseplate/weld OR severe concrete crack
4. More than one missing bolt OR bolts passing through baseplate holes
5. Failure of pier or connections

The summary of the 2012 ratings and 2014 ratings can be found in Table 4-1.

Table 4-1: Summary of Structure Base Ratings

Rating Category	Number of Occurrences			
	Section I		Section II	
	2012	2014	2012	2014
5	1	0	0	0
4	4	2	0	0
3	23	22	3	3
2	52	53	50	53
1	30	24	46	40
0	1	4	3	0
No Rating*	12	18	10	16
Total	123	123	112	112

**No rating was assigned to structure bases no longer in use or modified to support steel structures*

4.1 Category 5

As identified above, a structure base falling into Category 5 would have experienced complete failure of the structure support. There are currently no Category 5 structure bases.

4.2 Category 4

A structure falling into Category 4 would have either more than one missing bolt or bolts passing through the holes in the baseplate. In 2012, this was observed in B1, J1, P2 and R2 of Section I. B1 and P2 are still missing two of four bolts (see Figure 4-1). J1 and R2 have since been repaired.

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Figure 4-1: B1, Section I – Category 4 Structure Base

4.3 Category 3

There are several Category 3 structure bases in Section I and three instances in Section II. The most common occurrence was a missing bolt/nut. In Section I, structure base D3 has since been repaired and structure base H1 has been removed. The condition is unchanged at the remaining structure bases that had this issue in 2012 (A4, C5, F2, J9, K1, K2, P1, R5, V1, X3 of Section I and H2, X1 of Section II).

The severe corrosion build-up, noted at J2, J7, J11, J12, R6, R11 and R12 of Section I in 2012, has not increased by any appreciable amount over the past two years. The cracks in the baseplates at J2 and J7 and the deformations in the baseplates at J11 and J12 also do not appear to have worsened. Figure 4-2 shows the current condition of structure base J7.

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Figure 4-2: J7, Section I – Category 3 Structure Base

The severe cracks in the concrete piers appear to have worsened slightly at S3 (see Figure 4-3 and Figure 4-4) and W2 (see Figure 4-5 and Figure 4-6) of Section I. The severe crack at R7 of Section II appears unchanged.

Figure 4-3: S3, Section I, 2012 – Category 3 Structure Base

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Figure 4-4: S3, Section I, 2014 – Category 3 Structure Base

Figure 4-5: W2, Section I, 2012 – Category 3 Structure Base

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Figure 4-6: W2, Section I, 2014 – Category 3 Structure Base

No rating change was applied to the remaining category 3 structure bases – O3 (incorrect baseplate hole diameter for anchorbolts and cupped washers) and U5 (structural damage to angle) in Section I.

The rating for structure base J1 has been reduced from 4 to 3. The cracked plate, cupped washers and corroded nuts were replaced and the cracked weld was repaired. However, the 20mm of corrosion build-up is still present between the bottom plate and the concrete, as seen in Figure 4-7.

Figure 4-7: J1, Section I – Category 3 Structure Base

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4.4 Categories 1&2

The rating of few structure bases increased from Category 1 to Category 2. These include J3, J4, J5, and Q5 of Section I and A8, C2, C4, R2 and R6 of Section II. J3, J4, J5 and Q5 have severely corroded nuts and washers, as seen in Figure 4-8. At A8, C2, C4 and R6 of Section II there are cracks down the middle of the piers (the condition at A8 is shown in Figure 4-9). R2 has cupped washers.

Figure 4-8: J4, Section I – Category 2 Structure Base

Figure 4-9: A8, Section II – Category 2 Structure Base

The issues present at the nine structure bases identified above were present in 2012. No significant worsening of the condition has occurred; however additional field observations

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merited an increase in rating. As documented in 2012, there is no immediate concern at any of the Category 2 structure bases, although the progression of damage should be monitored closely, particularly at the larger structures that are subject to higher loads.

All of the remaining bases still in use were classified as Category 1 structure bases, with minimal corrosion residue or Category 0 structure bases, where no corrosion or damage was observed.

4.5 Anchor Rod Tests

4.5.1 Hydraulic Wrench Removal

Hydraulic wrench removal tests were carried out on November 13, 2014 by Hydraulic Systems Ltd. On site were Mr. Jeff Snook, P.Eng. of Hatch, Mr. Matthew Leonard, P. Eng. of NL Hydro, and Mr. Grant Moore, of Hydraulic Systems.

Various diameters of anchor nuts were tested using the hydraulic wrench. Torque readings were measured during the removal in an attempt to alleviate any overstressing of the bolt. Typical torque values for anchor rods were used as a guide.

A summary of the results is presented in Table 4-2 below;

Table 4-2: Hydraulic Wrench Removal Results

Mark Number	Diameter (inches)	Measured Torque (ft-lbs)	Typical Torque Value (Approximate)	Comments
C1	5/8	150	60	Nut rotated
J3	5/8	350	60	Anchor rotated in concrete
F1	¾	550	160	Anchor rotated in concrete
B2	¾	550-600	160	Nut rotated
A7	1	625	240	No movement – stopped torquing at this value. Note that another anchor nut on the same pier without a washer was tested and rotated at 150ft-lbs. See discussion for comment
R1	1	625	240	No movement – stopped torquing at this value

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As can be seen from the table above, the torque values required to remove the nuts were excessive. In a couple of cases the anchor rod itself rotated within the concrete prior to the nut moving. This is most likely due to the prying of the baseplates on the anchor nuts, creating excessive frictional forces on the anchor threads. This is particularly evident with the nut on pier A7 which removed easily at 150 ft lbs. This nut did not have an accompanying washer and thus no such 'prying' forces were in effect. A similar nut on the same pier did not move at 625 ft lbs.

4.5.2 *Ultrasonic Thickness Measurements*

Ultrasonic thickness (UT) measurements were carried out by TEAM Industrial on various lengths of A36 anchor rods to determine the effectiveness of the readings in assessing anchor rod damage. The UT readings were found to be indeterminate beyond a length of 8-10 inches along the rod.

The anchor rods at most of the major structures are embedded up to 3' – 4' below top of concrete. Thus the UT readings would only be effective for the top portion of anchors, which in most cases is exposed and can be assessed visually.

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5. Recommendations

The condition of each base along with the type of structure it supports was considered when making recommendations on prioritizing repair work. As in 2012, Priority A structures bases should be addressed as soon as possible, Priority B structure bases should be repaired within the next 12 months, and Priority C structure bases should be repaired within the next 24 months.

5.1 Priority A

The list of Priority A structure bases closely matches the list presented in 2012. The structure bases that were in critical state in 2012 have been repaired, leaving 14 structures in this group. All category 3 and 4 structure bases that support bus, box and take-off structures should be addressed as soon as possible. As well, all remaining structure bases classified as category 4 should also have top priority. The list of these structure bases is provided in Table 5-1.

Table 5-1: Priority A Structure Bases

Section I		Section I
A4 B1 J1*, J2, J7, J11, J12	O3 P2 R6, R11, R12 W2	R7

**Repairs were made to J1 in 2013; however, significant corrosion is still present between the bottom plate and concrete pier.*

A map identifying each of these structure bases is provided in Appendix C.

5.2 Priority B

The list of Priority B structure bases is the same as in 2012 (H1 of Section I has been removed because it no longer exists). These structure bases are listed in Table 5-2.

Table 5-2: Priority B Structure Bases

Section I			Section II
C5 F2 J9	K1, K2 P1 R5 S3	U5 V1 X3	H2 X1

Very little deterioration was noted over the past two years with the Priority B structure bases; however it is still recommended to rehabilitate these structure bases within a year to ensure the severity of damage does not progress and lead to failure of the support system.

A map identifying each of these structure bases is provided in Appendix D.

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5.3 Priority C

All remaining structure bases should be in the lowest priority category. The structure bases at this priority level are not cause for immediate concern. As with Priority B structures, they should be inspected regularly to ensure the conditions do not worsen, and repairs should be made within two years.

5.4 Removal of Anchor Nuts

Torque values measured during removal of anchor nuts proved excessive; in most cases torquing was stopped prior to nut rotation in order to avoid potential damage to the anchor rods.

For future base plate repairs which require anchor nut removal, it is recommended that torque values be measured during nut removal to ensure values are not excessive. Excessive torquing on anchor bolts could damage the anchor rod steel or compromise the integrity of the bond with the concrete. In the event of excessive torque values, the nut should be cut for removal.

5.5 Ultrasonic Thickness Measurements

Ultrasonic thickness readings were found to be ineffective as a practicable means of below-concrete anchor rod inspection. Future anchor rod inspections will be limited to visual assessment of the above-concrete portion only.

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Appendix A
Legend

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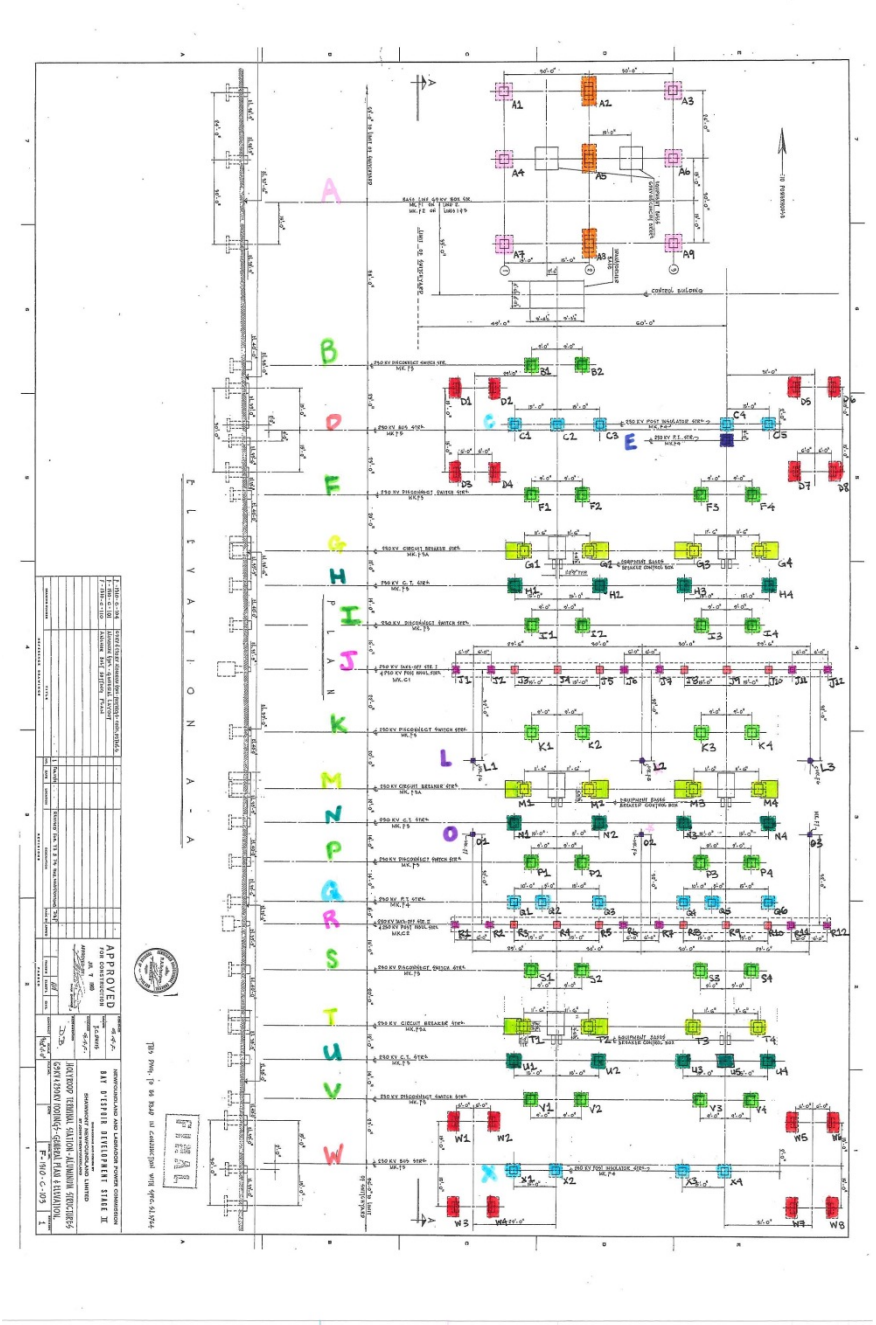

Appendix B
Checklists

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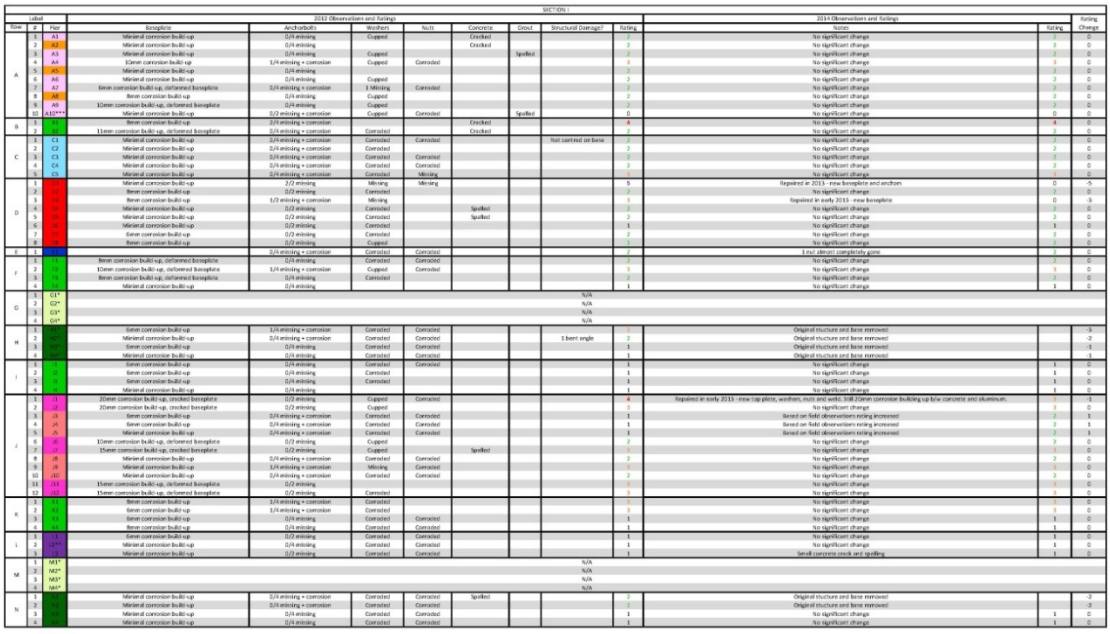
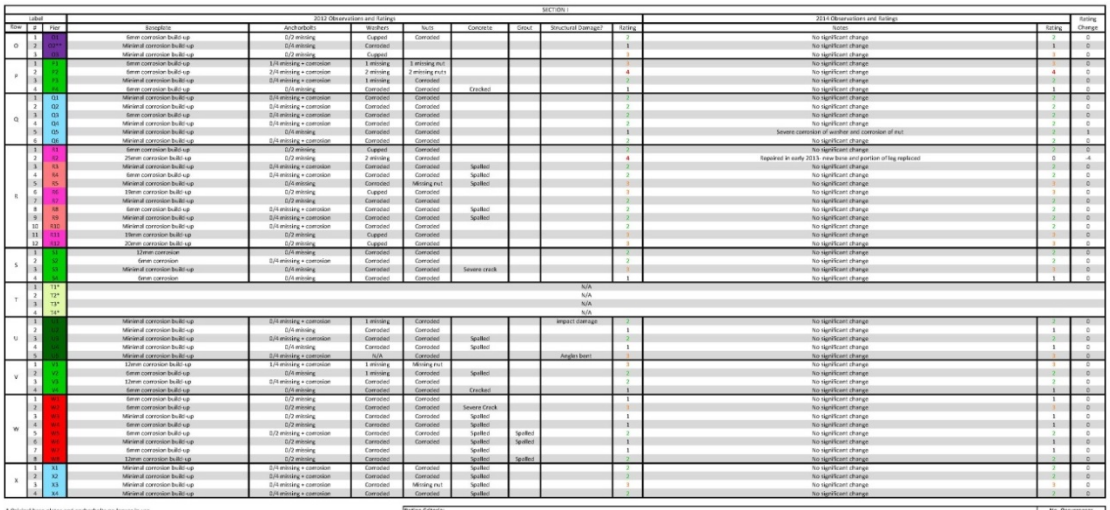


SECTION I

Row	Label #	Pier	2012 Observations and Ratings: Baseplate	Anchorbolt	Washers	Nuts	Concrete	Grout	Structural Damage?	Rating	2014 Observations and Ratings: Notes	Rating	Rating Change
A	1	A1	Minimal corrosion built-up	0/4 eroding	Cupped		Cracked			2	No significant change	2	0
	2	A2	Minimal corrosion built-up	0/4 eroding			Cracked			2	No significant change	2	0
	3	A3	Minimal corrosion built-up	0/4 eroding	Cupped			Spalled		3	No significant change	2	0
	4	A4	10mm corrosion built-up	1/4 eroding + corrosion	Cupped	Corroded				3	No significant change	3	0
	5	A5	Minimal corrosion built-up	0/4 eroding	Cupped					2	No significant change	2	0
	6	A6	Minimal corrosion built-up	0/4 eroding	Cupped					2	No significant change	2	0
	7	A7	6mm corrosion built-up, deformed baseplate	0/4 eroding + corrosion	1 Missing	Corroded				2	No significant change	2	0
	8	A8	8mm corrosion built-up	0/4 eroding	Cupped					2	No significant change	2	0
	9	A9	10mm corrosion built-up, deformed baseplate	0/4 eroding	Cupped					2	No significant change	2	0
	10	A10***	Minimal corrosion built-up	0/2 eroding + corrosion	Cupped	Corroded		Spalled		0	No significant change	0	0
B	1	B1	8mm corrosion built-up	2/4 eroding + corrosion			Cracked			4	No significant change	4	0
	2	B2	11mm corrosion built-up, deformed baseplate	0/4 eroding + corrosion	Corroded		Cracked			3	No significant change	3	0
C	1	C1	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded			Nut cantred on bolt	2	No significant change	2	0
	2	C2	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded					2	No significant change	2	0
	3	C3	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	4	C4	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	5	C5	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Missing				2	No significant change	2	0
D	1	D1	Minimal corrosion built-up	2/2 eroding	Missing	Missing				5	Repaired in 2013 - new baseplate and anchors	0	-5
	2	D2	8mm corrosion built-up	0/2 eroding	Corroded					2	No significant change	2	0
	3	D3	8mm corrosion built-up	1/2 eroding + corrosion	Missing					3	Repaired in early 2013 - new baseplate	0	-3
	4	D4	Minimal corrosion built-up	0/2 eroding	Corroded		Spalled			2	No significant change	2	0
	5	D5	Minimal corrosion built-up	0/2 eroding	Corroded		Spalled			2	No significant change	2	0
	6	D6	Minimal corrosion built-up	0/2 eroding	Corroded					1	No significant change	1	0
	7	D7	6mm corrosion built-up	0/2 eroding	Corroded					2	No significant change	2	0
	8	D8	8mm corrosion built-up	0/2 eroding	Cupped					2	No significant change	2	0
E	1	E1		0/4 eroding + corrosion	Corroded	Corroded				2	1 nut almost completely gone	2	0
F	1	F1	8mm corrosion built-up, deformed baseplate	0/4 eroding	Corroded	Corroded				2	No significant change	2	0
	2	F2	10mm corrosion built-up, deformed baseplate	1/4 eroding + corrosion	Cupped	Corroded				3	No significant change	3	0
	3	F3	8mm corrosion built-up, deformed baseplate	0/4 eroding	Corroded					2	No significant change	2	0
	4	F4	Minimal corrosion built-up	0/4 eroding						1	No significant change	1	0
G	1	G1*							N/A				
	2	G2*							N/A				
	3	G3*							N/A				
	4	G4*							N/A				
H	1	H1**	6mm corrosion built-up	1/4 eroding + corrosion	Corroded	Corroded				3	Original stucture and base removed		-3
	2	H2**	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded			1 bent angle	2	Original stucture and base removed		-2
	3	H3**	6mm corrosion built-up	0/4 eroding	Corroded	Corroded				1	Original stucture and base removed		-1
	4	H4**	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded				1	Original stucture and base removed		-1
I	1	I1	6mm corrosion built-up	0/4 eroding	Corroded	Corroded				1	No significant change	1	0
	2	I2	6mm corrosion built-up	0/4 eroding	Corroded					1	No significant change	1	0
	3	I3	6mm corrosion built-up	0/4 eroding	Corroded					1	No significant change	1	0
	4	I4	Minimal corrosion built-up	0/4 eroding						1	No significant change	1	0
J	1	J1	20mm corrosion built-up, cracked baseplate	0/2 eroding	Cupped	Corroded				4	Repaired in early 2013 - new top plate, washers, nuts and weld. Still 20mm corrosion building up b/w concrete and aluminum.	1	-3
	2	J2	20mm corrosion built-up, cracked baseplate	0/2 eroding	Cupped					3	No significant change	3	0
	3	J3	6mm corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				1	Based on field observations rating increased	2	1
	4	J4	6mm corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				1	Based on field observations rating increased	2	1
	5	J5	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				1	Based on field observations rating increased	2	1
	6	J6	10mm corrosion built-up, deformed baseplate	0/2 eroding	Cupped					2	No significant change	2	0
	7	J7	15mm corrosion built-up, cracked baseplate	0/2 eroding	Cupped		Spalled			3	No significant change	3	0
	8	J8	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	9	J9	Minimal corrosion built-up	1/4 eroding + corrosion	Missing	Corroded				3	No significant change	3	0
	10	J10	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	11	J11	15mm corrosion built-up, deformed baseplate	0/2 eroding						3	No significant change	3	0
	12	J12	15mm corrosion built-up, deformed baseplate	0/2 eroding	Corroded					3	No significant change	3	0
K	1	K1	8mm corrosion built-up	1/4 eroding + corrosion	Corroded					3	No significant change	3	0
	2	K2	6mm corrosion built-up	1/4 eroding + corrosion	Corroded					3	No significant change	3	0
	3	K3	6mm corrosion built-up	0/4 eroding	Corroded	Corroded				1	No significant change	1	0
	4	K4	8mm corrosion built-up	0/4 eroding	Corroded	Corroded				1	No significant change	1	0
L	1	L1	Minimal corrosion built-up	0/2 eroding	Corroded	Corroded				1	No significant change	1	0
	2	L2**	Minimal corrosion built-up	0/4 eroding	Corroded					1	No significant change	1	0
	3	L3**	Minimal corrosion built-up	0/2 eroding	Corroded	Corroded				1	Small concrete crack and spalling	1	0
M	1	M1*							N/A				
	2	M2*							N/A				
	3	M3*							N/A				
	4	M4*							N/A				
N	1	N1	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			3	Original stucture and base removed		-2
	2	N2	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	Original stucture and base removed		-2
	3	N3	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded				1	No significant change	1	0
	4	N4	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded				1	No significant change	1	0



SECTION I

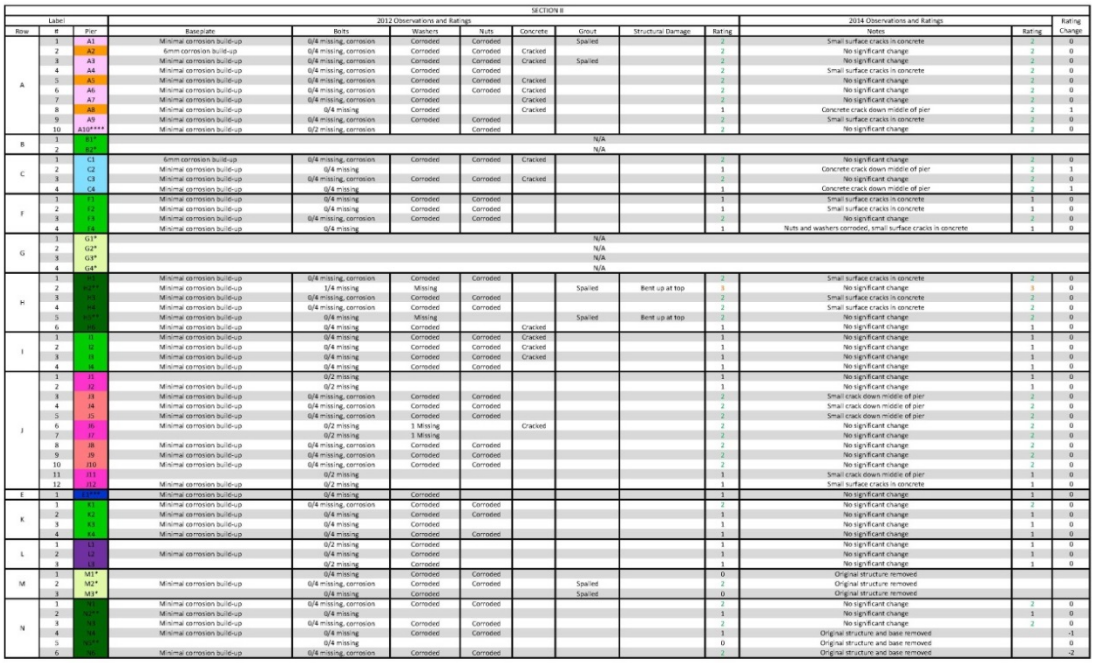
Row	Label #	Pier	2012 Observations and Ratings: Baseplate	Anchorbolt	Washers	Nuts	Concrete	Grout	Structural Damage?	Rating	2014 Observations and Ratings: Notes	Rating	Rating Change
O	1	O1	6mm corrosion built-up	0/2 eroding	Cupped	Corroded				2	No significant change	2	0
	2	O2**	Minimal corrosion built-up	0/4 eroding	Corroded					1	No significant change	1	0
	3	O3	Minimal corrosion built-up	0/2 eroding	Cupped					3	No significant change	3	0
P	1	P1	6mm corrosion built-up	1/4 eroding + corrosion	1 missing	1 missing nut				3	No significant change	3	0
	2	P2	6mm corrosion built-up	2/4 eroding + corrosion	2 missing	2 missing nuts				4	No significant change	4	0
	3	P3	Minimal corrosion built-up	1/4 eroding + corrosion	1 missing	Corroded				2	No significant change	2	0
	4	P4	6mm corrosion built-up	0/4 eroding	Corroded	Corroded	Cracked			1	No significant change	1	0
Q	1	Q1	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	2	Q2	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	3	Q3	6mm corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	4	Q4	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	5	Q5	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded				1	Severe corrosion of washer and corrosion of nut	2	1
	6	Q6	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
R	1	R1	6mm corrosion built-up	0/2 eroding	Cupped	Corroded				2	No significant change	2	0
	2	R2	25mm corrosion built-up	0/2 eroding	2 missing	Corroded				4	Repaired in early 2013 - new bone and portion of leg replaced	0	-4
	3	R3	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	4	R4	6mm corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	5	R5	Minimal corrosion built-up	0/4 eroding	Corroded	Missing nut	Spalled			1	No significant change	1	0
	6	R6	19mm corrosion built-up	0/2 eroding	Cupped	Corroded				3	No significant change	3	0
	7	R7	Minimal corrosion built-up	0/2 eroding	Corroded	Corroded				2	No significant change	2	0
	8	R8	6mm corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	9	R9	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	10	R10	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	11	R11	19mm corrosion built-up	0/2 eroding	Cupped	Corroded				3	No significant change	3	0
	12	R12	20mm corrosion built-up	0/2 eroding	Cupped	Corroded				3	No significant change	3	0
S	1	S1	12mm corrosion	0/4 eroding	Corroded	Corroded				2	No significant change	2	0
	2	S2	6mm corrosion	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	3	S3	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded	Severe crack			1	No significant change	1	0
	4	S4	6mm corrosion	0/4 eroding	Corroded	Corroded				1	No significant change	1	0
T	1	T1*							N/A				
	2	T2*							N/A				
	3	T3*							N/A				
	4	T4*							N/A				
U	1	U1	Minimal corrosion built-up	0/4 eroding + corrosion	1 missing	Corroded			Impact damage	2	No significant change	2	0
	2	U2	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded				1	No significant change	1	0
	3	U3	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	4	U4	Minimal corrosion built-up	0/4 eroding	Corroded	Corroded	Spalled			1	No significant change	1	0
	5	U5	Minimal corrosion built-up	0/4 eroding + corrosion	N/A	Corroded			Angles bent	3	No significant change	3	0
V	1	V1	12mm corrosion built-up	1/4 eroding + corrosion	1 missing	Missing nut				3	No significant change	3	0
	2	V2	6mm corrosion built-up	0/4 eroding	1 missing	Corroded	Spalled			2	No significant change	2	0
	3	V3	12mm corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded				2	No significant change	2	0
	4	V4	6mm corrosion built-up	0/4 eroding	Corroded	Corroded	Cracked			1	No significant change	1	0
W	1	W1	6mm corrosion built-up	0/2 eroding	Corroded	Corroded				1	No significant change	1	0
	2	W2	6mm corrosion built-up	0/2 eroding	Corroded	Corroded	Severe Crack			1	No significant change	1	0
	3	W3	Minimal corrosion built-up	0/2 eroding	Corroded	Corroded	Spalled			1	No significant change	1	0
	4	W4	6mm corrosion built-up	0/2 eroding	Corroded	Corroded	Spalled			1	No significant change	1	0
	5	W5	6mm corrosion built-up	0/2 eroding + corrosion	Corroded	Corroded	Spalled	Spalled		2	No significant change	2	0
	6	W6	Minimal corrosion built-up	0/2 eroding	Corroded	Corroded	Spalled	Spalled		1	No significant change	1	0
	7	W7	6mm corrosion built-up	0/2 eroding	Corroded		Spalled			1	No significant change	1	0
	8	W8	12mm corrosion built-up	0/2 eroding	Corroded		Spalled	Spalled		2	No significant change	2	0
X	1	X1	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	2	X2	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	3	X3	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Missing nut	Spalled			3	No significant change	3	0
	4	X4	Minimal corrosion built-up	0/4 eroding + corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0

* Original base plates and anchorbolts no longer in use

** Concrete reinforced at this footing with galvanized straps and increased pier size

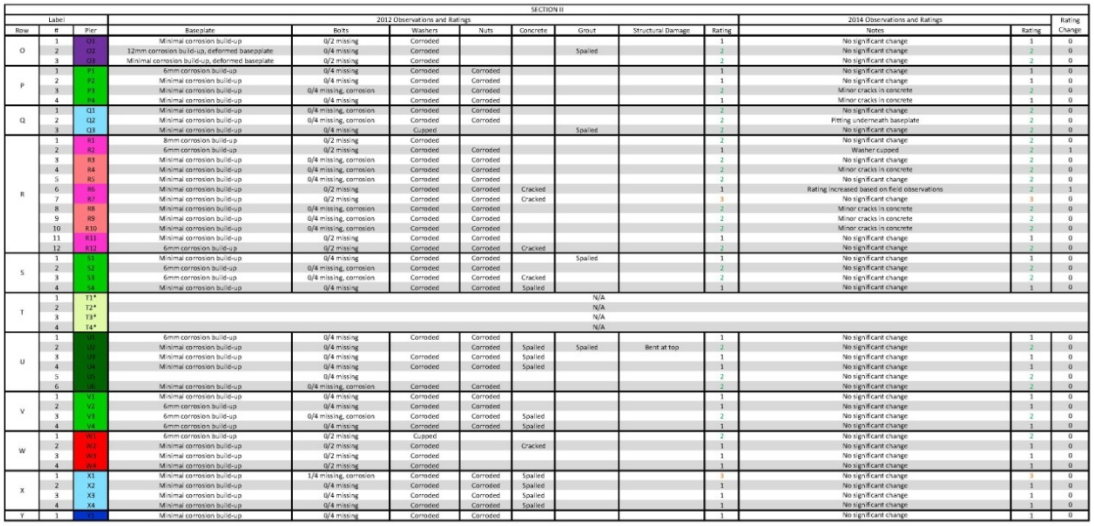
*** Not on strap

Rating Criteria:		No. Occurrences 2012	2014
0	no damage or corrosion	1	4
1	minimal corrosion	30	34
2	significant corrosion and/or corroded bolt(s) and/or cupped/missing washers and/or deformed baseplate	52	53
3	severe corrosion and/or missing bolt and/or nut and/or severe concrete crack and/or cracked baseplate and/or weld	23	22
4	more than one missing bolt and/or bolts pulled through baseplate	4	3
5	failure	1	0
		111	105



SECTION II

Row	Label #	Pier	2012 Observations and Ratings: Baseplate	Bolts	Washers	Nuts	Concrete	Grout	Structural Damage	Rating	2014 Observations and Ratings: Notes	Rating	Rating Change
A	1	A1	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded		Spalled		2	Small surface cracks in concrete	2	0
	2	A2	6mm corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked			2	No significant change	2	0
	3	A3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked	Spalled		2	No significant change	2	0
	4	A4	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small surface cracks in concrete	2	0
	5	A5	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked			2	No significant change	2	0
	6	A6	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked			2	No significant change	2	0
	7	A7	Minimal corrosion build-up	0/4 missing, corrosion	Corroded		Cracked			2	No significant change	2	0
	8	A8	Minimal corrosion build-up	0/4 missing	Corroded		Cracked			1	Concrete crack down middle of pier	2	1
	9	A9	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small surface cracks in concrete	2	0
	10	A10****	Minimal corrosion build-up	0/2 missing, corrosion		Corroded				2	No significant change	2	0
B	1	B1*						N/A					
	2	B2*						N/A					
C	1	C1	6mm corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked			2	No significant change	2	0
	2	C2	Minimal corrosion build-up	0/4 missing						1	Concrete crack down middle of pier	2	1
	3	C3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked			2	No significant change	2	0
	4	C4	Minimal corrosion build-up	0/4 missing						1	Concrete crack down middle of pier	2	1
F	1	F1	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	Small surface cracks in concrete	1	0
	2	F2	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	Small surface cracks in concrete	1	0
	3	F3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	4	F4	Minimal corrosion build-up	0/4 missing						1	Nuts and washers corroded, small surface cracks in concrete	1	0
G	1	G1*						N/A					
	2	G2*						N/A					
	3	G3*						N/A					
	4	G4*						N/A					
H	1	H1	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small surface cracks in concrete	2	0
	2	H2**	Minimal corrosion build-up	1/4 missing	Missing			Spalled	Bent up at top	3	No significant change	3	0
	3	H3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small surface cracks in concrete	2	0
	4	H4	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small surface cracks in concrete	2	0
	5	H5**	Minimal corrosion build-up	0/4 missing	Missing			Spalled	Bent up at top	2	No significant change	2	0
	6	H6	Minimal corrosion build-up	0/4 missing	Corroded		Cracked			1	No significant change	1	0
I	1	I1	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Cracked			1	No significant change	1	0
	2	I2	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Cracked			1	No significant change	1	0
	3	I3	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Cracked			1	No significant change	1	0
	4	I4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
J	1	J1		0/2 missing						1	No significant change	1	0
	2	J2	Minimal corrosion build-up	0/2 missing						1	No significant change	1	0
	3	J3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small crack down middle of pier	2	0
	4	J4	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small crack down middle of pier	2	0
	5	J5	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Small crack down middle of pier	2	0
	6	J6	Minimal corrosion build-up	0/2 missing	1 Missing		Cracked			2	No significant change	2	0
	7	J7		0/2 missing	1 Missing					2	No significant change	2	0
	8	J8	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	9	J9	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	10	J10	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	11	J11		0/2 missing						1	Small crack down middle of pier	1	0
	12	J12	Minimal corrosion build-up	0/2 missing						1	Small surface cracks in concrete	1	0
E	1	E1***	Minimal corrosion build-up	0/4 missing	Corroded					1	No significant change	1	0
K	1	K1	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	2	K2	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
	3	K3	Minimal corrosion build-up	0/4 missing	Corroded					1	No significant change	1	0
	4	K4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
L	1	L1		0/2 missing	Corroded					1	No significant change	1	0
	2	L2	Minimal corrosion build-up	0/4 missing	Corroded					1	No significant change	1	0
	3	L3		0/2 missing	Corroded					1	No significant change	1	0
M	1	M1*		0/4 missing	Corroded	Corroded				0	Original structure removed		
	2	M2*	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded		Spalled		2	Original structure removed		
	3	M3*		0/4 missing	Corroded			Spalled		0	Original structure removed		
N	1	N1	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	2	N2**	Minimal corrosion build-up	0/4 missing	Corroded					1	No significant change	1	0
	3	N3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	4	N4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	Original structure and base removed		-1
	5	N5*		0/4 missing						0	Original structure and base removed		0
	6	N6	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Original structure and base removed		-2



SECTION II

Row	Label #	Pier	2012 Observations and Ratings: Baseplate	Bolts	Washers	Nuts	Concrete	Grout	Structural Damage	Rating	2014 Observations and Ratings: Notes	Rating	Rating Change
O	1	O1	Minimal corrosion build-up	0/2 missing	Corroded					1	No significant change	1	0
	2	O2	12mm corrosion build-up, deformed baseplate	0/4 missing	Corroded			Spalled		2	No significant change	2	0
	3	O3	Minimal corrosion build-up, deformed baseplate	0/2 missing	Corroded					2	No significant change	2	0
P	1	P1	6mm corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
	2	P2	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
	3	P3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				1	Minor cracks in concrete	2	0
	4	P4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	Minor cracks in concrete	1	0
Q	1	Q1	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	2	Q2	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Fitting underneath baseplate	2	0
	3	Q3	Minimal corrosion build-up	0/4 missing	Cupped			Spalled		2	No significant change	2	0
R	1	R1	8mm corrosion build-up	0/2 missing	Corroded					2	No significant change	2	0
	2	R2	6mm corrosion build-up	0/2 missing	Corroded	Corroded				1	Washer cupped	2	1
	3	R3	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	4	R4	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Minor cracks in concrete	2	0
	5	R5	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	6	R6	Minimal corrosion build-up	0/2 missing	Corroded	Corroded	Cracked			1	Rating increased based on field observations	2	1
	7	R7	Minimal corrosion build-up	0/2 missing	Corroded	Corroded	Cracked			1	No significant change	1	0
	8	R8	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Minor cracks in concrete	2	0
	9	R9	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Minor cracks in concrete	2	0
	10	R10	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	Minor cracks in concrete	2	0
	11	R11	Minimal corrosion build-up	0/2 missing	Corroded	Corroded				1	No significant change	1	0
	12	R12	6mm corrosion build-up	0/2 missing	Corroded	Corroded	Cracked			2	No significant change	2	0
S	1	S1	Minimal corrosion build-up	0/4 missing	Corroded	Corroded		Spalled		1	No significant change	1	0
	2	S2	6mm corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
	3	S3	6mm corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Cracked			2	No significant change	2	0
	4	S4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
T	1	T1*						N/A					
	2	T2*						N/A					
	3	T3*						N/A					
	4	T4*						N/A					
U	1	U1	6mm corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
	2	U2	Minimal corrosion build-up	0/4 missing		Corroded	Spalled	Spalled	Bent at top	2	No significant change	2	0
	3	U3	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
	4	U4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
	5	U5		0/4 missing						2	No significant change	2	0
	6	U6	Minimal corrosion build-up	0/4 missing, corrosion	Corroded	Corroded				2	No significant change	2	0
V	1	V1	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
	2	V2	6mm corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0
	3	V3	6mm corrosion build-up	0/4 missing, corrosion	Corroded	Corroded	Spalled			2	No significant change	2	0
	4	V4	6mm corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
W	1	W1	6mm corrosion build-up	0/2 missing	Cupped					2	No significant change	2	0
	2	W2	Minimal corrosion build-up	0/2 missing	Corroded		Cracked			1	No significant change	1	0
	3	W3	Minimal corrosion build-up	0/2 missing	Corroded					1	No significant change	1	0
	4	W4	Minimal corrosion build-up	0/2 missing	Corroded					1	No significant change	1	0
X	1	X1	Minimal corrosion build-up	1/4 missing, corrosion	Corroded	Corroded	Spalled			3	No significant change	3	0
	2	X2	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
	3	X3	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
	4	X4	Minimal corrosion build-up	0/4 missing	Corroded	Corroded	Spalled			1	No significant change	1	0
Y	1	Y1	Minimal corrosion build-up	0/4 missing	Corroded	Corroded				1	No significant change	1	0

* Original base plates and anchorbolts no longer in use
** New piers (year of addition unknown)
*** Pier located between rows J and K for section 2
**** Not on map

Rating Criteria:		No. Occurrences 2012	2014
0	no damage or corrosion	3	0
1	minimal corrosion	46	40
2	significant corrosion and/or corroded bolts and/or cupped/missing washers and/or deformed baseplate	50	53
3	severe corrosion and/or missing bolt and/or nut and/or severe concrete crack and/or cracked baseplate and/or weld	3	3
4	more than one missing bolt and/or bolts pulled through baseplate	0	0
5	failure	0	0
		102	96

HATCH

Newfoundland and Labrador Hydro
Re-Assessment of Aluminum Structures
H347862

Appendix C
Map – Priority A Structure Bases

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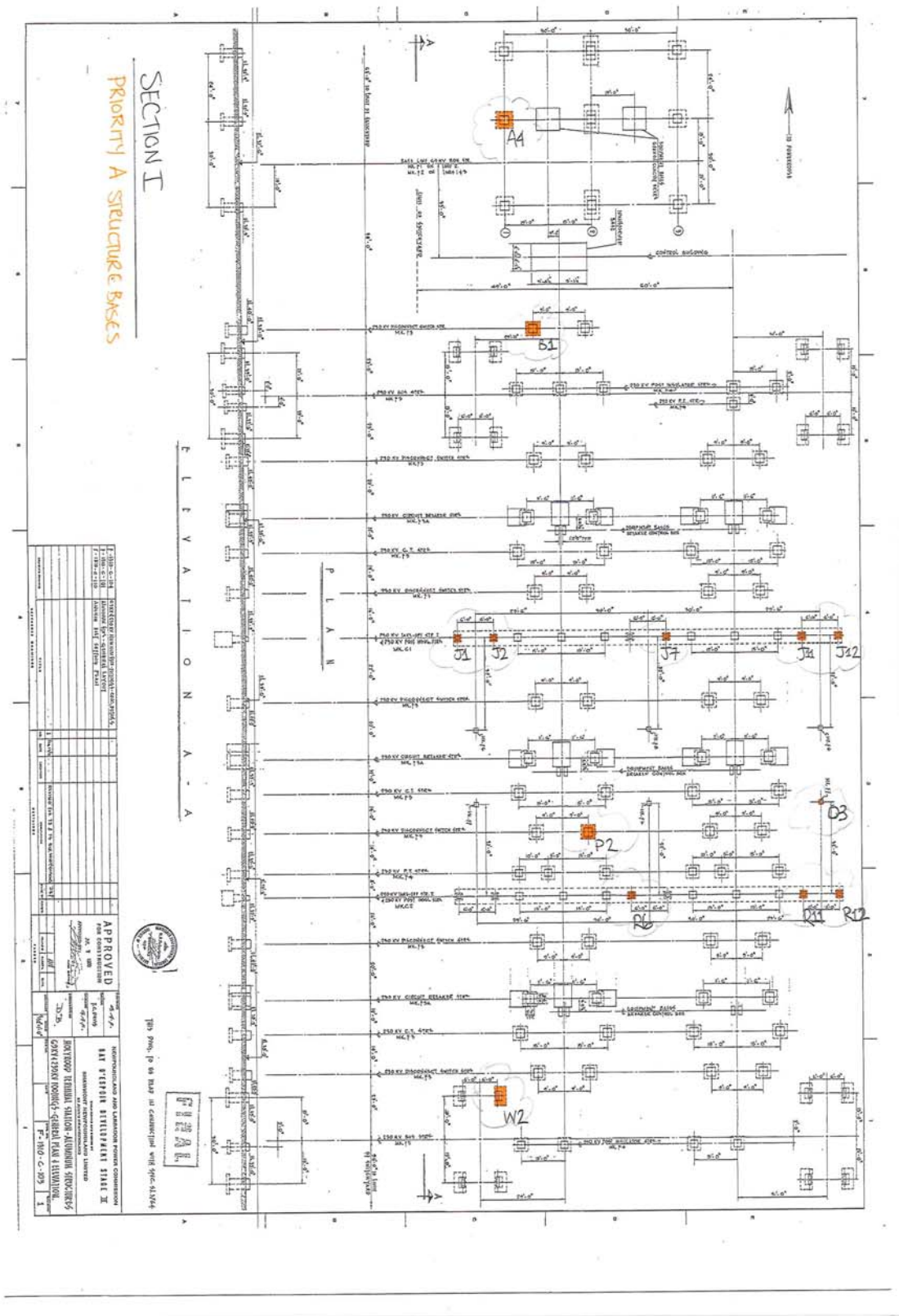
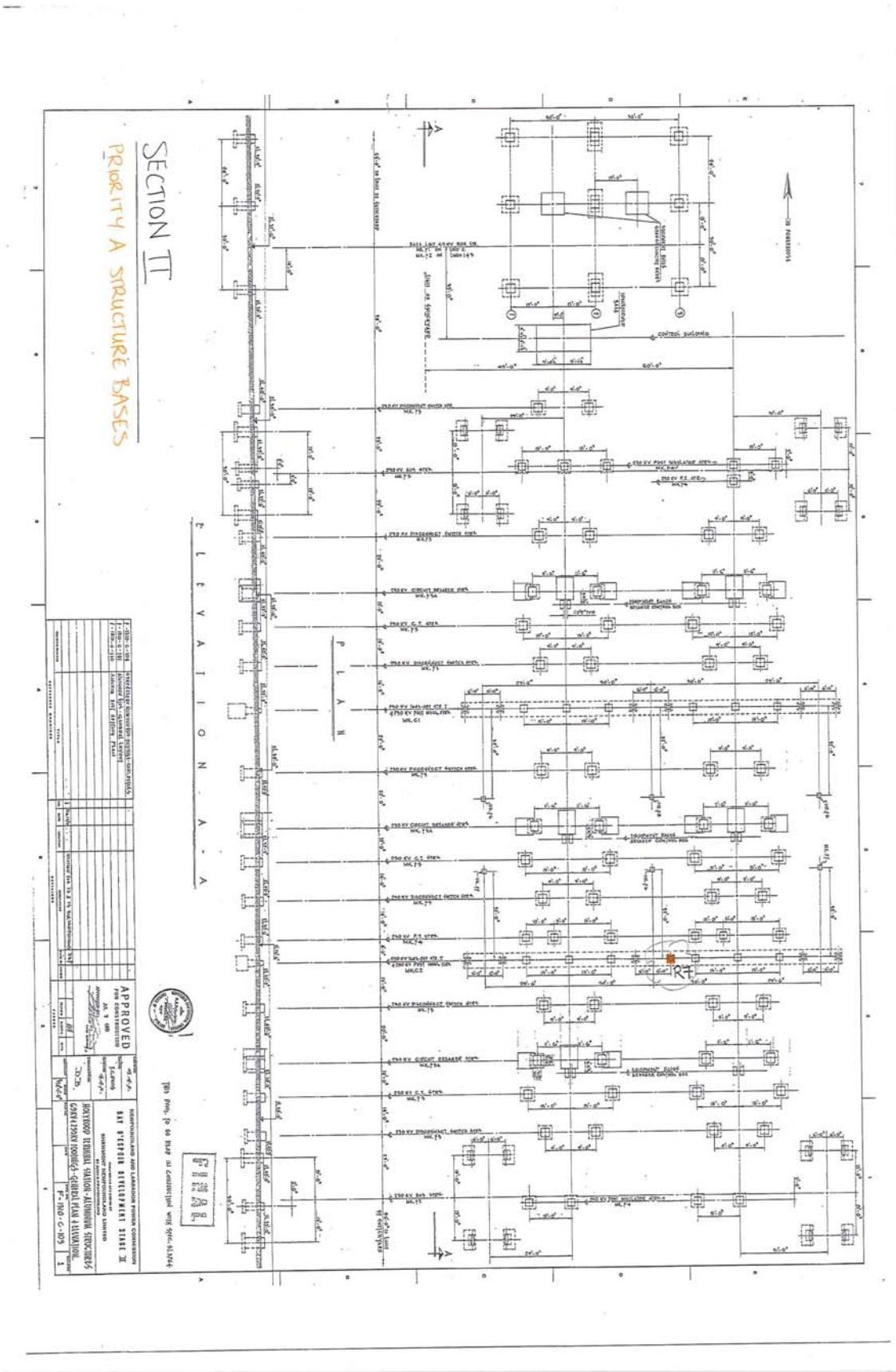

SECTION I
PRIORITY A STRUCTURE BASES
ELEVATION A - A
PLAN
A4
D1
J1
J2
J7
J11
J12
D3
P2
R1
R11
R12
W2
APPROVED


SECTION II
PRIORITY A STRUCTURE BASES
ELEVATION A-A
PLAN
APPROVED
FOR CONSTRUCTION
HIGHTOWER TERMINAL STATION-ALUMINUM STRUCTURES
GENERAL PLAN & ELEVATION
P-PRO-C-305

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Newfoundland and Labrador Hydro
Re-Assessment of Aluminum Structures
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Appendix D
Map – Priority B Structure Bases

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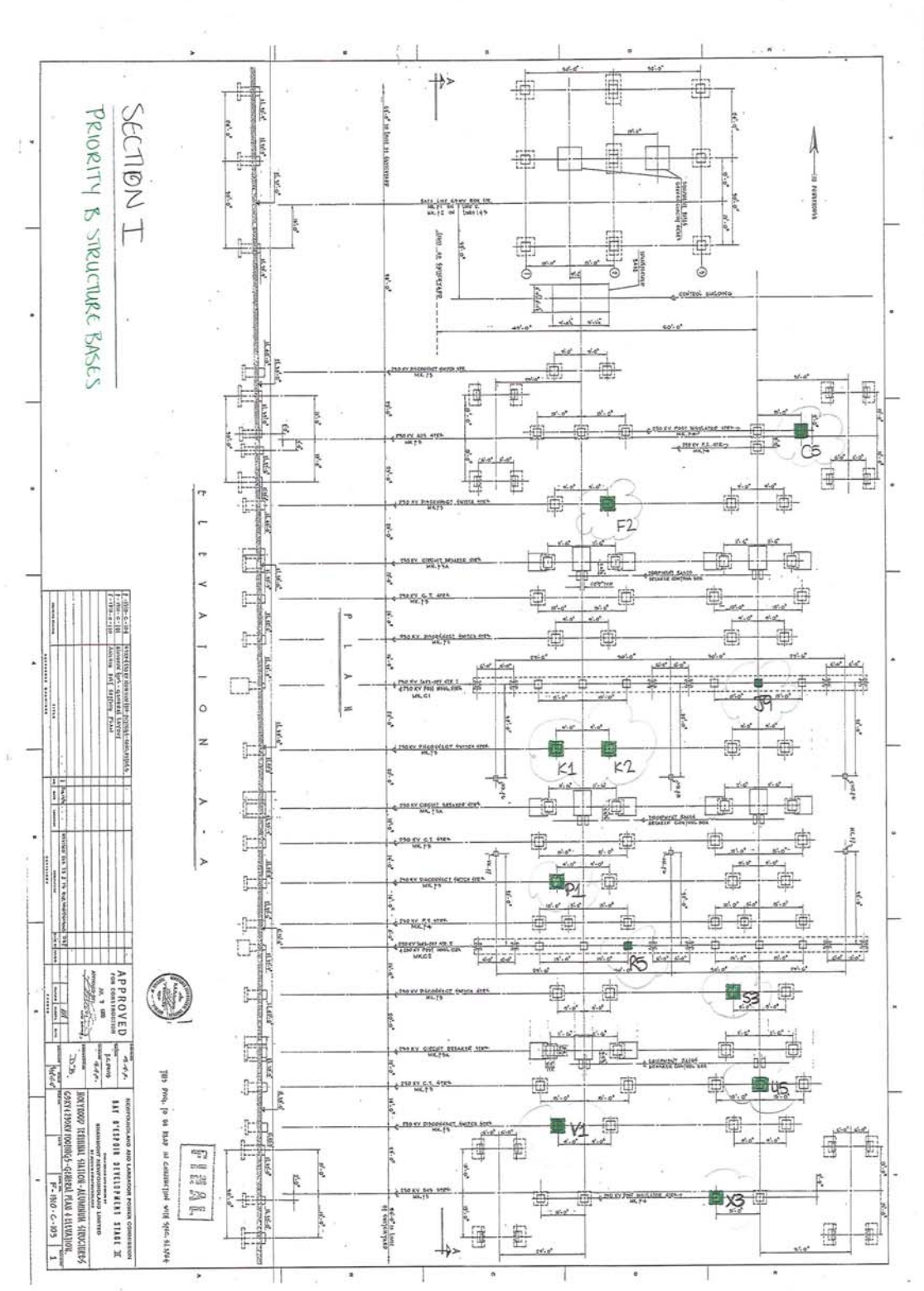
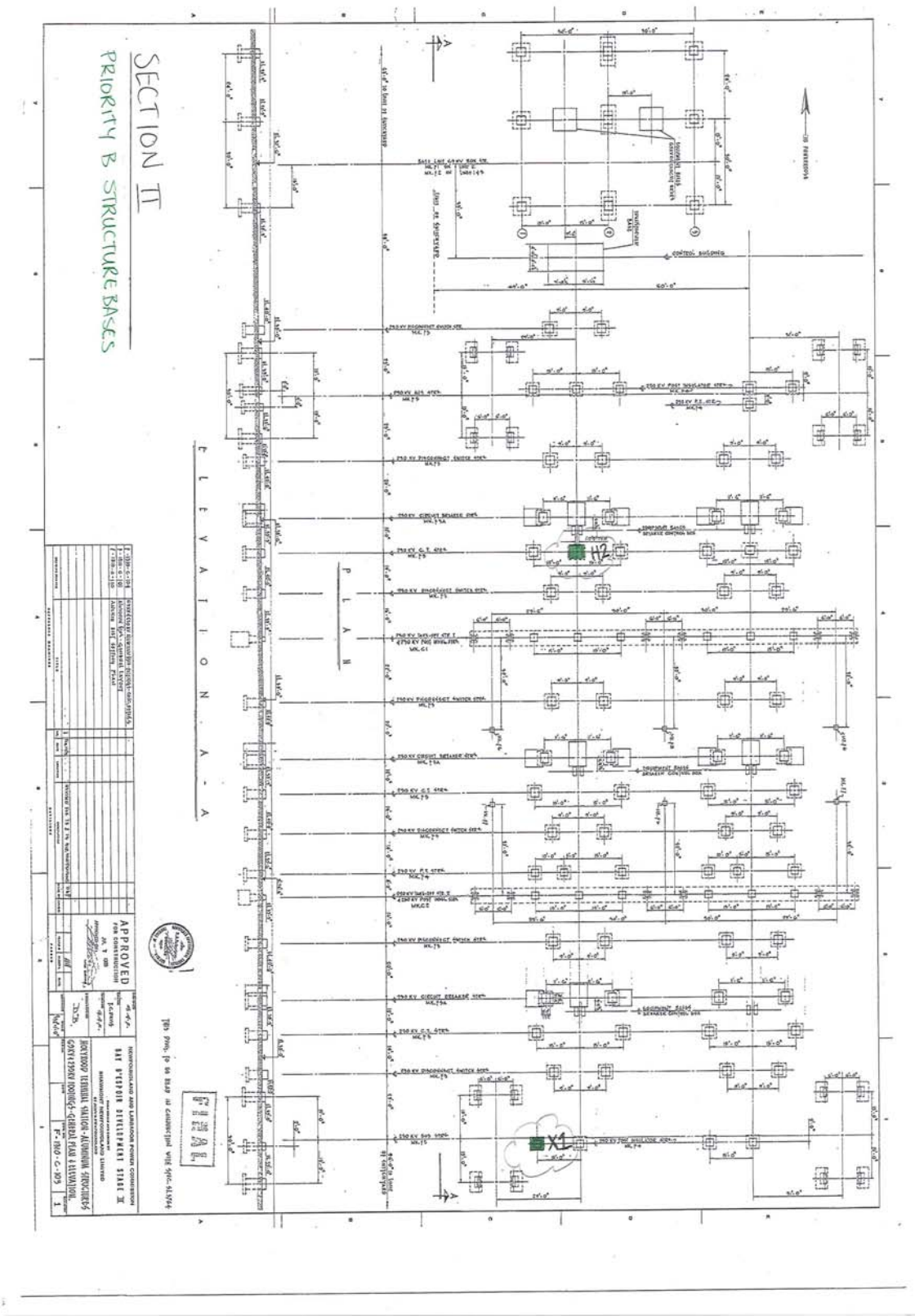

SECTION I
PRIORITY B STRUCTURE BASES
PLAN
ELEVATION A - A
F2
G6
J9
K1
K2
P1
R5
S3
U5
V1
X3


SECTION II
PRIORITY B STRUCTURE BASES
PLAN
ELEVATION A - A
H2
X1

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APPENDIX B

Newfoundland and Labrador Hydro

Holyrood Thermal Generation Plant

Sub-Station Aluminum Structure Inspection

Prepared for

Hatch

St. John's, NL

Consulting Services for

Newfoundland and Labrador Hydro Holyrood Thermal Generation Plant Sub Station Aluminum Structure Inspection

Prepared by:

Brouco Services Inc.
703 Cezanne Cres.
Orleans, ON
K4A 2A7

November 2012

INTRODUCTION

Brouco Services has been mandated by Mr. Greg Saunders of Hatch to perform an inspection of the aluminum footings of the power towers at the Holyrood thermal generation plant near Holyrood, NL. Heavy aluminum corrosion was observed on the bottom of the legs with the significantly more voluminous aluminum oxide corrosion products which created expansion forces that ultimatemely severed the lag bolts through stress corrosion cracking. This report presents our inspection results as performed in November 2012 by Rejean Brousseau, Ph.D.

RESULTS

Three main types of tower supports were observed during the inspection. These included the large main hydro tower supports mounted on a horizontal concrete surface, the large hydro tower supports on a sloped concrete surface, and miscellaneous small supports on a horizontal concrete surface. The tower legs were made with aluminum and the lag bolts were steel and nuts were galvanized steel.

Typically with aluminum, a protective dense oxide is formed on the surface in a neutral pH environment which provides excellent resistance to corrosion. However, concrete creates a high pH (alkaline) environment which breaks down the amphoteric aluminum oxide film causing additional corrosion and expansion forces generated by the accumulation of the aluminum corrosion products, i.e. a voluminous exfoliated aluminum oxide.

The worst areas were found on the large supports on the horizontal concrete surfaces (see photos #6-7). At these supports, extreme corrosion of the aluminum support had occurred where the aluminum was in contact with the concrete (see photos #1-4). The aluminum swelled and significantly expanded which caused the bolts to pop and crack. Since the concrete was flat, the water could accumulate and build up a high pH environment creating a corrosive environment. Under such tensile stress, the steel bolts became severed most likely by stress corrosion cracking. As a possible remedial measure we recommend lifting the supports, and removing the aluminum oxide under the support by

abrasive blasting. After the blasting, the surfaces between the concrete and aluminum support should be coated by epoxy injection using a coal tar epoxy such as Amercoat 78HB or equivalent. After completion, all bolts and nuts should be coated with an epoxy such as Amercoat 78HB or equivalent. A top plate under the nuts was observed to be cracked indicated high stressed at the bolting area, see photo #5.

The large supports on a sloped concrete surface had only mild corrosion. Since the concrete was sloped, the water did not accumulate and thus no pooling of corrosive higher pH water could result (see photos #8-9). Nevertheless, here we similarly recommend lifting the supports, and removing the aluminum oxide under the support by abrasive blasting. After the blasting, the surfaces between the concrete and aluminum support should be coated by epoxy injection using a coal tar epoxy such as Amercoat 78HB or equivalent. After completion, all bolts and nuts should be coated with an epoxy such as Amercoat 78HB or equivalent.

For the small supports on a horizontal concrete surface which had significant corrosion (see photos #10-12), bolting was found to be also damage at some locations due to the corrosion products generating expansionforces. Similarily, we recommend dismantling the supports, and removing the aluminum oxide under the support by abrasive blasting. After the blasting, the surfaces between the concrete and aluminum support should be coated along with the base component to be in contact with the concrete using a coal tar epoxy such as Amercoat 78HB or equivalent. After completion, all bolts and nuts should be coated with an epoxy such as Amercoat 78HB or equivalent.

CONCLUSIONS

The worse aluminum corrosion was observed at the bottom of the supports were the aluminum was in contact with a horizontal concrete surface. The aluminum corrosion caused significant expansion damaging the lab bolts. The high pH environment created by the concrete caused significant damage to the aluminum. We recommend removal of the aluminum oxide and application of the coal tar coating to prevent future corrosion.

APPENDIX – Photos

Photo #1: Corrosion expansion between leg and concrete

Photo #2: Corrosion expansion between leg and concrete

Photo #3: Corrosion expansion between leg and concrete

Photo #4: Corrosion expansion between leg and concrete

Photo #5: Cracked plate

Photo #6: Leg Support on Flat Concrete

Photo #7: Leg Support on Flat Concrete

Photo #8: Leg Support on Sloped Concrete

x

Photo #9: Leg Support on Sloped Concrete

Photo #10: Small Leg Support

Photo #11: Small Leg Support with Damaged Lag Bolt

Photo #12: Small Leg Support

Project Title: Replace Light Duty Mobile Equipment

Location: Various Sites

Category: General Properties - Transportation

Type: Other

Classification: Normal

Project Description:

This project proposes the replacement of 13 all-terrain vehicles, eight snowmobiles, and six light-duty trailers in accordance with the established replacement criteria as follows:

- Snowmobiles/All-Terrain Vehicles: Transmission Line crews 3-5 years
- Snowmobiles/All-Terrain Vehicles: Other 5-7 years
- Light-Duty Trailers 6-8 years
- Heavy-Duty Trailers 12-15 years

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	311.0	0.0	0.0	311.0
Labour	8.0	0.0	0.0	8.0
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.	13.0	0.0	0.0	13.0
Contingency	16.0	0.0	0.0	16.0
TOTAL	**348.0**	**0.0**	**0.0**	**348.0**

Justification:

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

Existing System:

Hydro operates a fleet of light-duty mobile equipment comprised of approximately 120 snowmobiles, 70 all-terrain vehicles, 120 trailers, ten forklifts and ten miscellaneous attachments (for example, lawn mowers, backhoes, salt spreaders, snow plows).

The mobile equipment fleet is strategically distributed across Hydro's operating areas throughout

the Province and is utilized on a daily basis to support staff engaged in the maintenance and repair of the electrical system.

The Transportation Department of Hydro maintains a close liaison with other Canadian Utilities through participation on the Canadian Utility Fleet Council and has established mobile equipment replacement guidelines, which consider the age and operating conditions for the equipment.

- Reliability Performance;
- Forecast Customer Growth; and
- Development of Alternatives.

Age of Equipment or System

Please see Appendix A for a detailed listing of the age of the assets being replaced under this system.

Major Work/or Upgrades

There have been no major upgrades since purchase.

Operating Experience:

Failure to replace units in accordance with the replacement policy will lead to increasing maintenance costs and less reliable vehicles. Employees maintain the electrical system 24 hours a day, seven days a week, and require dependable and safe vehicles for their work. As equipment ages, the equipment is at risk of increasing downtime, which could negatively affect response times for emergency outages or planned maintenance.

Legislative or Regulatory Requirements

Hydro complies with the environmental requirements stipulated in the following:

- Canadian Environmental Protection Act.
- Marine Spark-Ignition Engine and Off-Road Recreational Vehicle Emission Regulations.

Environmental Performance

Hydro complies with the Canadian Environmental Protection Act, Section 160, which applies to engines and vehicles of 2008 and later model years emissions requirements.

Industry Experience

Light-duty mobile equipment replacement scheduling varies dependent on location, exposure to harsh environmental conditions, and the severity of the service use for the equipment. The Transportation Department of Hydro maintains a close liaison with other Canadian Utilities through participation on the Canadian Utility Fleet Council and has established mobile equipment replacement guidelines, which consider the age and operating conditions for the equipment.

Vendor Recommendations

There are no vendor recommendations in regards to this project.

Maintenance or Support Arrangements

The Hydro fleet of light-duty mobile equipment is maintained by external service garages.

Maintenance History

Hydro does not maintain maintenance records for this type of equipment to this level of detail.

Historical Information

Table 1 provides a history of light-duty mobile equipment purchases.

Table 1: Mobile Equipment Less than $50,000

Year	Units Purchased					Budget ($000)	Actual ($000)
	All Terrain Vehicles	Snowmobiles	Trailers	Forklifts	Attachments		
2016B	13	8	6	0	0	348.0	
2015B	7	33	4	0	0	494.4	
2014	11	18	9	0	0	579.1	465.3
2013	14	21	3	1	0	476.5	448.2
2012	7	5	15	1	2	400.6	413.0
2011	14	12	29	1	0	757.0	582.5

Anticipated Useful life

The estimated service life for all-terrain vehicles, snowmobiles, trailers and attachments is as follows:

- Snowmobiles/All-Terrain Vehicles: Transmission Line crews 3-5 years
- Snowmobiles/All-Terrain Vehicles: Other 5-7 years
- Trailers: Light-Duty 6-8 years
- Trailers: Heavy-Duty 12-15 years

Evaluation of Alternatives

Purchase of this equipment is the only viable option to support the maintenance of Hydro's assets.

Conclusion:

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

Project Schedule:

This project is to be completed by December 31, 2016.

APPENDIX A

Replace Light-Duty Mobile Equipment – Various

Appendix A:

Type	Unit	Age at retire	Age	Condition
ATV	V7129	7.9	X	Rusty
ATV	V7234	6.2	X	
ATV	V7235	6.2	X	
ATV	V7236	6.2	X	
ATV	V7242	5.1	X	
ATV	V7098	9.1	X	
ATV	V7141	7.8	X	
ATV	V7245	5.1	X	
ATV	V7246	5.1	X	
ATV	V7247	5.1	X	
ATV	V7249	5.1	X	
ATV	V7251	5.1	X	
ATV	V7252	5.1	X	
Light Duty Trailers	V8856	15.0	X	
Light Duty Trailers	V8731	15.8	X	
Light Duty Trailers	V8889	7.6	X	
Light Duty Trailers	V8919	5.8	X	
Light Duty Trailers	V8890	6.6	X	
Light Duty Trailers	V8806	20.2	X	
Snowmobile	V7155	7.7	X	
Snowmobile	V7156	7.7	X	
Snowmobile	V7160	7.7	X	
Snowmobile	V7173	7.4	X	
Snowmobile	V7176	7.4	X	
Snowmobile	V7178	7.4	X	
Snowmobile	V7227	6.2	X	
Snowmobile	V7258	4.7	X	

Project Title: Upgrade Terminal Station Equipment Foundations

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: Pooled

Classification: Normal

Project Description:

This project is the third year of a multi-year program to upgrade the concrete foundations at Hydro's terminal stations. Work includes:

- the installation of bracing, required to temporarily support existing electrical equipment to facilitate the foundation repairs;
- removal and stockpile, for reuse, of existing yard gravel;
- hand excavation around concrete foundation;
- refurbishment of concrete pier, backfilling of structure; and
- the reinstatement of gravel topping.

Given the vast number of foundations at terminal stations within its system, Hydro recognized the need to establish a focused approach for the implementation of the foundation upgrade program. This approach will target the completion of foundation upgrades at all terminal stations located within defined geographical areas. It is believed that the adoption of such an approach will result in reduced construction costs, thus, maximizing return on the investment. For 2016, the upgrades will be a continuation of the 2015 proposal, with the focus remaining on Hydro's six 230 kV terminal stations, located on the Avalon Peninsula. These stations include Sunnyside, Come By Chance, Western Avalon, Holyrood, Hardwoods and Oxen Pond.

A follow-up inspection of the foundations, contained in the six stations, was completed in the spring of 2015. This inspection served to re-evaluate the foundations at Sunnyside, Come By Chance and Western Avalon, which were previously inspected in 2014. The inspection findings were used to finalize the selection of foundations to undergo repairs in 2015 as well as forecast structure repairs to be completed in future years (see Appendix A).

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

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	101.0	0.0	0.0	101.0
Consultant	10.0	0.0	0.0	10.0
Contract Work	130.3	0.0	0.0	130.3
Other Direct Costs	9.7	0.0	0.0	9.7
Interest and Escalation	18.8	0.0	0.0	18.8
Contingency	50.2	0.0	0.0	50.2
TOTAL	**319.9**	**0.0**	**0.0**	**319.9**

Justification:

The concrete foundations have deteriorated to the point at which upgrades are required. These foundations support high voltage electrical equipment which is a key component of the Island Interconnected System. Reliable operation of the high voltage equipment is critical to ensure the delivery of safe, reliable power to Hydro's customers. To ensure the equipment is able to perform as originally designed, upgrades to the foundations must be completed, providing a secure and stable base for the electrical equipment. Failure to complete the necessary foundation upgrades could result in a catastrophic failure of structures causing outages or, if people are in terminal stations, personal injury.

Existing System:

The majority of Hydro's terminal stations were constructed in late 1960s and early 1970s. The reinforced concrete foundations formed a part of the original terminal station construction and are now in excess of 40 years of age. These structures have not received any major work or upgrades since their original construction and are showing the signs of deterioration (see Appendix B).

Operating Experience:

The reinforced concrete foundations are utilized to support high voltage equipment in Hydro's terminal station yards. The majority of these structures formed part of the original station construction and are in excess of forty years of age. A significant number of the structures have deteriorated throughout the years, primarily as a result of repeated exposure to the forces generated during the freeze/thaw cycle.

These foundations support high voltage equipment such as circuit breakers, disconnect switches,

instrument transformers and post insulators. The continuous operation of this equipment is required to maintain power supply to the Island Interconnected System.

Maintenance or Support Arrangements

Maintenance of terminal station infrastructure is completed by Hydro Operations personnel. Major upgrades and repair work is typically completed by external contractors.

Maintenance History

The maintenance history for the reinforced concrete foundations is not readily available. Individual concrete foundations are not assigned an asset number. They are grouped under the asset number assigned to the piece of electrical equipment they support. Consequently, any maintenance completed on the concrete foundations would have been tracked under the equipment asset, making it difficult to isolate the maintenance history for each respective foundation.

Historical Information

Table 2 details the costs associated with foundation upgrades projects within the past five years.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit ($000)
2015B	302.3	-	-	-
2014	197.9	105.8	6	17.6

Anticipated Useful Life

The anticipated useful life for a concrete foundation ranges from 45 to 50 years.

Conclusion:

The foundations requiring upgrades under this program are in excess of 40 years of age. Throughout their service life, repeated exposure to damaging freeze/thaw cycles, weathering and age have resulted in their deterioration.

The completion of the proposed upgrades will extend the service life of the foundations, ensuring their continued ability to perform as originally designed.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Project start-up, scheduling, risk management	February 2016	February 2016
Design	Site visit and preparation of tender package	April 2016	May 2016
Procurement	Tender and award upgrades contract	May 2016	June 2016
Construction	Completion of concrete foundation upgrades	July 2016	September 2016
Commissioning	Final inspection and acceptance	-	September 2016
Closeout	Certificate of completion and asset assignment	-	October 2016

APPENDIX A

Equipment Foundation Upgrade Plan

STATION	UNIT ID	Equipment on Foundation	Installation Year	# of Piers Requiring Upgrades	Planned Repair
Sunnyside	L12G	Disconnect Switch	1967	4	2015
Sunnyside	B2L12-1	Disconnect Switch	1967	2	2015
Sunnyside	MID SPAN	Bus Structure	1967	1	2015
Sunnyside	L19L100-1	Disconnect Switch	1967	2	2015
Sunnyside	P.I. #1	Post Insulator	1967	1	2015
Sunnyside	T-O#1	Take-Off Structure	1967	2	2015
Sunnyside	T-O#2	Take-Off Structure	1967		2015
Western Avalon	B1T2	Disconnect Switch	1966	3	2015
Western Avalon	T-O#1	Take-Off Structure	1966	4	2015
Western Avalon	B1L37	Circuit Breaker	1966	4	2015
Western Avalon	P.I. #2	Post Insulator	1966	1	2015
Western Avalon	T-O #3	Take-Off Structure	1966	4	2015
Western Avalon	L03L17	Circuit Breaker	1966	1	2015
Sunnyside	P.I. Support	Post Insulator	1967	3	2016
Sunnyside	P.I. #2	Post Insulator	1967	1	2016
Western Avalon	B3T4	Disconnect Switch	1966	1	2016
Western Avalon	P.I. #1	Post Insulator	1966	1	2016
Western Avalon	B1L08-1	Disconnect Switch	1966	4	2016
Western Avalon	B1L08-2	Disconnect Switch	1966	3	2016
Western Avalon	B1L37-2	Disconnect Switch	1966	3	2016
Western Avalon	B1L37-1	Disconnect Switch	1966	1	2016
Western Avalon	P.I. #3	Post Insulator	1966	1	2016
Western Avalon	B1L17	Circuit Breaker	1966	1	2016
Western Avalon	L03L17-1	Disconnect Switch	1966	3	2016
Western Avalon	L03L17-2	Disconnect Switch	1966	1	2016
Hardwoods	T-O#1	Take-Off Structure	1967	1	2017
Oxen Pond	-	Bus Structure	1966	1	2017
Oxen Pond	P.I. #1	Post Insulator	1966	1	2017
Oxen Pond	B1T2	Circuit Breaker	1966	1	2017
Oxen Pond	P.I. #2	Post Insulator	1966	1	2017
Oxen Pond	P.I. #3	Post Insulator	1966	1	2017
Oxen Pond	P.I. #4	Post Insulator	1966	1	2017
Oxen Pond	T-O #1	Take-Off Structure	1966	2	2017

APPENDIX B

Foundation Photographs

Figure 1: Sunnyside L12G Disconnect Switch Foundation

Figure 2: Sunnyside P.I. #1 Post Insulator Foundation

Figure 3: Sunnyside L19L100-1 Disconnect Switch Foundation

Figure 4: Western Avalon B1L37 Circuit Breaker Foundation

Figure 5: Western Avalon Post Insulator Foundation

Project Title: Purchase Excavator

Location: Bay d'Espoir

Category: General Properties - Transportation

Type: Other

Classification: Normal

Project Description:

The scope of this work is to replace V7657, a 1988 bulldozer located in Bay d'Espoir, with an excavator which is more suitable to the type of work historically done by the bulldozer. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	280.0	0.0	0.0	280.0
Labour	3.0	0.0	0.0	3.0
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
Interest and Escalation	12.7	0.0	0.0	12.7
Contingency	14.3	0.0	0.0	14.3
TOTAL	**312.0**	**0.0**	**0.0**	**312.0**

Justification:

The project provides for the replacement of a bulldozer due to it age and condition with an excavator, which is more suitable for road and dyke maintenance because it is capable of ditch clearing, road grading and dyke rebuilding. Heavy equipment is an integral part of the maintenance crew equipment and is utilized extensively for road and dyke maintenance.

Technological improvements in modern equipment design have reduced the noise and heat levels in the cab compared to the pre 2000 model year equipment. Safety improvements include interlocks and holding valves to prevent unsafe operation of the newer units. Operating and maintenance costs were considered for both alternatives in the cost benefit analysis.

Existing System:

The bulldozer is 28 years old.

Operating Experience:

Bulldozers have an average life expectancy which ranges from 15 to 20 years, dependent on location and usage. This unit will be 28 years old at replacement. This unit is utilized extensively for road and dyke maintenance.

Technological improvements in 2000 and newer equipment design have reduced the noise and heat levels in the cab. Safety improvements include interlocks on the doors to prevent operation of the unit with the doors open and an automatic braking system.

Reliability Performance

Because of its age, the unit is no longer reliable and parts availability is limited.

Safety Performance

The equipment is required to maintain dykes and roads for public safety. Dyke maintenance is critical to prevent flooding caused by dyke washouts. Road maintenance is required to permit all weather access to all sites on the system.

Environmental Performance

Newer equipment fall within the Federal emission reduction requirements. This bulldozer does not meet current tier 4 emission standards.

Industry Experience

Heavy equipment is a standard component of Hydro's maintenance fleet which has to maintain dykes and access roads to all generating plants. The replacement criteria across the Canadian Utility Industry varies dependent on location, exposure to harsh environmental conditions and the severity of the service hours for the equipment. While some variances exist, it is generally the case that this type equipment is replaced in a 15–20 year time frame dependent on its functionality and condition. The criterion utilized by Hydro is to consider units which are 15 years old, then evaluate maintenance costs and technological issues. Units which meet the age requirement and warrant replacement are proposed to be replaced.

Vendor Recommendations

There are no vendor recommendations for this equipment.

Maintenance or Support Arrangements

The Hydro fleet of heavy tracked vehicles is primarily maintained by in-house mechanical maintenance personnel. Original equipment manufacturers repair facilities are utilized when the required maintenance is beyond the scope of our in-house expertise or specialized tooling is not available to complete repairs.

Maintenance History

The five-year maintenance history for the Bulldozer, Unit No. 7657, is shown in Table 3.

Table 3: Five-Year Maintenance History

Year	Preventive Maintenance ($000)	Corrective Maintenance ($000)	Total Maintenance ($000)
2014	0.2	1.5	1.7
2013	4.6	0.7	5.3
2012	0.5	2.9	3.4
2011	2.3	1.3	3.6
2010	1.0	1.0	2.0

Historical Information

Historical information is not applicable in this instance as this is a stand alone proposal to replace a unit that has been in service for 28 years.

Anticipated Useful Life

The anticipated useful life of this type of equipment is 15 to 20 years.

Development of Alternatives

This equipment is essential to dyke and road maintenance and there are two alternatives, rebuild the bulldozer or purchase an excavator.

Evaluation of Alternatives

A cost benefit analysis was completed which shows it is more beneficial to purchase an excavator which is more functional for ditch, dyke and road maintenance when compared to a bulldozer. The estimated cost to rebuild the bulldozer is $248,000, which does not include any unforeseen repairs on components not visible to the repair shop. Rebuilding the unit should extend the life of the unit five years before we encounter any extensive repairs provided there are no hidden damages.

The purchase of a new excavator complete with attachments for ditch, dyke and road work is estimated to cost $312,000. This unit should have a life span of more than 15 years and would be more reliable than the 28 year old bulldozer. The added flexibility of the excavator will increase productivity of the crew while performing maintenance on roads and dykes. Using a local contractor is not an option because there is only one contractor in the area, meaning this contractor cannot be relied upon to respond in emergency or urgent conditions.

Economic Analysis

Table 2 shows the results of the cost benefit analysis.

Table 2: Cost Benefit Analysis Results

Replace Bulldozer Unit No. 7657		
Alternative Comparison *Cumulative Net Present Value* *To The Year* **2015**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Purchase New Unit	269,391	0
Rebuild Unit	429,929	160,538

As can be seen from Table 2, the purchase option is the least cost alternative. By purchasing the new excavator, Hydro will realize a cost savings of $160,538 over the fifteen year period to 2030.

Conclusion:

Failure to replace this unit could lead to equipment failure or even personal injury because of the reliability of the unit. Dyke and road maintenance is critical for reliable generation and access to all our sites. By replacing the bulldozer with an excavator we achieve more flexibility and productivity in our regular maintenance of dykes and roads. The excavator is much more adaptable for tasks like ditching and dyke repair when compared to the bulldozer. The excavator is much more economical to purchase and operate when compared to the bulldozer.

Project Title: Upgrade Data Alarm Systems

Location: Stony Brook

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project is required to address station data alarm management enhancements that were deemed necessary following the investigation of the January 2014 outages. Action was taken to identify key priority alarms and an internal report was generated to assess enhancements at five major 230 kV terminal stations. This is intended to provide more detail to the Energy Control Center (ECC) operator and local responder at site when problems occur.

The identification of key priority alarms led to the determination that various additional local and supervisory alarms were required. This will require certain alarm groupings to be separated at the local annunciator in the terminal station and alarm points to be added to both the local annunciator and to the supervisory alarms to the ECC. Alarms provided to the ECC operator are designated as Sequence of Event (SOE) type and are time stamped to a resolution of 1 millisecond in order to align events across the system. The time stamping process is inherent to the equipment and communications protocol used by Hydro.

Historically, the grouping of some alarms has been done locally to minimize the number of indication points sent to the Energy Management System, which is the front-end data handling infrastructure for the ECC. The progress of technology has allowed for more data to be sent to the EMS and subsequent grouping done at a sub-level to the ECC operator. This allows for a top layer of general alarms to be presented to the operator and a secondary level of indications, widely known as Sequence of Events (SOE) points, which can be availed of for further diagnostic purposes.

The alarm reporting structure was evaluated at Stony Brook, a prominent 230kV terminal station, with the intent to reasonably increase the level of alarm detail both locally and to ECC to provide a more comprehensive view of a problem or outage. A report was developed to identify key priority alarms which would provide optimum detail for use in both responding to an event and conducting subsequent diagnostics. This report has established a standard set of alarms definitions which could be applied to other Hydro terminal stations. The report continued to build on the analysis of alarm

structure at Stony Brook and applied the template to four other major Hydro terminal stations.

This budget proposal addresses the development cost to apply alarm enhancements at Stony Brook terminal station.

Two issues were identified during a site visit to assess alarm enhancements:

- The existing supervisory junction box is full and there is no other wall space to mount a second box therefore additional supervisory alarms will have to be collected by some other means; and
- The local annunciator does not have the capacity to accommodate the additional alarms.

A SEL-2240 automation controller by Schweitzer Engineering Labs was considered for installation in a new cabinet to collect all additional local alarms and additional supervisory alarms. In addition, a remote data collection extension of the controller will be installed in the annunciator panel to collect all existing alarms. This will replace the local annunciator and eliminate the need for a second supervisory junction box. The automation controller will serve as both the local annunciator and source of new supervisory indications. The automation controller will provide time stamped alarms to the ECC by way of a communications connection to the Remote Terminal Unit (RTU). This also eliminates the need for cables for individual alarm to the supervisory junction box and further to the RTU hardware. An automation controller provides for expansion far above that which could be accommodated by a local annunciator and supervisory junction box. For instance, if one were to configure the proposed automation controller as digital inputs only and maximize the number of inputs, it would provide for 1296 inputs.

The budget for alarm management enhancements to be made at Stony Brook terminal station is provided in Table 1.

Table 1: Project Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	27.0	1.0	0.0	28.0
Labour	41.0	160.0	0.0	201.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.5	3.5	0.0	5.0
Interest and Escalation	4.9	22.8	0.0	27.7
Contingency	0.0	46.8	0.0	46.8
TOTAL	**74.4**	**234.1**	**0.0**	**308.5**

Justification:

Following the outages in January 2014, Hydro was requested to file a report with the Board of Commissioners of Public Utilities (the Board) related to Alarms, Event Recording Devices and Digital Relays. In report prepared by Hydro, a plan was provided to identify key priority alarms, which included updating alarms at Stony Brook terminal station. In its report to the Board report, it was indicated that although the existing state of alarms did not contribute to power disruptions, it was determined by Hydro that improvements can be made in the level of detail of alarms. Further investigation followed to identify key priority alarms that should be provided to the ECC.

An internal study was conducted by Hydro to identify required increases to alarm detail for five 230 kV terminal stations to the ECC. Stony Brook, Holyrood, Sunnyside, Oxen Pond, and Massey Drive were assessed. Stony Brook was reviewed in detail in order to develop the budget proposal. The remaining stations require more time to evaluate to determine the number of additional points. The conclusion of the study was that 96 additional SOE alarms and 47 local annunciator points are required to be provided to the ECC operators and locally annunciated alarms at Stony Brook terminal station. Stony Brook terminal station was selected for which to prepare a budget for the necessary modifications as it is a centrally located station and has the greatest number of changes.

Existing System:

Stony Brook terminal station is a centrally located 230 kV Hydro terminal station on the island by the former paper mill in Grand Falls-Windsor. Two 230 kV transmission lines terminate from Bay d'Espoir and two 230 kV lines terminate from Buchans terminal station. Other lower voltage transmission lines feed Grand Falls, South Brook, Bishops Fall and Glenwood. Figure 1 shows a portion of the panels at Stony Brook terminal station.

Figure 1: Stony Brook Terminal Station Control Room (left side)

When system events occur, alarms have historically been reported to the Energy Control Center by way of wired interconnections through the supervisory junction box. The supervisory junction box is the demarcation point between the Remote Terminal Unit (RTU), which interfaces the communication from the Energy Control Center to the terminal station, and the Protection and Control infrastructure of the terminal station. The supervisory junction box has three main areas of isolation: Control, Indication/Alarms and Telemetry. There are presently 114 alarms and indication points reported to the Energy Management System. The existing supervisory junction box at Stony Brook terminal station is shown in Figure 2.

Figure 2: Supervisory Junction Box

Local reporting of alarms is handled by the annunciator. An annunciator consists of an array of opaque plates with alarm names written on each plate. Contacts from various devices through the terminal station are wired to the annunciator. The change of state of each contact signifies an alarm

condition. When an alarm occurs, the associated window in the annunciator flashes and an internal horn is activated. The local responder to the alarm has the options to silence the alarm and acknowledge it by way of push buttons on the annunciator panel. Once acknowledged, the flashing ceases but the window remains illuminated until the alarm is cleared by way of another push button. If the contact that generated the alarm has not resolved to its normal state, the annunciator window remains lit although flashing has ceased.

Some alarms are repeated from the annunciator to the supervisory junction box; others are provided direct to the supervisory junction box. There are also instances where some alarms are grouped for both local annunciation and supervisory alarm purposes. Examples of such groupings include 'relay anomaly' and 'breaker heater fail' alarms. These groupings occur on the basis of lower criticality of alarm or that several contacts from various equipment represent the same general event. There are presently 49 assigned alarms out of a maximum of 72 at Stony Brook terminal station. Once the maximum number of alarms is reached, the annunciator will have to be replaced with a larger version as there is no means by which to expand this unit due to its age and configuration. The annunciator at Stony Brook terminal station is shown in Figure 3.

Figure 3: Annunciator

Alarms reported to the Energy Management System can originate directly from a protection and control panel device or from the annunciator subject to the nature of the alarm. All alarms going to the supervisory junction box are time stamped by the RTU regardless of criticality. Critical alarms that would be required for fault analysis would go directly to the supervisory junction box even if a local alarm is required. Minor alarms that are not time critical would typically go through the

annunciator and then repeated to the supervisory junction box.

There have not been any major upgrades to the annunciator or the supervisory junction box although points have been added to each over the years. This typically results from upgrades to other areas of the terminal station or it has been determined that additional alarm notification is warranted locally or to ECC.

Operating Experience:

The quantity and detail of alarms presented at the terminal station on the annunciator and to the ECC operator has historically been fairly general in nature. This has been so for the ECC operator so as not to inundate and overwhelm the operator with a high volume of alarms during outages. The limiting factors locally have been the panel space allocation for the annunciator and the cable congestion that would be created when providing for a high degree of alarm detail.

Reliability Performance

The reporting of existing alarms to ECC has proven to be very reliable. It has been identified that there is a necessity to enhance the detail of reporting. The reliability of such reporting is anticipated to remain unchanged.

Safety Performance

This subject matter of this proposal does not have a Safety Performance element.

Industry Experience

The Liberty Consulting Group drew upon industry experience in the field of utility practice in order to provide insight as to required enhancements as outlined in this report.

Anticipated Useful Life

An annunciator has an estimated service life of 30 years. The service life of an annunciator can be shortened if there is a need to increase the number of alarms but the capacity of the annunciator is exceeded.

The automation controller (SEL-2240) has an estimated service life of 30 years.

The estimated Mean Time Between Failure (MTBF) for the rack mounted computer in Alternative 2

is 11 years. The manufacturer's user manual states a minimum MTBF of 100,000 hours (11.4 years) based on service records. The Cost Benefit Analysis is done over a 30 year period which reflects the service life of the main components of each alternative.

Development of Alternatives:

In the development of alternatives, two issues had to be resolved:

- The existing supervisory junction box is full and there is no wall space available to mount a second junction box; and
- The existing annunciator does not have spare capacity to accommodate the additional local alarms that have been identified.

Two alternatives were considered to modify the existing local and supervisory alarm reporting at Stony Brook terminal station:

Alternative 1:

A new cabinet will be required to function as a second supervisory junction box. The cabinet will be furnished with terminal blocks to accommodate the 118 cables which will be run from various protection and control panels to this cabinet. Cables from the RTU will connect to the other side of the terminal blocks in the new cabinet to facilitate contact transfer to the RTU.

The existing annunciator has capacity for 72 alarms but is not able to be expanded. There are presently 49 alarms in use with 57 additional alarms needed. A new annunciator with sufficient capacity is required to replace the existing unit. The new annunciator selected for Alternative 1 of this proposal can accommodate 132 alarm points. This provides 25% spare capacity for future additions. Figure 4 shows the layout of a typical annunciator that would be purchased for this installation although the one needed for this project would be substantially larger.

Figure 4: Typical Modern Annunciator

Various wiring modifications and additional terminal blocks will be required for the additional points. This has been taken into account in the project estimating template.

This option will increase congestion in the cabling area of the annunciator panel. There is a limited capacity to install additional cables in the panel wings or install additional terminal blocks in the panel. Figure 5 shows the panel area where cables are to enter the panel. Figure 6 shows where the additional terminal blocks are to be installed.

Figure 5: Cable Entry Area

Figure 6: Location for New Terminal Blocks

The new supervisory junction box will be housed in a new cabinet since there is no available wall space for a second junction box. The cabinet will be located next to, and at a right angle, the last protection and control panel. A section of overhead cable tray will be added to permit cables to go from the existing cable tray to the new cabinet.

Figure 7 shows the area where the new cabinet will be located.

Figure 7: Area for new SJB Cabinet

The cost for Alternative 1 is estimated to be $309.8 as indicated in Table 2.

Table 2: Alternative 1 Project Costs

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	47.0	1.0	0.0	48.0
Labour	38.0	145.0	0.0	183.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.5	2.0	0.0	3.5
Interest and Escalation	6.1	22.3	0.0	28.4
Contingency	0.0	46.9	0.0	46.9
TOTAL	**92.6**	**217.2**	**0.0**	**309.8**

Alternative 2:

For Alternative 2, it is intended to utilize present day technology to collect alarms and display them on a computer mounted in the new cabinet. The intended device will display alarms locally as well as communicate alarms to the Energy Control Center without additional cabling to the Supervisory Junction Box and RTU. A new cabinet will be required to function as both new annunciator panel and supervisory point interface for new points. The cabinet would be in the same location as indicated for Alternative 1. The device chosen for this application is the SEL-2240 automation controller by Schweitzer Engineering Labs as it has been previously installed in Hydro terminal stations for this purpose.

Figure 8 shows a recent installation using an SEL-2240 automation controller. The graphical interface provided by the SEL-2240 allows for a dynamic single line representation of the terminal station as well as alarm screens. For this proposal it is only intended to develop alarm screens. At the top of Figure 8 is the combination computer and touchscreen LCD monitor which is the operator interface. The SEL-2240, located at the bottom of the cabinet, communicates graphical displays to the computer.

Figure 8: SEL-2240 (at bottom of figure)

Figure 9 shows the alarm screen which is able to be selected from the main single line graphic. Several alarm screens can be developed to accommodate many additional alarms without the need for additional panel space. In the event that the cabinet reaches capacity for terminal blocks and electronics components, this system can utilize distributed data collection hardware which can located in other panels.

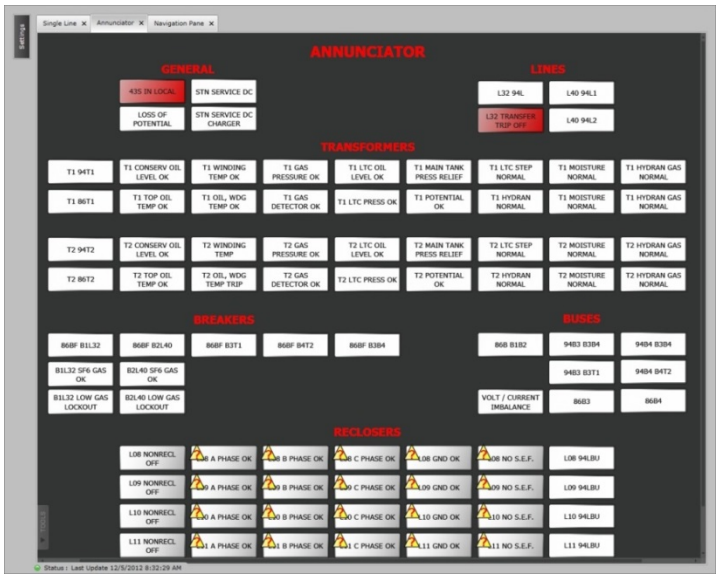


Figure 9: Annunciator screen (SEL-2240)

Graphics of various types can be developed by the user without concern for limitations in light of present and future needs. The expandability of this system is anticipated to far exceed the future requirements of any terminal station.

The cabinet will be furnished with terminal blocks to accommodate the cables representing the additional supervisory and local alarms. These cables will be run from various protection and control panels to this cabinet. The SEL-2240 will communicate to the RTU over a serial or Ethernet connection instead of by numerous cables.

The existing annunciator is obsolete and has a capacity for 72 alarms. There are presently 49 alarms in use with 57 extra needed. A set of distributed data collection modules for the SEL-2240 platform is to replace the existing annunciator. This set of modules will collect the 49 alarms presently handled by the annunciator and communicate them to the main processor for display in the new cabinet. The additional alarms will be wired directly to the new cabinet. The contacts from the existing annunciator panel which connect to the supervisory junction box will be accommodated through the use of a contact output module in the new equipment which will replace the annunciator. This architecture provides for easier expansion and distributed data collection. No additional terminal blocks will be required in the existing annunciator panel.

Various wiring modifications will be required in the protection and control panels for the additional points.

The cost for Alternative 2 is estimated to be $308.5 as indicated in Table 3.

Table 3: Alternative #2 Project Costs

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	27.0	1.0	0.0	28.0
Labour	41.0	160.0	0.0	201.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.5	3.5	0.0	5.0
Interest and Escalation	4.9	22.8	0.0	27.7
Contingency	0.0	46.8	0.0	46.8
TOTAL	**74.4**	**234.1**	**0.0**	**308.5**

Evaluation of Alternatives

The Net Present Value of Alternative 1 is marginally less than Alternative 2 by $1,128 as shown in Table 4. The analysis was conducted over a 30 year period and taking into account possible device replacement based on estimated life span from the manufacturer.

Although very close to the same project cost, the automation controller in Alternative 2 has the following advantages over the basic annunciator and supervisory junction box method of Alternative 1:

1. High volume of local and supervisory alarm points can be accommodated.
2. Distributed input modules can be used to minimize cable runs or where the expansion of alarms exceeds the panel space for terminal blocks and cables.
3. Each input can be time tagged to identify the sequence of both local and supervisory alarms.
4. The number of future alarms can be added to the graphical computer interface without any impact to the cabinet front whereas an annunciator may have to be either replaced or additional alarm modules added.
5. Additional communications hardware can be added to accept alarms directly from the protective relays instead of using numerous cables from auxiliary relays.

The annunciator proposed in Alternative 1 has an allowance for 132 alarms. This is a spare capacity of 26 alarms under the present identification of alarm needs. Should future expansion or further alarm detail dissemination exceed 132 alarms, then the annunciator will have to be reconfigured for four windows per module instead of the proposed three window type or replaced entirely as there is no expansion capability of this device. It is also anticipated that additional cables and terminal blocks for future alarms may not be able to be accommodated in the annunciator panel due to the

congestion created by the additional alarms added as proposed herein.

Economic Analysis

Long term tangible benefits are not able to be quantified at this time as it is unknown as to what extent future expansion will be required. The aforementioned advantages of Alternative 2 over Alternative 1 represent future potential cost savings in the event of significant expansion. The difference in net present value is not anticipated to outweigh the benefits of a technologically superior alternative which offers greater functionality and capacity for expansion.

Table 4: Net Present Value of Alternatives

132516AP Upgrade Data Alarm Management - Various		
Alternative Comparison *Cumulative Net Present Value To The Year* **2045**		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
Alt. #1 New SJB & Annunciator	270,591	0
Alt. #2 New HMI / Data Collector	271,720	1,128

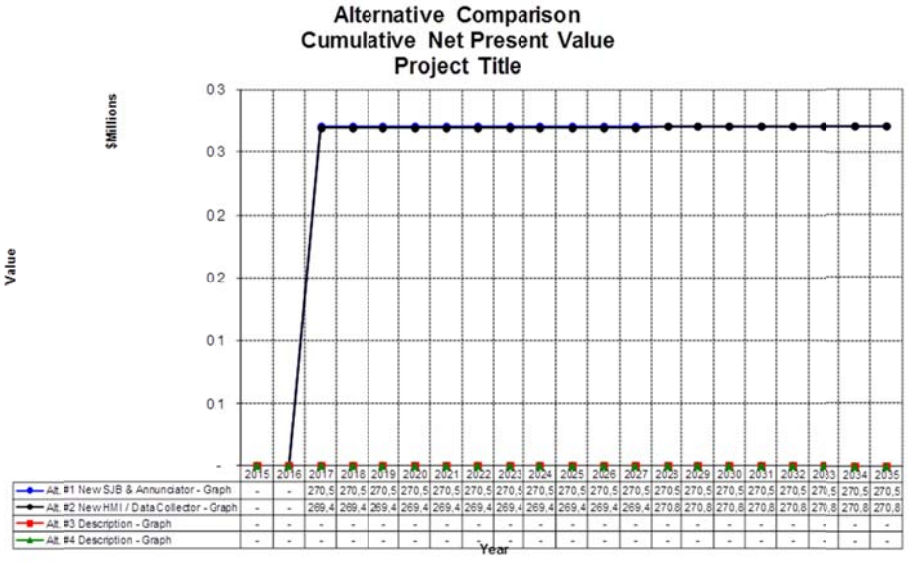


Figure 11: Graph of Net Present Value of Alternatives

Conclusion:

This project is necessary to provide both local responders to system problems and Energy Control

Center operators with an enhanced level of alarm detail for the purpose of diagnosing events.

Alternative 2 was chosen as the solution as it represents present day technology which offers distinct advantages over the previous methods of local and supervisory alarm reporting. It is anticipated that the advantages presented by Alternative 2 far outweigh the marginal difference in projected costs.

Project Schedule:

The project schedule is provided in Table 5.

Table 5: Project Schedule

Activity		Start Date	End Date
Planning	Project Commencement / Scope Review	April 2016	April 2016
	Site Safety Tour	May 2016	May 2016
	Site Work Assessment	May 2016	May 2016
Design	Prepare drawing revisions	June 2016	July 2016
	Prepare Controller configuration	Aug. 2016	Aug. 2016
	Prepare SOE point additions	Sept. 2016	Sept. 2016
Procurement	Order SEL-2240 components	July 2016	Aug. 2016
	Order new free standing cabinet	June 2016	July 2016
	Order cables and tray section	Aug. 2016	Sept. 2016
Construction	Install Cabinet and Controller	April 2017	April 2017
	Install Cable Tray	April 2017	May 2017
	Remove annunciator, install expansion rack	May 2017	June 2017
		June 2017	July 2017
	Install cables and connect	Aug. 2017	Aug. 2017
	Configure RTU		
Commissioning	Test configuration	July 2017	July 2017
Closeout	As-built drawing preparation	Aug. 2017	Aug. 2017
	Post Implementation Review	Aug. 2017	Sept. 2017

Project Title: Install Breaker Failure Protection

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Type: Other

Classification: Normal

Project Description:

This project involves the installation of breaker failure protection on B1G1 at Hinds Lake Generating Station, B1L24, B1L43, B1L45 and B1T2 at Howley Terminal Station and B1L23, B1L24 and B1L363 at Indian River Terminal Station. Refer to Appendix A for single line diagrams of these terminal stations.

This will involve the purchase of breaker failure relays, lockouts and blocking switches to be installed on existing protection and control panels.

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	33.5	0.0	33.5
Labour	56.9	98.3	0.0	155.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.4	15.8	0.0	20.2
Interest and Escalation	4.4	21.9	0.0	26.3
Contingency	0.0	41.8	0.0	41.8
TOTAL	**65.7**	**211.3**	**0.0**	**277.0**

Justification:

In 2014, Hydro completed a review of breaker failure protection in 66 kV and 138 kV terminal stations. There were a total of 34 terminal stations which included 21 at 66 kV and 13 at 138 kV. The 4.16 kV unit breaker at the Paradise River Generating Station was also reviewed for breaker failure protection. Of the 35 terminal stations, 15 do not have breakers. The remaining 20 terminal stations that do have breakers, they require the installation of breaker failure protection.

The draft Protection and Control Standard titled “Application of Breaker Failure Relaying” prepared by Hydro in 2014 says that “This standard applies to circuit breakers applied in transmission (66 kV and above) and distribution circuits (rated less than 66 kV) and to generator breakers.”

As per the standard, “The “breaker failure “ protection methodology is employed to safeguard the

power system in the event that a circuit breaker fails to open correctly during a fault clearing operation." It will cause adjacent or remote breakers to open within a defined time.

Hinds Lake Generating Station and the Howley and Indian River Terminal Stations are in the 138 kV transmission loop connecting western and central Newfoundland.

Existing System:

Hinds Lake Generating Station and Howley and Indian River Terminal Stations do not have existing breaker failure protection.

Operating Experience:

Reliability Performance

This is not applicable for this project.

Outage Statistics

This is not applicable for this project.

Legislative or Regulatory Requirements

There are no legislative requirements to install breaker failure protection. In 2014, Hydro committed to the Board of Commissioners of Public Utilities to "develop a plan to: a) redesign existing breaker failure relay protection schemes to provide that breaker failure will be activated with either a 138 kV or 230 kV breaker malfunction after a transformer failure; and b) install breaker failure relay protection for transformers in terminal stations where breaker failure relay protection is not in place." This project is to address this action.

Safety Performance

This project is not justified on safety performance.

Industry Experience

Breaker failure protection is common throughout the utility industry. It is used in all of the 230 kV terminal stations operated by Hydro.

Anticipated Useful Life

Breaker failure relays have a useful life of 20 years.

Development of Alternatives

There are no viable alternatives.

Energy Efficiency Benefits

This project will not provide energy efficiency benefits.

Conclusion:

Breaker failure protection will cause defined breakers to be operated to isolate the failed breaker within a set time.

The Protection and Control Standard "Application of Breaker Failure Relaying" prepared by Hydro in 2014 calls for breaker failure protection on transmission breakers rated at 66 kV and above.

Project Schedule:

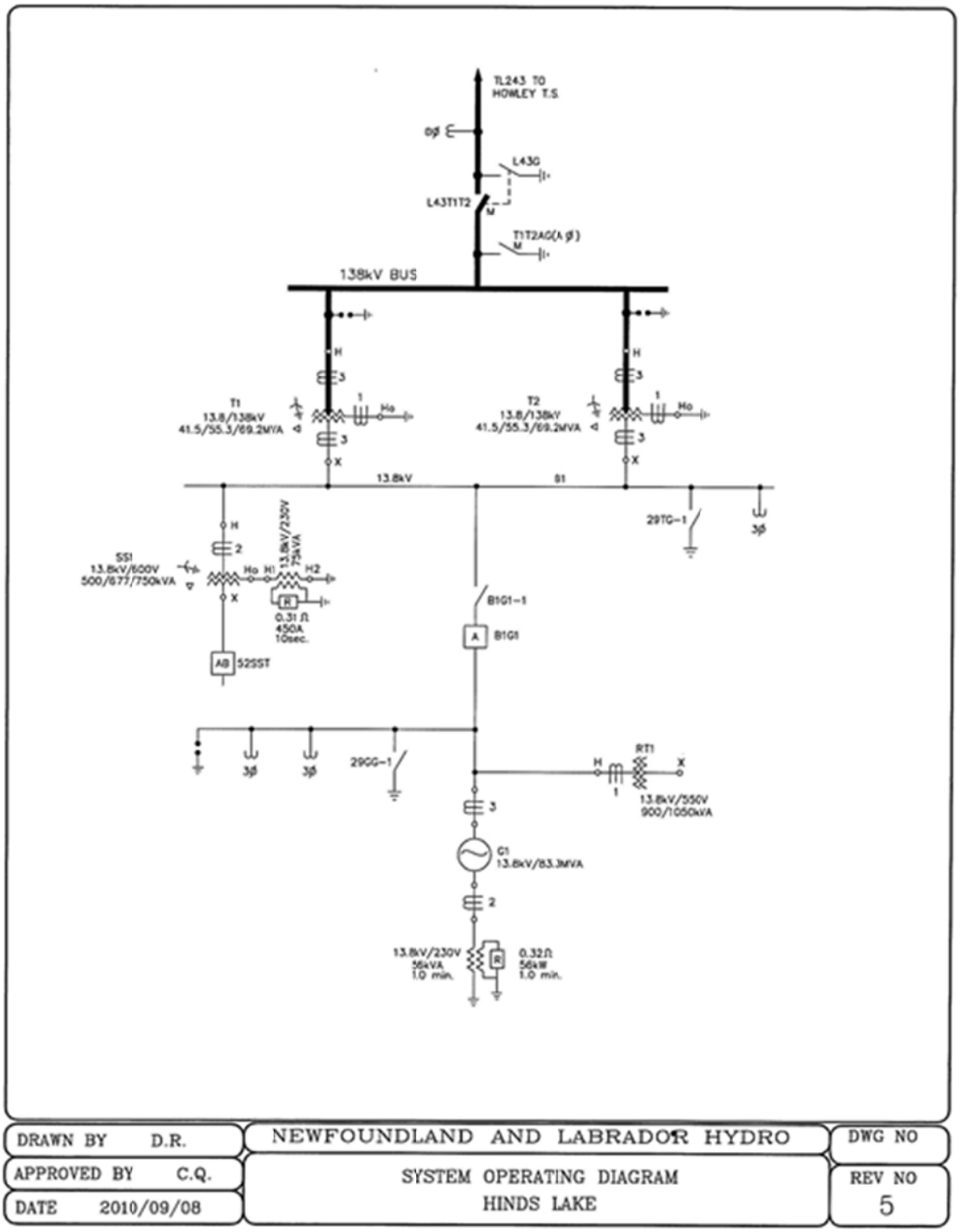
Table 1: Project Schedule

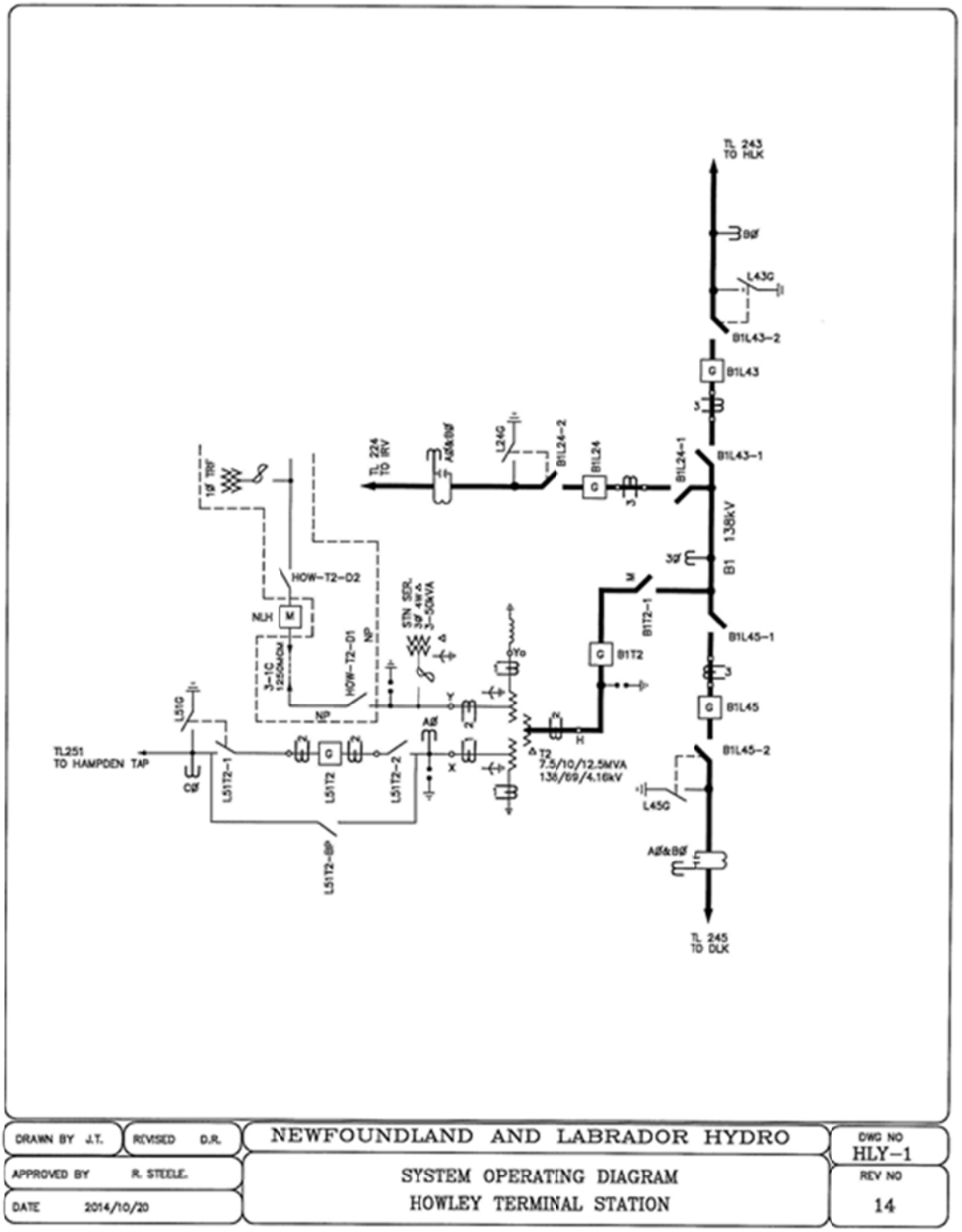
Activity		Start Date	End Date
Planning	Prepare scope statement	April 2016	April 2016
Design	Site visit Prepare drawings for three sites	August 2016 October 2016	August 2016 April 2017
Procurement	Purchase relays and other material Receive relays and other material	November 2016 February 2017	November 2016 February 2017
Construction	Install relays, lockouts, switches	June 2017	August 2017
Commissioning	Commission relays	June 2017	August 2017
Closeout	As built drawings Project closeout information	September 2017 October 2017	September 2017 October 2017

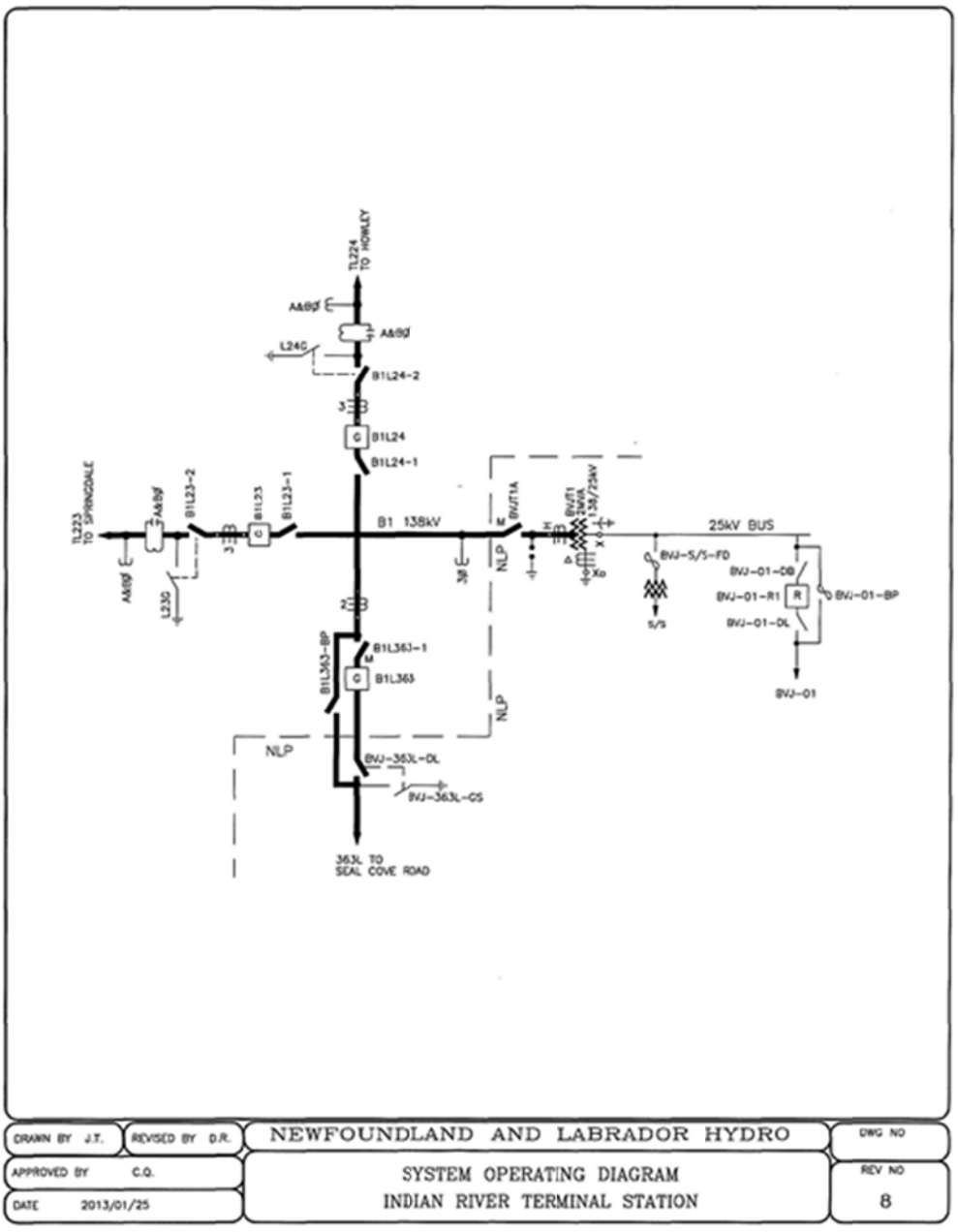
APPENDIX A

Single Line Diagrams for Hinds Lake Generating Station,

Howley Terminal Station & Indian River Terminal Station


TL243 TO HOWLEY T.S.
L43G
L43T1T2
T1T2AG(λ ø)
138kV BUS
T1
13.8/138kV
41.5/55.3/69.2MVA
T2
13.8/138kV
41.5/55.3/69.2MVA
13.8kV
B1
29TC-1
SSI
13.8kV/600V
500/677/750kVA
13.8kV/230V
75kVA
0.31 Ω
450A
10sec.
52SST
B1G1-1
B1G1
29GG-1
RT1
13.8kV/550V
900/1050kVA
G1
13.8kV/83.3MVA
13.8kV/230V
56kVA
1.0 min.
0.32Ω
56kW
1.0 min.
DRAWN BY D.R.
APPROVED BY C.Q.
DATE 2010/09/08
NEWFOUNDLAND AND LABRADOR HYDRO
SYSTEM OPERATING DIAGRAM
HINDS LAKE
DWG NO
REV NO
5


TL 243
TO HLK
B1L43-2
B1L43
B1L43-1
B1L24-1
B1L24
TL 224
TO BRY
L24G
B1L24-2
B1 138kV
B1T2-1
B1T2
B1L45-1
B1L45
B1L45-2
L45G
TL 245
TO DLK
HOW-T2-D2
HOW-T2-01
STN SER.
T2
7.5/10/12.5MVA
138/69/4.16kV
L51G
TL251
TO HAMPDEN TAP
L51T2-1
L51T2
L51T2-2
L51T2-BP
DRAWN BY J.T.
REVISED D.R.
APPROVED BY R. STEELE.
DATE 2014/10/20
NEWFOUNDLAND AND LABRADOR HYDRO
SYSTEM OPERATING DIAGRAM
HOWLEY TERMINAL STATION
DWG NO
HLY-1
REV NO
14


TL224
TO HOWLEY
A&BS
A&BS
L24G
B1L24-2
B1L24
B1L24-1
TL223
TO SPRINGDALE
A&BS
B1L23-2
B1L33
B1L23-1
B1 138kV
BVJT1A
BVJT1
138/25kV
25kV BUS
BVJ-S/S-FD
BVJ-01-CB
BVJ-01-R1
BVJ-01-BP
BVJ-01-DL
BVJ-01
S/S
A&BS
L23G
NLP
B1L363-BP
B1L363-1
B1L363
NLP
BVJ-363L-DL
BVJ-363L-GS
363L TO
SEAL COVE ROAD
DRAWN BY J.T.
REVISED BY D.R.
APPROVED BY C.Q.
DATE 2013/01/25
NEWFOUNDLAND AND LABRADOR HYDRO
SYSTEM OPERATING DIAGRAM
INDIAN RIVER TERMINAL STATION
DWG NO
REV NO
8

Project Title: Implement Industrial Billing Software

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project is to replace the Industrial Billing software for Industrial customers. This software is used on a monthly cycle to produce the bills for all our industrial customers. A software solution has been determined and the proposed solution will be implemented, following a confirmation of all users requirements and before the replacement software is purchased.

The proposed software will be able to integrate with our industrial meter reading software which is used to interrogate meters for our industrial customers such as Newfoundland Power or North Atlantic Refining Limited.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	125.0	0.0	0.0	125.0
Labour	74.8	0.0	0.0	74.8
Consultant	0.0	0.0	0.0	0.0
Contract Work	141.8	0.0	0.0	141.8
Other Direct Costs	16.3	0.0	0.0	16.3
Interest and Escalation	13.7	0.0	0.0	13.7
Contingency	71.6	0.0	0.0	71.6
TOTAL	**443.1**	**0.0**	**0.0**	**443.1**

Justification:

The current solution was developed in-house using Microsoft Excel 2003 which has not been supported since April 2014. This application in use today was originally developed in Lotus 123 and converted to Excel over 10 years ago. The proposed solution will decrease processing time for billing, interface with Hydro's JD Edwards System ERP (Enterprise Resource Planning), and integrate directly with the industrial meter reading software. The current system has a number of manual steps for the movement of meter data for the meter reading software to the billing system. Direct integration will allow for faster billing cycles and reduction of time spent creating industrial bills.

Existing System:

The current solution was written in house and is compiled of a large number of Excel calculations (scripts) that run on unsupported version of Microsoft Excel 2003. The existing solution is cumbersome, requires manual intervention and does not interface with the current meter reading software.

Operating Experience:

This budget proposal is for routine upgrade of software related to the corporation's shared Information Technology infrastructure.

Reliability Performance

Hydro reviews its software application portfolio on a yearly basis and uses two main criteria to determine if an upgrade to an environment is warranted. First, the status of vendor support for the applications is reviewed. Next, any functionality improvements are reviewed in the context of providing business value either through improved functionality or improvements in service.

Vendor Recommendations

One option for this project is to accept a solution offered by the current meter reading software vendor, and the solution suggested by the vendor integrates with our existing system. This will be considered, along with any other provider solution, when solutions are evaluated.

Conclusion:

Hydro reviews its software application portfolio on a yearly basis and uses two main criteria to determine if an upgrade to an environment is warranted. First, the status of vendor support for the applications is reviewed. Next, any functionality improvements are reviewed in the context of providing business value either through improved functionality or improvements in service. The proposed solution will add new functionality that will decrease processing time and can also interface with our accounting system.

Project Schedule:

The project is scheduled to start in February 2016 and be completed by the end of June 2016.

Project Title: Replace Peripheral Infrastructure

Location: Various Sites

Category: General Properties - Information Systems

Type: Other

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 2016, this project will consist of the replacement of 148 Multi-Function Devices (MFDs) used for printing, copying, faxing and scanning, including three with support for large format printing; as well as, 14 laser printers, one digital printing press and one multi-function, wide format drafting printer. There are 52 units to be replaced at St. John's, 28 at Bishops Falls, two at Deer Lake, 16 at Bay d'Espoir, 15 at Happy Valley, 24 at Port Saunders, two at Stephenville, and three at Wabush. In addition, this budget includes funds for the replacement of 12 projectors and two video conferencing units. Two devices in the proposal have higher unit cost than most other items. The digital printing press and multi-function, wide format drafting printer account for approximately $200,000 of the budget noted below.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	427.7	0.0	0.0	427.7
Labour	40.9	0.0	0.0	40.9
Consultant	34.8	0.0	0.0	34.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	7.2	0.0	0.0	7.2
Contingency	100.7	0.0	0.0	100.7
Sub-Total	**611.3**	**0.0**	**0.0**	**611.3**
Cost Recoveries	**(186.8)**	**0.0**	**0.0**	**(186.8)**
TOTAL	**424.5**	**0.0**	**0.0**	**424.5**

Justification:

This is the continuation of the Peripheral Infrastructure Replacement Project to replace peripheral devices as they reach the end of their useful lives. The units scheduled for replacement in 2016 have all been in service for five years or more and maintenance contracts and warranties have

expired. While the manufacturer will provide extended maintenance (at an increased cost) they will not guarantee the performance of these devices after five years. In this case Hydro would have to incur an unbudgeted capital expense in order to replace the device and could take several weeks before the unit is replaced. Smaller area offices have a single MFD and would have no services during this time.

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.

Existing System:

Table 2 presents a list of peripheral devices in service at different Hydro sites.

Table 2: Peripheral Devices in Service

Office Location	Number of Printers	Number of Employees	Buildings Per Location
Hydro Place	72	278	1
Bay d'Espoir	21	109	4
Happy Valley/Goose Bay	17	41	2
St. Anthony	6	29	2
Stephenville	3	21	2
Deer Lake	3	6	1
Wabush	4	15	2
Whitbourne	3	25	2
Bishop's Falls	37	98	3
Holyrood	16	112	4
Port Saunders	3	24	1
Springdale	2	12	1

Age of Equipment or System

The units scheduled for replacement have been in service for over five years.

The decision 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 be supported on older equipment);
- Users' printing requirements (color need, print volumes and speed);

- Number of users supported by the equipment;
- Availability of alternate printing;
- Available support for the equipment; and
- Age of equipment.

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.

Operating Experience:

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 vendor.

Alternatives

The only alternative is to consider leasing the equipment. The lease versus buy decision will be evaluated during the tendering process.

Industry Experience

Industry best practices indicate that the typical service life for a peripheral device is four to five years. Hydro has a life cycle plan for peripheral devices similar to that of other companies in the utility industry.

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 a manufacturer's warranty of one to three years duration.

Vendor Recommendations

The vendor (Xerox) recommends a maximum lifespan of five years for these devices. Other major vendors have not stated their recommended lifespan.

Historical Information

Table 3 contains a five-year history as well as the 2015 budget for the Peripheral Infrastructure Replacement Project.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per Unit[16] ($000)
2015B	200.5		43	
2014	200.7	220.4	54	4.1
2013	309.9	298.6	41	7.3
2012	327.5	328.5	45	7.3
2011	258.2	276.2	36	7.7
2010	222.0	227.0	34	6.7

Anticipated Useful Life

According to Gartner[17], the useful life for a color printer is three years while a black and white printer is between three and five years. The average age of Hydro's printers is five to seven years.

Evaluation of Alternatives:

There is no viable alternative to the planned replacement of peripheral infrastructure.

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 January 2016 and be completed before December 31, 2016.

[16] The variability in unit costs are due to specifications of the printers being replaced such as pages per minute, memory, fax and scanning capability.

[17] Gartner Inc. provides research and analysis on the global Information Technology industry. They assist companies in making informed technology and business decisions by providing in-depth analysis and advice on virtually all aspects of technology.

Project Title: Upgrade Enterprise Storage Capacity

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project is to replace software and hardware components supporting backup and disaster recovery functions for information systems. These functions are critical to the operation of Hydro's information systems and the ability to provide for backup and recovery of data and services which support the business.

One component of the enterprise storage subsystem, housing approximately 25% of data, will require replacement with a new unit and additional capacity for system growth. The current hardware will have been in service for six years and met its planned service life. A 20% growth in total capacity and replacement of the storage subsystem mentioned above are required in 2016.

Two SAN switches in the Energy Management System, which provide storage connectivity for a VMWare cluster, are at end of life and will be replaced.

The current disaster recovery system for Hydro's information systems uses a combination of disk-based backup data storage and tape-based offsite rotation for secondary copies of the data. Hydro's virtual infrastructure design is evolving to meet faster response and recovery times for key workloads, such as messaging, file services, and core applications. To protect key workloads on this platform, investments in data replication and storage equipment will be implemented to support rapid recovery of systems at a disaster recovery site during unforeseen events, system or datacenter outages. Additional disk storage, SAN equipment, data replication components and tape system will be deployed at a disaster recovery site.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2015**	**2016**	**Beyond**	**Total**
Material Supply	438.6	0.0	0.0	438.6
Labour	39.6	0.0	0.0	39.6
Consultant	26.6	0.0	0.0	26.6
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.8	0.0	0.0	2.8
Interest and Escalation	19.7	0.0	0.0	19.7
Contingency	101.5	0.0	0.0	101.5
Sub-Total	628.8	**0.0**	**0.0**	628.8
Cost Recoveries	(291.6)	**0.0**	**0.0**	(291.6)
TOTAL	**337.2**	**0.0**	**0.0**	**337.2**

Project Justification:

The factors that are driving Hydro's proposal to upgrade its storage environment include:

- Addressing obsolescence/maintaining vendor support;
- Managing the infrastructure;
- Providing disaster recovery protection; and
- Supporting core business applications.

Obsolescence/Vendor Support – Without vendor support, the applications reliant on storage infrastructure are at risk. As a result, Hydro's ability to support and ensure continuation of business functions and services is impeded. The storage systems provide critical functionality to the systems used by Hydro employees in daily business. Loss of availability of these services would have a negative effect on employee productivity by not allowing access to software applications and the data housed within the storage system.

Hydro requires a robust data backup and recovery system to maintain the availability of enterprise systems. The inability to backup and restore data, on a daily basis or during a larger outage, presents a high risk to the ability of business to resume normal operations within a reasonable period of time following an event. Services such as system control, electronic communications, asset management, financial and other systems must be recoverable in a timely manner should an event occur in a data center or data be corrupted through a cyber attack or other system corruption.

Increased virtualization of servers within the Hydro system reduces the number of physical servers which must be maintained with power, cooling, networking and rack space in Hydro data centers. Virtualization technologies also provide the potential to simplify management, consolidate, and enhance disaster recovery responsiveness. With virtualization, enterprise storage performance and

capacity is a key component of delivering corporate applications supporting business processes. An effective backup system along with the virtual server infrastructure in a disaster recovery site, ready to recover operations, is a core requirement for a stable system. Hydro seeks to improve its ability to manage and provision application workloads within its datacenters for performance, maintenance and disaster recovery protection.

Existing System:

The backup storage system provides backup and disaster recovery services to the various Hydro servers used to run applications for the organization. Applications include Hydro business applications, enterprise resource planning, file-print, database and email systems, monitoring, and system management applications. The IBM Tivoli Storage Manager (TSM) software with TSM for Virtual Environments software protects the physical and virtual machine environments.

Disaster recovery plans historically utilized a tape-based recovery approach, requiring physical tape transportation to an offsite location to perform a disaster recovery. This has the drawback of requiring substantial time, resources and labour in the event of a disaster. Hydro is moving to a more rapid recovery method using disk based systems, augmented with tape-based secondary copies. The tape based copy prevents loss of data should a disk system holding backup data be compromised or fail. The disk based system can be restored from tape should this occur. The benefit of disk based primary backup data storage is rapid recovery, remote data replication to a disaster recovery site, and reduced resource time, logistics and other costs associated with physical tape transport to a recovery site. Hydro maintains its backup and disaster recovery technology to support backup and restore operations, remain under vendor support, address emerging performance bottlenecks and handle increased growth in data. The ability to leverage modern disaster recovery features for data compression, de-duplication and site-to-site replication positions the backup system to respond to disaster recovery requirements of the organization in coming years.

Table 2: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2015	Installed updated disaster recovery systems at primary data centers.	Completed in 2014 Capital program
2014	Replace Storage Area Network switches used to connect systems with enterprise storage. Increase available capacity for current and future workloads.	Completed in 2014 Capital program
2013	Build storage capacity in the V7000 for current and upcoming workloads	Completed in 2013 Capital program.
2011	Additional DS5100 SAN Installed	New Controller and capacity installed.

This is an ongoing refresh program to maintain the Enterprise Storage systems.

The project is scheduled to start in February 2016 and be completed by the end of November 2016.

Operating Experience:

Reliability Performance

Disk capacity growth fluctuates from year to year depending on the activities of the business. A general growth rate of approximately 20% was used when planning storage requirements for the coming year. Hydro's enterprise storage system is used on a continuous basis which generates new and updates existing data on a daily basis. The daily backups use an efficient incremental backup method yet results in approximately 7 TB of changed versions of data files per day. Backed up data must be safely stored and available to be restored in an emergency or as a result of data loss or corruption. Systems to make data available for restoration include offsite tapes, high availability clusters and data replication technologies to speed the simplify system recovery and continued operations in the event of unforeseen events. Hydro standardizes on enterprise grade solutions to backup and recover its information systems.

Industry Experience

Hydro must keep its systems current in order to adequately support and protect information technology infrastructure required to operate its business. Failure to keep this infrastructure current will put Hydro at risk of unplanned information system outages, possible data loss, and possible data corruption. The replacement, addition and upgrading of hardware components to achieve this goal requires investment over the lifecycle of the infrastructure.

Vendor Recommendations

IBM Software Support Lifecycle Policy applies to the software which powers systems including the enterprise storage subsystems, SAN equipment, firm ware and management tools. As described in the policy, '5+3' Support – a minimum of five full years of standard support from the date the product release was made generally available by IBM, with the option to get support extensions for an additional three years following a product's end of support (EOS) date for an extra charge set by IBM.

Maintenance or Support Arrangements

Support and maintenance on storage systems is generally purchased at acquisition for a five year period, with one year of additional support purchased for the sixth year. While extended support offerings are available, the maintenance programs become increasingly more expensive as the hardware become older and parts are in shorter supply. After the initial five year warranty, the system is placed on a paid maintenance program with IBM that is renewed yearly until the system is replaced. Although IBM sold its server line to Lenovo in 2014, the enterprise storage business remains an IBM product line. Hydro's maintenance and support agreements remain in place.

Historical Information

Table 3 shows the historical costs of the enterprise storage upgrade project.

Table 3: Five-Year Historical Information

Year	Budget ($000)	Actual[18] ($000)	Comments
2015B	621.3		Storage capacity and disaster recovery equipment
2014	517.8	528.9	Added capacity; Replaced storage area network equipment
2013	194.9	194.9	Added capacity
2012	306.3	298.1	Added capacity and installed three new storage units for Energy Management and three LTO-4 tape units
2011	226.6	225.6	Added capacity and installed new storage system unit
2010	241.4	240.6	Five TB capacity increase and replace eight LTO-4 tape drives

Anticipated Useful Life

Industry standards indicate that most information systems hardware has a useful life of five years. Beyond this timeframe, technology advancements, hardware reliability and support cost and parts

[18] Price varies on a year to year basis due to changing storage requirements.

availability issues may become problematic. The average age of the equipment being replaced is six years.

Development of Alternatives

The alternative to an Enterprise Storage upgrade program is to replace systems as they fail. This would put the infrastructure at risk of unplanned outages, possible data loss, and data corruption. This is not a viable alternative. Tape based recovery remains a core function of the Hydro backup and disaster recovery strategy, however the ability to recover key systems more rapidly using virtualization and data replication methods will augment the tape based system.

Conclusion:

This is an ongoing refresh program to maintain the Enterprise Storage systems.

Project Schedule:

The project is scheduled to start in February 2016 and be completed by the end of November 2016.

Project Title: Replace Air Conditioning Units 8 and 14

Location: Hydro Place

Category: General Properties - Administrative

Type: Other

Classification: Normal

Project Description:

The scope of this project is to replace of the Energy Control Center (ECC) computer room air conditioner, Unit 14, and the Uninterrupted Power Supply (UPS) room air conditioner (AC), Unit 8. It is proposed that the current air conditioners be replaced with units of similar cooling size for both rooms. The ECC AC unit also has a roof top condenser and the associated piping to be replaced. The work will be managed by Hydro personnel with the execution of the work to be performed through a supply and install contract. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	1.5	0.0	1.5
Labour	31.6	22.7	0.0	54.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	145.0	0.0	145.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	3.0	20.1	0.0	23.1
Contingency	0.0	40.2	0.0	40.2
TOTAL	**34.6**	**229.5**	**0.0**	**264.1**

Justification:

Failure of the air conditioners puts the computer equipment in the ECC room and the power supply equipment in the UPS room at risk of malfunctioning as the temperature will rise above the maximum operating temperatures tolerated by the equipment. This will negatively affect Hydro's operation as the computer systems in the ECC room are critical to monitor the island interconnected system. An AC failure in the UPS room can cause the UPS units to not function properly putting the computer systems in Hydro Place at risk of not starting in the event of a power outage.

Existing Systems:

Unit 14 in the ECC computer room is original to Hydro Place construction in 1989, along with an identical unit that was replaced in 2008, which is not up for replacement under this proposal. Unit

14 is 26 years old and has surpassed its life expectancy. The AC unit provides continuous cooling and humidity control to the equipment in that room to ensure the equipment does not over heat. There have been no major upgrades on the AC unit since its installation.

Unit 8 AC in the UPS room is also original to the Hydro Place construction in 1989. The unit is 26 years old and has surpassed its life expectancy. The AC unit provides continuous cooling and humidity control to the equipment in that room to ensure the equipment does not over heat. There have been no major upgrades on the AC unit since its installation.

Operating Experience:

The ECC AC unit is aged and has deficiencies that cannot be repaired. One of two coils in the unit is out of service and a replacement of the coil is not possible. This, therefore, has resulted in reduced cooling output of the unit to half of its rated output. In 2009, IBM was contracted to assess the AC units in this room and has recommended their replacement to ensure reliable functional cooling in the ECC computer room. Since 2009 all the AC units in Hydro Place were assessed and a plan was developed for replacement units. The units were replaced based on condition, with the units in the worse condition being replaced first.

The units in the ECC room run autonomously. Each unit controls its own particular part of the room without regard to the operating status of the other unit. As such, it was not uncommon to observe one unit humidifying the room, while the other was de-humidifying. The heating circuit of one AC unit may be engaged while the other unit is simultaneously attempting to cool the room. The room only has a small cooling load but this is anticipated to increase so the same size unit is recommended. Refer to appendix A for the IBM report entitled 'IBM Site & Facilities Services Energy & Data Centre Health Check Report for Newfoundland Hydro'.

The AC unit that provides cooling to the UPS room is located in a different room and was not assessed in the IBM report. The unit was, however, addressed in the report under the section describing the UPS system, as seen in Appendix A. The report interprets the small air handling unit as a single point of failure. The AC unit would be undersized if all three UPS units were taxed to the limit, however the UPS arrangement is to provide redundancy and one UPS unit could handle the load present in Hydro Place.

Reliability Performance

The assessment of the AC units by IBM in October of 2009 has the largest concern orientated around the age of the units. IBM states that they have worked with several customers that have operated AC units beyond 20 years. Most of these customers reported that the reliability of these units deteriorates quickly beyond this age and service actions are made lengthier due to problems finding spare parts. As seen with Unit 14, the unit is running at half capacity due to a failed coil that cannot be replaced.

Environmental Performance

Due to the age of the units in Hydro Place, the units still use the R-22 type refrigerant. This refrigerant is being phased out due to the harmful effects this substance has on the Ozone Layer. The new proposed units will have R-407C type refrigerant.

Maintenance or Support Arrangements

The maintenance of the AC units and the roof top condensers is performed by contractor, Johnson Controls, on a regular yearly basis.

Maintenance History

No maintenance history is available for the air conditioning units.

Historical Information

Over the past number of years there have been replacements of AC units and roof top condensers in Hydro Place, the units were replaced based on condition. The costs of those replacements are in Table 2.

Table 2: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per ton[19] of cooling ($000)	Comments
2014	130	140.9	1 @ 15 tons	9.4	AC and Condenser replaced, unit located in the IT Computer Room, cooling critical electrical equipment
2014	130	131.2	1 @ 15 tons	8.8	AC and Condenser replaced, unit located in the IT Computer Room, cooling critical electrical equipment
2013	39	28.4	1 @ 3 tons	9.5	Only AC replaced, unit located in the Network Services Room, cooling critical electrical equipment.
2011	37	29.6	1 @ 3 tons	9.9	Only AC replaced, unit located in the Network Services Room, cooling critical electrical equipment.

Anticipated Useful Life

The AC units and the roof top condenser have an anticipated useful life of 20 – 25 years.

Conclusion:

The AC units located in the ECC and UPS rooms in Hydro Place are antiquated and require replacement. These units are unreliable and sourcing replacement parts is not possible. The units are in sensitive areas that require cooling and humidity control to important computer systems that control the Island Interconnected System. To ensure reliable uninterrupted power to the grid, it is recommended to replace these AC units with ones of similar sizing.

Project Schedule:

The anticipated project schedule is shown in Table 3.

[19] A ton, as used in the HVAC industry, is a term that describes how much heat the AC unit can remove from the space where it is installed. The measurement for heat is the British thermal unit (BTU). One ton of air conditioning can remove 12,000 BTUs of air per hour.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Project kick off meeting, safety plan, risk assessment, open project in JDE, and complete WBS.	February 2016	February 2016
Design	Prepare technical spec, Award install and supply contract, contractor to provide design details.	March 2016	July 2016
Procurement	Contractor to purchase AC units and condenser for the project	February 2017	July 2017
Construction	Install AC units, condenser, and required replacement piping.	July 2017	August 2017
Commissioning	Commissioning of both units	July 2017	August 2017
Closeout	Asset Assignment Forms, PIR Form, Lessons Learned Meeting, and Contract Close Out Certificate	October 2017	October 2017

APPENDIX A

IBM Site & Facilities Services
Energy & Data Centre Health Check Report
For Newfoundland Hydro

October 2009

To ensure reliability, the generator is start-tested weekly. The weekly test routine does not transfer the building loads onto the generators. However, it is reported that a transfer test is performed at least once yearly. Maintenance records for these units are filed in the building facilities room.

Four ASCO 400-amp automatic transfer switches are positioned downstream of the generators. Only two are shown in the diagram above, as these units are directly related to the EMS computer room.

The latest information on generator loading is taken from records relating to a building maintenance activity that was performed last spring. The building was run from the emergency generators from 23:24 on April 20th to 05:23 on April 21. During that time, the peak load on the generators was observed to be 130kW. This load would have been greater had the outage occurred during normal business hours because of increased building occupancy and the elevators would have been more in use. However, it is not expected that the generator load would have exceeded the N+1 redundancy clip level of 240kW. No appreciable load growth has occurred since April 2009.

Uninterruptible Power Systems (UPS)

Three Powerware 9330 UPS modules have been installed in a parallel configuration to provide support for the critical loads in the EMS computer room, as well as for some other external loads. Each unit is currently rated at 40kVA/28kW. The units are regularly maintained by the manufacturer and the maintenance logs are available for each UPS module. The loads on the UPS modules are shown in the table below:

Table 4: UPS Loading

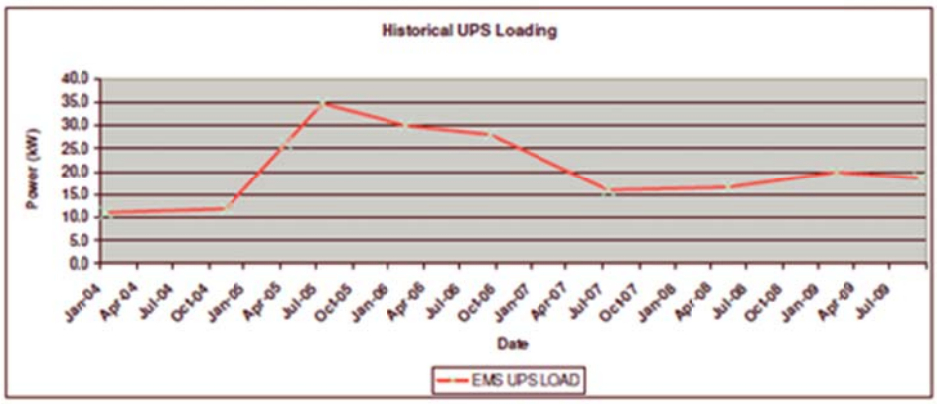
UPS Panel Readings - EMS Room												
UPM 1 Powerware 9330 (40kVA / 28kW)	**Input Voltage**	**Input Current**	**Input kVA**	**Input PF**	**Input kW**	**Output Voltage**	**Output Current**	**Output kVA**	**Output PF**	**Output kW**	**Effic. (%)**	**Load (%)**
Phase AB	208	22	7.9	0.98	7.8	208	19.3	7.0	0.97	6.8	87.9%	**24%**
Phase BC	208	22				208	20.4					
Phase CA	208	22				208	18.9					
UPM 2 Powerware 9330 (40kVA / 28kW)	**Input Voltage**	**Input Current**	**Input kVA**	**Input PF**	**Input kW**	**Output Voltage**	**Output Current**	**Output kVA**	**Output PF**	**Output kW**	**Effic. (%)**	**Load (%)**
Phase AB	208	20	6.8	0.93	6.4	208	16.8	6.0	0.96	5.8	90.9%	**21%**
Phase BC	208	21				208	16.9					
Phase CA	208	16				208	16.5					
UPM 3 Powerware 9330 (40kVA / 28kW)	**Input Voltage**	**Input Current**	**Input kVA**	**Input PF**	**Input kW**	**Output Voltage**	**Output Current**	**Output kVA**	**Output PF**	**Output kW**	**Effic. (%)**	**Load (%)**
Phase AB	208	18	6.5	0.92	6.0	208	16.9	5.5	0.97	5.3	89.2%	**19%**
Phase BC	208	18				208	15.8					
Phase CA	208	18				208	13.0					

With the observed loads, this bank of parallel UPS modules is running at "N+2" redundancy. Only one of the three modules is necessary to carry to the total load of 17.9kW. Future growth will likely reduce this redundancy level to "N+1", but this is still sufficient for NL Hydro needs.

The amount of battery time provided by the UPS systems is more than sufficient to ensure that the EMS computer room remains functional while the emergency generators start up during a power outage.

The service records for the UPS modules indicate that these units are regularly maintained and serviced. The load histories of each unit where reviewed to determine if there was any trend that could be identified. The graph below does not indicate that there is any relevant trend. The greatest UPS loads were experienced in 2005. Since that time, loads have been trending downward.

Figure 5: UPS Load History for EMS Computer Room



The UPS units themselves are installed in a small electrical room outside of the EMS computer room. An air duct from a small air handler supplies cooled air to the UPS room. This air handler could be interpreted as a single point of failure. An environmental sensor is installed in the UPS room to report any high-temperature conditions. This sensor did report a high-temperature alert in 2008, but the cause and the magnitude of the conditions cannot be determined.

Computer Room Power and Heat Load Calculations

The UPS is currently supporting 17.9kW of critical loads. However, only 8.6kW of that figure is actually installed in the EMS computer room; the majority of the UPS load is installed elsewhere in the building.

UPS inefficiencies, transformer losses and lighting loads provide other sources of heat to the computer room. The table that follows is an estimation of the computer room heat and power loads based on the data that was collected during the site visit.

Table 5: EMS Computer Room Loads

AC Sensible Load Calculations					
Existing Sources	**kW**	**KBTU/HR**	**25% Growth**	**kW**	**KBTU/HR**
Critical Loads	8.6	29.5	UPS Load (W)	10.8	36.9
UPS Heat Load	0.0	0.0	UPS Heat Load	0.0	0.0
Lighting (1W per sq ft)	0.7	2.4	Lighting (1W per sq ft)	0.7	2.4
Transformer losses	0.0	0.0	Transformer losses	0.0	0.0
Other	0.0	0.0	Other	0.0	0.0
Subtotal	**9.3**	**31.9**	Subtotal	**11.5**	**39.3**
AC Load (tons)	**2.7**		AC Load (tons)	**3.3**	

The columns on the right side of the table show how a 25% increase to the computer room loads would translate into heat load. UPS heat loads are shown as zero, since these units are not installed inside the computer room. There are no other significant heat sources in the computer room.

Mechanical Systems

Computer Room Air Conditioning

The temperature and humidity levels in the computer room are controlled by two Liebert precision air conditioning units. Each unit is rated at 15-tons (nominal). The following table lists the capacities and readings for each of these units:

Table 8: Air Conditioner Inventory

Model Information			Sensible Rating		Temperature (°F)			Humidification (RH)			Fan		Vane
Unit #	Model Number	Manu. Date	BTU	Tons	Reading	Set	Sens	Reading	Set	Sens	HP	CFM	Y/N
AC-13	Liebert FH199A-B00	Jun 1989	181,800	15.15	66	68	2	52%	45%	5%	3.0	8,400	N
AC-14	Liebert FH199A-B00	Jun 1989	181,800	15.15	68	68	2	42%	45%	5%	3.0	8,400	N
	TOTALS		363,600	30.3								16,800	

The air conditioning units in the computer room were manufactured in 1989. While these units are capable of operating beyond 20 years of age, it should be expected that reliability may become an issue as the years progress. There are previous service records left inside the AC units that indicate the units are maintained regularly. Other customers have reported to IBM that getting replacement parts for units of this age is becoming more difficult. NL Hydro has reported that it may not be possible to replace these units for another 2-3 years.

The AC units run autonomously. Each unit controls its own particular part of the room without regard to the operating status of the other unit. As such, it was not uncommon to observe one unit humidifying the room, while the other was de-humidifying. The heating circuit of one AC unit may be engaged while the other unit is simultaneously attempting to cool the room. The very small cooling load in the room (2.7 tons) is well below the total sensible capacity of either of these AC units. There is no issue with redundancy in the room. However, having such a small load offers other challenges with co-ordinated control and energy efficiency.

The set-points that have been selected for the AC units have the effect of over-cooling the room. A temperature logger was installed at mid-point at the face of two equipment racks (N-1 and N-3) to determine how well temperatures are being controlled at the face of the racks. The results indicate that air temperature for rack N-1 falls below the recommended temperature range of 64°F-80°F (see appendix). While this may not be a negative indicator of server performance and reliability, it does impact efficiency and power consumption.

The air temperature for the other rack (N-3) varied between 70°F-74°F. This temperature range is more aligned with the recommended temperature range. This area of the room was mainly influenced by the other AC unit that actually entered a heating phase from time to time.

Humidity levels in the EMS computer room appeared to be influenced by external migration of outdoor moisture. There were no observed vapour barriers installed in the walls of the computer room. On the day of the initial site inspection, the weather was extremely rainy. As a result, humidification cycles (and de-humidification cycles) alternated between each AC unit, sometimes operating at cross-purposes simultaneously. Despite this, however, humidity levels at the rack faces were controlled to within the recommend range (see appendix).

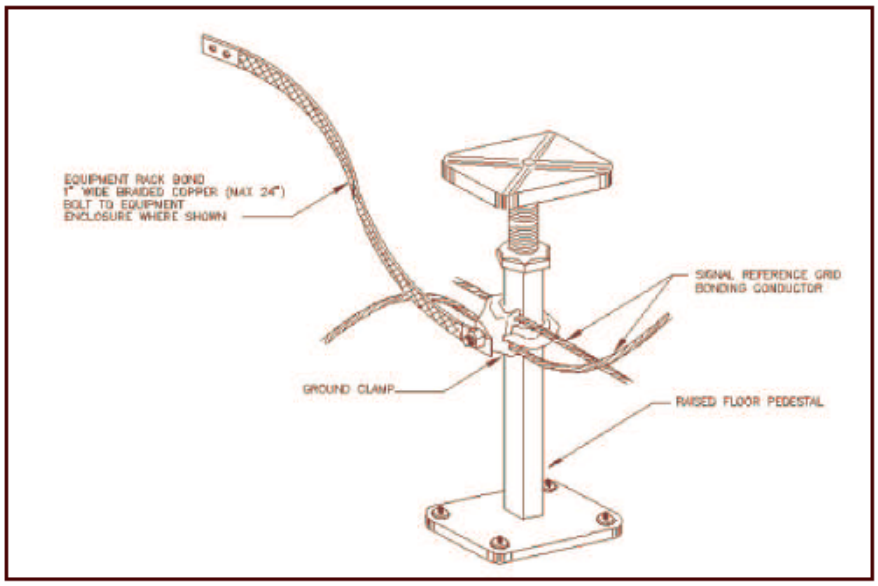
The roof-top condensers for the AC units were also inspected. These units are newer than the indoor units installed in the computer room; both were manufactured in 1998. However, the condition of the units varied widely. Condenser #3 (for AC unit 14) was discovered to have a significant amount of corrosion on the underside of the cooling coils. It was possible to collect a lot of rust by simply drawing an open hand across the face of the condenser coils. The other condenser did not display any significant corrosion at all. Each of the condensers have been fitted with a Lee Temp™ winter control system to allow them to operate properly should the outdoor air temperature fall as low as -20°F.

- It is not currently possible to identify which IT servers or devices are connected to which circuit breaker. A method of cross-referencing this information should be created. In this way, it will be a simple matter to know which IT devices are implicated by any circuit overloads or planned service actions.
- Branch circuit labelling should be consistently administered at each receptacle and at the breaker panels. Receptacles should be labelled at their faceplates with a mechanically created label. Up to date panel schedules should be kept with each circuit breaker panel. The names of the circuits servicing each IT equipment rack should be posted on the rack itself.

Grounding

- Grounding in the EMS computer room has not been installed as per the Canadian Electrical code or the IEEE-1100 grounding guidelines. The raised access floor must be bonded to ground. Individual IT equipment racks should also be bonded to the signal reference grid created by the floor ground. This also applies to air conditioning units, PDUs, circuit breaker panels, LAN racks, and any other device mounted on the raised floor.

Figure 18: Typical Rack Grounding Method



Mechanical Systems

AC Systems

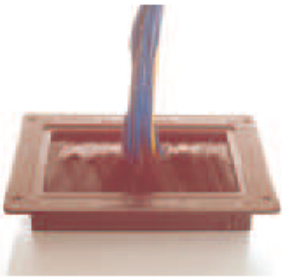
- The age of the AC units will likely require NL Hydro to replace them within the next two to three years. Hopefully these units will not become totally unreliable before that time. The AC units that will ultimately replace the existing units should have some features included that are not currently installed on the existing units. These features include:

- Un-loader technology, variable speed fans, and/or digital scroll compressor technology to accommodate lightly loaded room conditions.
- Web/SNMP connection capability to allow the new AC units to communicate directly to a monitoring system and/or internal LAN.
- Inter-unit communications capability to allow AC units to operate collaboratively within each room. Various control scenarios should be explored to understand which will work best for each room (teamwork mode vs. standby mode vs. cascade mode)
- Ducting capability to allow the ceiling plenum space to be used as a hot air return.

- In the interim, the existing AC units can be configured to use less energy. There is no need to run both AC units in the EMS room simultaneously. An auto-changeover controller could be installed that would cycle each of these units on and off according to a set schedule. The position of the AC units in the room with respect to the orientation of the IT equipment racks will likely require the units to be ducted into the ceiling so that the ceiling plenum space can be used as a hot air return. Zinc whisker contamination issues in the ceiling space will first need to be addressed.
- In the ADMIN room, it will still be necessary to run both units simultaneously. However, some set-point adjustments could still be made if the air flow patterns in the room can first be improved. Again, ducting of the AC units will help to improve hot air return. When the time comes to replace these AC units, more advantageous positioning of the new units and some strategic baffling under the raised floor may permit a "standby" mode to be used in this room as well. This would allow the AC units to take turns controlling the room instead of both units running simultaneously. However, careful planning should be done before this is attempted. CFD modeling of the space would likely be necessary to ascertain where the units should best be positioned in the room, if under-floor baffling provides an advantage, and if a single AC unit can maintain the environment under present and future design loads.
- The temperature set-points and sensitivity ranges should be standardized on each AC unit. If air flow improvements can be made to each room, it will be possible to raise the set points of each AC unit. This will have a significant and direct impact on energy consumption and efficiency.
- Water leak dams or pans should be installed below the AC units to channel possible leaks towards leak detectors that will need to be installed under the raised floor inside the water dams.
- The water leak detection system should be extended to include the drains that are present under the raised floor, especially in the ADMIN room. Each drain should be provided with a back-flow prevention device.

Air Flow

- Many cable cut-outs in the rear of equipment racks have not been properly sealed to prevent loss of air pressure under the floor. This also promotes air "bypass" problems for the air conditioning units. An example of a device that will greatly reduce this air leakage is shown at right. A "split" version of the device is available that will allow it to be installed over existing floor penetrations without disturbing the cables. There are also fire-rated memory-foam pillows that can be used to achieve the same effect. However, these devices are dependent on users replacing them back into the holes if they are removed, and do not absolve NL Hydro from also sealing the exposed wood-core cuts in the floor tiles with a fire-rated grommet.



Project Title: Upgrade Server Technology Program

Location: Hydro Place

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project involves the replacement, addition and upgrade of hardware components and software related to Hydro's shared server infrastructure, customer care system servers, and one system pertaining to collection of data from diesel generation units.

Based on the age of existing systems, each year an appropriate number of units will be refreshed. This ensures that Hydro has a reliable secure infrastructure environment required to support efficient operations.

The scope of this project affects 25 existing physical and virtual machine assets, and requires some new server assets be added to the system. The affected assets and planned changes are outlined below:

- One server asset used to collect meter data from diesel generation units requires replacement;
- One keyboard/video/mouse monitor unit requires replacement. This equipment is used by administrators to operate the servers when in the datacenter;
- Five server assets, comprising the customer care system, will be replaced by virtual machines requiring additional VMWare capacity on Hydro's existing system. This will be provided by the addition of one VMWare host to the existing shared virtual machine environment;
- Seven VMWare virtual machine host servers will be replaced due to end of equipment service life;
- Four servers running as virtual machines will be migrated to physical assets due to technical limitations created on the virtual machine environment by running these workloads. These provide file and database services. Displacement of these services to dedicated hardware is to reduce complexity of the virtual machine environment;

- Two print servers running as virtual machines will be reconfigured to leverage VMWare high availability protection. This change is due to technical limitations created on the virtual machine environment by running these workloads in their current form. Conversion is to reduce complexity of the virtual machine environment;
- One database server running as a virtual machine will be decommissioned and its databases migrated to another system;
- One physical and one virtual database server running as a clustered pair will be decommissioned and databases migrated to another system;
- One physical server asset running scanning software will be decommissioned and its functions moved to a virtual machine; and
- One Domain Controller and two VMWare virtual machine host servers will enhance disaster recovery capability for administrative systems, including messaging, file servers and corporate applications.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	279.0	0.0	0.0	279.0
Labour	56.2	0.0	0.0	56.2
Consultant	59.2	0.0	0.0	59.2
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	2.8	0.0	0.0	2.8
Interest and Escalation	16.0	0.0	0.0	16.0
Contingency	79.4	0.0	0.0	79.4
Sub-Total	492.5	**0.0**	**0.0**	492.5
Cost Recoveries	(228.5)	**0.0**	**0.0**	(228.5)
TOTAL	**264.0**	**0.0**	**0.0**	**264.0**

Justification:

The factors that are driving Hydro's proposal to upgrade servers in its environment include:

- 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; and
- Supporting current versions of applications
  As applications are upgraded and new applications implemented throughout the organization, many are built to take advantage of technologies such as virtualization, replication and high availability.

Existing System:

There are both physical and virtual servers which support applications for the organization. The applications that run on these servers include the Energy Management System, Enterprise Resource Planning, File, Print, Database and Email systems in addition to numerous other applications which comprise the operating environment. These applications are used by staff in running the business on a day to day basis and fall into one of four classification levels (0 to III) for the purpose of assigning a hardware replacement age.

The standard classifications used for server hardware replacement are shown in Table 2.

Table 2: Classifications for Server Hardware Replacement

Classification	Criteria	Maximum Age
Level 0	Critically important to business operations; hardware is known to have a longer general life expectancy; This classification requires additional measures for redundant components, application fault tolerance architectures, and signoff by system owners to extend the standard lifecycle timeframes accepting all associated risks in doing so.	8+ years
Level I	Critically important to business operations; access required on daily basis; outage/failure will have immediate negative impact on business and requires expedited problem resolution within one day or less.	5 years
Level II	Standard operating importance; used/accessed daily to weekly; outage would have less impact to business and requires immediate attention/resolution within one to three days.	6 years
Level III	Non-critical to business operations; accessed occasionally or performs automated procedures on a scheduled basis; outage would not impact business significantly unless not recovered after three days or more.	7 years

Summary of the physical asset hardware status:

Level 0

- None.

Level I

- One Windows based server in the Energy Management system and aged five years.
- Four VMWare virtual machine host servers in the Hydro system and aged five years.
- Three VMWare virtual machine host servers in the Hydro system and aged six years.
- Five Customer Care System servers in the Hydro System and aged six years.

Level II

- One Database server machine in the Hydro system and aged seven years.

Level III

- One keyboard/video/mouse appliance in the Hydro system and aged seven years.
- One scanning server machine in the Hydro system and aged seven years.

This is an ongoing refresh program to maintain server performance. Hydro continues to seek efficiencies in systems management tools and reducing energy, space and cooling usage by virtualizing eligible systems upon the end of the physical server's service life. Future replacements and upgrades will be proposed in future budget applications.

The project is scheduled to start in January 2016 and be completed by the end of November 2016.

Operating Experience:

Reliability Performance

Hydro's servers are used on a continuous basis. The servers are active for the life of the unit once placed in service. Hydro standardizes on enterprise grade hardware for both corporate and energy management applications. Hydro has had satisfactory performance and reliability levels from this hardware as a result.

Industry Experience

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.

Vendor Recommendations

General industry practice is that servers be replaced in a five year lifecycle. Parts may not be available after five years for the servers to be replaced depending on the component that fails.

Maintenance or Support Arrangements

IBM Software Support Lifecycle Policy applies to the software which powers systems including the enterprise server subsystems, drivers, firmware, and management tools. A minimum of five full years of standard support from the date the product release was made generally available by IBM, with the option to get support extensions for at least an additional three years following a product's end-of-service date for an extra charge set by IBM.

IBM warranty support for the servers is discontinued. Hydro has determined that the standard three year manufacturer warranty is insufficient for its Intel Server Infrastructure and increases this warranty to five years at time of purchase.

After the initial five year warranty, the server is placed on a maintenance program with IBM that is renewed yearly until the server is replaced.

IBM sold its server business to Lenovo during 2014, however the support lifecycles and hardware warranty and maintenance agreements remained unchanged at this time. Hydro's maintenance commitments from the vendor remain in place.

Historical Information

Table 3 shows the five-year historical costs of the Server Technology Upgrade Program as well as the budgeted amount for 2015.

Table 3: Five-Year Historical Information

Year	Budget ($000)	Actual ($000)	Servers
2015B	374.2		
2014	328.0	304.1	16
2013	367.6	367.6	45
2012	171.7	171.3	19
2011	209.3	213.5	18
2010	196.6	197.9	14

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. The average age of the equipment being replaced is approximately 6 years.

Development of 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.

Conclusion:

This is an ongoing refresh program to maintain server performance, improve systems management, availability and reduce energy, space and cooling usage by virtualizing systems upon the end of the physical servers service life. Future replacements and upgrades will be proposed in future budget applications.

Project Schedule:

As there are numerous subprojects in this proposal, the timelines for each will be dictated by many factors. In general terms, the work will occur mainly during the first three quarters of 2016 and occur on timelines based on resource and materials availability, contractor scheduling, and departmental change management approvals.

Project Title: Upgrade Energy Management System

Location: Hydro Place

Category: General Properties - Information Systems

Type: Other

Classification: Normal

Project Description:

This project is required to upgrade the OSI Monarch Energy Management System (EMS). The EMS system is used by the Energy Control Centre (ECC) in St John's on a 24 hour basis to control and monitor the provincial transmission grid and generation facilities operated by Hydro. The system software is upgraded on a yearly basis to allow for the inclusion of fixes and functionality changes to the software. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	30.2	0.0	0.0	30.2
Consultant	0.0	0.0	0.0	0.0
Contract Work	167.6	0.0	0.0	167.6
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	8.8	0.0	0.0	8.8
Contingency	39.6	0.0	0.0	39.6
TOTAL	**246.2**	**0.0**	**0.0**	**246.2**

Justification:

This project is a normal continuation of upgrades to ensure proper functionality. The EMS is essential to the continued efficient and reliable operation of the provincial transmission grid and generation facilities operated by Hydro. The EMS provides a critical function for Hydro and the operation of the Island Interconnected System. Without properly upgraded and functioning EMS, remote control of any system would be impossible and therefore all major stations would have to be staffed.

Existing System:

The existing system was installed in 2006 and the software has been upgraded every year since then on an annual basis. The computers that the software runs on were upgraded in 2014 and the computer system operating system was migrated from AIX to Linux.

The EMS system is used by the Energy Control Centre (ECC) in St John's on a 24 hour basis to control and monitor the provincial transmission grid and generation facilities operated by Hydro.

The following upgrades have occurred over the past five years:

Table 2: Major Work or Upgrades

Year	Major Work/Upgrade	Comments
2014	Software upgrade and Server Upgrade	Replaced servers and upgraded software for elimination of software Bugs fix and increased functionality of software
2013	Software Upgrade	Elimination of software bugs and increased functionality of software
2012	Software Upgrade	Elimination of software bugs and increased functionality of software
2011	Software Upgrade	Elimination of software bugs and increased functionality of software
2010	Software Upgrade	Elimination of software bugs and increased functionality of software

Operating Experience:

The EMS was purchased from Open Systems International in June 2006. It has been in continuous operation since commissioning. The software had been upgrade on a yearly basis from 2007 to 2014. The importance of this software to the operation of the power system requires that the software be upgraded annually to remove any software bugs and to be able to take advantage of any functionality that would benefit the operating of the power system.

Industry Experience

Hydro must keep its software used to control and monitor the provincial transmission grid and generation facilities up to date. Failure to keep this software current will put Hydro at risk of unplanned computer system outages which would affect the control and monitoring of the transmission grid and generation facilities.

Vendor Recommendations

The vendor recommends that the software be upgraded on a yearly basis as to allow known software bug fixes to be eliminated and to increase the functionality of the software.

Maintenance or Support Arrangements

The software is on Maintenance support which allows for the following from Open Systems International:

- Dedicated support staff for handling incoming support calls;
- After hours on-call support service;
- 24/7 support coverage;
- Web-based Customer Support portal;
- Fast response for critical support requests; and
- Comprehensive database tracking and reporting on support requests.

Historical Information

Table 3 provides information from previous capital budget applications.

Table 3: Historical Information

Year	Capital Budget ($000)	Actual Expenditures ($000)
2015B	194.4	
2014	187.9	184.3
2013	129.9	133.7
2012	117.8	107.0

Anticipated Useful Life

The anticipated useful life of this software is limited by the functionality that it provides to support the requirements of Hydro and the ongoing support of this software by the vendor. Software is depreciated over a 10 year period.

Conclusion:

This project is necessary as to allow Hydro to control and monitor the provincial transmission grid and generation facilities operated by Hydro. This project is done on a yearly basis to eliminate software bugs and increase the functionality of the software.

Project Schedule:

The project will be started in April 2016 and completed by the end of August 2016.

Project Title: Replace Radomes

Location: Various Sites

Category: General Properties - Telecontrol

Type: Pooled

Classification: Normal

Project Description:

This project 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. 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. The radome replacement program proposed by Hydro is based on operational experience and the manufacturers' recommendations. Due to 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 2016-2020 is provided in Appendix A. Eleven radomes are scheduled to be replaced in 2016. This project is completed through the joint effort of an external contractor, who performs the field work, and internal forces, performing project management and providing technical support. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	45.3	0.0	0.0	45.3
Consultant	0.0	0.0	0.0	0.0
Contract Work	134.2	0.0	0.0	134.2
Other Direct Costs	5.6	0.0	0.0	5.6
Interest and Escalation	13.1	0.0	0.0	13.1
Contingency	37.0	0.0	0.0	37.0
TOTAL	**235.2**	**0.0**	**0.0**	**235.2**

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 Coast Microwave System in 2001, approximately 20 antennas were installed. To avoid the logistical challenges that would be created by replacing each of these radomes in the same year, Hydro decided that the replacement program shall be distributed as much as practical. The current schedule for the next five years is included in Appendix A.

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 impact of a microwave failure today could have a greater effect compared to 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 230kV transmission lines are carried on the microwave network. Therefore, a microwave failure would cause the Energy Control Centre to lose control of the system stations and likely cause and/or extend customer outages.

Existing System:

Hydro has a network of microwave radios, 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 two meters to five 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 feed horn of the antennas (responsible for sending and receiving microwave radio signals) are covered with a flexible covering, stretched over the antenna shroud, 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 the feed horn, and do not interfere with the microwave radio signals. 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.

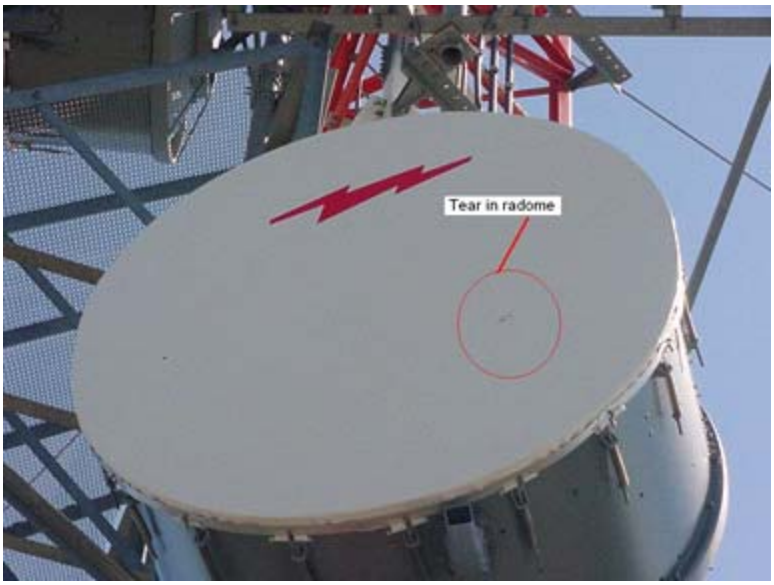


Figure 2: Tear in Radome

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 projectiles 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.

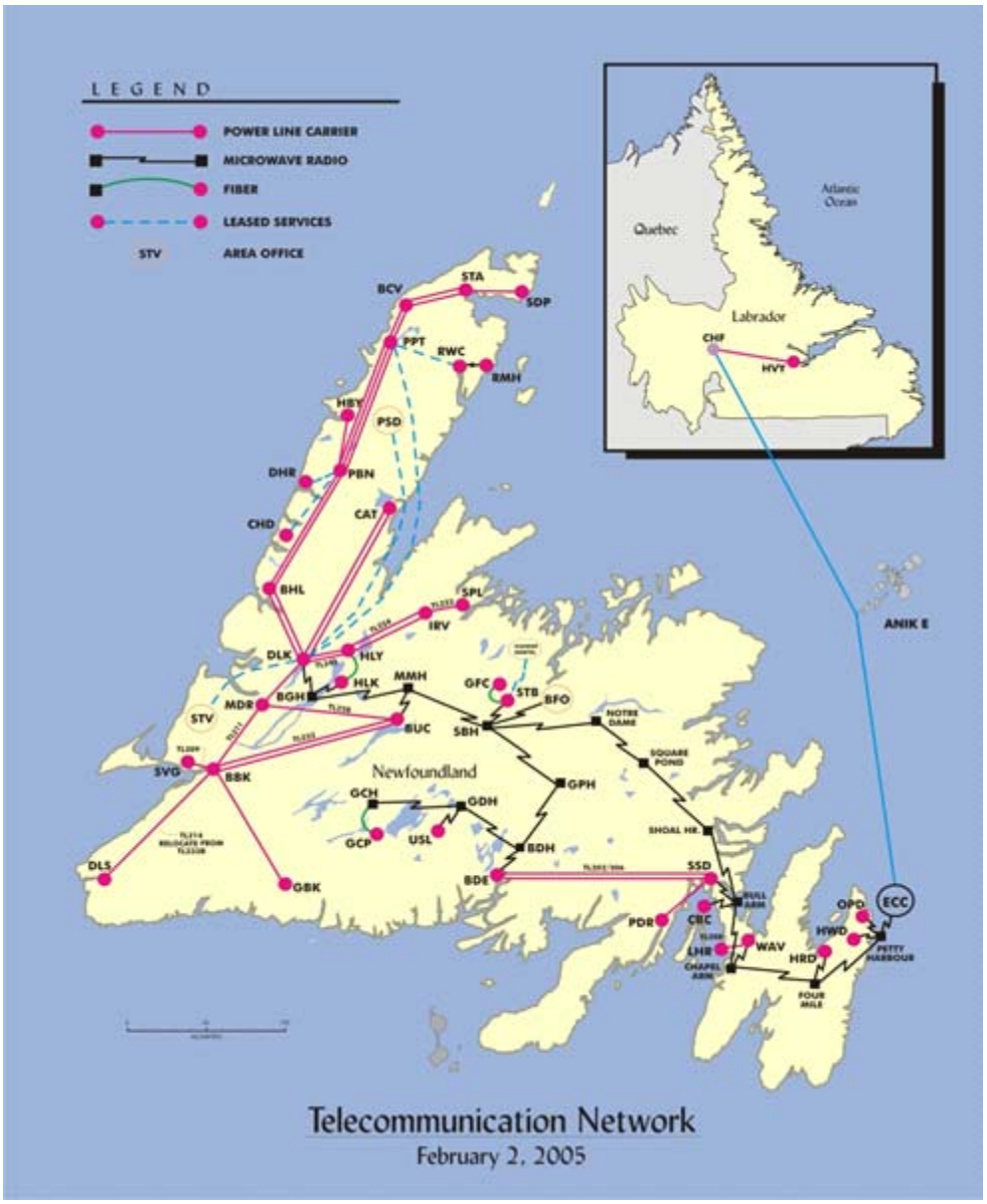


Figure 5: Location of Towers

Major Work and/or Upgrades

There are no upgrades available for a radome. It must be replaced based upon the estimated useful life or upon observed damage during inspection.

Operating Experience:

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.

There have been no other communication outages caused by radome failures since the 1996 storm.

Safety Performance

There are 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.

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 replacement frequency was developed:

- CableWave radomes (made of Hypalon material) should be replaced on a seven-year cycle; and
- 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 due to the structural differences associated with each type of antenna.

Maintenance or Support Arrangements

There are no maintenance or support arrangements associated specifically with radomes. Radome inspection is included as part of an overall tower inspection which occurs annually.

Maintenance History

Radomes are visually inspected each year when the tower is inspected, or as soon as practical after any extremely severe storm that might have affected a particular site. A visual inspection may also be required as part of any corrective maintenance investigation into any loss or degradation of signal that may have been caused by a radome tear damaging the feed horn assembly. The radomes are inspected for any tears and any failure of the mounting hardware. Radomes cannot be repaired and must be replaced when a tear of any size is visually detected. Even a small tear is unacceptable as it will become much larger due to the high stresses caused by wind and other environmental factors including icing.

Historical Information

Table 2 shows the historical information for the Radome Replacement Program since 20011.

Table 2: Capital Budget and Expenditures Since 20011

Year	Capital Budget ($000)	Actual Expenditures ($000)	Units	Cost per unit ($000)	Comments
2015	0.0	0.0	0		
2014	324.9	217.8	14	15.6	Favorable weather during construction; contingency not required.
2013	336.0	263.0	18	18.7	Not Complete.
2012	172.0	148.8	14	12.3	Incomplete due to weather restrictions.
2011	195.9	101.7	11	9.3	

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.

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 is based on operational experience and manufacturers' recommendations. Historically, this project has been executed by external contractors and supported by internal resources and this joint effort will continue in 2016.

Due 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.

Future Plans:

Future plans will be proposed in future capital budget applications. Radome replacements are planned for four of the next five years as listed in Appendix A of this report and shown in the five-year capital plan (2016 Capital Plan Tab, Appendix A).

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare Project Plan and site visits	January 2016	February 2016
Design	Complete Tender Package	February 2016	March 2016
Procurement	Purchase Radomes	April 2016	April 2016
Installation	Install Radomes	May 2016	September 2016
Commissioning	Site Inspections	October 2016	October 2016
Closeout	Project Closeout	November 2016	December 2016

APPENDIX A

Radome Replacement Schedule

2016 Radome Replacements

Tower	Direction	Antenna			
		Size	**Vendor**	**Model #**	**Last Replaced**
BAH	CAH	2.4m (8')	Andrew	HP8-71D	2009
BAH	CBC	1.8m (6')	Andrew	HP6-71E	2009
BAH	SSD	1.8m (6')	Andrew	HP6-71E	2009
GPH	SBH (main)	3.6m (12')	Andrew	HP12-71E	2009
GPH	SBH (div)	3.6m (12')	CW	DA12-71hp	2009
GPH	BDH	2.4m (8')	Andrew	HP8-71D	2008
GPH	BDH	1.8m (6')	CW	DA6-71hp	2008
SBH	GPH	3.6m (12')	CW	DA12-71hp	2009
SBH	GPH	3.6m (12')	Andrew	HP12-71E	2009
SBH	MMH	3.0m (10')	Andrew	HP10-71D	2009
SBH	STB	1.8m (6')	CW	DA6-71hp	2009

2017 Radome Replacements

None Required

2018 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
CAH	FMH (main)	3.0m (10')	Andrew	HP10-71D	2010
CAH	FMH (div)	2.4m (8')	Andrew	HP8-71D	2010
CAH	BAH (main)	3.0m (10')	Andrew	HP10-71D	2010
CAH	BAH (div)	2.4m (8')	Andrew	HP8-71D	2010
CAH	WAP	2.4m (8')	Andrew	HP8-71D	2010
FMH	PHH (main)	3.0m (10')	Andrew	HP10-71D	2010
FMH	CAH (main)	3.0m (10')	Andrew	HP10-71D	2010
FMH	CAH (div)	2.4m (8')	Andrew	HP8-71D	2010
FMH	HRP	2.4m (8')	Andrew	HP8-71D	2010
MMH	BUC	1.8m (6')	CW	DA6-71hp	2011
OPD	PHH	1.8m (6')	Andrew	HP6-71E	2010
PHH	FMH (main)	3.0m (10')	Andrew	HP10-71D	2010
PHH	FMH (div)	1.8m (6')	Andrew	HP6-71E	2010
STB	SBH	1.8m (6')	CW	DA6-71hp	2011
WAP	CAH	2.4m (8')	Andrew	HP8-71D	2010
WAP	WAV	2.4m (8')	Andrew	HP8-71D	2010
WAV	WAP	1.8m (6')	Andrew	HP6-71E	2010

2019 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	SHH (main)	2.4m (8')	Andrew	HP8-71GE	2011
BAH	SHH (div)	2.4m (8')	Andrew	HP8-71GE	2011
CBC	BAH	1.8m (6')	Andrew	HP6-71E	2011
DLP	DLK	3m x 4.9m	Microflect	90392	2011
ECC	PHH	1.8m (6')	Andrew	HP6-71E	2011
HWD	PHH	2.4m (8')	Andrew	HP8-71D	2011
MMH	SBH	3.0m (10')	Andrew	HP10-71D	2011
PHH	OPD	1.8m (6')	Andrew	HP6-71E	2011
PHH	HWD	1.8m (6')	Andrew	HP6-71E	2011
SSD	BAH	1.8m (6')	Andrew	HP6-71E	2011

2020 Radome Replacements

Tower	Direction	Antenna			
		Size	Vendor	Model #	Last Replaced
BAH	CAH	3.0m (10')	Andrew	HP10-71D	2012
GCH	GDH	3.0m (10')	Andrew	HP10-71D	2012
GCH	GDH	2.4m (8')	Andrew	HP8-71D	2012
GDH	GCH (main)	3.0m (10')	Andrew	HP10-71D	2012
GDH	GCH (div)	2.4m (8')	Andrew	HP8-71D	2012
HRP	FMH	2.4m (8')	Andrew	HP8-71D	2012
PHH	ECC	2.4m (8')	Andrew	HP8-71D	2012

Abv	Site Name
BAH	Bull Arm Hill Microwave/Repeater
BDE	Bay D'Espoir Terminal Station
BDH	Bay D'Espoir Hill Microwave/Repeater
BFI	Bishop Falls Office
BGH	Blue Grass Hill Microwave/Repeater
BUC	Buchans Terminal Station
CAH	Chapel Arm Hill Microwave/Repeater
CBC	Come By Chance Terminal Station
DLK	Deer Lake Terminal Station
DLP	Deer Lake Passive Repeater
ECC	Energy Control Center
FMH	Four Mile Hill Microwave/Repeater
GCH	Granite Canal Hill Microwave
GDH	Godaleich Hill Microwave/Repeater
GPH	Gull Pond Hill Microwave

Abv	Site Name
HRP	Holyrood Plant
HWD	Hardwoods Terminal Station
MMH	Mary March Hill Microwave
NDH	Notre Dame Hill
OPD	Oxen Pond Terminal Station
PHH	Petty Harbour Hill Microwave/Repeater
SBH	Sandy Brook Hill Microwave
SHH	Shoal Harbour Hill
SPH	Square Pond Hill
SSD	Sunnyside Terminal Station
STB	Stony Brook Terminal Station
USL	Upper Salmon Plant
WAP	Western Avalon Passive Repeater
WAV	Western Avalon Terminal Station

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Page Ref
		($000)			
GENERATION					
Install Infrared View Ports - Various Sites	83.7	113.1		196.8	
Replace Generator Cooling Water Piping - Hinds Lake		181.7		181.7	E-2
Study of Auxiliary Steam and Space Heating Requirements - Holyrood		148.7		148.7	E-6
Install Transfer Switches for Diesel Automation - Happy Valley		148.4		148.4	E-9
Replace Control Room/Communications Room Air Conditioning - Hinds Lake		41.3	53.0	94.3	E-11
Refurbish Unit Relay Protection - Paradise River	8.7	79.7		88.4	
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir		85.7		85.7	E-14
TOTAL GENERATION	92.4	798.6	53.0	944.0	
TRANSMISSION AND RURAL OPERATIONS					
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	189.3		199.3	
Install Fall Protection Equipment - Various Sites		198.8		198.8	E-18
Replace Surge Arrestors - Various Sites		144.4	53.0	197.4	E-29
Upgrade Warehouse Lighting - Bishop's Falls		15.2	180.4	195.6	E-37
Purchase Meters and Metering Equipment - Various Sites		190.4		190.4	E-39
Replace Station Lighting - Bay d'Espoir	16.7	160.3		177.0	
Install Variable Frequency Drives - Grey River		46.9	123.0	169.9	E-42
Replace Air Receivers and Compressors - St. Anthony		120.7		120.7	E-45
TOTAL TRANSMISSION AND RURAL OPERATIONS	26.7	1,066.0	356.4	1,449.1	
GENERAL PROPERTIES					
Remove Safety Hazards - Various Sites		199.3		199.3	E-47
Perform Minor Application Enhancements - Hydro Place		197.9		197.9	E-50
Replace Air Conditioners - Massey Drive and Happy Valley		39.9	152.0	191.9	E-52
Replace Network Communication Equipment - Various Sites		186.4		186.4	E-54
Replace Video Conferencing Bridge - Hydro Place		182.6		182.6	E-56
Upgrade Citrix - Hydro Place		159.6		159.6	E-58
Upgrade Sharepoint Document Repository - Hydro Place		143.5		143.5	E-64
Upgrade Access Roads to Microwave Sites - Gull Pond Hill and Sandy Brook Hill		141.1		141.1	E-66
Refresh Security Software - Hydro Place		123.5		123.5	E-71
Upgrade Remote Terminal Units - Various Sites		89.6		89.6	E-73
TOTAL GENERAL PROPERTIES		1,463.4	152.0	1,615.4	
TOTAL PROJECTS OVER $50,000 AND UNDER $200,000	119.1	3,328.0	561.4	4,008.5	

Project Title: Replace Generator Cooling Water Piping

Location: Hinds Lake

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project involves the replacement of the generator bearing cooling water piping, outside the generator housing, and cooling water flow measuring devices at Hinds Lake Hydroelectric Generating Station (Hinds Lake). Both the supply and discharge pipelines will be replaced with piping made of corrosion-resistant material.

The project budget estimate is provided in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	40.4	0.0	0.0	40.4
Labour	93.1	0.0	0.0	93.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.4	0.0	0.0	8.4
Interest and Escalation	11.4	0.0	0.0	11.4
Contingency	28.4	0.0	0.0	28.4
TOTAL	**181.7**	**0.0**	**0.0**	**181.7**

Operating Experience:

The cooling water system supplies cooling water at a specific rate to various critical components on the turbine and generator.

Pipes from this system have been found to have over 50% blockage. The filtration system at Hinds Lake is working well; however, the blockage has been caused by fouling and material building up on the interior surface of the pipes, decreasing the cooling water flows.

Project Justification:

Due to fouling, the cooling water pipes became clogged with organic slime and hardened organics that attach themselves to the pipe walls causing the cooling water flows to decrease significantly and; therefore, the bearings and stator temperatures to rise. Stator temperature alarm settings

have been increased to accommodate the low flow situation. The alarm settings are still acceptable; however, the bearings and stator ages decrease at a faster rate with respect to an increase in operating temperature.

The cooling water piping and flow measuring devices, outside the generator housing, have become unreliable and need be replaced in order to maintain the acceptable level of temperatures in the bearings and stator which is critical to the operation of Hinds Lake.

Development of Alternatives

Assessment of the cooling water system considered the following alternatives:

1. Status quo;
2. Replace existing piping with corrosion resistant piping;
3. Closed loop system; and
4. Chemical injection.

Status Quo

The cooling water piping outside the generator housing is original piping that was installed when the plant first came on-line in 1980. This piping is near the end of its useful life. The status quo is not acceptable because of the risk of having to de-rate the unit or take a forced outage because of high temperatures.

Replace Existing Piping with Corrosion Resistant Piping

Currently the piping material is carbon steel schedule 40. Two different piping materials have been considered for replacement of the carbon steel piping, they are 316 stainless steel pipe schedule ten and polyvinyl chloride (PVC) pipe schedule 80.

The 316 stainless steel schedule ten pipe is considered for corrosion resistance and fouling protection. This reduces future maintenance costs of cleaning the piping every year because of fouling. The stainless steel pipe will be placed in high traffic areas or in areas where the piping is likely to be hit to prevent damage.

The PVC schedule 80 pipe is considered because of its corrosion resistance, mechanical properties, and thermal properties. Schedule 80 will be more durable when compared with schedule 40. Due to PVC's excellent thermal properties there will be no need to insulate the pipe as compared to

stainless steel. The PVC pipe will be placed in low traffic areas where the probability of the pipe being damaged is remote.

Closed Loop System

By adding another heat exchanger to the existing service water system one can create a closed system. There are various heat exchangers that can be implemented into the system such as water-to-water, air-to-water, or chemical-to-water.

Water-to-water would be the most practical in this situation due to the amount of heat that is being transferred through the exchanger. An air-to-water heat exchanger would have a very large surface area in order to remove the quantity of heat within the system, making this solution not practical. Using a chemical within the closed circuit system is not necessary considering the temperatures that we are dealing with.

This additional heat exchanger will require pumps, piping and valves in order to be incorporated into the service water system. In addition the style and location of this new heat exchanger will be incorporated into the design of the new system so that maintenance will be easier. Also this system will have 100% capacity back up so that cleaning of the heat exchanger will not require any unit outages.

The use of a cooling pond to supply water to the service water system can be considered a closed loop system because you are reusing the existing water that is in the cooling pond. The water in the cooling pond can be chemically treated to ensure that it remains neutral and does not become acidic. Again space would be a restriction with this type of solution.

Chemical Injection

The chemical injection alternative is based on injecting a chemical known as FLOGARD POT6101 into the cooling water system. This chemical has both cathodic and anodic inhibitors that react with the water to prevent corrosion of the piping and organic build up within the piping.

Recommendations:

It is recommended to replace the piping outside the generator housing with corrosion resistant piping for Hinds Lake. The pipe's life expectancy within the cooling water system is coming to an end and will need to be replaced in the near future. Also, this solution will result in lower up front

and maintenance costs for the system. Another benefit is that no new design work has to be done in order for this solution to be implemented.

Future Plans:

There are plans to replace the cooling water pump and strainer in the future.

Project Schedule:

The anticipated project schedule is provided in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Open project; Review budget and schedule ; and Prepare scope statement	January 2016	January 2016
Design	Select piping materials.	February 2016	February 2016
Procurement	Prepare material requisitions; and Order and receive materials.	March 2016	May 2016
Construction	Install piping and flow measuring devices.	June 2016	June 2016
Commissioning	Perform commissioning of cooling water system.	June 2016	June 2016
Closeout	Prepare close out package.	August 2016	August 2016

Project Title: Study of Auxiliary Steam and Space Heating Requirements

Location: Holyrood

Category: Generation - Thermal

Definition: Other

Classification: Normal

Project Description:

This project is required to perform an engineering study to evaluate the following two options for Holyrood Thermal Generating Station (Holyrood):

Option 1: Install Auxiliary Boiler Plant

The short term function of the auxiliary boiler plant is to provide steam to support expedited plant start-up and space heating for the entire plant while the plant is placed in a generation stand-by mode (for the period post integration with the Labrador Island Link, and prior to the period when generation is no longer necessary from Holyrood). The long term function of the new auxiliary boiler plant is to provide space heating for the plant buildings as Holyrood discontinues operating in generation mode and continues to operate in synchronous condenser mode.

The auxiliary boiler plant would include two fire tube boilers, each with a capacity of 12,500 lb/hr, all associated equipment such as deaerator, softener, pumps, chemical feed system, stack, piping and electrical systems, instrumentation, control systems and tie-ins with existing equipment.

Option 2: Install Light Oil Fired Air Heaters

As this option does not involve auxiliary boilers to support expedited plant start-up, Hydro will maintain the plant in hot stand-by mode in order to have the plant available to start quickly and provide generation in the unlikely event it is needed. The specifics of what configuration exists for the hot stand-by mode will be examined. This will be the case for the time when the plant is in the generation stand-by period.

Light oil fired air heaters would be installed in different areas of the plant to provide space heating, required to be in service when the plant discontinues generate and stand-by mode.

The engineering study will determine the requirements, material list, basic specifications, advantages, disadvantages, cost estimate (capital, operation and maintenance costs) for each option.

The project budget estimate is provided in Table 1.

Table 1: Budget Estimate.

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	30.2	0.0	0.0	30.2
Consultant	88.8	0.0	0.0	88.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	5.9	0.0	0.0	5.9
Contingency	23.8	0.0	0.0	23.8
TOTAL	**148.7**	**0.0**	**0.0**	**148.7**

Operating Experience:

Auxiliary steam is currently used at Holyrood for space heating in the powerhouse, office block, pumphouse and water treatment plant. It is also used to heat Bunker C fuel tanks and piping, to preheat combustion air and to atomize fuel so it can be burned in the main power boilers.

Currently the auxiliary steam at Holyrood is extracted from the main power boilers when one or more of the three power boilers is operated to provide high pressure steam of approximately 1,990 psig and 802^{o}F for power generation. The auxiliary steam is obtained by reducing the main high pressure steam to approximately 225 psig and 397 °F for use in the auxiliary steam system.

Holyrood was originally equipped with two 25,000 lb/hr, oil fired auxiliary steam boilers at a pressure of 200 psi, and were used to provide auxiliary steam when the power boilers are shut down. The auxiliary boilers were operated only when all three power boilers were not operating and thus were operated for only a short period each year. This short operating season meant that the boilers were left idle for extended periods and were subjected to extensive corrosion. In 1992, an assessment of the two auxiliary boilers concluded that their conditions had deteriorated and cost of repairs was equal to the cost of replacement. It was decided to condemn the auxiliary boilers, largely based on the assumption that it would be highly unlikely that the plant would ever again experience a complete plant outage.

Project Justification:

Once the plant is placed in generation stand-by, the original source of space heating using the main power boilers will not be in continuous service. Therefore, a continuous source of space heating from the auxiliary boilers or light oil fired heaters will be required to heat the plant buildings. Also, a support to expedited plant start-up will be required during the generation stand-by period. This will be achieved by placing the plant in hot stand-by mode or using the auxiliary boilers.

Generation from Holyrood will be no longer expected to be required after the stand-by period. Hence, the boiler powerhouse portion including the boilers will be decommissioned and demolished. The wastewater treatment plant and the existing 880,000 barrel tank farm including the day tank and associated pipelines will no longer be required; however, the turbine powerhouse portion, lab, administrative offices, maintenance and water treatment areas will remain intact. Therefore, the new source of space heating will continue to operate to heat the buildings that will remain intact after decommissioning of the power boilers.

Future Plans:

A capital application will be submitted to execute the most viable option.

Project Schedule:

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open job and prepare scope statement.	January 2016	January 2016
Design	Prepare the engineering study and report.	February 2016	April 2016
Procurement	Issue request for proposals (RFP); Evaluate proposals; and Award contract.	January 2016	February 2016
Closeout	Prepare close out documents	April 2016	April 2016

Project Title: Install Transfer Switches for Diesel Automation

Location: Happy Valley

Category: Generation - Gas Turbines

Definition: Other

Classification: Normal

Project Description:

This project is to install electrically controllable transfer switches for the air compressor system and 24 V DC battery charger. These transfer switches will be controlled by the gas turbine control system at the Happy Valley Gas Turbine site. Modifications are to be made to the control circuits so that, in the event of loss of station service and diesel starting automatically, the 24 V DC charger and air compressor are gradually loaded onto the diesel to ensure voltage output stability of the diesel.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	10.0	0.0	0.0	10.0
Labour	99.0	0.0	0.0	99.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.0	0.0	0.0	6.0
Interest and Escalation	10.4	0.0	0.0	10.4
Contingency	23.0	0.0	0.0	23.0
TOTAL	**148.4**	**0.0**	**0.0**	**148.4**

Operating Experience:

The following operating issues are addressed in this proposal:

1. During a black-out situation, the diesel is required to start prior to starting the gas turbine to ensure the integrity of the 125 V DC battery bank. A 24 V DC battery bank that is used to start the diesel is charged from the regular station service AC supply. Once station service fails, the diesel starts automatically but its battery bank is no longer charged therefore reducing the capacity to restart in the event of a failed start or trip. An electrically controllable transfer switch is required to supply the 24 V DC battery charger from the diesel AC output on loss of regular station service.
2. The air compressor system used to start the gas turbine has a manual transfer switch for AC supply which can be used to select supply from station service or diesel. An operator is

required during black-outs to go to site to transfer the air compressor from station service to the diesel supply. This inhibits remote starting of the gas turbine following the depletion of the compressed air reserve thereby reducing the availability. An electrically controllable transfer switch is required.

3. The loading criteria for the diesel have to be modified to ensure loads are applied gradually. The gas turbine control system will control the transfer switches to gradually load the diesel.

Project Justification:

The air compressor system is critical to the starting of the gas turbine and should be supplied by emergency power from the diesel in the event of loss of AC station service supply while the gas turbine is not running. The 24 V DC battery bank is critical to the starting of the diesel. Transfer switches are required to supply the 24 V DC battery bank charger and the air compressor system from the diesel following loss of station service. The existing manual transfer switch for the air compressor system relies on the presence of an operator to change the AC supply of the air compressor over to the diesel supply and therefore should be replaced with an electrically controllable transfer switch. Modifications to the gas turbine controls are required to monitor the diesel output and maintain diesel stability following each successive addition of load.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Site visit, drawing review	February 2016	February 2016
Design	Revise / prepare schematics and wiring	March 2016	May 2016
Procurement	Order transfer switches and cables	April 2016	June 2016
Construction	Remove one and install two transfer switches	June 2016	July 2016
Commissioning	Test transfer switch operations	July 2016	July 2016
Closeout	Project Closeout	August 2016	September 2016

Future Plans:

None.

Project Title: Replace Control Room/Communications Room Air Conditioning

Location: Hinds Lake

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project is for the direct replacement of the air conditioning (AC) unit that serves both the control room and the communication room in the Hinds Lake Generating Station. The unit is located in a hallway between both of these rooms with the cool air being channeled through ductwork to supply the rooms. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	20.0	2.0	0.0	22.0
Labour	17.1	23.0	0.0	40.1
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	1.6	9.9	0.0	11.5
Interest and Escalation	2.6	3.4	0.0	6.0
Contingency	0.0	14.7	0.0	14.7
TOTAL	**41.3**	**53.0**	**0.0**	**94.3**

Operating Experience:

The AC unit (Figure 1) in the Hinds Lake Generating Station is from the original construction of the plant and was installed in 1980. Over the past 35 years of service, the AC unit has performed well to cool the equipment in both the control room and the communication room. However, in the past five years there have been a number of operational issues with this AC unit that has prompted the need for a replacement. During the past five years, the AC unit has had the compressor replaced twice, fan problems, and a contactor failure. When these failures occur, operations are notified due to high ambient temperatures either in the control room or communications room and they are called out to investigate. During these failures, temperatures in the control room can become unbearable for employees because of the heat generated by electrical equipment located in this room. Further, lack of controlled temperatures and humidity puts sensitive electrical equipment at risk of failure as the equipment requires specific environmental conditions to operate properly. Portable fans have to be installed and doors opened to complete day to day tasks and to ensure the

equipment does not get exposed to extreme environmental conditions while the AC unit is under repair.

The AC unit is a water cooled type that uses R-22 type refrigerant. This type of refrigerant is currently being phased out because R-22 is a powerful greenhouse gas with a global warming potential of 1810, which indicates 1810 times as powerful as carbon dioxide. During the past three years, the refrigerant on this unit has been replaced twice and, on one occasion, the refrigerant was released to the atmosphere due to a failure.

Figure 1: Air Conditioning Unit in Hinds Lake Generating Station

Project Justification:

The main purpose of this AC unit is to control the temperature and humidity in both the control room and the communication room at the Hinds Lake Generating Station. These rooms house sensitive electrical equipment that requires specific environmental conditions to operate correctly and reliably. If the humidity is too high, moisture in the air can short out the electrical equipment or if the humidity is too low, static electrical charges in the air can short out the equipment. As well, if the temperature is too high, components in the electrical equipment could fail due to high heat.

The AC unit is 35 years old and has surpassed its anticipated life of 20 years. As expected, the reliability of the unit has suffered creating operation problems. This lack of reliability along with the environmental issues concerning the R-22 refrigerant is the justification for this project. In order for Hydro to ensure continued reliable service from the Hinds Lake Generating Station this unit must be replaced.

Project Schedule:

The anticipated schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Project kick off meeting, safety plan, risk assessment, open project in JDE, and complete WBS.	April 2016	June 2016
Design	Prepare technical spec, site visit if necessary.	April 2016	April 2016
Procurement	Based on technical spec purchase unit that meets criteria and is least cost	June 2016	June 2016
Construction	Remove old unit, connect temporary unit if required, install new unit, dispose of old unit.	February 2017	February 2017
Commissioning	Commissioning of unit.	February 2017	February 2017
Closeout	Asset Assignment Forms, PIR Form, Lessons Learned Meeting, and Contract Close Out Certificate	March 2017	March 2017

Project Title: Assess Vent Chambers Units 1 to 6

Location: Bay d'Espoir

Category: Generation - Hydraulic

Definition: Other

Classification: Normal

Project Description:

This project involves a condition assessment and an engineering technical review of the operation of the existing air vent system for each of the generating Units 1-6 spiral cases. It will include detailed inspection and Non Destructive Testing (NDT) of the vent chambers and high pressure piping. Based on the results of the testing and the technical review, a report with future recommendations will be prepared to identify any future capital expenditures. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	1.0	0.0	0.0	1.0
Labour	31.5	0.0	0.0	31.5
Consultant	14.8	0.0	0.0	14.8
Contract Work	15.0	0.0	0.0	15.0
Other Direct Costs	3.1	0.0	0.0	3.1
Interest and Escalation	7.2	0.0	0.0	7.2
Contingency	13.1	0.0	0.0	13.1
TOTAL	**85.7**	**0.0**	**0.0**	**85.7**

Operating Experience:

Each vent system (Figure1) on Units 1-6 is required to remove air in order to fill and pressurize the spiral case prior to opening the spherical valve on the penstock, which supplies water to the unit at design pressure of 250 psi. The controls of the spherical valve have to meet a sequence of computer logical controls before the spherical valve can be operated. The vent chamber is important to these controls because it allows sensors to pick up pressure readings and the presence of water in the scroll case.

In 2006, a weld failure was identified on generating Unit 2 on the discharge of the vent chamber. This weld failure was corrected during annual maintenance of the unit. No other chambers were found with defective welds. The chambers are original to the plant construction and have shown

signs of wear over the past ten years as seen in Figures 2 and 3. Notice the heavy pitting on the chamber walls and the ring of rust along the base diameter of the chamber.

Figure 1 : Vent Chamber

Figure 2: Interior of a Vent Chamber

Figure 3: Interior of a Vent Chamber

Project Justification:

The vent chambers and piping are original and are now 48 years old. Failure of one vent chamber has the potential to flood the powerhouse1 in Bay d'Espoir, considering the water pressure. These chambers experience at least 250 psi. Due to the critical role that these vent chambers have in the Bay d'Espoir plant and observed condition, these chambers require a more detailed assessment.

Future Plans:

Hydro will review the results of the assessment once complete and plan for future improvements as required.

Project Schedule:

The anticipated schedule for this project is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open work order, Create WBS.	February 2016	February 2016
Design	Technical Engineering review of vent system.	March 2016	March 2016
Procurement	Procurement of engineering consultant and NDT testing contractor.	April 2016	April 2016
Construction	Inspection and NDT of Vent Chambers.	July 2016	July 2016
Closeout	Close out, lessons learned and final report.	September 2016	September 2016

Project Title: Install Fall Protection Equipment

Location: Various Sites

Category: Transmission and Rural Operations

Definition: Pooled

Classification: Mandatory

Project Description:

This project is required to design, supply and install fall protection systems at several Hydro facilities. It includes installation of a ladder station and fall protection systems for William's Harbour Control Building and anchor plates for transformers at various locations where needed. The budget estimate is $198,800, as shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	30.0	0.0	0.0	30.0
Labour	74.4	0.0	0.0	74.4
Consultant	20.0	0.0	0.0	20.0
Contract Work	28.0	0.0	0.0	28.0
Other Direct Costs	34.7	0.0	0.0	34.7
Interest and Escalation	11.7	0.0	0.0	11.7
Contingency	0.0	0.0	0.0	0.0
TOTAL	**198.8**	**0.0**	**0.0**	**198.8**

Operating Experience:

Hydro initiated a five year program in 2005 to install fall protection systems on transformers, fuel tanks and roofs at its facilities. 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 required fall protection systems. Because of the large number of sites, (see Appendix A) Hydro concluded that all required fall protection systems could not be installed in the original five year program. The 2016 project is the twelfth year of the program which started in 2005 and sites were addressed on a priority basis. The project is expected to continue for several years beyond 2016.

Below is a summary of the three basic types of fall protection systems installed by Hydro. The photographs illustrate how each system is used.

Roof Fall Protection Systems

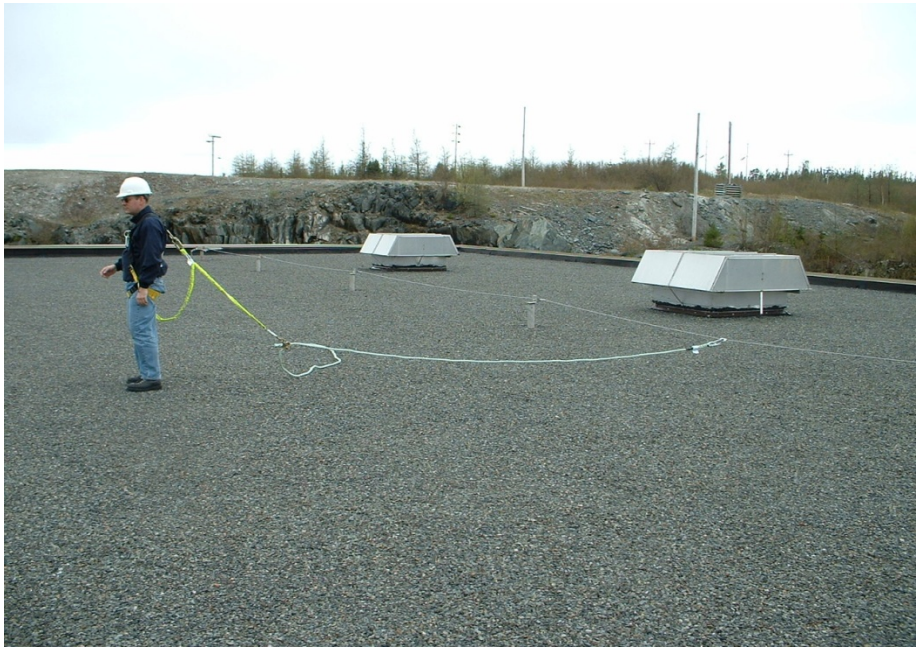


Photo 1: Roof Fall Protection System

Generally, a fall protection system is not a complex system. Photo 1 above shows an example of fall restraint system where a worker is 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. The fall restraints system ensures that the worker is prevented from approaching the edge of a building. This will ensure that falls are prevented from happening.

Ladder Fall Protection System

In this system, a safety cable is installed vertically on the side of the ladder as shown in photo 2 and 3 to the right. The workers secure themselves to the ladder fall protection system by attaching themselves (via a 'D' ring), as shown in the picture, that is attached to a cable grab which in turn rides on the cable. The cable grab allows the worker to move with ease

up the ladder but in the event of a sudden downward movement, as in a fall, the cable grab is designed to abruptly grab the cable, securing the worker and preventing a fall. This action is similar to the operation of a seat belt in a car.

Photos 2 and 3: Ladder Fall Protection System

Transformer Fall Protection System

Photo 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.

Photo 4: Transformer Fall Protection System

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 10 years.

Project Justification:

This project is justified on the requirement to provide a safe work environment and to comply with Section 140, 141, and 142, under Part X: Fall Protection, of the Occupational Health and Safety Regulations. Fall protection systems are required to perform work safely at elevations above 3.05 meters. Hydro must conform to these sections of the Occupational Health and Safety Regulations. Section 141 "General Requirements" states in part "where a worker is exposed to the hazard of falling from a work area that is: 3 meters or more

above the nearest safe surface or water; above a surface or thing; or above any open tank, pit or vat containing hazardous material, the employer shall ensure that the worker is provided with a fall arrest system that meets the requirements of section 142". The complete regulations contained under sections 140, 141, and 142 are presented in Table 3. Without proper fall protections systems in place, a worker can refuse to perform his/her assigned duties.

The fall protection 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 course of the program. Table 2 presents annual budget and actual expenditures for years 2010 to 2015.

Table 2: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)	Comments
2015B	198.9		Ladders and roofs
2014	199.4	139.1	Railing, roofs and transformer
2013	196.6	163.5	Ladders and roofs
2012	199.2	186.5	Ladders and roofs
2011	198.4	213.2	Ladders and roofs
2010	198.4	215.5	Ladders, transformers and roofs

In order to be compliant with Section 140 "Fall Protection Systems", Section 141 " General Requirements and Section 142 "Fall Arrest Systems", (Table 3) under Part X: Fall Protection, of the Occupational Health and Safety Regulations, this program of annual projects must continue until all facilities are properly equipped with fall protection systems.

Table 3: Section 140 "Fall Protection Systems", Section 141 "General Requirements" & Section 142 "Fall Arrest System", Part X: Fall Protection of the Provincial Occupational Health and Safety Regulations

Fall protection systems

140. Where an employer determines it is impractical to provide adequate work platforms or staging, the employer shall ensure that fall protection systems are used by all workers who are exposed to the hazard of falling, as required in section **141**.

General requirements

141. Where a worker is exposed to the hazard of falling from a work area that is

(a) 3 metres or more above the nearest safe surface or water;

(b) above a surface or thing that could cause injury to the worker if the worker were to fall on the surface or thing; or

(c) above an open tank, pit or vat containing hazardous material,

the employer shall ensure that

(d) the worker is provided with a fall arrest system that meets the requirements of section **142**;

(e) a guardrail that meets the requirements of section **28** is constructed or installed at the work area;

(f) a personnel safety net that meets the requirements of section **143** is installed at the work area;

(g) temporary flooring that meets the requirements of section **146** is constructed or installed at the work area; or

(h) the worker is provided with another means of fall protection that provides a level of safety equal to or greater than a fall arrest system that meets the requirements of section **142**.

Fall arrest system

142. (1) A fall arrest system that is provided in accordance with section **141** shall

(a) be adequately secured to

(i) an anchorage point, or

(ii) a lifeline that is

(A) securely fastened to anchor points, or

(B) attached to a static line that is securely fastened to anchorage points and that is capable of withstanding either the maximum load likely to be imposed on the anchorage point or a load of 22.2 kilonewtons, whichever is the greater;

(b) include a lanyard

(i) that is attached to an anchorage point or lifeline, where practicable, above the shoulder of the worker, and

(ii) that complies with CSA Standard Z259.11 "Energy Absorbers and Lanyards";

(c) prevent a free fall greater than 1.22 metres where

(i) the fall arrest system is not equipped with a shock absorption system that complies with CSA Standard Z259.11 "Energy Absorbers and Lanyards" and that reduces the shock level of a fall to less than 4 kilonewtons, or

(ii) the combined free fall and shock absorbed deceleration distance exceeds the distance between the work area and a safe surface; and

(d) include a full body harness that
(i) is attached to a lanyard,
(ii) is adjusted to fit the user of the harness, and
(iii) complies with CSA Standard Z259.10 "Full Body Harnesses".

(2) Where a fall arrest system includes a lifeline, the lifeline shall
(a) comply with CSA Standard Z259.2.1 "Fall Arresters, Vertical Lifelines and Rails";
(b) extend to a safe surface below the work area and be securely attached to an anchorage point;
(c) be secured at the bottom of the lifeline to prevent tangling or disturbance of the line and be free of knots, lubricants and imperfections;
(d) be free of splices, except where they are necessary to connect the lifeline to an anchorage point;
(e) be provided with softeners at all sharp edges or corners to protect against cuts or chafing; and
(f) be clearly identified as a lifeline by colour or by another means that provides an equivalent level of safety.

(3) No worker shall
(a) use a lifeline in a fall arrest system while that fall arrest system is being used by another worker; or
(b) provide a rope for use, or permit a rope to be used, as a lifeline in a fall arrest system where the rope has been used for another purpose.

(4) Where a fall arrest system provided to a worker includes a rope grab, the rope grab used shall comply with CSA Standard Z259.2.1 "Fall Arresters, Vertical Lifelines and Rails".

(5) An employer who provides a worker with a fall arrest system shall ensure the fall arrest system is inspected by a qualified person before each work shift undertaken by the worker.

(6) A qualified person who carries out an inspection of a fall arrest system shall advise the employer where a component of the system is defective in condition or function and the employer shall ensure that the system is not used until the defective component is replaced or repaired.

(7) Where a fall arrest system has arrested the fall of a worker at a work area, the employer shall ensure that the fall arrest system
(a) is removed from service and inspected by a qualified person; and
(b) is repaired, before it is reused, to the original manufacturer's specifications, where an inspection under paragraph (a) reveals that a component of the system is defective.

(8) Where a fall arrest system includes a static line, the static line shall
(a) have a nominal diameter of at least 12.7 millimetres and be made of improved plow wire rope;

(b) be equipped with vertical supports at least every 9 metres and have a maximum deflection, when taut, of no greater than 381 millimetres for a 9 metre span;
(c) be equipped with turnbuckles or other comparable tightening devices that provide an equivalent level of protection, at the ends of the static line;
(d) be equipped with softeners at all sharp edges or corners to protect against cuts or chafing;
(e) be made only of components that are able to withstand either the maximum load likely to be imposed on the components or a load of 8 kilonewtons, whichever is the greater; and
(f) comply with CSA Standard Z259.13 "Flexible Horizontal Lifeline Systems" and CSA Standard Z259.16 "Design of Active Fall Protection Systems".

(9) Where a fall arrest system is provided to an arborist, the fall arrest system shall
(a) include a tree climbing or tree trimming harness or saddle;
(b) be adequately secured to
(i) an anchorage point, or
(ii) a lifeline that is
(A) securely fastened to anchorage points, or
(B) attached to a static line that is securely fastened to anchorage points;
(c) include a climbing rope or safety strap;
(d) where practicable, include a second climbing rope or safety strap that
(i) provides additional stability, and
(ii) back-up fall protection; and
(e) be capable of withstanding either the maximum load likely to be imposed or a load of 22.2 kilonewtons, whichever is the greater.

(10) Where an employer uses a fall arrest system or a personnel safety net as a means of fall protection, the employer shall have a written fall protection plan that specifies
(a) the procedure to assemble, maintain, inspect, use and disassemble the fall arrest system or personnel safety net; and
(b) the procedure for the rescue of a worker who has fallen and is suspended by the fall arrest system or personnel safety net, but is unable to effect self-rescue.

Future Plans:

A list of future fall protection installations are included in Appendix A and will be proposed in future capital budget applications. See five-year capital plan (Capital Plan 2016 Tab, Appendix A).

APPENDIX A

Fall Protection Project List

Fall Protection Project List

Planned 2015 Projects

Location	Description	Comment
Bay 'Espoir		
General	Surge Tanks 1, 2 & 3 Balcony Gates	Planned for 2015
Powerhouse 1	Unit #1-6 Rotor/Stator access Ladder	Planned for 2015
	Unit #2 railing install toeboards	Planned for 2015
	Grating Unit #4 Improvement	Planned for 2015
	Grating Unit #5 Improvement	Planned for 2015
	Grating Unit #6 Improvement	Planned for 2015
Powerhouse 2	Railing to Fire Pump Area	Planned for 2015
	Sump Pit Ladder	Planned for 2015
Up Country	Suitable access to aircraft warning lights at Salmon Spillway	Planned for 2015
Central		
Bishop's Falls	Lifelines on Service Building	Planned for 2015
	Fall Protection Systems – Office Building	Planned for 2015
	Fall Protection System on Diesel Building Roof	Planned for 2015
	Fall Protection System on Salvage Stores	Planned for 2015
St. Brendan's	Fall Protection System on Diesel Plant Roof	Planned for 2015
Labrador		
Happy Valley	Sure-Track ladder system on North side plant ladder	Planned for 2015
Holyrood		
Holyrood TS	Fall Protection System on Control Building Roof	Planned for 2015

Planned 2016 Projects

Location	Description	Comment
Bay 'Espoir		
Powerhouse 1	Overhead Crane Access Ladder	Planned for 2016
Up-Country	Burnt catwalk for gate control building	Planned for 2016
	Burnt gate control building access ladder	Planned for 2016
Central		
Various Transformers	Anchor plates for Transformers	Planned for 2016
Northern		
William's Harbour	Fall protection system on control building roof	Planned for 2016

Future Projects

Location	Description	Comment
Bay 'Espoir		
Cat Arm	Intake ladder Slider	Future projects
	New ladder for spherical valve pit	Future projects
	Rail for stairs to fire pump room	Future projects
	Remove penstock access ladder safety slide	Future projects
	Ladder System on Powerhouse roof	Future projects
General	Support for Oil Tank Rescue	Future projects
	Intake #4 gate control access rail	Future projects
	Access catwalk for installing stoplogs	Future projects
	Intake #2 Access ladder modifications/safety slide	Future projects
	Intake #3 Access ladder modifications/safety slide	Future projects
	Intake #4 Access ladder modifications/safety slide	Future projects
	Platform Access to hoist control panel at Salmon Spillway	Future projects
Granite Canal	Intake Railing Modifications	Future projects
	By-pass stoplog railing	Future projects
	Gap in Rail on overhead crane landing	Future projects
	Modify rail to fire pump room	Future projects
	Extend ladder side rails for overhead crane	Future projects
	Draft tube crane access mezzanine extension	Future projects
Hinds Lake	Sump pit ladder at powerhouse	Future projects
	Ladder cable system at warehouse roof	Future projects
	Ladder with barrier at draft tube area – powerhouse	Future projects
	Spillway ladder modification/safety slide	Future projects
	Install handrail for stairs leading to penstock-powerhouse	Future projects
	Extend handrail near control room to close gap-powerhouse	Future projects
	Remove intake safety slide rail	Future projects
	Remove control structure safety slide rail	Future projects
	Intake ladder modification/safety slide	Future projects
	Ladder with barrier at east end of powerhouse	Future projects
	Ladder with barrier at west end of powerhouse	Future projects
Paradise River	Platform for powerhouse overhead crane	Future projects
	Install intermediate rail	Future projects
	Overhead crane ladder modification/safety slide	Future projects
	Install flip rail or gate	Future projects
	Remove penstock access ladder safety slide	Future projects
	Install penstock access fall arrest	Future projects
	Railing around top of unit	Future projects
Powerhouse 1	Fall arrest or restraint system when working atop overhead crane	Future projects
	Unit #5 Spherical valve rail/ladder mod	Future projects

Location	Description	Comment
Bay 'Espoir		
Powerhouse 1 (con't)	Unit #6 Spherical valve rail/ladder mod	Future projects
	Overhead crane access ladder	Future projects
	Downstream Unit 5 ladder	Future projects
	Downstream Unit 6 ladder	Future projects
	Cable Tunnel shelter ladder	Future projects
Up Country		
	Ladder to upper deck at Victoria Control Structure	Future projects
	Ladder with barrier to Staffgauge at Victoria Control Structure	Future projects
	Burnt Diesel Tank Modifications	Future projects
Upper Salmon		
	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
	Intake ladder modification/safety slide-powerhouse	Future projects
	Diver access ladder at West Salmon Spillway	Future projects
	Rotor access platform/Stairway-Powerhouse	Future projects

Project Title: Replace Surge Arresters

Location: Various Sites

Category: Transmission and Rural Operations - Terminal Stations

Definition: Other

Classification: Normal

Project Description:

This project is part of an ongoing program to replace aging 25 kV, 69 kV, 138 kV, and 230 kV surge arresters within Hydro's terminal stations on the island interconnected system. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	55.0	0.0	0.0	55.0
Labour	72.7	10.9	0.0	83.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	8.4	0.0	0.0	8.4
Interest and Escalation	8.3	12.7	0.0	21.0
Contingency	0.0	29.4	0.0	29.4
TOTAL	**144.4**	**53.0**	**0.0**	**197.4**

The surge arresters targeted for replacement in 2016, based primarily on their age, include the following:

- three 230 kV rated surge arresters for transformer T2 located in the Grand Falls Frequency Converter terminal station[1];
- three 230 kV rated surge arresters for transformer T3 located in the Western Avalon terminal station;
- three 138 kV rated surge arresters for transformer T3 located in the Western Avalon terminal station;
- three 230 kV rated surge arresters for transformer T4 located in the Western Avalon terminal station; and
- three 138 kV rated surge arresters for transformer T4 located in the Western Avalon terminal station.

[1] The frequency converter system in the Grand Falls Frequency Converter (GFC) Terminal Station was decommissioned in May 2002. The Terminal Station still maintains the proper name of GFC.

The 230 kV surge arresters on Transformer T3 in the Western Avalon Terminal Station are shown in Figure 1.

Figure 1: Western Avalon Terminal Station Transformer T3 230 kV Surge Arresters

Operating Experience:

Surge arresters are used on major terminal station equipment to protect that equipment from voltage surges due to lightning and switching effects. Surge arresters fail because of the cumulative effects of lightning strikes and switching surges. The wide variety of operating environments across the system makes it difficult to predict surge arrester failures. Hydro has approximately 440 surge arresters in service in all three voltage classes ranging in age from one year to more than 40 years.

Project Justification:

Surge arresters provide critical overvoltage protection of power system equipment from lightning and switching surges. Surge arresters are regularly inspected every 120 days and replacements are made based on these maintenance assessments as well as in-service failures.

When a surge arrester fails, it is not repairable and must be replaced immediately; otherwise the major equipment is exposed to serious damage from voltage surges. Failure of any major equipment could result in major system disturbances, which may cause system outages and interruption of service to customers.

Hydro has developed a Long Term Asset Management Plan (LTAMP) for surge arresters. The LTAMP is a prioritized list of surge arresters scheduled for replacement. The LTAMP replacement schedule is based primarily on the age of the surge arrester, but in some instances the replacement is based on known defects. The LTAMP is revised annually based on the above criteria. The surge arresters targeted for replacement in 2016 were selected based upon age and condition in comparison to all of the surge arresters contained in Hydro's system.

Future Plans:

This is an ongoing program and a number of arresters are scheduled to be replaced each year as per the Long Term Asset Management Plan (LTAMP) for surge arresters. Hydro's five-year plan for surge arrester replacements is presented in Appendix A.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Project initiation and planning	January 2016	February 2016
Design	Design transmittal, project work package and commissioning procedures	March 2016	April 2016
Procurement	Material requisition, specification and procurement. Coordinate material delivery. *(four month lead time)*	March 2016	August 2016
Construction Year 1	Deliver surge arresters to designated station, perform outage including required permits, install surge arresters	September 2016	November 2016
Commissioning Year 1	Commission new surge arresters	September 2016	November 2016
Construction Year 2	Deliver surge arresters to designated station, perform outage including required permits, install surge arresters	May 2017	June 2017
Commissioning Year 2	Commission new surge arresters	May 2017	June 2017
Closeout	Project close-out	December 2017	December 2017

APPENDIX A

Five-Year Plan For

Surge Arrester Replacements

TABLE A1: 2016 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2016	Grand Falls Frequency Converter	GFC – T2 H1
2016	Grand Falls Frequency Converter	GFC – T2 H2
2016	Grand Falls Frequency Converter	GFC – T2 H3
2016	Western Avalon	WAV – T3 H1
2016	Western Avalon	WAV – T3 H2
2016	Western Avalon	WAV – T3 H3
2016	Western Avalon	WAV – T3 X1
2016	Western Avalon	WAV – T3 X2
2016	Western Avalon	WAV – T3 X3
2016	Western Avalon	WAV – T4 H1
2016	Western Avalon	WAV – T4 H2
2016	Western Avalon	WAV – T4 H3
2016	Western Avalon	WAV – T4 X1
2016	Western Avalon	WAV – T4 X2
2016	Western Avalon	WAV – T4 X3

TABLE A2: 2017 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2017	Hampden	HDN – T1 X1
2017	Hampden	HDN – T1 X2
2017	Hampden	HDN – T1 X3
2017	Hardwoods	HWD – T5 H1
2017	Hardwoods	HWD – T5 H2
2017	Hardwoods	HWD – T5 H3
2017	Hardwoods	HWD – GT1 H1
2017	Hardwoods	HWD – GT1 H2
2017	Hardwoods	HWD – GT1 H3
2017	Hawke's Bay	HBY – T3 H1
2017	Hawke's Bay	HBY – T3 H2
2017	Hawke's Bay	HBY – T3 H3
2017	Hinds Lake	HLK – T1 H1
2017	Hinds Lake	HLK – T1 H2
2017	Hinds Lake	HLK – T1 H3
2017	Hinds Lake	HLK - T2 H1
2017	Hinds Lake	HLK - T2 H2
2017	Hinds Lake	HLK – T2 H3
2017	Oxen Pond	OPD – GT1 H1
2017	Oxen Pond	OPD – GT1 H2
2017	Oxen Pond	OPD – GT1 H3
2017	Rocky Harbour	RHR – T1 H1
2017	Rocky Harbour	RHR – T1 H2
2017	Rocky Harbour	RHR – T1 H3
2017	Rocky Harbour	RHR – T1 X1
2017	Rocky Harbour	RHR – T1 X2
2017	Rocky Harbour	RHR – T1 X3

TABLE A3: 2018 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2018	Roddickton Woodchip	RWC GT1 - H1
2018	Roddickton Woodchip	RWC GT1 H2
2018	Roddickton Woodchip	RWC GT1 H3
2018	Western Avalon	WAV – GT1 H1
2018	Western Avalon	WAV – GT1 H2
2018	Western Avalon	WAV – GT1 H3
2018	Sunnyside	SSD – T1 H1
2018	Sunnyside	SSD – T1 H2
2018	Sunnyside	SSD – T1 H3
2018	Sunnyside	SSD – T1 X1
2018	Sunnyside	SSD – T1 X2
2018	Sunnyside	SSD –T1 X3
2018	Stony Brook	STB – T2 H1 OVERALL
2018	Stony Brook	STB – T2 H2 OVERALL
2018	Stony Brook	STB – T2 H3 OVERALL
2018	Stony Brook	STB – T2- X1
2018	Stony Brook	STB – T2- X2
2018	Stony Brook	STB – T2- X3

TABLE A4: 2019 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2019	Corner Brook Frequency Converter	CBFTS – T1 H1
2019	Corner Brook Frequency Converter	CBFTS – T1 H2
2019	Corner Brook Frequency Converter	CBFTS – T1 H3
2019	Corner Brook Frequency Converter	CBFTS – T2 H1
2019	Corner Brook Frequency Converter	CBFTS – T2 H2
2019	Corner Brook Frequency Converter	CBFTS – T2 H3
2019	Holyrood	HRD – T8 H1
2019	Holyrood	HRD – T8 H2
2019	Holyrood	HRD – T8 H3
2019	Holyrood	HRD – T8 X1
2019	Holyrood	HRD – T8 X2
2019	Holyrood	HRD – T8 X3
2019	Holyrood	HRD – T10 H1
2019	Holyrood	HRD – T10 H2
2019	Holyrood	HRD – T10 H3
2019	Holyrood	HRD – T10 X1
2019	Holyrood	HRD – T10 X2
2019	Holyrood	HRD – T10 X3
2019	Holyrood	HRD SST-1-2 H1
2019	Holyrood	HRD SST-1-2 H2
2019	Holyrood	HRD SST-1-2 H3

TABLE A5: 2020 SURGE ARRESTER REPLACEMENT PLAN

Target Year	Terminal Station Location	Asset Description
2020	Holyrood	HRD – T3 H1
2020	Holyrood	HRD – T3 H2
2020	Holyrood	HRD – T3 H3
2020	Sunnyside	SSD – T4 H1
2020	Sunnyside	SSD – T4 H2
2020	Sunnyside	SSD – T4 H3
2020	Sunnyside	SSD – T4 X1
2020	Sunnyside	SSD – T4 X3
2020	Sunnyside	SSD – T4 X3
2020	Bay d'Espoir	BDE–T7 H1 OVERALL
2020	Bay d'Espoir	BDE–T7 H2 OVERALL
2020	Bay d'Espoir	BDE–T7 H3 OVERALL
2020	Holyrood	HRD – T1 H1
2020	Holyrood	HRD – T1 H2
2020	Holyrood	HRD – T1 H3
2020	Holyrood	HRD SST-3-4 H1
2020	Holyrood	HRD SST-3-4 H2
2020	Holyrood	HRD SST-3-4 H3

Project Title: Upgrade Warehouse Lighting

Location: Bishop's Falls

Category: Transmission and Rural Operations - Properties

Definition: Other

Classification: Normal

Project Description:

This project consists of the purchase and installation lighting fixtures at the Bishop Falls warehouse. The existing metal halide 250 watt luminaires will be removed. The replacement luminaires will utilize the same infrastructure, provide better lighting, and be more energy efficient.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	34.0	0.0	34.0
Labour	10.3	57.4	0.0	67.7
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	36.0	0.0	36.0
Other Direct Costs	3.6	7.8	0.0	11.4
Interest and Escalation	1.3	15.4	0.0	16.7
Contingency	0.0	29.8	0.0	29.8
TOTAL	**15.2**	**180.4**	**0.0**	**195.6**

Operating Experience:

The existing luminaires were installed over forty years ago.

Project Justification:

The existing fixtures have been in service for over forty years and have reached the end of their service life. A luminance measurement survey was completed in 2006 and the results indicated that the existing lighting levels inside the building are substandard. The measured lighting levels ranged from 14.4 to 227 lux. The Illuminating Society of North America (IES) standard for lighting indicates that lighting levels in a facility of this type should be at least 300 lux. The replacement luminaires will provide better lighting to allow workers to carry out tasks safely, and consume 42% less energy than the existing lighting system.

Figure 1 - Bishop's Falls Warehouse Existing Lighting

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Scope, schedule, cost, risk, quality and communications planning	February 2016	March 2016
Design	Complete detailed electrical design	April 2016	May 2016
Procurement	Tender for electrical contract / procure material	May 2017	July 2017
Construction	Replace existing fixtures	September 2017	October 2017
Commissioning	Commission new equipment	October 2017	October 2017
Closeout	As built drawing review, financial close out, post implementation review	October 2017	November 2017

Project Title: Purchase Meters and Metering Equipment

Location: Various Sites

Category: Transmission and Rural Operations - Metering

Definition: Other

Classification: Normal

Project Description:

This project consists of purchasing 200 demand meters, 10 high-end terminal station meters and associated equipment for use in Hydro revenue metering applications. Hydro is required to replace a portion of meters each year due to government retest, technology changes or obsolescence. This project also includes purchasing the associated equipment required to upgrade the Bay d'Espoir Automatic Meter Reading (AMR) 1-way system to the new power line carrier (PLX), 2 way system. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	134.0	0.0	0.0	134.0
Labour	20.0	0.0	0.0	20.0
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	5.6	0.0	0.0	5.6
Contingency	30.8	0.0	0.0	30.8
TOTAL	**190.4**	**0.0**	**0.0**	**190.4**

Operating Experience:

Meters of the electromechanical design have reached or surpassed their life expectancy of 25 years, are obsolete and can no longer be purchased. Electromechanical meters can still be recertified and sealed, however, Measurement Canada has shortened its seal period from six years to four years due to accuracy concerns. Electronic meters are the best option and failure to purchase meters to replace these obsolete meters would affect metering accuracy, reliability and regulatory requirements.

The AMR 1-way system has also reached end of life from the manufacturer. As such, we are unable to purchase additional TS1 endpoints to integrate into Hydro's demand meters. Currently, there are enough AMR-ready demand meters in stock to meet current requirements, but availability going

forward will be limited to the stock on hand. This stock is forecasted to be depleted by the end of 2016.

Project Justification:

Revenue meters are required to be purchased each year so that meters are available for new service applications and for replacements due to government retest, damaged meters, technology changes and obsolescence. Under the Electricity and Gas Inspection Act and Regulations, Hydro is mandated by Measurement Canada to ensure that in-service meters are accurate and in good working condition. Furthermore, revenue meters must be certified and sealed and the requirement states that these meters are to be removed from service before its expiry date. Failure to replace meters that are due to be replaced may result in monetary penalties as per the new requirements under the Electricity and Gas Inspection Act and Regulations. Furthermore, it is far less economical to certify and seal electromechanical meters compared to electronic meters for the following reasons:

- It takes approximately 6 hours to certify and seal electromechanical meters vs 2 hours to certify and seal electronic meters; and
- The seal period for electromechanical meters is 4 years compared to 10 years for electronic meters.

Therefore, the certification and sealing of electromechanical meters vs electronic meters would result in additional cost and maintenance due to longer meter shop testing time and the fact that the older electromechanical meters would have to be replaced every 4 years rather than every 10 years.

Due to the discontinuation of TS1 in 2014 by the manufacturer, TS1 endpoints can no longer be purchased therefore Hydro must upgrade to the PSX system or choose to go back to the non-automated system which would require meter readers. As proven in previous capital budgets non-automated meter reading does not provide as much functionality, flexibility and is less economical then the AMR options.

Since we already have Landis & Gyr's data collection software (Command Centre) in place, it would be a smooth transition to upgrade to Landis & Gyr's latest technology. PLX is the next generation of power line carrier, giving Hydro more flexibility overall. Some of the key benefits of the new PLX system are:

(1) TS1 and PLX can co-exist in the new PLX system;

(2) Faster response time for information from meter, 27 hours for TS1 compared to 15 minutes for PLX;

(3) Voltage monitoring gives Hydro the ability to pinpoint customer outages;

(4) 2-way communications versus 1-way, gives Hydro the flexibility to program meters over the power line and perform remote disconnects, where applicable; and

(5) Provides customer load profile data.

Therefore, to ensure uninterrupted AMR operation, it is recommended to upgrade the current TS1 sites to the new PLX system.

Future Plans:

This project is part of a multi-year program to upgrade the existing TS1 system to PLX and to ensure that meters are available to install/replace/upgrade revenue metering due to new service applications, government retest, technology changes and obsolescence.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		**Start Date**	**End Date**
Planning	Prepare order	January 2016	January 2016
Design	Prepare drawings	January 2016	January 2016
Procurement	Order meters and Equipment	January 2016	March 2016
Construction	Install meters and Equipment	May 2016	October 2016
Commissioning	Verify installations	May 2016	October 2016
Closeout	Close out projects	November 2016	December 2016

Project Title: Install Variable Frequency Drives

Location: Grey River

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Justifiable

Project Description:

The scope of this project is the procurement, installation and commissioning of four Variable Frequency Drives (VFDs) on each of the two radiator motors and two ventilation motors in the Grey River Diesel Plant (Grey River), as well as the installation of two thermowells to facilitate control of the VFDs. The installation will be carried out by Hydro internal forces. The procured VFDs will be sized according to the existing motors they are intended to control.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	13.4	0.0	13.4
Labour	25.8	61.6	0.0	87.4
Consultant	14.8	0.0	0.0	14.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	3.1	9.5	0.0	12.5
Interest and Escalation	3.2	12.9	0.0	16.1
Contingency	0.0	25.6	0.0	25.6
TOTAL	**46.9**	**123.0**	**0.0**	**169.9**

Operating Experience:

Of Hydro's isolated diesel stations, Grey River has one of the highest station service loads in proportion to plant gross output, with an annual station service energy consumption of approximately 20% of gross energy output, based on a five-year average between 2010 and 2014. During this same period, the average station service consumption for all Hydro owned diesel plants was 8%.

The Grey River plant's ventilation intake and exhaust motors, as well as the radiator fan motors, consume more than half of the total station service load. The peak station service load in the Grey River plant is 16 kW, with an annual energy consumption of 128,413 kWh. All motors are presently manually controlled, resulting in excessive power consumption of the motors relative to the air flow

requirements of each fan application. There are two radiators in the plant; Radiator 1 serves diesel Units 1 and 2, while Radiator 2 serves Unit 3. Although Units 1 and 2 are not typically operated simultaneously, Radiator 1 is sized to cool both units. Both radiators are operated at full speed, regardless of diesel engine loading.

Project Justification:

The airflow required to cool a diesel generator is directly proportional to the generator's output, while the input power to the motor is directly proportional to the cube of motor speed. As all fan motors currently operate at a higher speed than that required, energy savings are possible by reducing the speed of each fan. The installation of VFDs on both ventilation motors as well as both radiator fan motors would result in energy savings of approximately 69,000 kWh annually, which equates to approximately 21,000 liters of fuel saved per year, based on historical generator loading. These energy savings equate to a 95% reduction in energy consumed by the plant's fan motors. A cost-benefit analysis was performed, comparing the proposed project against the status quo. For analysis, the proposed project was compared using the calculated 95% energy savings, as well as a more conservative scenario resulting in 50% energy savings. In both cases, the proposed project was found to be the least-cost alternative.

Table 2: Cost-Benefit Anaylsis of Alternatives

Alternative	Cumulative Net Present Value (CPW)	CPW Different Between Alternative and Least Cost Alternative
Install VFDs	$161,021	0
Install VFDs (50% savings)	$175,518	$14,496
Status Quo	$281,784	$120,763

Future Plans:

None.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Scheduling and job setup	January 2016	February 2016
Design	Engineering design	February 2016	June 2016
Procurement	Procurement of VFDs, cables, and sensors	June 2016	August 2016
Construction	Construction	June 2017	June 2017
Commissioning	Commissioning	June 2017	June 2017
Closeout	Project closeout	July 2017	September 2017

Project Title: Replace Air Receivers and Compressors

Location: St. Anthony

Category: Transmission and Rural Operations - Generation

Definition: Other

Classification: Normal

Project Description:

This project will replace five air receivers and two air compressors at the St. Anthony diesel plant. Some modifications to the air start piping system will be required to install the new air compressors and receivers.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	50.1	0.0	0.0	50.1
Labour	37.6	0.0	0.0	37.6
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	6.4	0.0	0.0	6.4
Interest and Escalation	7.8	0.0	0.0	7.8
Contingency	18.8	0.0	0.0	18.8
TOTAL	**120.7**	**0.0**	**0.0**	**120.7**

Operating Experience:

The energy from the St Anthony diesel plant is produced via six connected generators driven by internal combustion engines, for a total capacity of 8,000 kW. Diesel engine start-up is via compressed air supplied from five air receivers which are fed by two air compressors.

Four air receivers were manufactured in 1972 and the fifth was manufactured in 1980. There are leaks in the air receivers causing the compressors to start with greater frequency than normal creating excessive wear on these compressors. The two air compressors were installed in 1973 and they are beyond their useful life. The air compressors have a life expectancy of 15 to 20 years.

Project Justification:

The existing air receivers and compressors at the St. Anthony diesel plant are obsolete as replacement parts such as valves and pressure switches are no longer available.

It is required to inspect the air receivers periodically as per the Newfoundland and Labrador Boiler, Pressure Vessel and Compressed Gas Regulations, 119/96. The air receivers at St. Anthony diesel plant are inspected by the government inspector every three years. The government inspector recommended in 2014 replacing these air receivers due to their age.

The St. Anthony diesel plant is critical to maintain system integrity during any line outage on the Great Northern Peninsula area of the province as well as maintaining total island system integrity during peak loads. There is a high potential failure of the air start system due to the current condition of the air receivers and compressors which could lead to unplanned outages of the St. Anthony diesel plant.

Future Plans:

None.

Project Schedule:

The anticipated project schedule is provided in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open project; Review budget and schedule; and Prepare scope statement.	January 2016	January 2016
Design	Prepare technical specifications.	February 2016	February 2016
Procurement	Prepare material requisitions; and Order and receive materials.	February 2016	May 2016
Construction	Install air receivers and compressors.	July 2016	July 2016
Commissioning	Perform commissioning of air start system.	July 2016	July 2016
Closeout	Prepare closeout package.	August 2016	August 2016

Project Title: Remove Safety Hazards

Location: Various Sites

Category: General Properties - Administrative

Definition: Other

Classification: Normal

Project Description:

This project is required to ensure adequate capital funding is available to quickly address safety hazards as they are identified through Hydro's Safe Work Observation Program (SWOP). A component of this program involves identifying and reporting conditions that can potentially lead to an incident or an accident. This work is estimated to be approximately $200,000, which correlates to the recent 2014 actual expenditures and 2015 budget estimate. The budget estimate for the project is shown in Table 1.

Table 1: Project Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	45.0	0.0	0.0	45.0
Labour	89.4	0.0	0.0	89.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	45.0	0.0	0.0	45.0
Other Direct Costs	6.2	0.0	0.0	6.2
Interest and Escalation	13.6	0.0	0.0	13.63
Contingency	0.0	0.0	0.0	0.0
TOTAL	**199.3**	**0.0**	**0.0**	**199.3**

Existing System:

In Hydro's 2014 Capital Budget Application, the Board of Commissioners of Public Utilities approved a budget of $257,800 to address safety hazards in the workplace. Table 2 lists the projects completed in 2014, which total $207,600.

Table 2: Projects for 2014

Location	**Project Description**	**Cost ($000)**
Cat Arm- BDE	Needle Access Platform	$27.3
Bishop's Falls	Steel Tower Ramps	$42.7
Holyrood	WWTP Emergency Egress	$85.4
Holyrood	Tote Storage Platform	$52.2
TOTAL:		**$207.6**

Process for Selecting Eligible Projects

These safety hazards are identified through Hydro's SWOP Program by employees, contractors and others who access Hydro facilities. Often mitigation of the safety concern can be accomplished through an operating or procedural change, or as a communication or an operating budget item. When it is concluded that a mitigation measure is a capital item, a cost estimate is completed for the mitigation work which is submitted to Hydro's Project Execution and Technical Services (PETS) department for consideration under the Remove Safety Hazards category. These requests are reviewed, and if warranted, the funding is approved by the Vice President of Regulated Operations and Vice President of PETS.

Historical Information

Table 3 shows the budget and actual expenditures for years 2011-2015.

Table 3: Capital Expenditure History

Year	Capital Budget ($000)	Actual Expenditures ($000)
2015B	194.9	
2014	257.8	207.6
2013	250.5	67.0
2012	249.1	141.4
2011	252.1	239.9

Actual expenditures are subject to the magnitude of the approved work scopes, in conjunction with the location in which the work is to be completed – both of which are unknown during the budget proposal process. The requested funding amount will enable the successful elimination of safety hazards approved under the program. Only the actual capital expenditures incurred to remove safety hazards are included in Hydro's rate base.

Project Justification:

This project is justified on Hydro's requirement to provide a safe work environment for its employees in compliance with the Occupational Health and Safety Regulations, Section 14 which states:

> *"14. (1) An employer shall ensure, so far as is reasonably practicable, that all buildings, structures, whether permanent or temporary, excavation, machinery, workstations, places of employment and equipment are capable of withstanding the*

stresses likely to be imposed upon them and of safely performing the functions for which they are used or intended.

(2) An employer shall ensure that necessary protective clothing and devices are used for the health and safety of his or her workers.

(3) The employer shall ensure that safe work procedures are followed at all workplaces.

(4) An employer shall ensure, so far as is reasonably practicable, that work procedures promote the safe interaction of workers and their work environment to minimize the potential for injury."

In an effort to avoid injury and/or fatality, Hydro has initiated a Safe Work Observation Program (SWOP). The SWOP program involves workers actively looking for safety hazards and problems that may otherwise go unnoticed, which could lead to serious health and/or safety issues for Hydro customers, employees, contractors, and the general public. This project provides Hydro with the budget to address unsafe situations where capital work is identified as the solution, and enables Hydro to respond quickly to address unsafe conditions rather than waiting for the normal capital budget process. These deficiencies, as reported under the SWOP program, need to be immediately corrected to provide a safe work environment. Criteria for the selection of acceptable projects include, but are not necessarily limited to, the remediation of safety deficiencies identified in the SWOP program.

Future Plans:

Future Safety Hazards Removal projects will be proposed in future capital budget applications. Also see five-year capital plan (2016 Capital Plan Tab, Appendix A).

Project Schedule:

As this budget relates to unanticipated safety issues, no schedule is available.

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 Reporting Suite, the Oracle Business Intelligence and the Microsoft Office Productivity Suite. This project is necessary to enhance these applications to support changing business requirements. The application enhancement project provides for minor enhancements to applications in response to unforeseen requirements such as regulatory and changing business needs.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	45.0	0.0	0.0	45.0
Labour	44.9	0.0	0.0	44.9
Consultant	180.0	0.0	0.0	180.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	22.8	0.0	0.0	22.8
Contingency	54.0	0.0	0.0	54.0
Sub-Total	346.7	0.0	0.0	346.7
Cost Recoveries	(148.8) [1]	0.0	0.0	(148.8)
TOTAL	**197.9**	**0.0**	**0.0**	**197.9**

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 2014, the most recent year for which final data is available, the following application enhancements were made:

- Upgrade TapRoot Enterprise Software. TapRoot is a systematic process, software, and training

[1] The Information Systems (IS) shared services methodology for calculating appropriate charges to non-regulated components is based on a ratio considering the average of the number of full time equivalents (FTEs) and Lower Churchill contractors, email users, personal computers and JD Edwards users across each line of business.

tool used for asset based systems to facilitate root cause analysis and corrective action recommendations;

- Upgrade Industrial Meter Reading Software. The software is used for interrogating Industrial customer meters; and
- Upgrade data encryption and secure file sharing software. The software is used for securely sharing files.

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 2010-2015B.

Table 2: Application Enhancements

Year	Budget ($000)	Actual ($000)	Comments[1]
2015B	329.5[2]		Upgrade
2014	126.8	132.5	Upgrade
2013	126.8	113.3	Upgrade
2012	123.4	113.3	Upgrade
2011	120.7	142.9	Upgrade
2010	120.7	122.9	Upgrade

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity	Start Date	End Date
Planning	January 2016	April 2016
Design	February 2016	June 2016
Procurement	March 2016	August 2016
Construction	March 2016	November 2016
Commissioning	May 2016	November 2016
Closeout	May 2016	December 2016

Future Plans:

Future enhancements will be proposed in future capital budget applications.

[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. This dollar amount is pre cost recovery.

Project Title: Replace Air Conditioners

Location: Massey Drive and Happy Valley

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project is for the replacement and first time installation of air conditioning (AC) units at two locations operated by Hydro's Network Services Department. The first location is the Massey Drive Terminal Station. This terminal station is on the West Coast of Newfoundland and the AC unit will be replaced with a similar sized unit. The other location is the Happy Valley Terminal Station in Labrador. This terminal station is currently not equipped with an AC unit so therefore requires the design and installation of a new AC system. Both installations will be managed by Hydro's Project Execution and Technical Services (PETS) team from St. John's, and both will be provided through a supply and install contract. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	19.7	21.7	0.0	41.4
Consultant	14.8	0.0	0.0	14.8
Contract Work	0.0	85.0	0.0	85.0
Other Direct Costs	3.1	4.6	0.0	7.7
Interest and Escalation	2.3	10.9	0.0	13.2
Contingency	0.0	29.8	0.0	29.8
TOTAL	**39.9**	**152.0**	**0.0**	**191.9**

Operating Experience:

The AC unit in the Massey Drive Terminal Station (MDR) was installed in 1992 and has been in service for over 23 years. The unit is maintained by contract. The AC unit has performed well during its service life but due to the age of the unit it is time to be replaced. All the AC units under the Network Services Network were assessed in 2014 and a plan was set for the replacement of the AC units based on the age of the units. AC units have an economic life of approximately 20 years; after 20 years of service the reliability decreases and parts become more difficult to source.

The Happy Valley Terminal Station (HVYTS) was never equipped with an AC unit. During the past number of years there has been additional equipment installed in the terminal station causing the ambient temperature to increase, necessitating a method of controlling the temperature. New

electrical equipment was installed at this location when the Trans Labrador fiber was connected in November of 2012, and additional equipment was also added when the Tap Station for voltage regulation was installed in November of 2012. To ensure the new and existing equipment is provided with the proper temperature in which to function properly, an AC unit is required to regulate the temperatures in HVYTS.

Project Justification:

Proper Air Conditioning is essential for the reliable operation of communications equipment and the units should be replaced before permanent failure occurs. In 2014, an AC unit in Come By Chance failed after 25 years of service. This unit could not be repaired and an unbudgeted capital job was completed to replace the unit. In years leading to the final failure of the unit at Come By Chance, there were other failures resulting in the loss of cooling and costly repairs to keep the unit running. In order to keep sensitive communications equipment in proper working order and to provide least cost service to these terminal stations, this project is required.

Project Schedule:

The anticipated project schedule is in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Open project in JDE, WBS, Design transmittal, scope and budget review.	July 2016	July 2016
Design	Procure consultant for design of HVYTS AC needs.	July 2016	August 2016
Procurement	Based on consultant sizing and design, procure contractor for supply and install at both locations	August 2016	May 2017
Construction	Contractor to supply and install both units, one at MDR and the other in HVYTS.	May 2017	June 2017
Commissioning	Commission both units	May 2017	June 2017
Closeout	Post implementation review, lessons learned	August 2017	August 2017

Project Title: Replace Network Communications Equipment

Location: Various Sites

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project is required to replace 31 networking devices in Hydro's corporate Local Area Network (LAN) that have been discontinued and unsupported by the vendor, Cisco Systems, since 2010 or later. These devices will be replaced with their updated technology equivalents. The following devices will be replaced in this project:

- 7 Cisco C2924MXL switches (last supported by vendor in April, 2009)
- 1 Cisco C2924XL switch (last supported by vendor in November,2006)
- 3 Cisco C2924XLV switches (last supported by vendor in November, 2006)
- 2 C3508GXL switches (last supported by vendor in September, 2010)
- 12 C3524WRXL switches (last supported by vendor in August, 2008)
- 6 C3524XL switches (last supported by vendor in July, 2007)

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	58.5	0.0	0.0	58.5
Labour	80.0	0.0	0.0	80.0
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
Interest and Escalation	12.2	0.0	0.0	12.2
Contingency	29.0	0.0	0.0	29.0
TOTAL	**186.4**	**0.0**	**0.0**	**186.4**

Operating Experience:

Cisco Systems networking devices have been proven to be reliable and secure when properly maintained. Cisco had regularly released software updates to address any deficiencies identified in its integrated operating system as well as security updates when required.

Project Justification:

The devices are critical to daily operations for hundreds of users. The 31 devices that are now considered obsolete can no longer be covered by Cisco's maintenance and support packages since September 2010 or earlier. Cisco also no longer releases software updates to address software deficiencies or security updates for these devices. Therefore, devices not updated could leave Hydro's network susceptible to new security vulnerabilities.

Future Plans:

Hydro will continue to identify End of Support devices in its network and replace them on a year to year basis, as required.

Project Schedule:

Because the network upgrades proposed are at different sites throughout Hydro's network, the construction activity and commissioning activity will overlap. The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Scope statement, Resource and network outage scheduling	January 2016	February 2016
Design	Network Drawings and Design Packages, Refine Bill of Materials	February 2016	February 2016
Procurement	Submit requisition for Cisco Equipment (Standing Offer)	March 2016	March 2016
Construction	Configure and install new equipment	May 2016	November 2016
Commissioning	Test network connectivity	March 2016	November 2016
Closeout	Closeout Project	November 2016	December 2016

Project Title: Replace Video Conferencing Bridge

Location: Hydro Place

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project will replace Hydro's existing Polycom video conferencing architecture with a new Cisco Systems video conferencing architecture.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	81.5	0.0	0.0	81.5
Labour	27.9	0.0	0.0	27.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	35.0	0.0	0.0	35.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	11.6	0.0	0.0	11.6
Contingency	26.6	0.0	0.0	26.6
TOTAL	**182.6**	**0.0**	**0.0**	**182.6**

Operating Experience:

The video conferencing architecture at Hydro Place consists of five components: the bridge, the gatekeeper and three firewall traversal devices. The video conferencing bridge and gatekeeper allows Hydro to host video meetings between its many locations over its wide area network. The addition of the firewall traversal devices allows Hydro to also host, and participate, in video conferences with external companies over the public internet.

Project Justification:

Video conferencing is widely used by all lines of business and should be maintained to provide reliable service and good performance. The existing Polycom architecture has been in service since 2008 and some of its components are no longer supported by the manufacturer. The project outlined in this proposal will provide a newer video conferencing architecture that is fully supported by Cisco Systems' SMARTnet support contract.

Future Plans:

The video conferencing system will be expanded to include more locations as well as mobile users.

Project Schedule:

The anticipated project schedule is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Complete Statement of Work	January 2016	February 2016
Design	Issue for Tender	February 2016	April 2016
Procurement	Submit requisition for New Equipment Award Tender	April 2016	May 2016
Construction	Equipment configured and tested in contractor Lab environment	June 2016	August 2016
Commissioning	Integrate new system into Hydro's Network	September 2016	October 2016
Closeout	Closeout	November 2016	December 2016

Project Title: Upgrade Citrix

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

Citrix XenApp 6.5 is at end of its mainstream service life and has entered extended support as of 2015. This project is to review current business and application requirements pertaining to XenApp as an application delivery platform. A detailed business and system gap analysis must be performed culminating in a set of findings and recommendations on the XenApp platform.

Approximately 800 concurrent users access the Citrix XenApp system on a daily basis. The system is used by both internal and remote access users. Citrix XenApp servers also provide the primary method of remote access to applications for users travelling or accessing the system after hours or in emergency situations. A variety of devices are used to connect, including laptops, desktops, thin client and tablet devices.

The scope of this project will include:

1. An external engagement to perform a review of the Citrix XenApp environment, analyze suitability to current business requirements and use cases, identify opportunities to enhance the platform.
2. Implementation of any recommendations deemed acceptable and achievable, with planning for any roadmap items in following years.

The external engagement will perform a review of the Citrix XenApp environment, analyze suitability to current business requirements and use cases, identify opportunities to enhance the platform for improved user experience, client devices, printing methods and remote access. The analysis will Investigate where the current platform may be underperforming or degrading user efficiency, identify possible changes to either replace or improve the overall effectiveness of the platform to deliver applications to end users across the lines of business. The engagement will not be limited to simply upgrading the current platform, but to identify functions which may be delivered using alternative technologies such as virtual desktop infrastructure, conversion to web based

applications, or using other technologies. Suggested focus areas include, but not limited to:

- User experience (logins, printing, file access, application delivery, remote access, thin client experience, external roaming (laptop and tablet);
- Application delivery alternatives including: Virtual Desktop Infrastructure (VDI) with XenDesktop or VMWare Horizon View; Application streaming to XenApp Sessions, or other potential products;
- Mobile access including simplified access for known devices, alternative multifactor authentication options, mobile delivery via Citrix @Worx or other containerized mobile tablet options;
- Server efficiencies for management, deployment, disaster recovery and patch management;
- Leverage existing investments where possible, and practical, to minimize impact and cost of proposed solutions; and
- Provide methodology and approach whereby Hydro can implement proposed changes to the application delivery platform with a roadmap for the following 1-3 year timeframe.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	55.0	0.0	0.0	55.0
Labour	90.0	0.0	0.0	90.0
Consultant	88.8	0.0	0.0	88.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	4.7	0.0	0.0	4.7
Interest and Escalation	11.4	0.0	0.0	11.4
Contingency	47.7	0.0	0.0	47.7
Sub-Total	**297.6**	**0.0**	**0.0**	**297.6**
Cost Recoveries	**(138.0)**	**0.0**	**0.0**	**(138.0)**
TOTAL	**159.6**	**0.0**	**0.0**	**159.6**

Operating Experience:

This budget proposal is for the assessment and potential enhancement of software related to the application infrastructure.

Reliability Performance

Hydro's servers are used on a continuous basis. The servers are active for the life of the unit once placed in service. Hydro standardizes on enterprise grade software for both corporate and energy

management applications. Hydro has had satisfactory performance and reliability levels from this approach as a result.

Industry Experience

Hydro must keep its systems 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 systems to achieve this goal requires investment over the lifecycle of the infrastructure.

Vendor Recommendations

Recommendations will be made by the assessment performed under this project.
Also see information under "Maintenance or Support Arrangements" below for product support statements from Citrix.

Maintenance or Support Arrangements

Hydro maintains active maintenance and support contracts on its Citrix XenApp software products. However it must also adhere to the vendor's specific lifecycle policy for the contracts to have value. If the products used by Hydro are no longer supported, it creates risk to the delivery of corporate applications.

Lifecycle Milestones for XenApp

The product follows the typical lifecycle policies described in more detail on the Lifecycle Phases and Lifecycle Milestones pages. In addition to the typical phases and milestones, the End of Extended Support milestone defined below also applies to this product.

XenApp core components, including Secure Gateway and Web Interface, are covered through all phases, including Extended Support.

For each significant XenApp release for a particular server platform, Citrix supports the most recent hotfix rollup pack (HRP) and maintains it provided the requests are commercially viable. In addition, Citrix supports the previous hotfix rollup pack for 12 months after the most recent HRP is available. Hotfixes for security vulnerabilities are only provided for the most recent hotfix rollup pack.

End of Extended Support (EOES)

This milestone signifies when a specific product release will no longer be covered under the Extended Support Program. The EOES milestone for a Citrix product version is intended to align with Microsoft's current End of Extended Support milestone for the corresponding server OS version. This should enable customers to plan their XenApp migration as part of the underlying OS migration planning. The Extended Support Program puts customers in control of their upgrade strategy by offering technical support and maintenance after the End of Maintenance (EOM) milestone.

Historical Information

The current application delivery platform has been in place since 2003, although several incremental Operating Systems and Citrix software version upgrades occurred in that time, the basic deployment method of published applications from a remote desktop services platform has not changed.

The last major version change was designed at the end of 2011 to move from Windows Server 2003 and Citrix Presentation Server 4.5 based servers to the current platform, based on Windows Server 2008 R2 and Citrix XenApp 6.5.

The migration design cost was $25,000 and deployment was performed, as servers running Citrix were replaced, under the Upgrade Server Technology lifecycle program.

Anticipated Useful Life

Hydro anticipates that the next version of Citrix XenApp, version 7.x, will be supported until mid 2018, based on published lifecycle dates. The Windows Server 2008 R2 platform is supportable through this date as well, according to Microsoft published lifecycle dates (approximately 2020).

Hydro deploys its Citrix XenApp servers as virtual machines, which disconnects any alignment to replacing software when hardware assets are replaced. Therefore, Hydro will focus on software and operating system lifecycle milestones to determine when updates or upgrades should occur on virtual machines. The current XenApp system must be upgraded during 2016, the follow on system is expected to have a two year useful life beyond that date.

Software and operating systems undergo ongoing patching and maintenance to remain supported and secured against threats and to add features of bug fixes. Maintenance and Support agreements are in place to enable this.

Development of Alternatives

The alternative to this project is to run the Citrix XenApp system beyond end of life, which is not acceptable since this would put the application delivery infrastructure at risk of unsupported vulnerabilities or software issues. The total replacement of the system with a different platform would likely incur disruption and unforeseen issues and/or costs. The preferred approach is to perform an assessment to make this determination and build on past investments where possible to minimize impact of change and replacement costs.

Project Justification:

There are four virtual machine hosts and over 30 virtual machines, running Citrix XenApp software, which support applications for the organization. The applications that run on these servers include the Enterprise Resource Planning, File, Print, Office Productivity, Reporting and Email systems in addition to other applications access from web browser, Lotus Domino and Sharepoint via the XenApp platform which comprise the business operating environment. These applications are used by staff in running the business on a day to day basis.

The factors that are driving Hydro's proposal to perform an assessment on Citrix XenApp and implement achievable recommended actions in its environment include:

- Addressing obsolescence/maintaining vendor support;
- Managing the application delivery infrastructure; and
- Supporting current versions of applications.

Addressing obsolescence/maintaining vendor support – Without vendor support, the applications and services delivered by the Citrix XenApp 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. As the systems are used by Hydro employees to provide support in running the business on a daily basis, loss of availability of the XenApp services would have a negative effect on employee productivity by not allowing access to software applications.

Managing the infrastructure – Hydro must actively manage the applications and the systems which deliver them to users. Hydro relies on reliable access to its applications and data to run the business.

Supporting current versions of applications – As applications are upgraded and new applications implemented throughout the organization, many are built to take advantage of technologies such as virtualization, mobility and high availability.

Future Plans:

This is a refresh program to maintain application delivery platform performance, improve user access and leverage investments in virtualized systems for scalability and disaster recovery. Future replacements and upgrades will be proposed in future budget applications.

Project Schedule:

The project is scheduled to start in January 2016 and be completed by the end of May 2016.

Project Title: Upgrade SharePoint Document Repository

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

The purpose of this project is to upgrade the current SharePoint 2010 installation, including all sites, applications and data, to a SharePoint 2013 installation. The design and implementation of the SharePoint 2013 installation will be based on the findings of a thorough review of the information management strategy, business and technical requirements, and the development of a SharePoint governance framework.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	13.6	0.0	0.0	13.6
Labour	77.8	0.0	0.0	77.8
Consultant	103.6	0.0	0.0	103.6
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	24.0	0.0	0.0	24.0
Interest and Escalation	4.8	0.0	0.0	4.8
Contingency	43.8	0.0	0.0	43.8
Sub-Total	**267.6**	**0.0**	**0.0**	**267.6**
Cost Recoveries	**(124.1)**	**0.0**	**0.0**	**(124.1)**
TOTAL	**143.5**	**0.0**	**0.0**	**143.5**

Operating Experience:

The SharePoint 2010 environment currently in use at Hydro began life as a single server instance implemented to serve a small number of business users. Following its initial creation, the SharePoint environment began being used by an increasing number of business users for day to day business purposes. SharePoint is now an essential business tool used to support business operations.

Project Justification:

To position Hydro for enterprise use of SharePoint, a properly designed and architected solution, and overall SharePoint strategy is required. The SharePoint strategy needs to be aligned with Nalcor's Information Management strategy.

Increased requests for the creation of SharePoint sites and increased use by business units have put increased demands on the SharePoint environment resulting in a requirement to have a SharePoint implementation suitable for enterprise use. The designed SharePoint environment and infrastructure will allow for high availability and reliable performance.

Future Plans:

The SharePoint infrastructure and software will be evaluated on an annual basis with upgrades and improvements completed as needed.

Project Schedule:

This project will be started in June 2016 and completed by the end of August 2016.

Project Title: Upgrade Access Roads to Microwave Sites

Location: Gull Pond Hill and Sandy Brook Hill

Category: General Properties - Telecontrol

Definition: Other

Classification: Normal

Project Description:

This project involves the completion of drainage improvements to the access roads for Hydro's microwave sites at Gull Pond Hill and Sandy Brook Hill, see Figures 1 and 2.

Figure 1: Sandy Brook Hill Repeater Site General Location

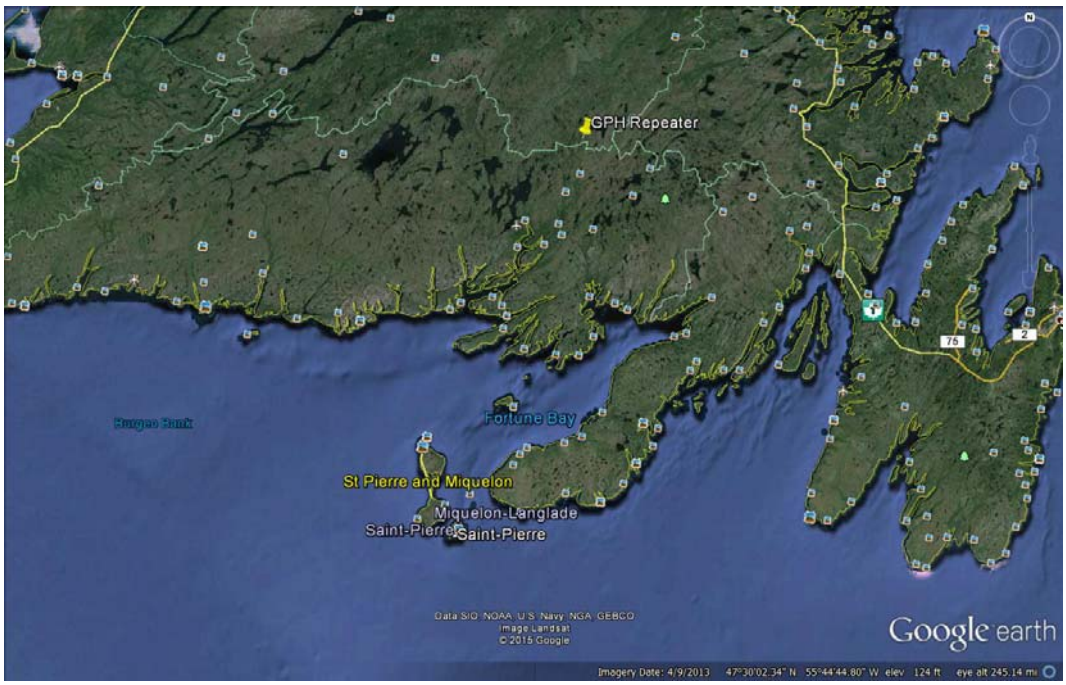


Figure 2: Gull Pond Hill Repeater Site General Location

The Gull Pond Hill access road is approximately 800 meters in length, while the Sandy Brook Hill access road measures approximately 18 kilometers. Upgrades to the Gull Pond Hill Road consist solely of a culvert replacement, located at the halfway point of the road, while Sandy Brook Hill will involve the completion of upgrades to the last 1,500 meters of the roadway.

The scope of work generally includes: the replacement of drainage culverts with new culvert, sized to better accommodate surface water flows; the completion of roadside ditching; and the supply and placement of imported granular material to upgrade select areas of the roadway, at which the subgrade has been compromised as a result of repeated flooding. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	24.9	0.0	0.0	24.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	76.0	0.0	0.0	76.0
Other Direct Costs	11.3	0.0	0.0	11.3
Interest and Escalation	6.3	0.0	0.0	6.3
Contingency	22.5	0.0	0.0	22.5
TOTAL	**141.1**	**0.0**	**0.0**	**141.1**

Operating Experience:

The majority of the access roads leading to Hydro's microwave communication sites were constructed in the late 1970s. They have not received any major work or upgrades in their approximately 40 years of service and are deteriorated, primarily as a result of localized flooding. The flooding is due to the inability of existing drainage ditches to divert water from the roadway's surface. During a flood event, the roadway's overexposure to water results in the development of soft spots and the removal of roadway topping material which exposes the larger, course road base aggregate, see Photos 1 and 2.

Photo 1: Roadway Soft Spot Resultant of Inadequate Drainage Ditches

Photo 2: Exposed Road Base Aggregate Resultant of Inadequate Drainage Ditches

Immediately following periods of substantial water runoff resulting from significant rainfall events and spring melt the roads are often impassable. Routine maintenance, completed to address problem areas, provide a short term solution with washouts typically reoccurring immediately during the next substantial runoff. The proposed upgrades are required to address the core issue of site drainage.

Recognizing the need to complete the road upgrades in 2016, Hydro submitted a Crown Land Easement application to the office of Crown Lands in February 2015. This easement form of title has been determined to be appropriate for Hydro's needs as Hydro does not need to exclude others from using the road but it does require the legal right to have secure access over it, to make improvements to the road and to build and maintain structures such as guard rails, bridges and culverts. This is the form of title upon which Hydro holds a significant amount of its distribution and transmission plant. All government department reviews were completed in May 2015, with no objections raised to the application. Hydro is presently awaiting a letter from Crown Lands, approving the application in principal, pending the completion of a legal land survey for the roadways.

Project Justification:

Hydro's microwave sites are critical for providing administrative networks, teleprotection of

transmission lines and remote SCADA[1] control of major generation facilities and terminal stations. Access to these sites is required by Hydro personnel for the completion of routine equipment maintenance and repairs. Private fuel suppliers are also required to access the sites on a routine basis to ensure an adequate fuel supply is maintained for the back-up generators.

The site access roads have deteriorated, due to repeated washouts, following periods of substantial surface water runoff. Hydro personnel must often travel to the site via helicopter for the completion of required maintenance and repair work and, recently, private fuel suppliers have been unable to access the sites and deliver fuel for the backup generators as a result of the road conditions.

To ensure the continued reliable operation of these microwave sites, the access roads must be restored to a safe condition. The proposed upgrades are required to address the drainage issues which form the root cause of the repeated road deterioration, thus, preventing its continued occurrence.

Future Plans:

Funding to complete similar upgrades at various Hydro microwave sites will be applied for in future years.

Project Schedule:

The anticipated project schedule for this work is shown in Table 2.

Table 2: Project Schedule

Activity		Start Date	End Date
Planning	Site visit, Scheduling, Scope definition, Design transmittal	May 2016	May 2016
Design	Prepare tender package	May 2016	June 2016
Tender	Tender and award contract	June 2016	July 2016
Construction	Completion of road upgrades	August 2016	August 2016
Commissioning	Final inspection and acceptance	-	August 2016
Closeout	Final billing, Certificate of completion, asset assignment	-	September 2016

[1] **SCADA** (**supervisory control and data acquisition**) is a system operating with coded signals over communication channels so as to provide control and monitoring of remote equipment.

Project Title: Refresh Security Software

Location: Hydro Place

Category: General Properties - Information Systems

Definition: Other

Classification: Normal

Project Description:

This project will refresh Hydro's Information Security and Cyber Safety tools and improve Hydro's cyber threat detection and mitigation capabilities. This will be accomplished by:

- Implementing a solution to securely erase data during IT asset disposal processes, including distribution of secure data erasure software, and data erasure reporting for auditing purposes;
- Implementing an antivirus and antimalware solution for mobile phones and tablets;
- Implementing improved advanced threat detection and prevention capabilities for Hydro's network and server infrastructure; and
- Refreshing and improving software and hardware toolsets used by Hydro's IS Security staff and IS support staff.

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

Table 1: Budget Estimate

Project Cost: *($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	148.6	0.0	0.0	148.6
Labour	9.4	0.0	0.0	9.4
Consultant	31.8	0.0	0.0	31.8
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	0.0	0.0	0.0	0.0
Interest and Escalation	2.6	0.0	0.0	2.6
Contingency	38.0	0.0	0.0	38.0
Sub-Total	**230.4**	**0.0**	**0.0**	**230.4**
Cost Recoveries	**(106.9)**	**0.0**	**0.0**	**(106.9)**
TOTAL	**123.5**	**0.0**	**0.0**	**123.5**

Operating Experience:

Hydro uses and maintains security software tools and hardware to mitigate threats to computers systems and networks. The security software tools are used by IS Security staff and IS Support staff on a daily basis. While Hydro has been successful in protecting its IT assets from malicious threats,

continual updates and improvements are necessary to protect against the global growth and increasing sophistication of cyber threats and the cyber criminal industry.

Project Justification:

Hydro's increasing reliance on information systems and expanding data networks increases exposure to information security threats to its critical infrastructure. Major risk exposures in this environment relate to information security (e.g. loss of critical infrastructure stability and processing capability due to hardware/software failure or threat of virus attacks), availability of information (e.g. loss of communication across the wide area network) and risk of corporate data loss (e.g. loss of data through cybercriminal malware and attacks).

External threats to Hydro's computer systems are mitigated through the use of firewalls, anti-virus tools and detection/intrusion prevention appliances. Internet access is tightly controlled and managed by security appliances and software that help reduce the risk of potential computer viruses. A serious incident involving the loss of corporate data, or access to critical business, plant or energy control systems, would result in unplanned costs to contain, investigate and remediate the incident, as well as investments to change systems or processes if required. These incidents could negatively affect financial results, reputation, and the province's power grid.

Future Plans:

Hydro's computer systems and network infrastructure require constant protection from cyber threats. This is accomplished through continuous evaluation of IS security tools and services.

Project Schedule:

This project will begin January 2016 and be completed by December 2016.

Project Title: Upgrade Remote Terminal Units

Location: Various Sites

Category: General Properties - Telecontrol

Type: Pooled

Classification: Normal

Project Description:

A critical component of Hydro's supervisory control and data acquisition (SCADA) network is the GE Multilin D20-based remote terminal unit (RTU). It can be found in substations, generating stations or any part of the network from which data must be collected and sent back to the Energy Control Centre (ECC) for monitoring of the Hydro system, and to allow the ECC to send signals to stations to control the electrical system. Hydro has used the D20 RTU since the early 1990s and has reached an installed base of 71 units throughout the province.

In order to minimize the probability of an outage attributable to the RTU, in 2016 it is proposed to commence replacement of the processor modules in the three older RTUs with the latest model of the D20 processor. The third generation D20 RTU processor card, the D20M++, has been manufacturer discontinued since in the late 1990s. Replacement with new sixth generation D20MX processors will improve reliability as well as provide increased functionality from the advanced communications features, such as Ethernet, built into the newer processors. Due to operational risks associated with the failure of any portion of the SCADA network, this project is a proactive approach to ensuring that the likelihood of failure of the oldest D20 modules is minimized.

This project will be completed using Hydro's internal construction forces. All changes will be fully tested in a lab environment before deployment to the field due to the critical role that the RTU plays in the monitoring and control of the network. The budget estimate for this project is shown in Table 1.

Table 1: Budget Estimate

Project Cost:*($ x1,000)*	**2016**	**2017**	**Beyond**	**Total**
Material Supply	19.7	0.0	0.0	19.7
Labour	42.9	0.0	0.0	42.9
Consultant	0.0	0.0	0.0	0.0
Contract Work	0.0	0.0	0.0	0.0
Other Direct Costs	7.6	0.0	0.0	7.6
Interest and Escalation	5.4	0.0	0.0	5.4
Contingency	14.0	0.0	0.0	14.0
TOTAL	**89.6**	**0.0**	**0.0**	**89.6**

Justification:

The third generation D20 RTU processor card, the D20M++, has been manufacturer discontinued since in the late 1990s. Due to the unavailability of electronics components for the D20M++, the manufacturer will no longer accept defective modules for repair. As a result, the Hydro spares inventory has been depleted. Subsequent failures will lead to a forced and unscheduled upgrade of the D20 RTU which would lead to extended periods during which ECC would have no monitoring or control ability of the affected station. This in turn could lead to extended customer outages.

Existing System:

There have been 71 RTUs installed throughout Hydro's system since the early 1990s. The units have generally provided very reliable service and, as the vendor has continued to develop the product, it is expected to continue as the RTU of preference for the foreseeable future.

Each D20 RTU is a system composed of a main processor, cabling, and peripherals to collect data or send control signals, all contained in a 7-foot high enclosed cabinet. The "brain" of the RTU is its main processor. This unit has changed over the years to keep pace with evolving computing enhancements and communications protocols. Table 2 shows the inventory of existing D20 processor units.

Table 2: D20 Installed Base

GE Multilin D20 Processor Model	Installed Base
D20M++ (1990s)	22
D20ME (2000s)	48
D20MX (2013+)	1
Total	71

Any RTU outage is considered a serious event as it blocks the ability of operators at ECC to monitor or control equipment connected to the RTU. It is proposed to commence replacement of the oldest

D20M++ processors over the next several years with the newest D20MX model. The D20M++ has reached end of life. Due to a lack of readily available electronics components that are either difficult to source or to have manufactured, it is no longer economically feasible to repair faulty modules. As a result, the Hydro spares inventory has been depleted to five units. As well, the D20M++ cannot support communications with new Ethernet based devices that are commonly installed in the terminal and generating stations today. Gradual replacement will also help to maintain a spares inventory until all units can be replaced.

Appendix A shows a planned schedule for replacement of the D20M++ processors. Due to operational risks associated with the failure of corporate SCADA equipment, this project is a proactive approach to ensuring that the likelihood of failure of a D20M++ processor is minimal.

Operating Experience:

Outage Statistics

The GE D20 RTU processors have proven to be very reliable for Hydro. This, combined with regular attention to maintenance, has helped to minimize complete SCADA outages attributable to the D20 processor. The last event, in July of 2014, required that a spare unit be used to complete repairs as GE indicated that they can no longer repair defective modules.

Vendor Recommendations

In April 2014, a D20M++ was scheduled to be returned to GE MULTILIN for repairs. At that time, GE MULTILIN advised that they strongly recommended upgrading the board to the current platform as "*repair charges are very high for this obsolete board*". The reason for the high cost for repair is related to the 1990-vintage electronics components that are difficult to source or manufacture.

Maintenance or Support Arrangements

There are no maintenance or support arrangements associated specifically with D20 RTUs beyond the regular warranty period.

Maintenance History

Experience with the GE MULTILIN D20 RTUs has indicated that regular maintenance is not required. As communications between ECC operators and the RTUs is a continuous 24 hour process, any anomaly is immediately reported to Network Services for investigation and repair.

Anticipated Useful Life

NL Hydro's GE MULTILIN D20-based RTU network continues to grow and evolve. It is the primary interface from which ECC operators can monitor the health of Hydro facilities as well as issue controls to the network. There is no consideration to switching to another platform or technology in the foreseeable future.

Alternatives

There are no viable alternatives to upgrading remote terminal units.

Conclusion:

It is essential to commence a program of upgrading GE MULTILIN D20M++ RTUs to the D20MX platform in order to maintain a highly reliable SCADA network at Hydro. Failure of an RTU causes an ECC operator to lose all visibility of components monitored and controlled by that RTU which can lead to prolonged and unexpected customer outages. In addition, the newer D20MX platform will allow the integration of advanced protection and control devices into the network providing additional information and resources to ECC operators and asset owners.

Due to operational risks associated with the failure of supervisory control and data acquisition equipment, this project is a proactive approach to ensuring that the likelihood of RTU failure is minimal.

Future Plans:

Future plans will be proposed in future capital budget applications. RTU upgrades will be completed over the period from 2016 to 2020.

Project Schedule:

The anticipated project schedule is shown in Table 3.

Table 3: Project Schedule

Activity		Start Date	End Date
Planning	Prepare Project Plan and site visits	January 2016	February 2016
Design	Complete Tender Package	February 2016	March 2016
Procurement	Purchase Upgrade Kits	April 2016	April 2016
Installation	Install Upgrade Kits	May 2016	September 2016
Commissioning	Site Inspections	October 2016	October 2016
Closeout	Project Closeout	November 2016	December 2016

APPENDIX A

D20M++ RTU Replacement Schedule

RTU Replacement Schedule			
Site Abbrev.	**Location**	**Site Type**	**Scheduled Replacement**
HWD	Hardwoods	Terminal Station	2016
SLK	Star Lake	Plant	2016
WAV	Western Avalon	Terminal Station	2016
DHR	Daniel's Harbour	Terminal Station	2017
HBY	Hawke's Bay	Terminal Station	2017
PBN	Peter's Barren	Terminal Station	2017
SDP	St. Anthony Diesel	Plant	2017
STA	St. Anthony Airport	Terminal Station	2017
NSD	North Salmon Dam	Dam	2018
RBK	Rattle Brook	Plant	2018
USI	Upper Salmon Intake	Intake	2018
WSS	West Salmon Spillway	Spillway	2018
HLC	Hinds Lake Control Structure	Control Structure	2019
HLI	Hinds Lake Intake	Intake	2019
HLS	Hinds Lake Spillway	Spillway	2019
HLX	Hinds Lake Concentrator	Concentrator	2019
HMC	Hinds Lake Control Stru Sub	Control Structure	2019
HMI	Hinds Lake Intake Sub	Intake	2019
HMS	Hinds Lake Spillway Sub	Spillway	2019
CAI	Cat Arm Intake	Intake	2020
CAS	Cat Arm Sync Remote	Remote	2020
CMS	Cat Arm Sync Sub	Sync	2020

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Replace Aircraft Markers at Grand Lake Crossing - TL228		589.6	978.3	1,567.9	Other
TOTAL MANDADORY PROJECTS	0.0	589.6	978.3	1,567.9	
NORMAL PROJECTS					
Upgrade Circuit Breakers - Various Sites (2016-2020)		6,969.1	54,491.3	61,460.4	Other
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods		3,699.0	22,861.9	26,560.9	Other
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,873.8		13,062.9	Pooled
Replace Site Facilities - Bay d'Espoir		928.3	11,053.0	11,981.3	Other
Upgrade Power Transformers - Various Sites	4,440.4	7,002.3		11,442.7	Other
Upgrade Distribution Systems - Various Sites (2016-2017)		285.6	6,350.3	6,635.9	Other
Upgrade Powerhouse Building Envelope - Holyrood		2,723.8	3,754.0	6,477.8	Other
Overhaul Steam Turbine Generator Unit 3 - Holyrood		5,868.6		5,868.6	Other
Additions for Load Growth - L'Anse au Loup and Postville		883.4	4,746.0	5,629.4	Other
Provide Service Extensions - All Service Areas		5,150.0		5,150.0	Pooled
Replace Diesel Units - Cartwright and Charlottetown		1,840.5	3,098.4	4,938.9	Other
Install Fire Protection Systems - Nain and Cartwright		3,030.7	1,376.4	4,407.1	Other
Upgrade Distribution Systems - All Service Areas		3,890.0		3,890.0	Pooled
Replace Instrument Transformers - Various Sites	1,684.4	1,511.7	471.9	3,668.0	Pooled
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir		2,959.6		2,959.6	Other
Perform Wood Pole Line Management Program - Various Sites		2,919.0		2,919.0	Other
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood		2,755.5		2,755.5	Other
Replace Vehicles and Aerial Devices - Various Sites (2015-2016)	2,377.1	225.3		2,602.4	Other
Overhaul Diesel Units - Various Sites		2,078.4		2,078.4	Pooled
Install Spare Transformer - Happy Valley		2,040.9		2,040.9	Other
Replace Insulators - TL203		1,985.6		1,985.6	Other
Replace Vehicles and Aerial Devices - Various Sites (2016-2017)		1,443.3	534.2	1,977.5	Other
Replace Disconnect Switches - Various Sites (2016-2017)		646.9	1,320.9	1,967.8	Pooled
Upgrade Distribution Systems - Various Sites (2015-2016)	1,136.1	818.8		1,954.9	Pooled
Upgrade Work - Cat Arm		558.3	1,353.0	1,911.3	Other
Replace Protective Relays - Various Sites		700.6	1,156.4	1,857.0	Other
Install Transformer On line Gas Monitoring - Various Sites	700.5	975.7		1,676.2	Other
Replace Disconnect Switches - Various Sites	963.7	642.9		1,606.6	Pooled
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	1,061.4		1,550.8	Other
Upgrade Microsoft Office Products - Hydro Place		366.6	1,024.5	1,391.1	Other
Install Fire Protection - L'Anse Au Loup	220.6	1,126.2		1,346.8	Other
Overhaul Turbine/Generator Units 6 and 7 - Bay d'Espoir		1,345.6		1,345.6	Other
Replace Unit 2038 - Mary's Harbour	103.5	1,241.5		1,345.0	Other

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Definition
			($000)		
NORMAL PROJECTS (cont'd.)					
Inspect Fuel Storage Tanks - Various Sites		1,326.9		1,326.9	Other
Rehabilitate Salmon River Spillway - Bay d'Espoir	745.6	556.8		1,302.4	Other
Construct Overhead Distribution Line - Pilley's Island to Long Island		1,239.9		1,239.9	Other
Replace MDR 4000 Microwave Radio East - Various Sites		77.4	1,093.1	1,170.5	Other
Rehabilitate Shoreline Protection - Cat Arm		112.2	1,030.7	1,142.9	Other
Upgrade Office Facilities and Control Buildings - Various Sites		1,134.0		1,134.0	Other
Replace Station Service Breakers - Cat Arm	644.9	363.4		1,008.3	Other
Replace Programmable Logic Controllers - Various Sites	366.9	346.0	245.1	958.0	Other
Replace UPS Systems - Hydro Place		889.8		889.8	Pooled
Replace Battery Banks and Chargers - Various Sites		425.0	456.6	881.6	Other
Replace Personal Computers - Various Sites		861.7		861.7	Other
Upgrade Line Depots - Various Sites		861.4		861.4	Other
Replace Powerline Carrier - Various Sites		73.4	763.4	836.8	Other
Purchase Diesel Plant Production Data Collection Equipment - Various Sites	538.7	280.7		819.4	Other
Install Fire Protection in 230 kV Stations - Bay d'Espoir		200.0	566.0	766.0	Other
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	633.3		648.0	Other
Replace Roof - Hydro Place		639.5		639.5	Other
Replace Roof on Services Building - Bishop's Falls		612.8		612.8	Other
Additions for Load Growth - Happy Valley		593.7		593.7	Other
Upgrade Telecontrol Facilities - Sandy Brook Hill		101.6	462.4	564.0	Other
Purchase Vehicles and Aerial Devices - Various Sites		382.5	172.7	555.2	Other
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	522.5		545.2	Other
Overhaul Pumps - Holyrood		536.2		536.2	Other
Upgrade Digital Fault Recorders - Various Sites		197.9	304.6	502.5	Other
TOTAL NORMAL PROJECTS	20,638.3	89,517.5	118,686.8	228,842.6	
JUSTIFIABLE PROJECTS					
Construct 230 kV Transmission Line - Bay d'Espoir to Western Avalon	4,403.0	75,284.3	211,970.7	291,658.0	Other
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,525.4		5,180.6	Other
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	239.9	1,038.4	901.6	2,179.9	Other
Install Automated Meter Reading - Labrador West		433.8	533.4	967.2	Pooled
Install Automated Meter Reading - Various Sites (2015-2016)	559.9	401.8		961.7	Other
TOTAL JUSTIFIABLE PROJECTS	7,858.0	79,683.7	213,405.7	300,947.4	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
TOTAL MANDATORY PROJECTS		0.0		0.0	
NORMAL PROJECTS					
Replace Diesel Unit 254 - Paradise River	66.8	429.3		496.1	Other
Upgrade Ventilation Systems -Various Sites	175.9	317.3		493.2	Pooled
Design and Install Fire Protection in 230 kV Stations - Holyrood	67.6	424.3		491.9	Pooled
Upgrade Terminal Station for Mobile Substation - Cow Head		40.0	444.7	484.7	Other
Upgrade Terminal Station Protection and Control - Various Sites	172.7	307.2		479.9	Other
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir		477.6		477.6	Pooled
Upgrade Transformers - Cartwright and Postville		465.2		465.2	Other
Implement Industrial Billing Software - Hydro Place		443.1		443.1	Other
Replace Human Machine Interface - Various Sites		114.0	320.0	434.0	Other
Replace Peripheral Infrastructure - Various Sites		424.5		424.5	Other
Replace Powerhouse 1 Station Service Transformer - Bay d'Espoir		46.7	354.5	401.2	Other
Upgrade Aluminum Support Structure - Holyrood		401.1		401.1	Other
Replace Off Road Track Vehicle Unit 7861 - Stephenville	1.1	397.8		398.9	Other
Replace Vibration Monitoring System Unit 7 - Bay d'Espoir		366.0		366.0	Other
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	311.3		357.0	Other
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir		183.6	167.9	351.5	Other
Replace Light Duty Mobile Equipment - Various Sites		348.0		348.0	Other
Upgrade Enterprise Storage Capacity - Hydro Place		337.2		337.2	Other
Refurbish Intakes - Bay d'Espoir	72.6	262.3		334.9	Other
Perform Condition Assessment of Control Structure - Hinds Lake		323.4		323.4	Other
Upgrade Terminal Station Equipment Foundations - Various Sites		319.9		319.9	Pooled
Install Hydrometeorological Equipment - Various Sites		314.1		314.1	Other
Purchase Excavator - Bay d'Espoir		312.0		312.0	Other
Replace Fuel Piping - Hardwoods and Stephenville		44.8	267.0	311.8	Other
Upgrade Data Alarm Systems - Stony Brook		74.4	234.1	308.5	Other
Refurbish Station Water System - Upper Salmon		96.6	197.6	294.2	Other
Install Breaker Failure Protection - Various Sites		65.7	211.3	277.0	Other
Replace Air Conditioning Units 8 and 14 - Hydro Place		34.6	229.5	264.1	Other
Upgrade Server Technology Program - Hydro Place		264.0		264.0	Other
Upgrade Energy Management System - Hydro Place		246.2		246.2	Other
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	197.6		243.8	Other
Replace Radomes - Various Sites		235.2		235.2	Pooled
TOTAL NORMAL PROJECTS	648.6	8,625.0	2,426.6	11,700.2	
JUSTIFIABLE PROJECTS					
TOTAL JUSTIFIABLE PROJECTS		0.0		0.0	

PROJECT DESCRIPTION	Expended to 2015	2016	Future Years	Total	Definition
			($000)		
MANDATORY PROJECTS					
Install Fall Protection Equipment - Various Sites		198.8		198.8	Pooled
				0.0	
TOTAL MANDATORY PROJECTS		198.8		198.8	
NORMAL PROJECTS					
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	189.3		199.3	Other
Remove Safety Hazards - Various Sites		199.3		199.3	Other
Perform Minor Application Enhancements - Hydro Place		197.9		197.9	Other
Replace Surge Arrestors - Various Sites		144.4	53.0	197.4	Other
Install Infrared View Ports - Various Sites	83.7	113.1		196.8	Pooled
Upgrade Warehouse Lighting - Bishop's Falls		15.2	180.4	195.6	Other
Replace Air Conditioners - Massey Drive and Happy Valley		39.9	152.0	191.9	Other
Purchase Meters and Metering Equipment - Various Sites		190.4		190.4	Other
Replace Network Communication Equipment - Various Sites		186.4		186.4	Other
Replace Video Conferencing Bridge - Hydro Place		182.6		182.6	Other
Replace Generator Cooling Water Piping - Hinds Lake		181.7		181.7	Other
Replace Station Lighting - Bay d'Espoir	16.7	160.3		177.0	Other
Upgrade Citrix - Hydro Place		159.6		159.6	Other
Study of Auxiliary Steam and Space Heating Requirements - Holyrood		148.7		148.7	Other
Install Transfer Switches for Diesel Automation - Happy Valley		148.4		148.4	Other
Upgrade Sharepoint Document Repository - Hydro Place		143.5		143.5	Other
Upgrade Access Roads to Microwave Sites - Gull Pond Hill and Sandy Brook Hill		141.1		141.1	Other
Refresh Security Software - Hydro Place		123.5		123.5	Other
Replace Air Receivers and Compressors - St. Anthony		120.7		120.7	Other
Replace Control Room/Communications Room Air Conditioning - Hinds Lake		41.3	53.0	94.3	Other
Upgrade Remote Terminal Units - Various Sites		89.6		89.6	Pooled
Refurbish Unit Relay Protection - Paradise River	8.7	79.7		88.4	Other
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir		85.7		85.7	Other
TOTAL NORMAL PROJECTS	119.1	3,082.3	438.4	3,639.8	
JUSTIFIABLE PROJECTS					
Install Variable Frequency Drives - Grey River		46.9	123.0	169.9	Other
TOTAL JUSTIFIABLE PROJECTS		46.9	123.0	169.9	

Type	Number	($000)
Clustered	0	0.0
Pooled	18	37,738.6
Other	102	509,328.0
Total	**120**	**547,066.6**

Includes multi-year projects but excludes contingency fund

2016 LEASING COSTS

THERE ARE NO ITEMS FOR THIS SECTION

	ACTUALS				BUDGET					
	2011	**2012**	**2013[1]**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
GENERATION	13,131	24,297	43,000	122,571	28,257	26,065	26,815	20,539	23,159	21,699
TRANSMISSION AND RURAL OPERATIONS	41,251	45,705	35,820	75,771	237,511	147,991	206,802	182,866	79,684	85,887
GENERAL PROPERTIES	8,734	7,250	5,935	6,386	8,482	9,643	14,138	14,902	8,293	4,722
TOTAL CAPITAL EXPENDITURES	63,116	77,252	84,755	204,728	274,249	183,698	247,755	218,307	111,136	112,307

[1] Excludes insurance proceeds, which are offset against the cost of capital assets, of $3323.6 for Restore Unit 1 Holyrood, $1,071.2 for Rewind Gas Turbine Alternator Stephenville and $104.3 for Black Tickle Plant Rehabilitation.

Total Capital Project Variance
2015 Overview
($000)

Asset Type	Board Approved Budget	Total Project Expenditures and Forecast	Variance
HYDRAULIC	14,243	14,303	60
THERMAL	9,954	10,251	297
GAS TURBINES	6,855	6,855	-
TERMINAL STATIONS	41,934	41,934	-
TRANSMISSION	5,011	5,011	-
DISTRIBUTION	31,385	31,404	20
RURAL GENERATION	25,574	26,627	1,053
PROPERTIES	3,313	3,313	-
METERING	2,054	2,054	-
RURAL SYSTEMS TOOLS AND EQUIPMENT	2,069	1,964	(105)
INFORMATION SYSTEMS	3,392	3,392	-
TELECONTROL	1,794	1,794	-
TRANSPORTATION	5,503	5,503	-
ADMINISTRATIVE	1,550	1,487	(63)
ALLOWANCE FOR UNFORESEEN	1,000	1,000	-
SUPPLEMENTAL PROJECTS	769,543	460,194	(309,350)
PROJECTS LESS THAN $50,000	123	123	-
TOTAL CAPITAL BUDGET	**925,295**	**617,207**	**(308,088)**

2015 Capital Expenditures By Year
($000)

Summary	Capital Budget[1]										Actual Expenditure and Forecast										
	2010	2011	2012	2013	2014	Carryover 2015	Original 2015[3]	Revised 2015[3]	2016 and Beyond	Total Original Budget	2010	2011	2012	2013	2014[2]	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance
2015 Projects							61,265.3	61,265.3	27,816.3	89,081.6						13,567.2	47,738.4	27,776.0	-	89,081.6	0.0
2014 Projects					173,298.2	25,576.1	207,102.1	232,678.2	399,524.0	779,924.3					119,176.6	38,724.7	23,207.3	289,475.7	-	470,584.3	(309,340.0)
2013 Projects				8,851.1	29,588.6	10,030.9	836.1	10,867.0	1,983.5	41,259.3			76.6	2,505.4	26,816.5	6,014.0	4,913.0	1,983.5	-	42,309.0	1,049.7
2012 Projects			110.4	-	-	-	-	-	-	110.4			43.6	69.2	-	-	-	-	-	112.8	2.4
2011 Projects		750.7	704.3	720.0	738.9	798.1	758.5	1,556.6	-	3,672.4		391.1	332.4	657.0	735.3	141.7	1,414.9	-	-	3,672.4	(0.0)
2010 Projects	1,088.9	3,501.2	3,840.7	969.5	608.9	(634.5)	1,238.2	603.7	-	11,247.4	1,524.6	2,825.0	4,120.6	1,129.8	1,243.4	348.2	255.5	-	-	11,447.1	199.7
Grand Total	1,088.9	4,251.9	4,655.4	10,540.6	204,234.6	35,770.6	271,200.2	306,970.8	429,323.8	925,295.4	1,524.6	3,216.1	4,573.2	4,361.4	147,971.8	58,795.8	77,529.1	319,235.2	-	617,207.2	(308,088.2)

Revised 2015 Budget

2015 Capital Budget Approved by Board Order No. P.U. 50 (2014)	76,832.9
New Project Approved by Board Order No. 16 (2014)	9,248.8
New Project Approved by Board Order No. 29 (2014)	1,226.4
New Project Approved by Board Order No. 34 (2014)	360.0
New Project Approved by Board Order No. 38 (2014)	61.1
New Project Approved by Board Order No. 45 (2014)[3]	1,238.2
New Project Approved by Board Order No. 53 (2014)	18,964.7
New Project Approved by (O.C. 2014-033)[4]	163,145.3
2014 New Projects under $50,000 Approved by Hydro	122.8
Total Approved Capital Budget Before Carryovers	271,200.2
Carryovers from 2014 to 2015	35,770.6
TOTAL APPROVED CAPITAL BUDGET	306,970.8

[1] Annual budgets previous to 2015 pertain to projects that have expenditures in 2015.

[2] Includes Insurance Proceeds relating to Sunnyside - Transformer T1 Replacement ($1.8M).

[3] As per P.U 45 (2014) the Board did not approve the $0.2M Voltage Conversion - Labrador City actual costs over budget from 2010 to 2013. Upon completion of the capital job Hydro will exclude the $0.2M from average rate base.

[4] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014 of which $163.1M was included in the 2015 Capital Budget. The capital expenditures associated with this project are $11.3 as at June 30, 2015 and are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board of Commissioners of Public Utilities.

2015 Capital Expenditures By Category
($000)

Hydraulic Generation Projects	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2012	2013	2014	Actual YTD 2015	Forecast Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects																		
Refurbish Unit Relay Protection - Paradise River	-	-	-	-	8.7	8.7	79.7	88.4	-	-	-	4.3	4.4	79.7	-	88.4	-	
Refurbish Generation Unit - Snook's Arm	-	-	-	-	352.9	352.9	-	352.9	-	-	-	153.3	199.6	-	-	352.9	-	
Replace Station Service Breakers - Cat Arm	-	-	-	-	644.9	644.9	363.4	1,008.3	-	-	-	174.7	470.2	363.4	-	1,008.3	-	
Refurbish Access Road - Cat Arm	-	-	-	-	990.0	990.0	-	990.0	-	-	-	32.5	957.5	-	-	990.0	-	
Replace ABB Exciter Unit 2 - Cat Arm	-	-	-	-	845.9	845.9	-	845.9	-	-	-	195.7	650.2	-	-	845.9	-	
Replace Interior Coating on Surge Tank 3 - Bay d'Espoir	-	-	-	-	1,629.3	1,629.3	-	1,629.3	-	-	-	621.5	1,007.8	-	-	1,629.3	-	
Rehabilitate Salmon River Spillway - Bay d'Espoir	-	-	-	-	745.6	745.6	556.8	1,302.4	-	-	-	51.1	694.5	556.8	-	1,302.4	-	
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	-	-	-	-	14.7	14.7	633.3	648.0	-	-	-	0.8	13.9	633.3	-	648.0	-	
Automate Generator Deluge Systems - Bay d'Espoir	-	-	-	-	645.2	645.2	-	645.2	-	-	-	64.4	580.8	-	-	645.2	-	
Replace Pump House and Associated Equipment - Bay d'Espoir	-	-	-	-	22.7	22.7	522.5	545.2	-	-	-	10.2	12.5	522.5	-	545.2	-	
Upgrade Public Safety Around Dams and Waterways - Various Sites	-	-	-	-	483.9	483.9	-	483.9	-	-	-	22.9	461.0	-	-	483.9	-	
Install Hydrometeorological Stations - Various Sites	-	-	-	-	377.9	377.9	-	377.9	-	-	-	56.7	321.2	-	-	377.9	-	
Upgrade Equipment Doors - Various Sites	-	-	-	-	348.5	348.5	-	348.5	-	-	-	92.3	256.2	-	-	348.5	-	
Refurbish Intakes - Bay d'Espoir	-	-	-	-	72.6	72.6	262.3	334.9	-	-	-	8.2	64.4	262.3	-	334.9	-	
Replace Automatic Greasing Systems Units 2 and 4 - Bay d'Espoir	-	-	-	-	254.4	254.4	-	254.4	-	-	-	155.8	98.6	-	-	254.4	-	
Install Infrared View Ports - Various Sites	-	-	-	-	83.7	83.7	113.1	196.8	-	-	-	29.9	53.8	113.1	-	196.8	-	
Replace Generator Bearing Coolers - Bay d'Espoir	-	-	-	-	153.8	153.8	-	153.8	-	-	-	87.9	65.9	-	-	153.8	-	
Overhaul Turbine/Generator Units - Bay D'Espoir and Paradise River	-	-	-	-	304.4	304.4	-	304.4	-	-	-	190.0	114.4	-	-	304.4	-	
Purchase Tools and Equipment Less than $ 50,000	-	-	-	-	108.6	108.6	-	108.6	-	-	-	-	108.6	-	-	108.6	-	
2014 Projects																		
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	-	110.2	(15.9)	1,201.9	1,186.0	-	1,312.1	-	-	126.1	320.3	865.7	-	-	1,312.1	-	
Upgrade Victoria Control Structure - Bay d'Espoir	-	-	495.1	415.5	-	415.5	-	495.1	-	-	79.6	24.8	390.7	-	-	495.1	-	
Upgrade Generator Bearings Unit 2 - Bay d'Espoir	-	-	18.9	9.5	396.0	405.5	-	414.9	-	-	9.4	77.0	328.5	-	-	414.9	-	
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - BDE	-	-	57.5	44.7	96.3	141.0	-	153.8	-	-	12.8	8.4	132.6	-	-	153.8	-	
Install Handheld Pendant to Overhead Crane - Bay d'Espoir	-	-	49.9	4.9	170.8	175.7	-	220.7	-	-	45.0	13.3	162.4	-	-	220.7	-	
2013 Projects																		
Upgrade Units 1 to 6 By-Pass Valves - Bay d'Espoir	-	141.9	-	(43.1)	-	(43.1)	-	141.9	3.0	9.5	172.5	(5.7)	22.6	-	-	201.9	60.0	
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	885.8	-	12.3	-	12.3	-	885.8	15.0	223.1	635.4	(24.9)	37.2	-	-	885.8	-	
Total Hydraulic Generation Projects	-	1,027.7	731.6	427.9	9,952.7	10,380.6	2,531.1	14,243.1	18.0	232.6	1,080.8	2,365.4	8,075.2	2,531.1	-	14,303.1	60.0	

2015 Capital Expenditures By Category
($000)

Thermal Generation Projects	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2012	2013	2014	2015	Forecast Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects																		
Overhaul Turbine Valves Unit 1 - Holyrood	-	-	-	-	1,577.5	1,577.5	-	1,577.5	-	-	-	92.0	1,485.5	-	-	1,577.5	-	
Overhaul Boiler Feed Pump East Unit 1 - Holyrood	-	-	-	-	196.3	196.3	-	196.3	-	-	-	-	196.3	-	-	196.3	-	
Replace DC Distribution Panels and Breakers - Holyrood	-	-	-	-	127.9	127.9	-	127.9	-	-	-	70.6	57.3	-	-	127.9	-	
Upgrade Powerhouse Roofing - Holyrood	-	-	-	-	1,047.8	1,047.8	-	1,047.8	-	-	-	86.7	961.1	-	-	1,047.8	-	
Upgrade Quarry Brook Dam Equipment - Holyrood	-	-	-	-	498.7	498.7	-	498.7	-	-	-	65.0	433.7	-	-	498.7	-	
Upgrade Fire Protection (Main Warehouse) - Holyrood	-	-	-	-	46.2	46.2	197.6	243.8	-	-	-	30.6	15.6	197.6	-	243.8	-	
Overhaul Extraction Pumps - Holyrood	-	-	-	-	189.6	189.6	-	189.6	-	-	-	4.9	184.7	-	-	189.6	-	
Purchase Tools and Equipment Less than $ 50,000	-	-	-	-	15.7	15.7	-	15.7	-	-	-	11.8	3.9	-	-	15.7	-	
2014 Projects																		
Replace Economizer Inlet Valves - Holyrood	-	-	192.0	58.4	329.1	387.5	-	521.1	-	-	133.6	23.7	363.8	-	-	521.1	-	
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood	-	-	49.8	(51.5)	467.4	415.9	-	517.2	-	-	101.3	623.0	(207.1)	-	-	517.2	-	
Upgrade Plant Elevators - Holyrood	-	-	533.2	(46.7)	-	(46.7)	-	533.2	-	-	579.9	309.7	(52.6)	-	-	837.0	303.8	1
Upgrade Vibration Monitoring System - Holyrood	-	-	524.9	48.1	-	48.1	-	524.9	-	-	476.8	9.8	38.3	-	-	524.9	-	
Install Fire Protection Upgrades - Holyrood	-	-	56.6	(255.4)	312.5	57.1	-	369.1	-	-	312.0	60.5	(3.4)	-	-	369.1	-	
Replace DC Distribution Panels and Breakers - Holyrood	-	-	174.2	148.6	-	148.6	-	174.2	-	-	25.6	90.7	57.9	-	-	174.2	-	
Purchase Tools and Equipment Less than $50,000	-	-	59.2	15.1	-	15.1	-	59.2	-	-	37.7	-	15.1	-	-	52.8	(6.4)	
2013 Projects																		
Install Variable Frequency Drives on Forced Draft Fans - Holyrood	-	697.6	2,659.7	390.7	-	390.7	-	3,357.3	13.8	206.0	2,746.8	290.4	100.3	-	-	3,357.3	-	
Total Thermal Generation Projects	-	697.6	4,249.6	307.3	4,808.7	5,116.0	197.6	9,953.5	13.8	206.0	4,413.7	1,769.4	3,650.4	197.6	-	10,250.9	297.4	

2015 Capital Expenditures By Category
($000)

Gas Turbine Generation Projects	Capital Budget								Actual Expenditure and Forecast									
	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2012	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryover to 2016	Total	Project Variance	Notes
2015 Projects																		
Upgrade Gas Turbine Plant Life Extension - Stephenville	-	-	-	-	2,655.2	2,655.2	2,525.4	5,180.6	-	-	-	924.8	1,730.4	2,525.4	-	5,180.6	-	
Replace Alternator Shaft - Happy Valley	-	-	-	-	484.4	484.4	-	484.4	-	-	-	91.2	393.2	-	-	484.4	-	
2013 Projects																		
Upgrade Gas Turbine PLC - Happy Valley	-	61.4	1,128.6	734.2	-	734.2	-	1,190.0	2.3	22.6	430.9	390.0	344.2	-	-	1,190.0	-	
Total Gas Turbine Generation Projects	-	61.4	1,128.6	734.2	3,139.6	3,873.8	2,525.4	6,855.0	2.3	22.6	430.9	1,406.0	2,467.8	2,525.4	-	6,855.0	-	

2015 Capital Expenditures By Category
($000)

Terminal Stations Projects	Capital Budget									Actual Expenditure and Forecast									Project Variance	Notes
	2011	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2011	2012	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total		
2015 Projects																				
Upgrade Circuit Breakers - Various Sites (2015-2016)	-	-	-	-	-	6,189.1	6,189.1	6,873.8	13,062.9	-	-	-	-	1,407.3	4,781.8	6,873.8	-	13,062.9	-	
Replace Surge Arrestors - Various Sites	-	-	-	-	-	198.1	198.1	-	198.1	-	-	-	-	58.0	140.1	-	-	198.1	-	
Install Transformer On line Gas Monitoring - Various Sites	-	-	-	-	-	700.5	700.5	-	700.5	-	-	-	-	401.6	298.9	-	-	700.5	-	
Upgrade Power Transformers - Various Sites	-	-	-	-	-	4,440.4	4,440.4	7,002.3	11,442.7	-	-	-	-	355.7	4,084.7	7,002.3	-	11,442.7	-	
Replace Disconnect Switches - Various Sites (2015-2016)	-	-	-	-	-	963.7	963.7	642.9	1,606.6	-	-	-	-	43.2	920.5	642.9	-	1,606.6	-	
Design and Install Fire Protection in 230 kV Station - Various Sites	-	-	-	-	-	67.6	67.6	424.3	491.9	-	-	-	-	33.7	33.9	424.3	-	491.9	-	
Perform Site Work for Mobile Substation - Barachoix	-	-	-	-	-	489.3	489.3	-	489.3	-	-	-	-	34.1	455.2	-	-	489.3	-	
Upgrade Terminal Station Protection and Control - Various Sites	-	-	-	-	-	172.7	172.7	307.2	479.9	-	-	-	-	57.6	115.1	307.2	-	479.9	-	
Upgrade Terminal Station Foundations - Various Sites	-	-	-	-	-	302.3	302.3	-	302.3	-	-	-	-	43.8	258.5	-	-	302.3	-	
Upgrade Control Wiring Phase 1 to Terminal Station 1 - Bay d'Espoir	-	-	-	-	-	301.0	301.0	-	301.0	-	-	-	-	55.7	245.3	-	-	301.0	-	
Install Support Structures C2 Capacitor Bank - Hardwoods	-	-	-	-	-	199.3	199.3	-	199.3	-	-	-	-	19.6	179.7	-	-	199.3	-	
Replace Station Lighting - Bay d'Espoir	-	-	-	-	-	16.7	16.7	160.3	177.0	-	-	-	-	11.4	5.3	160.3	-	177.0	-	
Upgrade Transformer Differential Protection - Grandy Brook	-	-	-	-	-	154.0	154.0	-	154.0	-	-	-	-	21.9	132.1	-	-	154.0	-	
2014 Projects																				
Upgrade Circuit Breakers - Various Sites	-	-	-	3,695.4	2,123.7	1,642.5	3,766.2	-	5,337.9	-	-	-	1,571.7	1,585.4	2,180.8	-	-	5,337.9	-	
Replace Disconnect Switches - Various Sites	-	-	-	815.9	667.5	189.5	857.0	-	1,005.4	-	-	-	148.4	763.2	93.8	-	-	1,005.4	-	
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside	-	-	-	89.1	70.9	96.9	167.8	-	186.0	-	-	-	18.2	184.6	(16.8)	-	-	186.0	-	
2013 Projects																				
Replace Instrument Transformers - Various Sites	-	-	593.2	552.8	206.7	538.4	745.1	1,983.5	3,667.9	-	9.6	230.7	699.0	233.8	511.3	1,983.5	-	3,667.9	-	
Replace Insulators - Various Sites	-	-	187.1	287.9	41.6	-	41.6	-	475.0	-	5.1	67.0	361.3	57.7	(16.1)	-	-	475.0	-	
2011 Projects																				
Perform Grounding Upgrades - Various Sites	321.2	324.0	329.0	337.1	51.8	345.4	397.2	-	1,656.7	287.6	240.7	507.2	224.0	45.9	351.3	-	-	1,656.7	-	
Total Terminal Stations Projects	321.2	324.0	1,109.3	5,778.2	3,162.2	17,007.4	20,169.6	17,394.3	41,934.4	287.6	255.4	804.9	3,022.6	5,414.2	14,755.4	17,394.3	-	41,934.4	-	

2015 Capital Expenditures by Category
($000)

Transmission Projects	Original 2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects														
Perform Wood Pole Line Management Program - Various Sites	-	-	2,830.6	2,830.6	-	2,830.6	-	1,114.4	1,716.2	-	-	2,830.6	-	
2014 Projects														
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	1,191.7	980.2	988.2	1,968.4	-	2,179.9	211.5	27.4	1.0	1,940.0	-	2,179.9	-	
Total Transmission Projects	1,191.7	980.2	3,818.8	4,799.0	-	5,010.5	211.5	1,141.8	1,717.2	1,940.0	-	5,010.5	-	

2015 Capital Expenditures By Category
($000)

Distribution Projects	Capital Budget										Actual Expenditure and Forecast											
	2010	2011	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2010	2011	2012	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects																						
Construct Second Distribution Feeder - Nain	-	-	-	-	-	-	1,050.3	1,050.3	-	1,050.3	-	-	-	-	-	41.2	1,009.1	-	-	1,050.3	-	
Relocate Voltage Regulator - Hawkes Bay	-	-	-	-	-	-	166.4	166.4	-	166.4	-	-	-	-	-	21.4	145.0	-	-	166.4	-	
Provide Service Extensions - All Service Areas	-	-	-	-	-	-	6,248.0	6,248.0	-	6,248.0	-	-	-	-	-	1,719.7	4,528.3	-	-	6,248.0	-	
Provide Service Extensions - All Service Areas - CIAC	-	-	-	-	-	-	(168.0)	(168.0)	-	(168.0)	-	-	-	-	-	(82.6)	(85.4)	-	-	(168.0)	-	
Upgrade Distribution Systems - All Service Areas	-	-	-	-	-	-	3,382.0	3,382.0	-	3,382.0	-	-	-	-	-	1,350.6	2,031.4	-	-	3,382.0	-	
Upgrade Distribution Systems - All Service Areas - CIAC	-	-	-	-	-	-	(42.0)	(42.0)	-	(42.0)	-	-	-	-	-	(9.4)	(32.6)	-	-	(42.0)	-	
Upgrade Distribution Systems - Various Sites (2015/2016)	-	-	-	-	-	-	1,136.1	1,136.1	818.8	1,954.9	-	-	-	-	-	255.9	880.2	818.8	-	1,954.9	-	
2014 Projects																						
Replace Recloser Control Panels - Various Sites	-	-	-	-	111.3	26.3	84.4	110.7	-	195.7	-	-	-	-	85.0	73.3	37.4	-	-	195.7	-	
Upgrade Distribution Systems - Various Sites (2014/2015)	-	-	-	-	2,499.8	177.1	4,850.1	5,027.2	-	7,349.9	-	-	-	-	2,142.5	1,712.8	3,314.4	-	-	7,169.7	(180.2)	
2010 Projects																						
Voltage Conversion - Labrador City[5]	1,088.9	3,501.2	3,840.7	969.5	608.9	(634.5)	1,238.2	603.7	-	11,247.4	1,524.6	2,825.0	4,120.6	1,129.8	1,243.4	348.2	255.5	-	-	11,447.1	199.7	
Total Distribution Projects	1,088.9	3,501.2	3,840.7	969.5	3,220.0	(431.1)	17,945.5	17,514.4	818.8	31,384.6	1,524.6	2,825.0	4,120.6	1,129.8	3,470.9	5,431.1	12,083.3	818.8	-	31,404.1	19.5	

[5] As per P.U 45(2014) the Board did not approve the $0.2M Voltage Conversion - Labrador City actual costs over budget from 2010 to 2013. Upon completion of the capital job Hydro will exclude the $0.2M from average rate base.

2015 Capital Expenditures By Category
($000)

Rural Generation Projects	Capital Budget									Actual Expenditure and Forecast									Project Variance	Notes
	2011	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2011	2012	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total		
2015 Projects																				
Overhaul Diesel Units - Various Sites	-	-	-	-	-	1,199.2	1,199.2	-	1,199.2	-	-	-	-	460.9	738.3	-	-	1,199.2	-	
Install Disconnect Switches for Mobile Generators - Various Sites	-	-	-	-	-	10.0	10.0	189.3	199.3	-	-	-	-	-	10.0	189.3	-	199.3	-	
Inspect Fuel Storage Tanks - Various Sites	-	-	-	-	-	1,761.1	1,761.1	-	1,761.1	-	-	-	-	156.4	1,604.7	-	-	1,761.1	-	
Increase Fuel Storage - Rigolet	-	-	-	-	-	1,666.8	1,666.8	-	1,666.8	-	-	-	-	119.6	1,547.2	-	-	1,666.8	-	
Upgrade Ventilation Systems - Various Sites	-	-	-	-	-	175.9	175.9	317.3	493.2	-	-	-	-	34.4	141.5	317.3	-	493.2	-	
Upgrade Building Exterior - Makkovik	-	-	-	-	-	309.5	309.5	-	309.5	-	-	-	-	34.0	275.5	-	-	309.5	-	
Increase Generation Capacity - Makkovik	-	-	-	-	-	272.6	272.6	-	272.6	-	-	-	-	27.5	245.1	-	-	272.6	-	
Replace Unit 2038 - Mary's Harbour	-	-	-	-	-	103.5	103.5	1,241.5	1,345.0	-	-	-	-	44.0	59.5	1,241.5	-	1,345.0	-	
Replace Unit 254 - Paradise River	-	-	-	-	-	66.8	66.8	429.3	496.1	-	-	-	-	25.7	41.1	429.3	-	496.1	-	
Replace Programmable Logic Controllers - Various Sites	-	-	-	-	-	366.9	366.9	591.1	958.0	-	-	-	-	25.5	341.4	591.1	-	958.0	-	
Install Fire Protection - L'Anse Au Loup	-	-	-	-	-	220.6	220.6	1,126.2	1,346.8	-	-	-	-	22.7	197.9	1,126.2	-	1,346.8	-	
2014 Projects																				
Install Fire Protection System - Nain	-	-	-	107.1	66.4	892.2	958.6	-	999.3	-	-	-	40.7	22.2	936.4	-	-	999.3	-	
Construct Storage Facility - Postville	-	-	-	183.8	177.8	-	177.8	-	183.8	-	-	-	66.7	15.3	162.5	-	-	244.5	60.7	
Upgrade Diesel Plant Production Data Collection Equipment-Various	-	-	-	268.9	161.1	269.8	430.9	280.7	819.4	-	-	-	107.8	1.2	429.7	280.7	-	819.4	-	
2013 Projects																				
Additions for Load Isolator Generation Stations - Various Sites	-	-	2,040.2	9,357.9	4,310.1	-	4,310.1	-	11,398.1	-	27.8	1,196.4	6,853.5	2,074.6	2,235.5	-	-	12,387.8	989.7	
2012 Projects																				
Perform FEED for Diesel Plant Remediation - Various Sites	-	110.4	-	-	-	-	-	-	110.4	-	43.6	69.2	-	-	-	-	-	112.8	2.4	
2011 Projects																				
Perform Arc Flash Remediation - Various Sites	429.5	380.3	391.0	401.8	746.3	413.1	1,159.4	-	2,015.7	103.5	91.7	149.8	511.3	95.8	1,063.6	-	-	2,015.7	-	
Total Rural Generation Projects	429.5	490.7	2,431.2	10,319.5	5,461.7	7,728.0	13,189.7	4,175.4	25,574.3	103.5	163.1	1,415.4	7,580.0	3,159.8	10,029.9	4,175.4	-	26,627.1	1,052.8	

2015 Capital Expenditures By Category
($000)

Properties Projects														
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects														
Replace Accommodations and Septic System - Ebbegunbaeg	-	-	489.4	489.4	1,061.4	1,550.8	-	31.0	458.4	1,061.4	-	1,550.8	-	
Upgrade Line Depots - Various Sites	-	-	953.3	953.3	-	953.3	-	79.7	873.6	-	-	953.3	-	
Reshingle Roof - Stephenville	-	-	76.8	76.8	-	76.8	-	27.0	49.8	-	-	76.8	-	
Install Fall Protection Equipment - Various Sites	-	-	198.9	198.9	-	198.9	-	18.5	180.4	-	-	198.9	-	
Upgrade HVAC System - Port Saunders	-	-	137.0	137.0	-	137.0	-	46.5	90.5	-	-	137.0	-	
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2015-2016)	-	-	158.6	158.6	40.3	198.9	-	128.3	70.6		-	198.9	-	
2014 Projects														
Legal Survey of Primary Distribution Line Right of Ways - Various Sites (2014-2015)	156.8	(90.6)	40.3	(50.3)	-	197.1	247.3	(50.5)	0.2	-	-	197.0	(0.1)	
Total Properties Projects	156.8	(90.6)	2,054.3	1,963.7	1,101.7	3,312.8	247.3	280.5	1,723.5	1,061.4	-	3,312.7	(0.1)	

2015 Capital Expenditures By Category
($000)

Metering Projects	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects													
Purchase Meters, Equipment and Metering Tanks - Various Sites	-	196.2	196.2	-	196.2	-	103.1	93.1	-	-	196.2	-	
Install Automatic Meter Reading - Various Sites (2015-2016)	-	559.9	559.9	401.8	961.7	-	12.5	547.4	401.8	-	961.7	-	
2014 Projects													
Purchase Meters, Equipment and Metering Tanks - Various Sites	61.4	-	61.4	-	199.0	137.6	9.6	51.8	-	-	199.0	-	
Install Automatic Meter Reading - Various Sites (2014-2015)	23.7	340.2	363.9	-	697.1	333.2	167.6	196.3	-	-	697.1	-	
Total Metering Projects	85.1	1,096.3	1,181.4	401.8	2,054.0	470.8	292.8	888.6	401.8	-	2,054.0	-	

2015 Capital Expenditures By Category
($000)

Rural Systems Tools and Equipment Projects	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects														
Replace Light Duty Mobile Equipment - Various Sites	-	-	494.4	494.4	-	494.4	-	61.8	432.6	-	-	494.4	-	
Replace Off Road Track Vehicles - Unit 7861, Stephenville (2015 - 2016)	-	-	1.1	1.1	397.8	398.9	-	-	1.1	397.8	-	398.9	-	
Tools and Equipment Less than $ 50,000	-	-	622.7	622.7	-	622.7	-	106.4	516.3	-	-	622.7	-	
2014 Projects														
Tools and Equipment Less than $50,000	553.3	31.3	-	31.3	-	553.3	416.7	30.9	0.4	-	-	448.0	(105.3)	2
Total Tools and Equipment	553.3	31.3	1,118.2	1,149.5	397.8	2,069.3	416.7	199.1	950.4	397.8	-	1,964.0	(105.3)	

2015 Capital Expenditures By Category
($000)

Information Systems Projects	Capital Budget							Actual Expenditure and Forecast								
	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects																
Perform Minor Application Enhancements - Hydro Place	-	-	-	329.5	329.5	-	329.5	-	-	83.9	245.6	-	-	329.5	-	
Cost Recoveries	-	-	-	(141.6)	(141.6)	-	(141.6)	-	-	(36.1)	(105.5)	-	-	(141.6)	-	
Upgrade Energy Management System - Hydro Place	-	-	-	194.9	194.9	-	194.9	-	-	154.9	40.0	-	-	194.9	-	
Upgrade Lotus Notes - Hydro Place	-	-	-	635.4	635.4	-	635.4	-	-	76.5	558.9	-	-	635.4	-	
Cost Recoveries	-	-	-	(273.1)	(273.1)	-	(273.1)	-	-	(32.9)	(240.2)	-	-	(273.1)	-	
Replace Customer Care System - Hydro Place	-	-	-	134.9	134.9	-	134.9	-	-	19.9	115.0	-	-	134.9	-	
Replace Peripheral Infrastructure - Various Sites	-	-	-	200.5	200.5	-	200.5	-	-	107.5	93.0	-	-	200.5	-	
Upgrade Enterprise Storage Capacity - Hydro Place	-	-	-	621.3	621.3	-	621.3	-	-	149.1	472.2	-	-	621.3	-	
Cost Recoveries	-	-	-	(267.0)	(267.0)	-	(267.0)	-	-	(14.8)	(252.2)	-	-	(267.0)	-	
Replace Personal Computers - Various Sites	-	-	-	573.3	573.3	-	573.3	-	-	303.6	269.7	-	-	573.3	-	
Upgrade Server Technology Program - Hydro Place	-	-	-	601.3	601.3	-	601.3	-	-	366.7	234.6	-	-	601.3	-	
Cost Recoveries	-	-	-	(227.1)	(227.1)	-	(227.1)	-	-	(80.8)	(146.3)	-	-	(227.1)	-	
2013 Projects																
Upgrade Microsoft Project - Hydro Place	656.7	455.1	14.4	465.2	479.6	-	1,577.0	619.6	477.8	531.1	(51.5)	-	-	1,577.0	-	
Cost Recoveries	(236.4)	(163.8)	(5.1)	(167.5)	(172.6)	-	(567.7)	(223.1)	(172.0)	(191.2)	18.6	-	-	(567.7)	-	
Total Information Systems Projects	420.3	291.3	9.3	2,680.0	2,689.3	-	3,391.6	396.5	305.8	1,437.4	1,251.9	-	-	3,391.6	-	

2015 Capital Expenditures By Category
($000)

Telecontrol Projects	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects														
Purchase Tools and Equipment less than $50,000	-	-	45.6	45.6	-	45.6	-	5.1	40.5	-	-	45.6	-	
Replace Network Communications Equipment - Various Sites	-	-	169.5	169.5	-	169.5	-	154.7	14.8	-	-	169.5	-	
Upgrade Site Facilities - Various Sites	-	-	48.3	48.3	-	48.3	-	12.7	35.6	-	-	48.3	-	
Replace Telephone Systems - Various Sites	-	-	132.7	132.7	-	132.7	-	44.2	88.5	-	-	132.7	-	
Replace WIFI Access Points - Various Sites	-	-	126.3	126.3	-	126.3	-	89.7	36.6	-	-	126.3	-	
Replace GDC Metroplex - Various Sites	-	-	69.2	69.2	-	69.2	-	2.8	66.4	-	-	69.2	-	
Replace DTI Phone Turrets Energy Control Center - Hydro Place	-	-	44.7	44.7	-	44.7	-	4.9	39.8	-	-	44.7	-	
2014 Projects														
Replace Battery Banks and Chargers - Various Sites	267.0	(26.5)	398.0	371.5	-	665.0	293.5	86.8	284.7	-	-	665.0	-	
Upgrade IP SCADA Network - Various Sites	254.2	109.4	238.7	348.1	-	492.9	144.8	105.1	243.0	-	-	492.9	-	
Total Telecontrol Projects	521.2	82.9	1,273.0	1,355.9	-	1,794.2	438.3	506.0	849.9	-	-	1,794.2	-	

2015 Capital Expenditures By Category
($000)

Transportation Projects	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Notes
2015 Projects														
Replace Vehicles and Aerial Devices Hydro System (2015-2016)	-	-	2,377.1	2,377.1	225.3	2,602.4	-	167.8	2,209.3	225.3	-	2,602.4	-	
2014 Projects														
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)	1,809.1	908.6	1,091.0	1,999.6	-	2,900.1	900.5	1,022.3	977.3	-	-	2,900.1	-	
Total Transportation	1,809.1	908.6	3,468.1	4,376.7	225.3	5,502.5	900.5	1,190.1	3,186.6	225.3	-	5,502.5	-	

Administrative Projects	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryovers to 2016	Total	Variance	Notes
2015 Projects														
Remove Safety Hazards - Various Sites - 2015	-	-	194.9	194.9	-	194.9	-	-	194.9	-	-	194.9	-	
Replace Roof - Hydro Place	-	-	671.9	671.9	-	671.9	-	84.3	587.6	-	-	671.9	-	
Replace Cooling Tower and Auxiliaries - Hydro Place	-	-	45.7	45.7	311.3	357.0	-	7.0	38.7	311.3	-	357.0	-	
Purchase Tools and Equipment less than $50,000	-	-	68.0	68.0	-	68.0	-	10.6	57.4	-	-	68.0	-	
2014 Projects														
Remove Safety Hazards - Various Sites - 2014	257.8	50.2	-	50.2	-	257.8	207.6	(10.6)	(2.1)	-	-	194.9	(62.9)	
Total Administrative	257.8	50.2	980.5	1,030.7	311.3	1,549.6	207.6	91.3	876.5	311.3	-	1,486.7	(62.9)	

2015 Capital Expenditures By Category ($000)

Allowance For Unforeseen

	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryover to 2016	Total	Project Variance	Notes
2015 Projects																
Contingency Fund	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	1,000.0	-	-	1,000.0	-	
Total Allowance For Unforeseen	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	1,000.0	-	-	1,000.0	-	

Supplemental Projects

	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryover to 2016	Total	Project Variance	Notes
2015 Projects																
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2014 Projects																
100 MW (Nominal) Combustion Turbine Addition - Holyrood	-	109,677.0	14,241.5	9,248.8	23,490.3	-	118,925.8	-	95,435.5	29,296.1	4,694.6	-	-	129,426.2	10,500.4	
Labrador West Transmission Project - Construction Phase[6]	-	37,484.2	-	163,145.3	163,145.3	128,962.6	329,592.1	-	10,996.0	272.1	300.0	-		11,568.1	(318,024.0)	3
Transformer T1 Replacement - Sunnyside (Netted against Insurance Proceeds)[7]	-	7,197.8	2,135.1	1,226.4	3,361.5	-	8,424.2	-	3,236.7	548.2	2,813.3	-	-	6,598.2	(1,826.0)	4
Excitation Transformers Replacement - Bay d'Espoir	-	636.7	255.7	360.0	615.7	-	996.7	-	381.0	425.4	190.3	-	-	996.7	-	
Replace Unit #1 Air Compressor - Holyrood	-	259.5	145.6	61.1	206.7	-	320.6	-	113.9	206.0	0.7	-	-	320.6	-	
Purchase of Critical Spares	-	491.8	491.8	-	491.8	-	491.8	-	-	99.3	392.5	-	-	491.8	-	
230 kV Transmission Line - Bay d'Espoir to Western Avalon	-	2,412.6	2,412.6	18,964.7	21,377.3	270,280.7	291,658.0	-	-	569.8	3,833.2	287,255.0	-	291,658.0	-	
2013 Projects																
Increase 230 kV Transformer Capacity - Oxen Pond	3,823.6	15,310.4	4,369.1	-	4,369.1	-	19,134.0	153.6	14,611.3	2,658.2	1,710.9	-	-	19,134.0	-	
Total Supplemental Projects Approved by PUB	3,823.6	173,470.0	24,051.4	193,006.3	217,057.7	399,243.3	769,543.2	153.6	124,774.4	34,075.1	13,935.5	287,255.0	-	460,193.6	(309,349.6)	

Projects Less than $50,000

	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2013	2014	2015	Jul-Dec 2015	2016 and Beyond	Carryover to 2016	Total	Variance	Notes
2015 Projects																
Replace Pumps on Mobile Transformer P235 - Bishop's Falls	-	-	-	30.4	30.4	-	30.4	-	-	-	30.4	-	-	30.4	-	
Replace Generator Unit # 580 - William's Harbour	-	-	-	9.8	9.8	-	9.8	-	-	16.2	(6.4)	-	-	9.8	-	
Purchase Pick-Up - Holyrood Gas Turbine	-	-	-	36.7	36.7	-	36.7	-	-	-	36.7	-	-	36.7	-	
Replace 125VDC Battery Bank - Paradise River Hydro Plant				45.9	45.9	-	45.9	-	-	19.6	26.3	-	-	45.9	-	
Total Projects Less than $50,000	-	-	-	122.8	122.8	-	122.8	-	-	35.8	87.0	-	-	122.8	-	

[6] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014 of which $163.1M was included in the 2015 Capital Budget. The capital expenditures associated with this project are $11.3 as at June 30, 2015 and are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board of Commissioners of Public Utilities.

[7] Includes Insurance Proceeds relating to Sunnyside - Transformer T1 Replacement ($1.8M).

Variance expenditure explanations are provided below for projects whose overall expenditures, on a total project basis, have a variance of more than $100K and 10% from the budgeted amount. Due to this report being a mid-year report, variance from annual expenditures are not discussed below but will be included in the year-end report when annual expenditures are final.

1. Upgrade Plant Elevators - Holyrood

Budget: $533.2 Total: $837.0 Variance: $303.8

This is a single year project that was carried over from 2014 and completed in 2015. The scope of work for the upgrade resulted from a condition assessment performed on both elevators by the Original Equipment Manufacturer (OEM) in 2010. The main focus was on elevator controls, but complete elevator system, electrical and mechanical was assessed. The increase in cost to complete the project was related to the elevator shaft being classified as a confined space which led to an increase in internal and contract labor. Service NL also required additional upgrades to the elevator that were not in the original scope of work.

2. Tools and Equipment Less than $50,000

Budget: $553.3 Total: $448.0 Variance: ($105.3)

This project was a one year project started in 2014. Approximately $30 thousand of expenditures was carried into 2015 and completed. The variance from planned expenditures is due to lower costs than estimated.

3. Labrador West Transmission Project – Construction Phase

Budget: $329,592.1 Total: $11,568.1 Variance: ($318,024.0)

$329.6 million was the total budget to build this transmission line which would help supply power for planned new developments in Labrador West, such as the Kami Iron Ore Project. In September 2014, work on construction of the line was temporarily suspended until completion of Alderon's financing plan. This resulted in the total project forecast expenditures being suspended, and at this time, Hydro is not including a forecast beyond 2015 until additional funding is secured by Alderon and the project is proceeding again. The $11.6 million is all project costs incurred to date. The variance of $318 million is a total project variance.

The 2015 forecast contained in the preceding tables is related to IDC that is being charged on the project.

4. Transformer T1 Replacement – Sunnyside (Netted against Insurance)

Budget: $8,424.2 Total: $6,598.2 Variance: ($1,826)

The total project budget was $8.4 million. Hydro received insurance proceeds related to events at Sunnyside Terminal Station of which $1.8 million was applied against the project costs. This project is on track to be completed in 2015. Hydro expects the costs for this project to come in lower than initial estimates, and are evaluating project expenditures to finish the project.

Plan of Projected Operating Maintenance Expenditures 2016 - 2025 For Holyrood Generating Station

Newfoundland and Labrador Hydro

July 2015

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1 INTRODUCTION

In the Decision and Order No. P. U. 14(2004) of the Board of Commissioners of Public Utilities ("the Board"), dated May 4, 2004, (the 'Order) Newfoundland and Labrador Hydro ("Hydro") is required to **"**file a ten year plan of maintenance expenditures for the Holyrood Generating Station with its annual capital budget application, until otherwise directed by the Board" (p. 64 and Paragraph 12, p. 166 of the Order).

This requirement is specifically related to system equipment maintenance (SEM) 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 the expenditures vary from year to year.

This report addresses the identified and expected maintenance expenditures for the years 2016 to 2025 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 and its associated equipment, is in excess of 30 years old. 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, uniform ten year plan of SEM is difficult to complete given the harsh operating environment, varied production requirements and the age of units may trigger revision of the maintenance plan to control unforeseen events. Even though expenses for major overhauls are included in capital rather than operating budgets, some variability in the annual budget will remain as a result of the complexity of numerous components and integrated systems that form a fossil fired thermal electric generating system. This report will endeavor to identify the regular variations in the annual operating costs for the Holyrood Thermal plant.

2 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 10 year plan of maintenance expenditures for the Holyrood Generating Station to be updated annually to reflect changing operating circumstances."

The maintenance effort aims to prevent functional failure and extend the operational life of assets, helping to minimize total asset life cycle cost.

The type and amount of maintenance applied is dependent on the criticality of the asset and the impact of failure on service delivery.

Hydro seeks to balance the cost of maintenance against the cost of failure and the impact on safe, reliable service when applying maintenance strategies and tactics.

The following are the three main types or categories of maintenance undertaken at Holyrood:

2.1 Preventive Maintenance

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 comprises routine inspections, minor 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). This also includes discarding equipment or components rather than repairing them when it is less costly 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).

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.

2.2 Corrective Maintenance

In addition to the preventive maintenance tactics outlined in 1) above, there are also corrective maintenance requirements. This includes work performed to identify, isolate and restore equipment, machines or systems to a level in which it can be operated safely and used for its intended purpose. The requirement of corrective maintenance may arise for various reasons including failure, wear and tear and harsh environments (humidity, salt laden atmosphere). Examples include wear and tear on pumps, pipes and valves in the main and auxiliary systems.

2.3 Projects

Operating projects are low cost repairs and annual inspections that are required to return structures and equipment to their original or near original condition, to maintain structural

integrity, improve efficiency, improve availability and prevent or reduce environmental risks. Such projects include emissions monitoring and testing and periodic basin cleaning in the Waste Water Treatment Plant.

3 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 unpredictable due to the changing energy production demands on the units from year to year. Due to the accounting methodology changes approved under Board Order P.U. 13(2012), major overhauls and inspections with a frequency of greater than one year are capitalized, reducing the fluctuation in maintenance expenditures experienced in prior periods. 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 as time progresses.

4 DETAILED ANALYSIS

Attached are Appendices A to D, which set out the ten-year maintenance plan for the Holyrood Thermal Plant, as requested by the Board. Appendix A is a summary and indicates the expected expenditures in each of the major equipment groupings containing SEM costs for the years 2016 to 2025. Appendices B to D, inclusive, show the expected SEM costs categorized according to Preventive, Corrective, Annual Overhauls and Operating Projects for each of the major equipment groupings containing SEM costs.

It should be noted that the ten year plan spans the period during which the role of Holyrood will change as a result of the Labrador Interconnection. This significantly impacts cost and activity levels for Holyrood for the stand by period 2018 through 2020/2021 and also post Generation 2021 onward.

This plan was prepared using the 2015 preventive, corrective and annual overhaul data and the current 2016 to 2020 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 2014 Hydro forecast. A single escalation rate was used in this exercise and is as follows:

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
%	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Appendix B lists the categories of SEM costs for generating units for the years 2016 to 2025 in each of the major equipment groupings. The categories listed are:

Preventive	Routine preventive maintenance activities carried out every year
Corrective	Typical but unknown breakdown/emergency repairs carried out during the year
Boiler	Boiler overhauls carried out annually with one unit per year overhauled on a reduced scope as a result of better fuel quality
Operating Projects	Non-capitalized projects, justified on the basis of safety, environment, reliability or cost benefit analyses

Appendices C and D 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 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 preventive maintenance work orders performed on plant equipment annually. Corrective items include a large number of low cost jobs, the majority of which are largely unknown until they happen; thus, it is not practical to provide a breakout of the costs.

5 SUMMARY

This Plan is based on the 2015 system equipment maintenance budget and adjusted using the best available information including up to date maintenance tactics and known restoration and inspection work to establish a ten-year forecast of the maintenance projects for the Holyrood Plant. 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.

APPENDIX A

APPENDIX A
TOTAL HOLYROOD 10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES
($000)

	Base Year 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Unit 1 Total System Equipment Maintenance	$2,050	$2,101	$1,168	$1,197	$1,227	$260	$217	$222	$228	$234
Unit 2 Total System Equipment Maintenance	$1,569	$2,279	$1,236	$1,267	$1,298	$260	$217	$222	$228	$234
Unit 3 Total System Equipment Maintenance	$2,050	$1,533	$1,179	$1,208	$1,238	$286	$293	$300	$308	$315
Common Equipment Total System Equipment Maintenance	$1,841	$1,887	$1,451	$1,487	$1,524	$523	$536	$550	$564	$578
Buildings & Grounds Total System Equipment Maintenance	$419	$429	$330	$338	$347	$119	$122	$125	$128	$131
WT Plant Total System Equipment Maintenance	$113	$116	$89	$91	$94	$32	$33	$34	$35	$35
WWT Plant Total System Equipment Maintenance	$28	$29	$22	$23	$23	$8	$8	$8	$9	$9
Environmental Monitoring Total System Equipment Maintenance	$174	$178	$137	$141	$144	$49	$51	$52	$53	$55
Total Operating Projects	$130	$181	$140	$284	$108	$53	$0	$55	$0	$57
Total Holyrood System Equipment Maintenance	**$8,374**	**$8,734**	**$5,752**	**$6,036**	**$6,003**	**$1,590**	**$1,477**	**$1,569**	**$1,552**	**$1,648**

APPENDIX B

10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES FOR GENERATING UNITS
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Unit No. 1										
Preventive	573	587	452	463	474	163	167	171	175	180
Corrective	341	350	269	275	282	97	50	51	53	54
Boiler O/H	1,136	1,164	448	459	470	0	0	0	0	0
Subtotal	$2,050	$2,101	$1,168	$1,197	$1,227	$260	$217	$222	$228	$234
Operating Projects										
Boiler Chemical Clean										
Total Op Projects - Unit 1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Unit No. 1	**$2,050**	**$2,101**	**$1,168**	**$1,197**	**$1,227**	**$260**	**$217**	**$222**	**$228**	**$234**
Unit No. 2										
Preventive	573	587	452	463	474	163	167	171	175	180
Corrective	341	350	269	275	282	97	50	51	53	54
Boiler O/H	655	1,342	516	529	542	0	0	0	0	0
Subtotal	$1,569	$2,279	$1,236	$1,267	$1,298	$260	$217	$222	$228	$234
Operating Projects										
Boiler Chemical Clean										
Total Op Projects - Unit 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Unit No. 2	**$1,569**	**$2,279**	**$1,236**	**$1,267**	**$1,298**	**$260**	**$217**	**$222**	**$228**	**$234**
Unit No. 3										
Preventive	573	587	452	463	474	179	184	188	193	198
Corrective	341	350	269	275	282	107	109	112	115	118
Boiler O/H	1,136	596	458	470	482	0	0	0	0	0
Subtotal	$2,050	$1,533	$1,179	$1,208	$1,238	$286	$293	$300	$308	$315
Operating Projects										
Boiler Chemical Clean										
Total Op Projects - Unit 3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Unit No. 3	**$2,050**	**$1,533**	**$1,179**	**$1,208**	**$1,238**	**$286**	**$293**	**$300**	**$308**	**$315**

APPENDIX C

APPENDIX C

10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES FOR ANCILLARY UNITS

($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Common Equipment										
Preventive	1,650	1,691	1,300	1,333	1,366	469	481	493	505	518
Corrective	191	196	151	154	158	54	56	57	58	60
Subtotal	$1,841	$1,887	$1,451	$1,487	$1,524	$523	$536	$550	$564	$578
Operating Projects										
Total Op Projects - Common	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Common Equipment	**$1,841**	**$1,887**	**$1,451**	**$1,487**	**$1,524**	**$523**	**$536**	**$550**	**$564**	**$578**
Buildings & Grounds										
Preventive	364	373	287	294	301	103	106	109	111	114
Corrective	55	56	43	44	46	16	16	16	17	17
Subtotal	$419	$429	$330	$338	$347	$119	$122	$125	$128	$131
Operating Projects										
Total Op Projects - Bldgs & Grounds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total - Bldgs & Grounds	**$419**	**$429**	**$330**	**$338**	**$347**	**$119**	**$122**	**$125**	**$128**	**$131**
Water Treatment Plant										
Preventive	23	24	18	19	19	7	7	7	7	7
Corrective	90	92	71	73	75	26	26	27	28	28
Subtotal	$113	$116	$89	$91	$94	$32	$33	$34	$35	$35
Operating Projects										
Resin Replacement	78	80	61	63	65	0	0	0	0	0
Total Op Projects - WTP	$78	$80	$61	$63	$65	$0	$0	$0	$0	$0
Total - Water Treatment Plant	**$191**	**$196**	**$151**	**$154**	**$158**	**$32**	**$33**	**$34**	**$35**	**$35**

APPENDIX D

APPENDIX D

10 YEAR SYSTEM EQUIPMENT MAINTENANCE EXPENDITURES FOR ANCILLARY UNITS

($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Environmental Monitoring										
Preventive	92	94	72	74	76	26	27	27	28	29
Corrective	82	84	65	66	68	23	24	24	25	26
Subtotal	$174	$178	$137	$141	$144	$49	$51	$52	$53	$55
Operating Projects										
Emmissions Monitoring	52	53	41	42	43	0	0	0	0	0
Stack Emmissions Testing				128						
Tube Bundle Replacement			38							
Total Op Projects - Environment	$52	$53	$79	$170	$43	$0	$0	$0	$0	$0
Total - Environmental Monitoring	**$226**	**$232**	**$216**	**$311**	**$187**	**$49**	**$51**	**$52**	**$53**	**$55**
Waste Water Treatment Plant										
Preventive	5	5	4	4	4	1	1	1	2	2
Corrective	23	24	18	19	19	7	7	7	7	7
Subtotal	$28	$29	$22	$23	$23	$8	$8	$8	$9	$9
Operating Projects										
WWTP Periodic Basin Cleaning		24		26		27		28		29
WWTP Continuous Basin Clean-Out		24		25		26		27		28
Total Op Projects - WWTP	$0	$48	$0	$51	$0	$53	$0	$55	$0	$57
Total - Waste Water Treatment	**$28**	**$77**	**$22**	**$74**	**$23**	**$61**	**$8**	**$63**	**$9**	**$66**