Table of Contents

VOLUME I – Application and Evidence

A. Application

B. Rates Schedules

C. Company Evidence

Table of Contents
(cont'd.)

VOLUME II - Exhibits

D. Exhibits

Exhibit 1	Organizational Responsibility
Exhibit 2	Annual Report on Key Performance Indicators
Exhibit 3	Provincial Electrical Systems
Exhibit 4	Corner Brook Pulp and Paper Generation Credit Report
Exhibit 5	Hatch letter re Modelling Approach for Determining System Capability
Exhibit 6	Allowed Range of Return on Rate Base Report
Exhibit 7	Non-Regulated Operations Report
Exhibit 8	Intercompany Transaction Costing Guidelines
Exhibit 9	Cost of Service Study/Utility and Industrial Rate Design Report
Exhibit 10	Capital Expenditures and Carryover Reports (2006-2012)
Exhibit 11	Review of Demand Billing to Newfoundland Power 2008 Report
Exhibit 12	Review of Industrial Customers Rate Design 2008 Report
Exhibit 13	Cost of Service
Exhibit 14	Holyrood Thermal Generating Station Decommissioning Study

Organizational Responsibility

June 2013

Table of Contents

1.0 OVERVIEW

In June, 2007, the Government of Newfoundland and Labrador passed legislation to create a new provincial energy corporation, now known as Nalcor. Nalcor is the parent company of Hydro, along with other lines of business.

While Nalcor is not subject to regulation by the Board of Commissioners of Public Utilities (the Board), its creation and organizational structure have resulted in changes to the organizational structure of Hydro. Nalcor's corporate structure is described further in Section 3.4.3 of the evidence. Hydro is organized[1] into functional areas: Operations, Systems Operations and Planning and Corporate Services. Hydro provides services to Nalcor and other lines of business, and vice versa. The resulting intercompany charges are described in Section 3.4 of the evidence.

Schedule 1 to this exhibit contains the relevant organizational structure of Nalcor and more particularly, Hydro. The company which holds each position is noted and indicated on each of the pages. As shown on Page 1 of Schedule 1, Nalcor's President and Chief Executive Officer (CEO) reports to the Board of Directors, and the vice-presidents of Nalcor's various lines of business, including Hydro, report to the President and CEO (Schedule 1, Page 2).

2.0 OPERATIONS

Operations (Schedule 1, Page 3) are responsible for the operation and management of Hydro's generation, transmission, distribution and communications assets from asset inception to retirement, in order to bring safe, long term least cost and reliable service to consumers of Hydro's electrical service. This includes long term asset planning, short term planning and scheduling of maintenance work, the execution of the work

[1] This report reflects new organizational changes which were effective April, 2013.

and the operation of these assets. A brief description of the various regulated systems[2] supported by Operations is found in Exhibit 3. The areas within Operations responsible for facilities used to provide regulated service are Hydro Generation, Thermal Generation and Transmission and Rural Operations (TRO).

More specifically, Operations' responsibilities include:

- Operating and maintaining the Company's hydraulic and thermal electricity generating plants and related systems;
- Operating and maintaining the transmission and terminal station infrastructure for the interconnected systems;
- Operating and maintaining the distribution and isolated diesel systems;
- Operating and maintaining support facilities and equipment such as the vehicle fleet and warehouses;
- Operating and maintaining the Company's telecommunications network facilities; and
- Developing formal long-term asset renewal or replacement plans, updating design standards and operating parameters, ensuring critical spare availability, and standardizing maintenance tactics within an asset group.

Within each area of Operations, the organizational structure has changed to reflect the revised asset management strategy described in Section 2.3.4 of the evidence. As a result, the areas now include separate responsibility for:

- Long Term Asset Planning (LTAP);
- Work Execution (WEx);
- Operations;
- Short-Term Planning and Scheduling;

[2] Hydro is also responsible for operating and maintaining the Exploits generation assets and the facilities at Menihek, both of which are non-regulated. Transactions associated with these services are governed by the Intercompany Transaction Costing Guidelines provided in Exhibit 8.

- Environment, Safety and Health; and
- Support Services.

2.1 Generation

There are areas within Hydro with primary responsibility for generation.

Generation (Schedule 1, Page 4) is responsible for the operation, work execution, short-term planning and scheduling, and long-term asset planning of Hydro's six major hydroelectric plants, two mini-hydro plants, and related facilities on the island. Most staff are located in Bay d'Espoir with the exception of a small group based at the Hinds Lake plant. This latter group facilitates the safe and reliable operation and maintenance of the Cat Arm and Hinds Lake plants.

Thermal Generation (Schedule 1, Page 5) is directly responsible for the operation, work execution, short-term planning and scheduling, and long-term asset planning of the Holyrood Thermal Generating Station (Holyrood) and related facilities, including three steam electric generating units.

Other than the changes related to Asset Management, the most significant organizational change in Generation since 2006 occurred at Holyrood with the addition of an Emergency Response group which is integrated under the Manager, Environment, Health and Safety (EHS).

2.2 Transmission and Rural Operations (TRO)

The three TRO regions, Central, Northern and Labrador, (Schedule 1, Page 6) are responsible for the work execution and short-term planning and scheduling of the transmission systems, and rural distribution and isolated diesel assets. TRO also has responsibility for the frequency converter at Corner Brook, gas turbines (at Hardwoods, Stephenville and Happy Valley-Goose Bay), interconnected diesel generating plants (at St. Anthony, Hawkes Bay and Happy Valley-Goose Bay) and the Roddickton mini-hydro plant on the Great Northern Peninsula. These generating facilities are operated by TRO which utilizes the skilled personnel available in the areas for operations and work execution.

In April 2010, there was reorganization within TRO to support a new approach for Asset Management.

The most significant changes within TRO include:

1. The consolidation of all three Regions (Central, Northern and Labrador) under a new position of General Manager with some common services reporting directly or indirectly, to the General Manager including: Network Services, Safety, Health and Environment, TRO Services, and the LTAP Managers for Transmission and Distribution, and Generation and Terminals;
2. Now reporting to General Manager is the Manager of Health, Safety and Environment;
3. Now reporting to the TRO Services Manager are: the Equipment Maintenance and Facilities Maintenance Supervisors, the Asset Specialist Fleet, the Bishop's Falls Warehouse Supervisor, Vegetation Control Specialist and the warehousing staff at Bishop's Falls, Port Saunders and Happy Valley-Goose Bay;
4. Now reporting to the LTAP Managers are the Asset Specialists and Equipment Engineers for all of TRO;
5. Now reporting to the Manager of Health, Safety and Environmental is the Work Methods Specialist; and
6. The Northern and Labrador regions now share supervisory services for Planning and Scheduling, Distribution Services and Support Services.

The TRO Central office in Bishop's Falls also includes positions for some centralized TRO services and regulated utility services including:

- Health, Safety and Environment field support for TRO;
- Long-term asset planning for TRO;
- Voice and data network services; and

- Transportation services, which include fleet and air services contract management.

This centralized responsibility reduces administration costs and ensures consistency throughout the TRO areas.

3.0 SYSTEM OPERATIONS AND PLANNING

System Operations and Planning (Schedule 1, Page 6) was formed as a stand-alone division of Hydro in April 2013. The division is an amalgamation of the former System Operations and System Planning departments and carries out all activities previously completed by the two departments. In addition the new division will lead the operational transition relating to the integration of Muskrat Falls and the connection of the current Isolated Island system to the North American grid via two separate High Voltage direct current (HVdc) interconnections.

3.1 Systems Operations

System Operations, through the Energy Control Centre (ECC), manages the operation of the Island and Labrador Interconnected Systems. The ECC is a technologically sophisticated operation which dispatches generation in the most economic means possible. It controls the operation of transmission lines to ensure reliable power delivery to customer delivery points, taking into consideration hydrology, weather, planned outages and contingencies. As well, the ECC has distribution feeder control where communication facilities exist, and maintains control over most hydraulic structures for reservoir and water management purposes.

The engineering staff of System Operations specializes in hydroelectric and thermal generation scheduling using a variety of computer simulation tools to model the interaction of the various reservoir influences and storage characteristics of Hydro's extensive system. System Operations also has the responsibility for:

- Assessing and reporting the performance of the power system in areas of reliability, efficiency and some environmental aspects;
- Scheduling major equipment outages on the power system to enable effective completion of system maintenance and capital upgrades while maintaining a secure energy supply to customers;
- Providing engineering support to the ECC as required for complex system issues, major system disturbances and the introduction of new system procedures;
- Forecasting thermal plant fuel requirements and power purchase expenses; and
- Communicating directly with Industrial Customers and Newfoundland Power to coordinate outage planning, switching, power delivery arrangements and general customer service matters.

3.2 System Planning

System Planning is responsible for the following tasks, which include both regulated and non-regulated activities:

- Preparing operational and long-term planning load forecasts for interconnected and isolated power systems which are used to assess and ensure facilities are available to serve the provincial electricity requirements;
- Planning all new generation, transmission, and distribution facilities required to address the forecast growth in power and energy requirements on the Island and Labrador Interconnected and the Isolated Rural systems;
- Recommending system modification or expansion, and completing system studies such as load flow, stability, and short circuit analysis; and
- Preparing thermal fuel price projections for use in planning and budgeting and also providing operational support such as system studies, recommendations on system design capability and other technical matters.

4.0 CORPORATE SERVICES

Certain divisions or departments provide corporate services (or shared services) across the Nalcor lines of business. Transactions associated with these services are governed by the Intercompany Transaction Costing Guidelines provided in Exhibit 8.

Corporate Services are provided to Hydro from Project Execution and Technical Services, Finance, Human Resources and Operational Effectiveness, and Corporate Relations divisions.

4.1 Project Execution and Technical Services

The Project Execution and Technical Services division (Schedule 1, Page 8) is a shared service division, responsible for providing comprehensive services to support asset management through the Office of Asset Management (OAM), providing for the technical needs of the business and completing the design, planning and delivery for both operating and capital projects, from concept to final implementation and close-out.

The OAM was established to support a new approach for Asset Management to ensure a consistent approach is applied throughout Nalcor. The Project Execution section consists of both regulated and non-regulated departments and is the key interface between Engineering Services and each of Nalcor's lines of business.

The Project Execution sections were established to provide accountability for:

- Delivering capital and operating projects on time and on budget;
- Defining project management standards, guidelines and methods that can be used consistently throughout Nalcor;
- Supporting the lines of business in all elements of the planning, design and execution of projects to satisfy the requirements of the line of business; and
- Providing technical and operating assistance from the appropriate discipline experts when needed.

Project Execution and Technical Services still includes separate departments for Civil, Electrical, Protection and Control, Mechanical, Transmission and Distribution Engineering, and Research and Development. In 2011, the Telecommunication Engineering Services department was merged into the Protection and Control Engineering department. Each Engineering Services department includes personnel in their respective areas of engineering expertise and provides project execution and technical/operating assistance support.

4.2 Finance

Overall, the services provided to Hydro from the Finance division (Schedule 1, Page 9) remain unchanged since the inception of Nalcor, however, the distribution of these tasks and responsibilities has changed within the Finance division.

A General Manager of Finance and Corporate Services (Schedule 1, Page 10) has been established, with responsibility for:

- **Controller and Shared Services** functions including capital asset accounting, establishment of accounting policies and financial statement preparation and reporting, maintaining accounts payable and receivable, tax services, and general accounting functions;
- **Information Systems** which provides information technology services for the various applications Hydro uses in its business including the Energy Management System; and
- **Supply Chain** which provides procurement services, inventory management, and Hydro Place administration.

In addition, the following functions are provided to Hydro by departments included in the Finance division:

- **Rates and Regulation** which provides cost of service, rate design and general support for Hydro's filings to the Board;

- **Commercial and Financing** which provides treasury related services including debt management and risk and insurance services which secures insurance coverage for Hydro's assets and operations and coordinates other risk management activities; and
- **Investment Evaluation** which is responsible for evaluation of potential investments and financial planning.

4.3 Human Resources and Organizational Effectiveness

A restructuring of Hydro in 2005 resulted in a reorganization of several corporate functional areas into a new division called Human Resources and Organizational Effectiveness (HROE). These functional areas include Environmental Services, Safety and Health, and Human Resources (HR). Since the creation of Nalcor, the division has made the necessary modifications to its structure by transferring certain positions to Nalcor, with time charged to each line of business as it is incurred.

A brief description of these major functions follows.

Environmental Services provides environmental services and support to all areas of Hydro, as well as general strategic and policy leadership in relation to environmental stewardship. Key focus areas include: environmental management system implementation, environmental impact and site assessment, environmental protection planning, pollution prevention, environmental emergency response planning and training, and regulatory compliance, monitoring and auditing.

Safety and Health provides functional services and support, as well as strategic and policy leadership, to all areas of Hydro on all matters related to safety and health, including occupational health and wellness, employee/family assistance program, disability management (workers' compensation, short-term and long-term disability), pre-employment medical program, development of corporate safety standards, assisting field operations with regulatory compliance activities, maintaining the corporate safety and health management system, work protection code, corporate emergency response program, and the industrial hygiene program.

Human Resources provides overall strategic HR leadership to Hydro, in the development and implementation of policies, procedures and processes in all key areas of human resources management, including recruitment, compensation, people development (training, leadership development, human resource planning, succession planning, and performance management), and organizational effectiveness. HROE maintains an effective liaison with the Labour Relations and Safety and Health departments, in particular, to ensure divisional alignment in key areas. The Labour Relations staff provides labour relations services and support to all areas of Hydro. They oversee the Collective Bargaining Agreement administration by providing advice/guidance concerning aspects of all Collective Bargaining Agreements.

4.4 Corporate Relations

Corporate Relations (Schedule 1, Page 12) has accountability for Hydro's customer service and energy efficiency activities, as well as corporate wide accountability for corporate communications, shareholder relations and corporate social responsibility. The Corporate Relations division is comprised of:

- Nalcor's Communications staff;
- Hydro’s Customer Services department; and
- Hydro's Energy Efficiency department.

One Communications Advisor is assigned primarily to Hydro with some corporate wide functional responsibilities. Other team members with corporate wide functional responsibilities will charge time to Hydro if they are working on activities specific to Hydro, or a shared service or activity from which Hydro will benefit. The primary responsibilities include:

- Corporate communications;
- Media relations;
- Employee communications;
- Community investment and community relations; and
- Stakeholder engagement and consultation.

Energy Conservation and Efficiency efforts are managed by the Energy Efficiency team comprised entirely of Hydro employees. The major activities are:

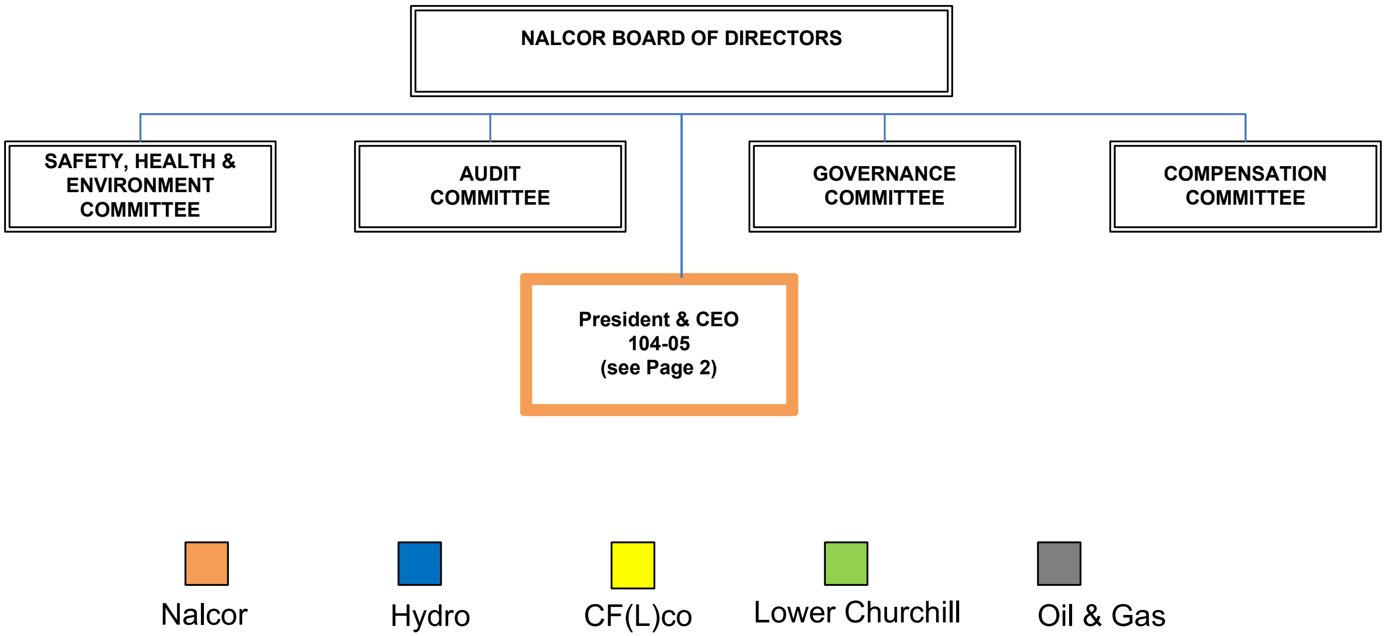
- Development and implementation of demand and energy conservation programs, both internally and externally;
- Partnership with Newfoundland Power, the Provincial Government and other stakeholders to develop a coordinated approach for conservation education and initiatives for the Province; and
- Development of promotional activities through media campaigns to support conservation awareness.

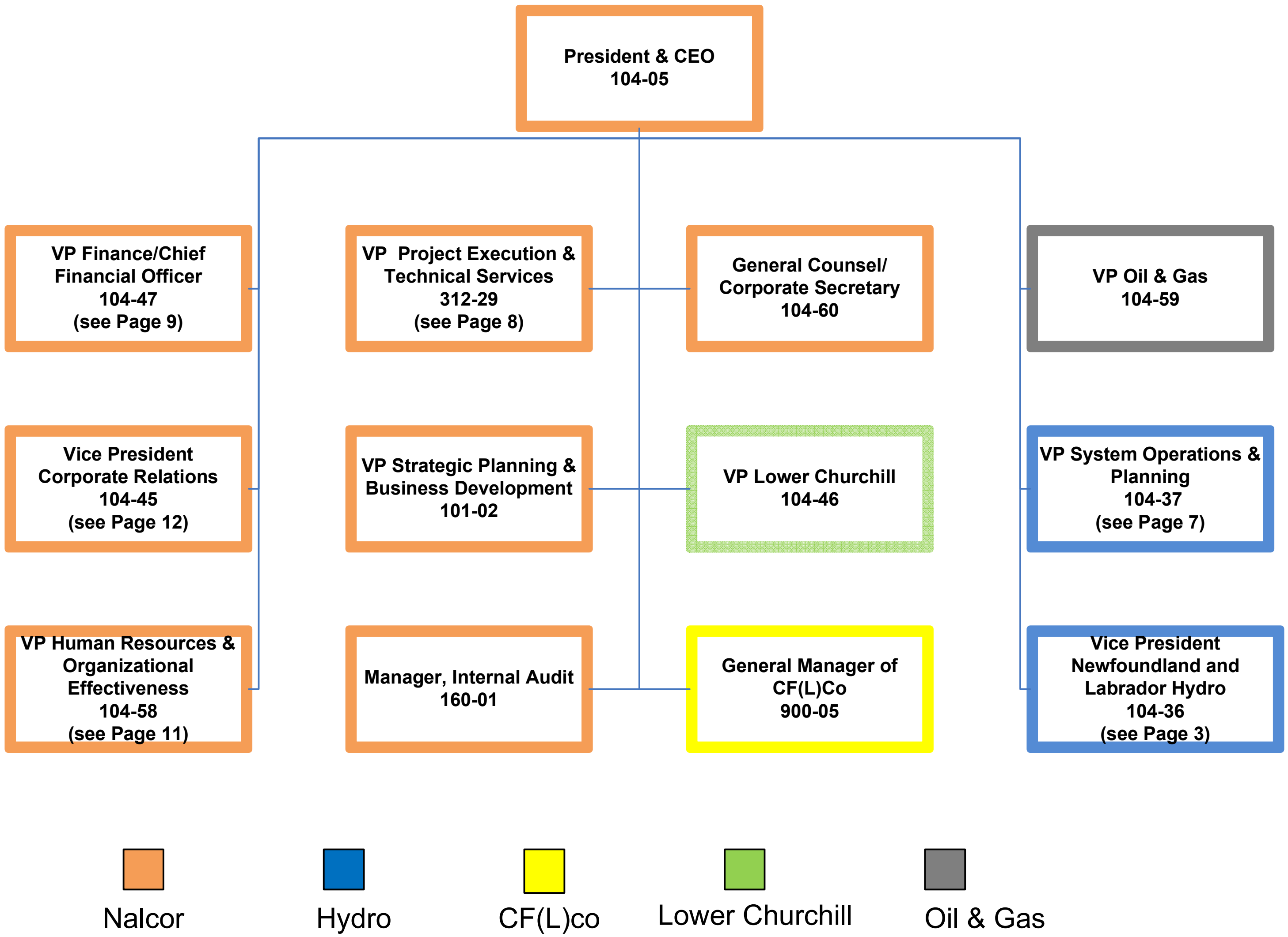
Customer Services staff, who are employees of Hydro, lead Hydro's customer service responsibilities for its Rural Customers. The specific responsibilities of the department are:

- Communication with Rural Customers related to account enquiries, service requests and outage reporting;
- Calculation of Contribution in Aid of Construction;
- Assessment and response for Rural Customer damage claims;
- Provision of meter reading, billing and collections from customers;
- Provision of billing, metering and customer services to utility and industrial customers served by Hydro; and
- Provision of meter shop services.

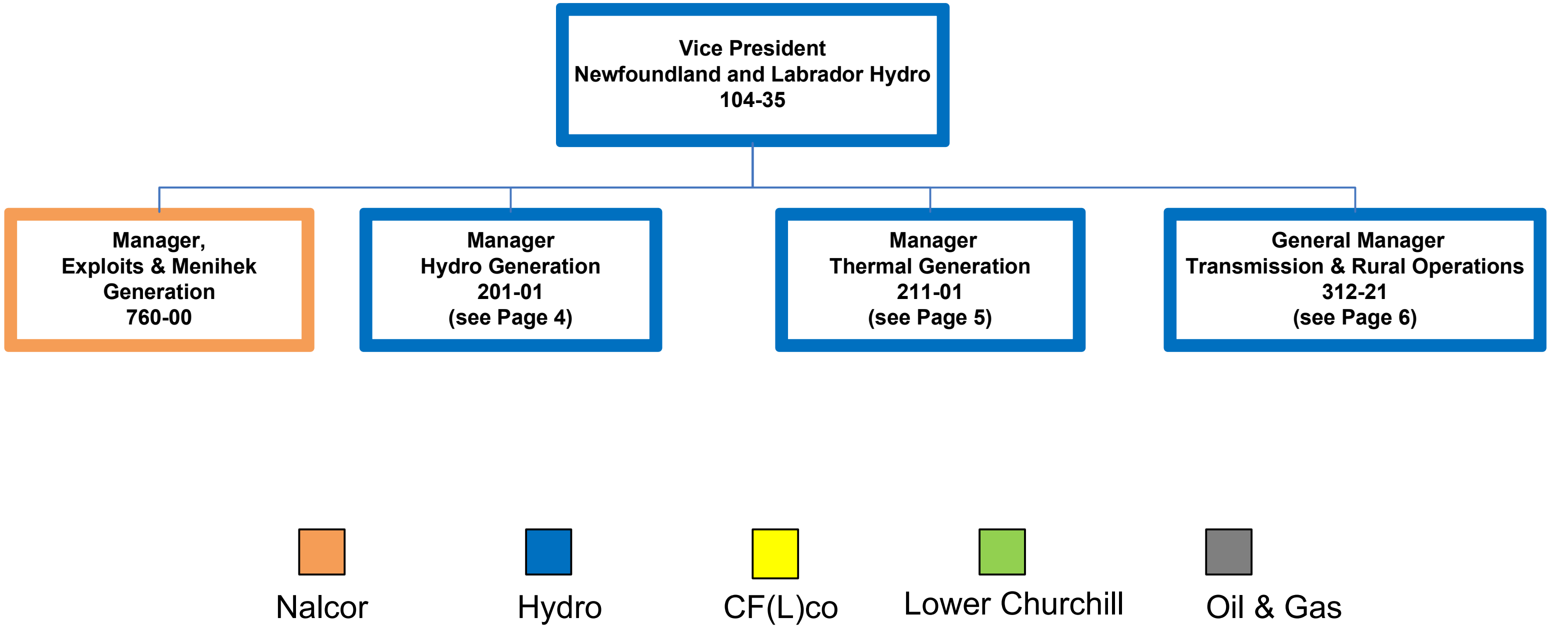
4.5 Other

The General Counsel and Corporate Secretary, and Internal Audit functions are primarily in Nalcor, with employees charging time to Hydro in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

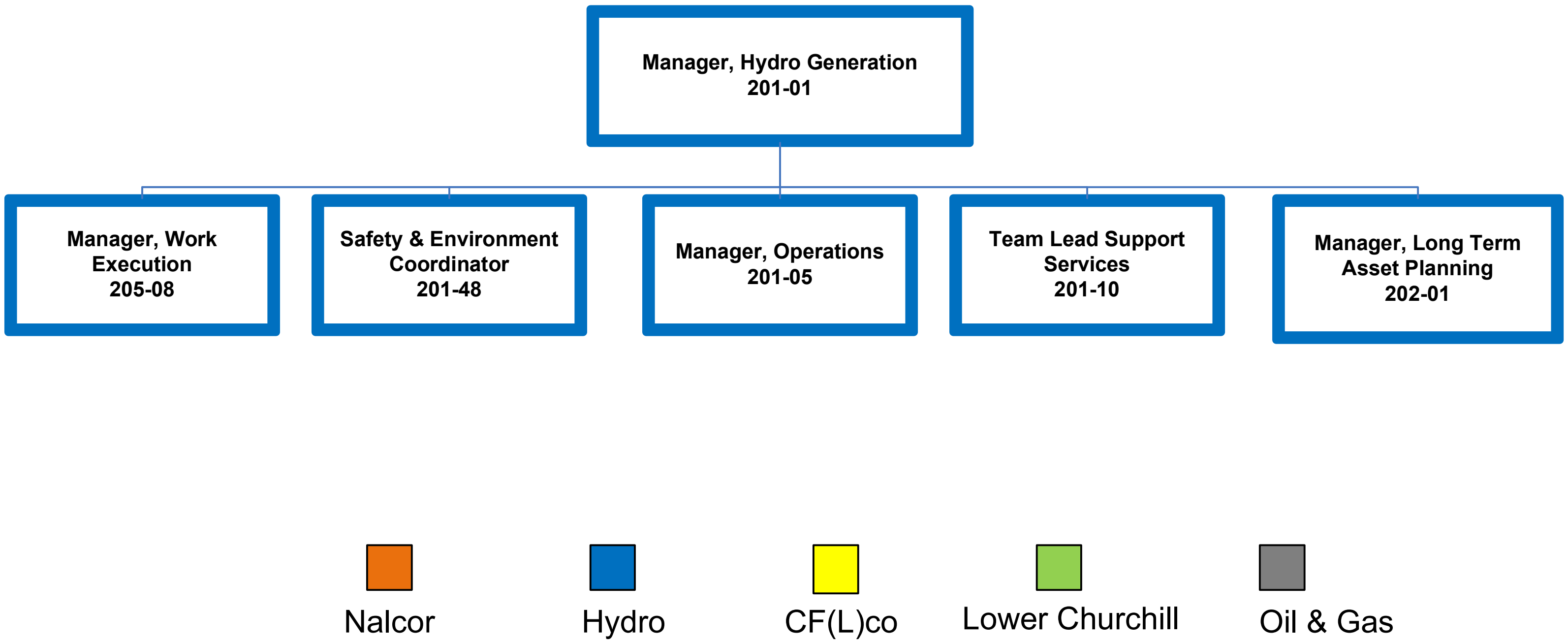

NALCOR BOARD OF DIRECTORS
SAFETY, HEALTH & ENVIRONMENT COMMITTEE
AUDIT COMMITTEE
GOVERNANCE COMMITTEE
COMPENSATION COMMITTEE
President & CEO
104-05
(see Page 2)
Nalcor
Hydro
CF(L)co
Lower Churchill
Oil & Gas


President & CEO
104-05
VP Finance/Chief Financial Officer
104-47
(see Page 9)
VP Project Execution & Technical Services
312-29
(see Page 8)
General Counsel/ Corporate Secretary
104-60
VP Oil & Gas
104-59
Vice President Corporate Relations
104-45
(see Page 12)
VP Strategic Planning & Business Development
101-02
VP Lower Churchill
104-46
VP System Operations & Planning
104-37
(see Page 7)
VP Human Resources & Organizational Effectiveness
104-58
(see Page 11)
Manager, Internal Audit
160-01
General Manager of CF(L)Co
900-05
Vice President Newfoundland and Labrador Hydro
104-36
(see Page 3)
Nalcor
Hydro
CF(L)co
Lower Churchill
Oil & Gas

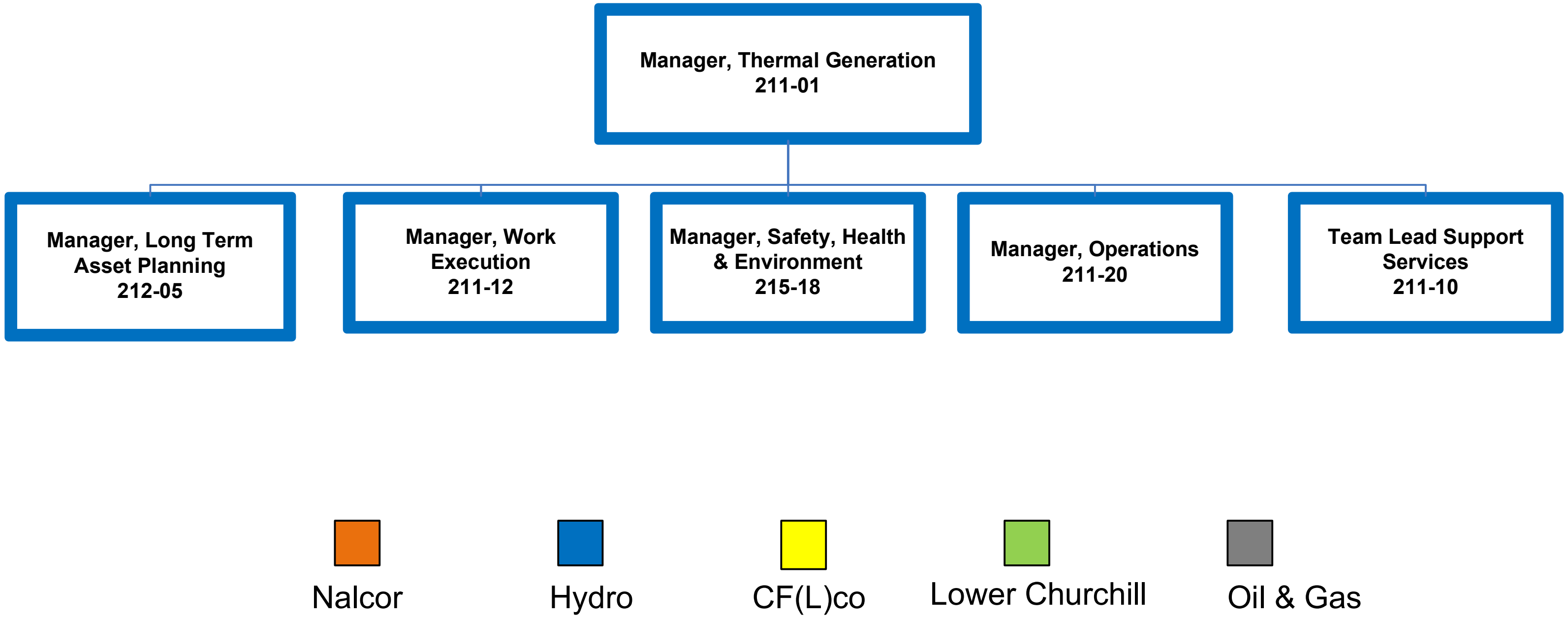
OPERATIONS


Vice President
Newfoundland and Labrador Hydro
104-35
Manager,
Exploits & Menihek
Generation
760-00
Manager
Hydro Generation
201-01
(see Page 4)
Manager
Thermal Generation
211-01
(see Page 5)
General Manager
Transmission & Rural Operations
312-21
(see Page 6)
Nalcor
Hydro
CF(L)co
Lower Churchill
Oil & Gas

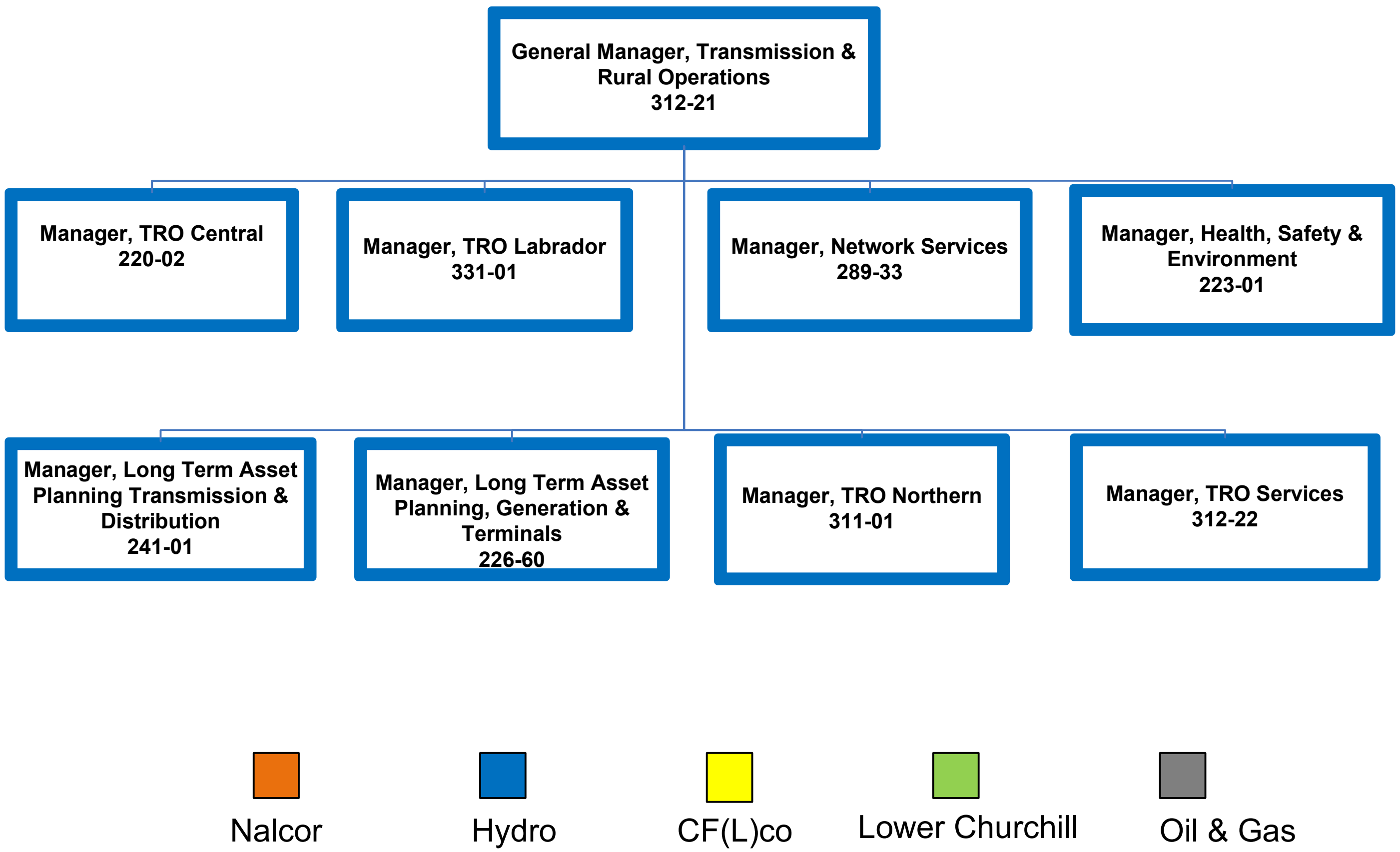
HYDRO GENERATION



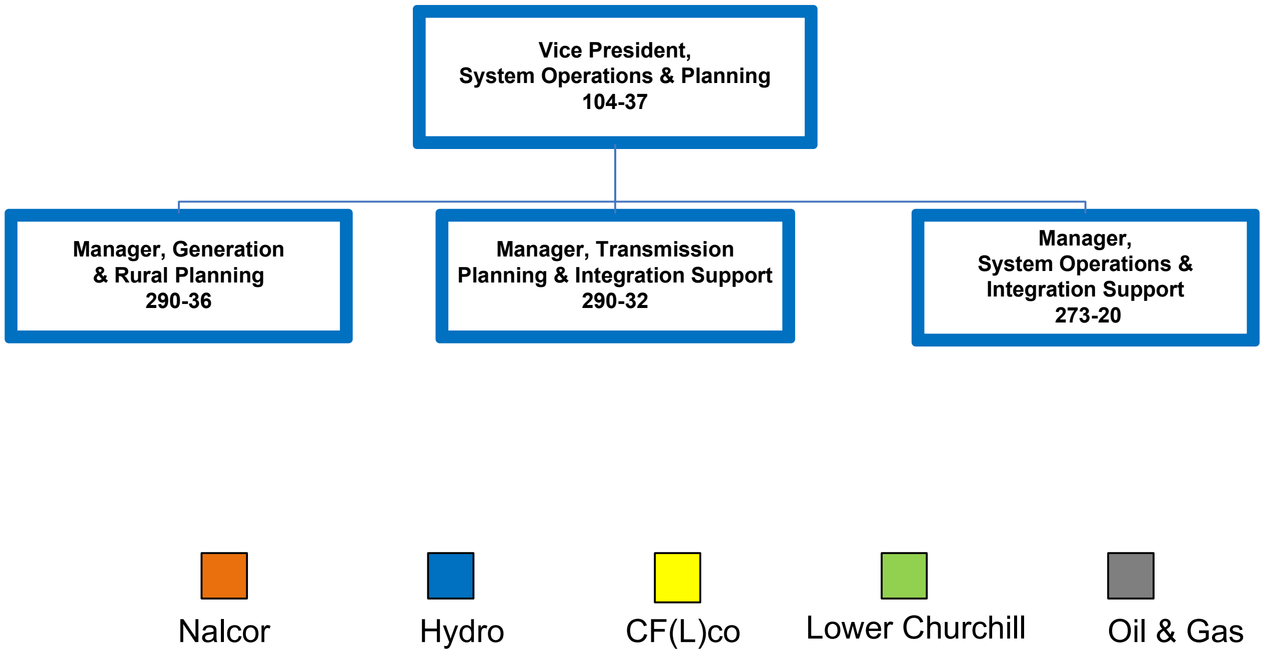
THERMAL GENERATION



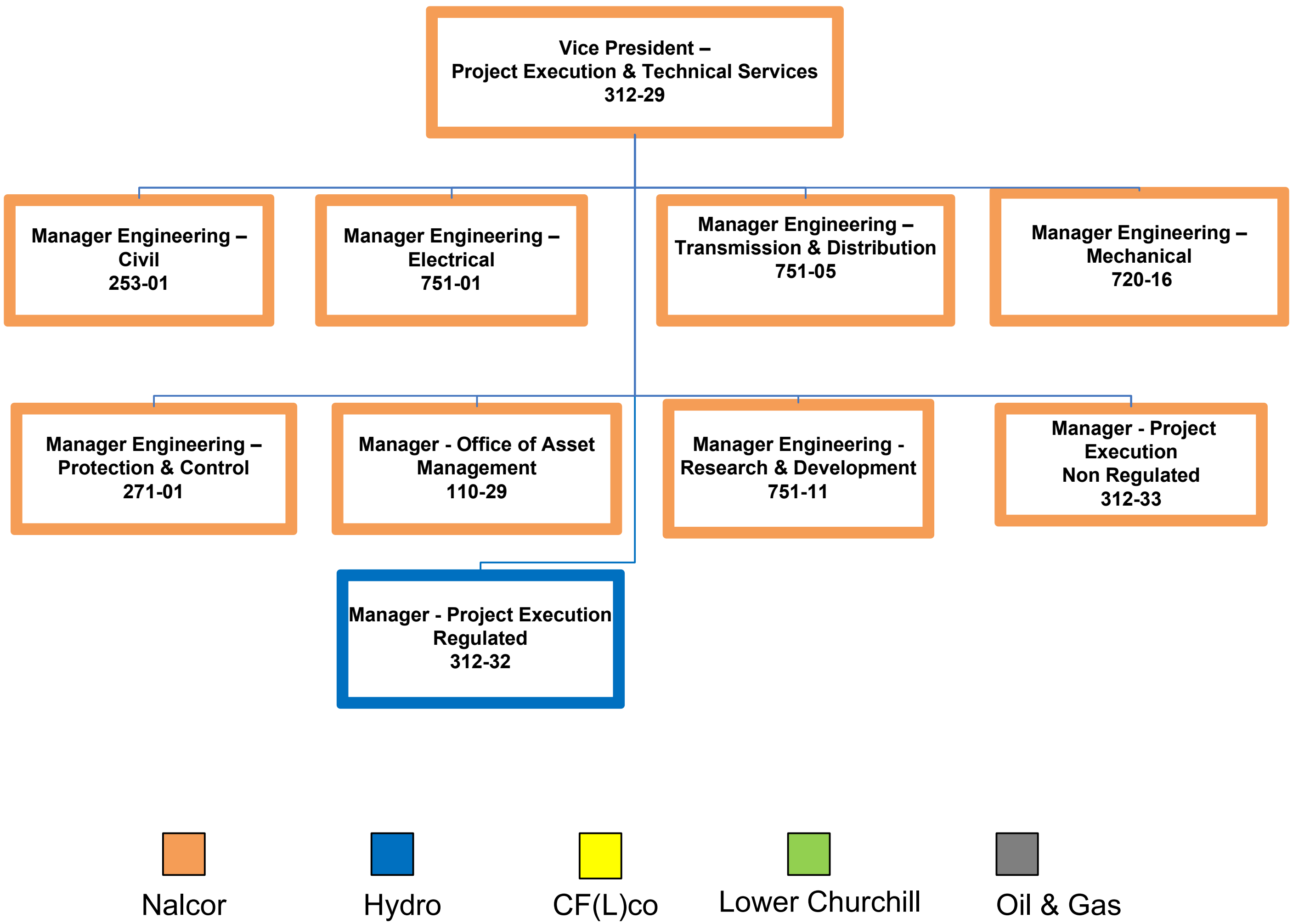
TRANSMISSION & RURAL OPERATIONS



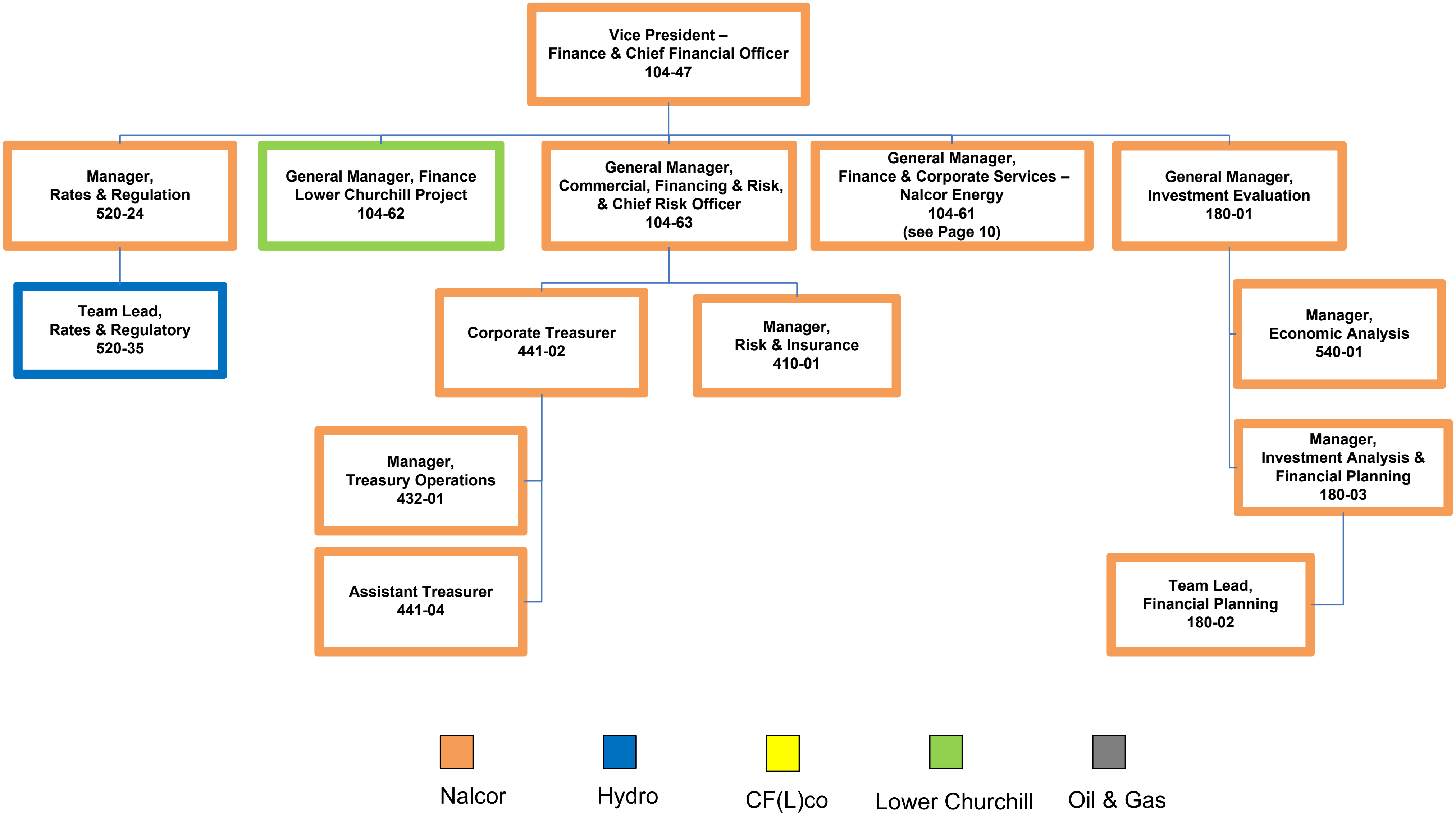
SYSTEM OPERATIONS & PLANNING



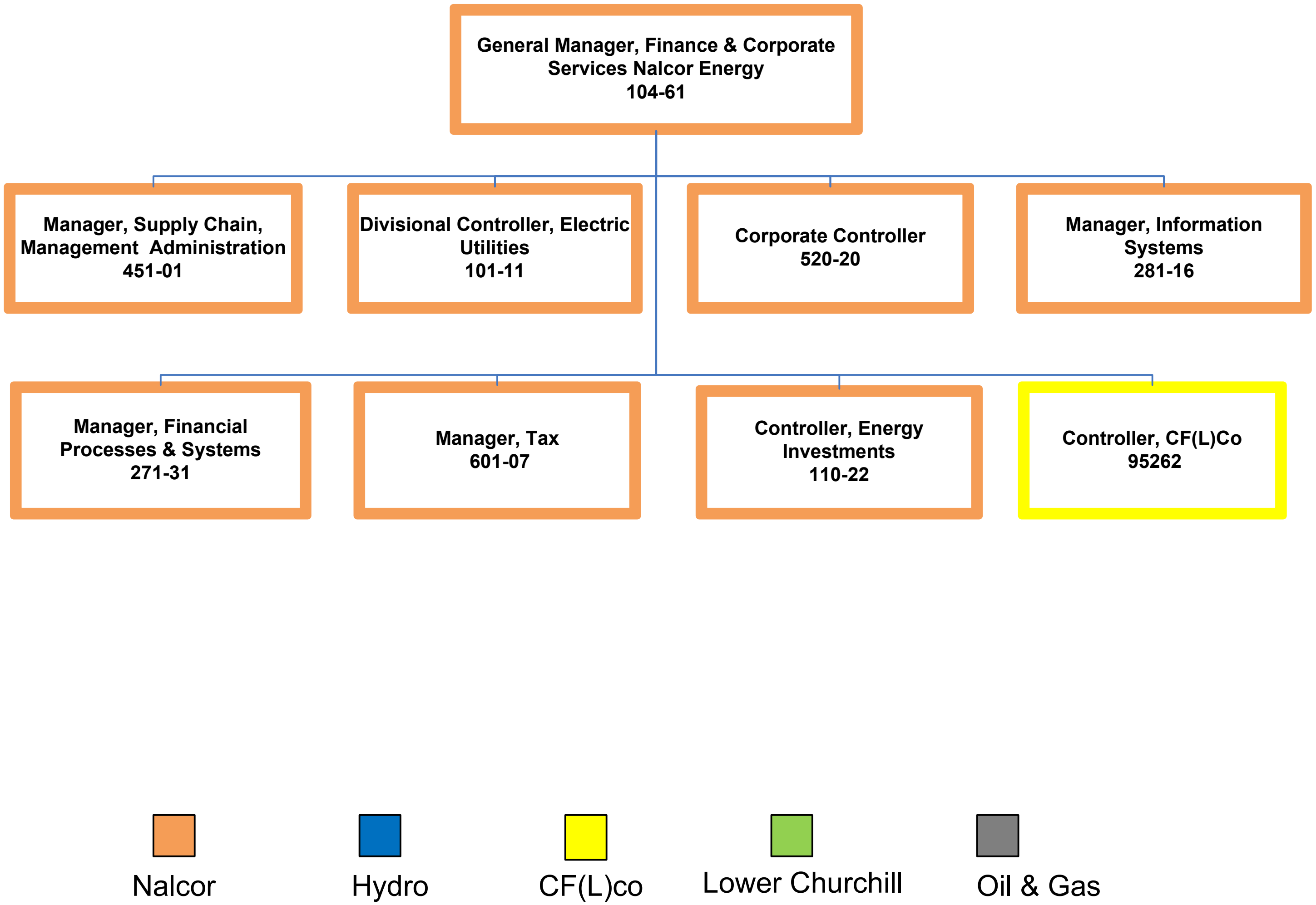
PROJECT EXECUTION & TECHNICAL SERVICES



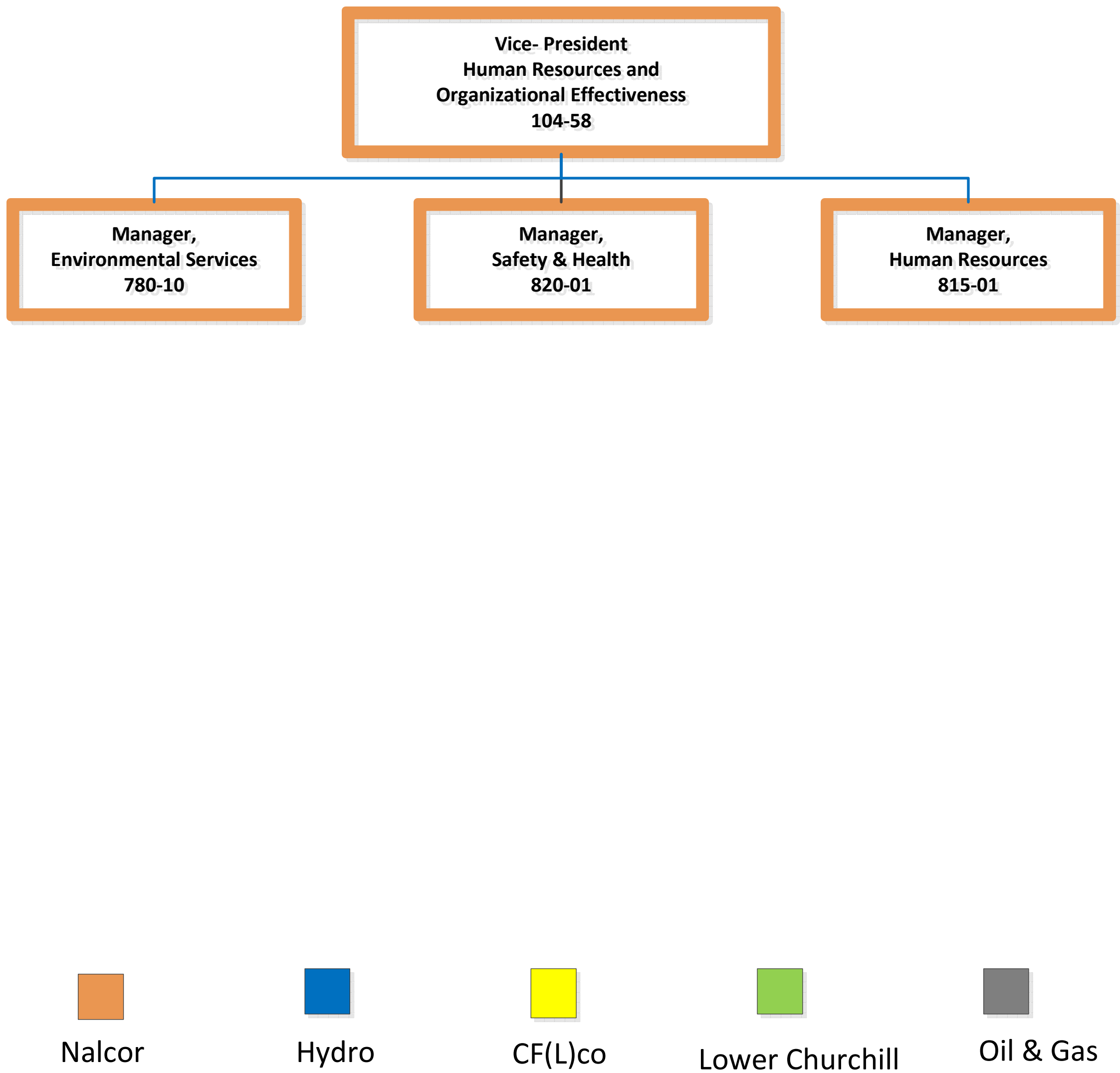
FINANCE


Vice President –
Finance & Chief Financial Officer
104-47
Manager,
Rates & Regulation
520-24
General Manager, Finance
Lower Churchill Project
104-62
General Manager,
Commercial, Financing & Risk,
& Chief Risk Officer
104-63
General Manager,
Finance & Corporate Services –
Nalcor Energy
104-61
(see Page 10)
General Manager,
Investment Evaluation
180-01
Team Lead,
Rates & Regulatory
520-35
Corporate Treasurer
441-02
Manager,
Risk & Insurance
410-01
Manager,
Economic Analysis
540-01
Manager,
Investment Analysis &
Financial Planning
180-03
Manager,
Treasury Operations
432-01
Assistant Treasurer
441-04
Team Lead,
Financial Planning
180-02
Nalcor
Hydro
CF(L)co
Lower Churchill
Oil & Gas

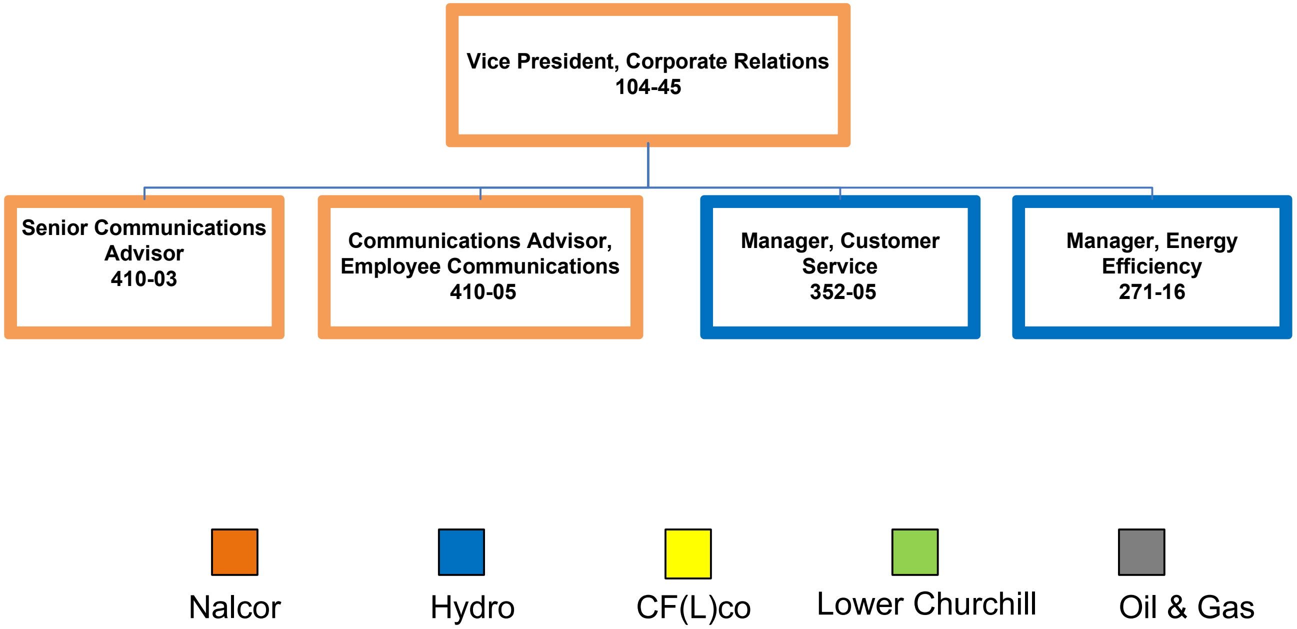
FINANCE & CORPORATE SERVICES



HUMAN RESOURCES & ORGANIZATIONAL EFFECTIVENESS



CORPORATE RELATIONS



A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2012 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1 Introduction

In Order No. P.U. 14 (2004), the Board required Newfoundland and Labrador Hydro (Hydro) to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. CEA data has been published only to 2011. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2012 compared with the prior year as well as a comparison of actual KPI results compared with targets. This is followed by a detailed analysis of each individual KPI within the four categories named above in Section 3.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available.

The 2012 financial data and 2013 targets in Section 4 Data Table of Key Performance Indicators are not available at this time. This section will be re-filed after the financial data is available and the 2013 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Performance in 2012 versus 2011

Generation performance continued to improve in some areas in 2012, particularly with the thermal units. The Capability Factor for the Holyrood Generating Station improved significantly from 2011 and is now better than the latest CEA five-year average. The hydro plants experienced a decreased performance in this area due to an extended planned maintenance outage on Bay d'Espoir Unit 4. The performance of gas turbines was impacted by the failure of the Stephenville Gas Turbine which occurred in December 2011. The unit was not available in 2012 due to this forced outage.

The underfrequency load shedding performance met the target in 2012 with a total of five events and remains under the previous five-year average of 5.4 events per year. Performance in this area deteriorated from the three events experienced in 2011, which was the best performance since these events started being recorded in 1998.

Transmission and Distribution reliability improved significantly in 2012 from 2011. Improvements were seen in all areas and measures are comparable to the values seen before 2011. In 2011, there were a number of severe weather related events which caused numerous and lengthy outages, primarily in the Northern and Central regions.

The operating KPIs for energy conversion showed a slight reduction in performance for the Holyrood fuel conversion rate. Unit operating time continued to be minimized in 2012, with units placed on line only as required to support Avalon transmission and system peak loads.

The hydraulic conversion factor at Bay d'Espoir improved slightly in 2012 from 2011. In 2011, high water levels required the operation of the plant to reduce and control the spill of water, particularly during the summer months. This was not required in 2012 as the water levels were more in-line with normal levels.

Hydro's 2012 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.

The final category of KPIs called "Customer-Related" deals with Hydro's residential customer satisfaction. Customer satisfaction in 2012 of 80%, was the lowest of the previous five-years.

2.2 Performance in 2012 versus 2012 Target

The table below summarizes Hydro's KPI performance in 2012 compared to targets set for each measure. Targets were met with respect to the generation forced outage rate, transmission SAIDI, SAIFI and SARI the number of underfrequency load shedding events and the hydraulic conversion rate. Other targets were not met due to a number of challenges further described in this report.

The 2012 rationale for Hydro's 2012 KPI Targets is included in this report as Appendix A.

Hydro's KPI Targets and Operating Results for 2012

Category	KPI	Units	2012 Target	2012 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	84.9	82.9	No
	DAFOR	%	2.7	2.3	Yes
	T-SAIDI	Minutes/Point	265[1]	171[2]	Yes
	T-SAIFI	Number/Point	2.0[1]	1.9[2]	Yes
	T-SARI	Minutes/Outage	133[1]	90[2]	Yes
	SAIDI	Hours/Customer	5.9	8.3	No
	SAIFI	Number/Customer	3.7	4.4	No
	Underfrequency Load Shedding	# of events	6	5	Yes
Operating	Hydraulic CF	GWh/MCM	0.433	0.434	Yes
	Thermal CF	kWh/BBL	630	599	No
Financial	Controllable Unit Cost	$/MWh	N/A	14.93	
Other	Customer Satisfaction (Residential)	Max=100%	>90%	80%	No

[1] Transmission reliability targets were set on combined planned and unplanned outages.
[2] The transmission reliability indicator shown is for planned and unplanned outages.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator (KPI) data within four general categories: Reliability, Operating, Financial, and Customer-Related.

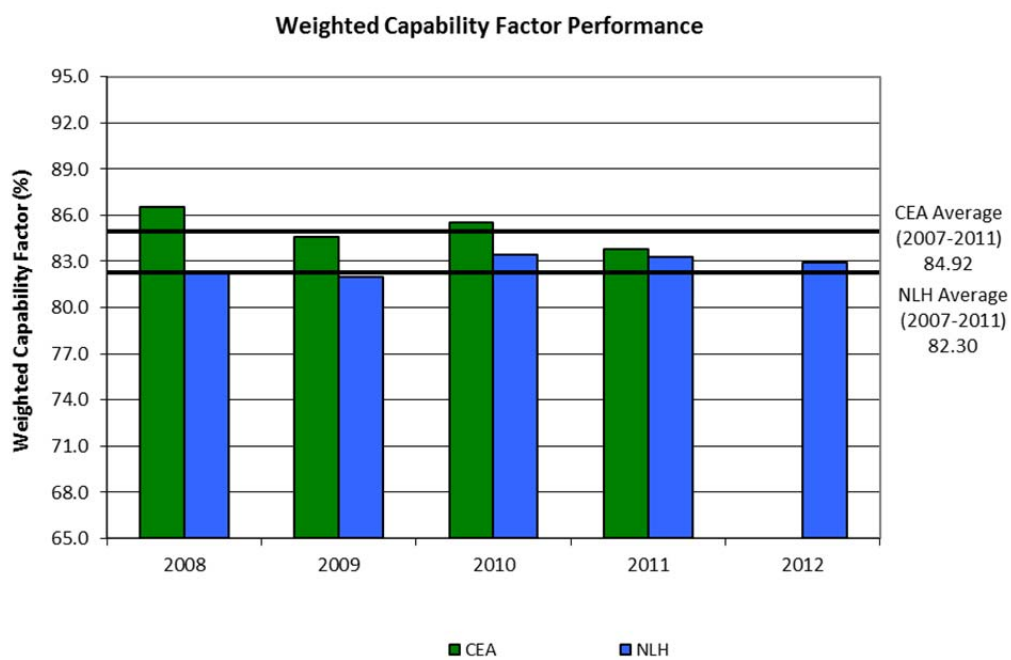
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2012, Hydro's WCF was 82.9%. This is lower than the target of 84.9%; however, it does reflect an improvement over the 2007 to 2011 five-year average of 82.3%.



Thermal unit performance improved in 2012 to 76% from 67% in 2011. Holyrood Unit 1 had the lowest capability factor of 70% and Unit 2 had the highest capability factor of 83%. Unit 3 had a capability factor of 75%. There were no major equipment failures in 2012.

Overall, the hydraulic unit performance declined slightly in 2012, to 91% compared to 93% in 2011. There were no major issues with the hydraulic generation and all units, except Bay d'Espoir Unit 4, experienced a capability factor above 90%. The capability factor of this unit was reduced to 68% in 2012 due to an extended planned outage required for a stator rewind.

Gas turbine performance decreased to 53% in 2012 from 71% in 2011. The capability factor for the Stephenville unit was 0%. The Stephenville unit failed in December 2011 due to a stator ground fault. This unit is not anticipated to be available again until repairs are completed in the spring of 2013. Calculation details for weighted capability as well as a list of factors that may impact KPI performance are in Appendix B of this report.

The table below provides a comparison by unit type along with the weightings applied to the CEA values to provide for the comparison to Hydro for the period 2007-2011. Hydro's hydro generation capability was slightly better than the comparable weighted national average. The weighted average is lower for Hydro's thermal-oil fired units and gas turbines.

Capability Factor Performance

	CEA (2007-2011)	**NLH (2007-2011)**	**Weighting Factor**
Hydro	91.31	92.79	50%
Thermal - Oil Fired	74.13	62.41	33%
Gas Turbine	87.21	70.05	17%

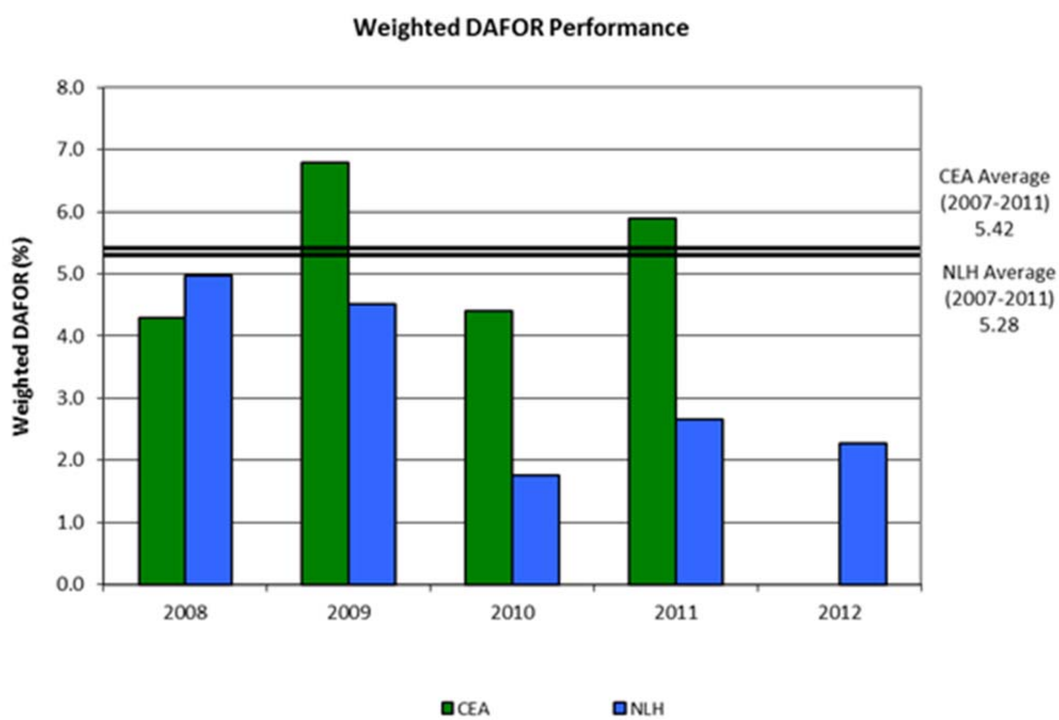
The weighted national average is developed by using national average capabilities values for the unit types in Hydro's system (hydro, oil-fired thermal and gas turbine) and applying weightings to these based upon the maximum continuous ratings of Hydro's generation. The quoted CEA value is therefore not a CEA published value but a re-stated value to facilitate a comparison to Hydro.

3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2012, Hydro's weighted DAFOR was 2.3% versus a target of 2.7%. The DAFOR was impacted by a hydrogen leak, high vibration on No. 1 bearing, and a problem with the turning gear, all associated with Holyrood Unit 1. There was also a problem with the condenser on Holyrood Unit 3 which affected the DAFOR. Hydro's overall weighted DAFOR from 2007 to 2011 of 5.3%, is slightly better than the equivalently weighted national average for the same period of 5.4%. The following table provides a 2007-2011 comparison by unit type:

DAFOR Performance

	CEA (2007-2011)	NLH (2007-2011)	Weighting Factor
Thermal - Oil Fired	9.84	13.81	34%
Hydro	3.19	0.97	66%



[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.

3.1.1.1 Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2011 and for the latest Canadian Electricity Association (CEA) national average for the period 2007-2011 are included for comparison.

Generation Performance Indices

Index		**Hydro**	**Thermal**	**Gas Turbine**
Failure Rate (Forced Outages per 8,760 operating hours)	NLH 2012 NLH 2011 CEA '07-'11	2.33 2.12 2.01	9.87 2.95 7.52	231.67 137.66 21.58
Incapability Factor (Percent of Time)	NLH 2012 NLH 2011 CEA '07-'11	9.35 6.56 8.69	24.04 33.32 25.87	32.88 24.90 12.79
Derating Adjusted Forced Outage Rate (Percent of Time)	NLH 2012 NLH 2011 CEA '07-'11	1.05 0.82 3.19	6.24 7.88 9.84	
Utilization Forced Outage Probability (Percent of Time)	NLH 2012 NLH 2011 CEA '07-'11			55.05 10.45 10.04

3.1.1.1 (a) Hydro Unit Performance

As indicated in the above Generation Performance Indices table, all hydro unit measures deteriorated in 2012 when compared to 2011. However, the hydraulic unit derating adjusted forced outage rate continues to be significantly better than the latest five-year national average.

3.1.1.1 (b) Thermal Unit Performance

Thermal unit performance improved in 2012 in the measures of derating adjusted forced outage rate and incapability factor. Performance in both of these measures is better than the national five-year averages. There was a significant decline in 2012 in the failure rate measure and performance is now worse than the national five-year average.

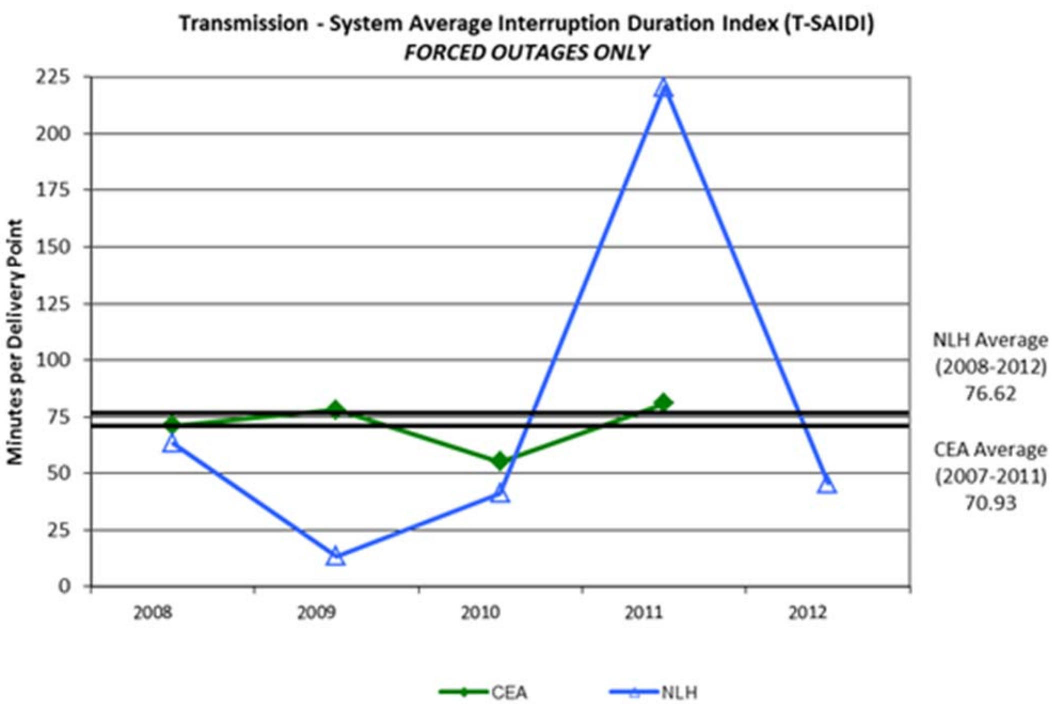
3.1.1.1 (c) Gas Turbine Unit Performance

The Generation Performance Indices table also indicates that Hydro's gas turbines performance declined significantly in 2012 from 2011 for all measures, and continues to be below the national average. This was primarily due a failure at the Stephenville gas turbine in December 2011 which rendered the unit inoperable for all of 2012. The failure rate calculation is very volatile due to the normally low operating hours of Hydro's gas turbines. Of particular importance to Hydro's use of gas turbines is the utilization forced outage probability (UFOP). The measure describes the degree to which a standby unit can be called upon to supply load when requested. The Stephenville failure had a significant effect on these measures.

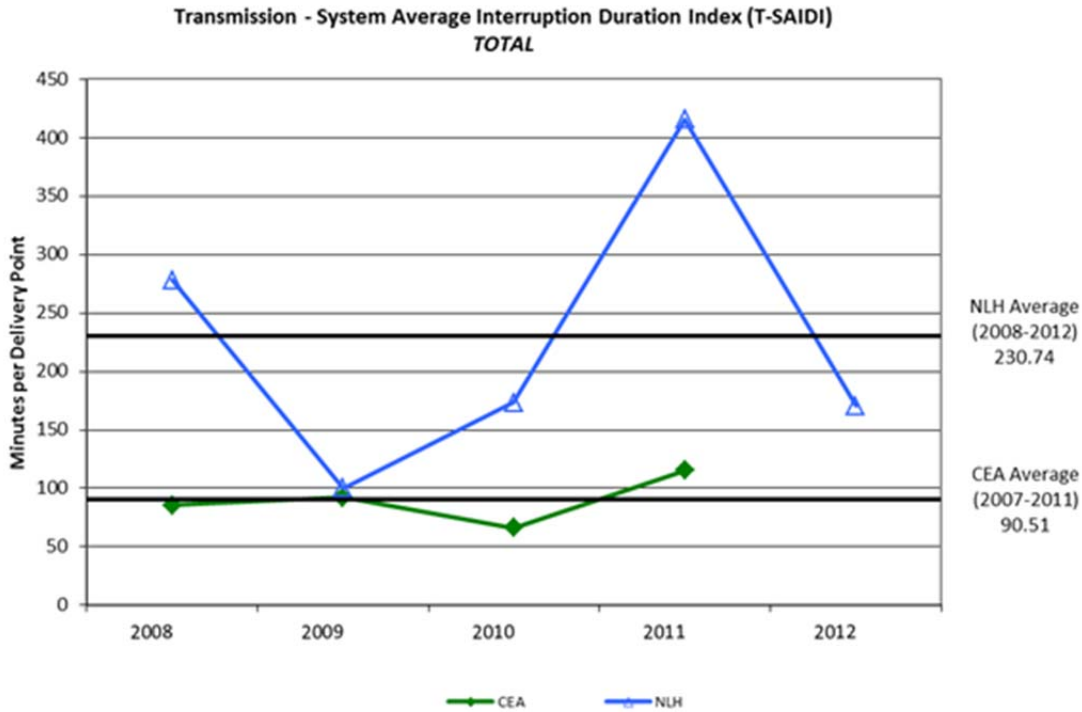
3.1.2 Reliability KPI: Transmission

3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 32.4 minutes per delivery point (forced and planned combined). The total 2012 T-SAIDI was 171 minutes per delivery point, 35% below the 2012 target[4] of 265 minutes per delivery point. In comparison, the 2011 total was 432 minutes per delivery point. The forced outage duration in 2012 decreased to 46 minutes from 221 minutes in 2011. The planned outage duration decreased to 125 minutes from 211 minutes in 2011. Of note is that, for the fourth quarter, the contribution of the force outage duration was 56% of the 2012 total.



[4] "Target" means less than or equal to the value set as a performance outcome.



There were a number of forced outages and three planned outages in the fourth quarter. A summary of these outages follows:

Forced

On October 12, customers served by the Hawke's Bay and Parsons Pond Terminal Stations experienced a series of unplanned outages due to salt contamination. Refer to the following table for details:

Date	Delivery Point	Time of Incident	Time of Restoration	Outage Duration	Cause of Outage
October 12	Hawke's Bay	1727	1730	3 minutes	Salt Contamination
October 12	Hawke's Bay	1828	1829	1 minute	Salt Contamination
October 12	Hawke's Bay	1831	1837	6 minutes	Salt Contamination
October 12	Parson's Pond	1459	1506	7 minutes	Salt Contamination
October 12	Parson's Pond	1620	1642	22 minutes	Salt Contamination

On October 14, all customers supplied by the South Brook Terminal Station experienced an unplanned outage of 35 minutes in duration. Crews found a jumper burnt off voltage regulator T1B1-VR1 at the station. Disconnect switch L22T1 was opened by Hydro's Energy Control Centre immediately, resulting in the unplanned outage. The jumper was repaired and the station was restored to service. The jumper burnt off due a severely corroded connector. Some customers continued to experience an outage due to faults on the distribution system during this time.

On October 16, customers north of Plum Point on the Great Northern Peninsula (GNP) experienced unplanned outages. The table below outlines the outage details (all were a result of salt contaminated equipment):

Date	Delivery Point	Time of Incident	Time of Restoration	Outage Duration	Cause of Outage
October 16	Bear Cove	445	907	4 hrs & 22 mins	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL 244.
October 16	Plum Point	657	859	2 hrs & 2 mins	TL241 trip and Plum Point Reactor R1 locked.
October 16	St. Anthony	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
October 16	Main Brook	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
October 16	Roddickton	445	500	15 minutes*	138 kV Bus Lockout at Bear Cove TS and trip of TL241 and TL244.
*Note: Customers in St. Anthony, Main Brook, and Roddickton were restored via St. Anthony Diesel Plant.					

On October 24, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of 32 minutes in duration. This outage occurred after transmission line L1301 tripped due to the operation of the lockout relay on transformer T31 at Churchill Falls. Personnel were working on the transformer, which was out of service, but the gas pressure relay was not blocked. This relay should have been blocked prior to starting work on the transformer.

On November 17, all customers supplied by the Farewell Head Terminal Station experienced an unplanned outage of ten minutes in duration. Newfoundland Power's Cobb's Pond Substation tripped due to a lockout of transformer T2. This lockout also tripped transmission line 142L which supplies Farewell Head via the Boyd Cove Substation and transmission line TL254.

On December 22, Newfoundland Power customers supplied by transmission line TL215 in the Port Aux Basque area experienced an unplanned outage of three minutes in duration. The outage occurred after high winds tripped TL215. Since the circuit breaker B1L15 was bypassed at the Doyles Terminal Station, TL214 tripped to isolate the fault. Newfoundland Power customers in the Doyles area were also affected by this event.

On December 24, all customers supplied by transmission line TL227 in Parson's Pond Area experienced an unplanned outage of one hour and two minutes in duration. The outage was caused by salt contamination on the line. The section of TL227 between the Parson's Pond and Daniel's Harbour Terminal Stations was isolated and customers were restored by closing in the Cow Head end of TL227.

On December 26, all customers supplied by the Rocky Harbour Terminal Station experienced an unplanned outage of 53 minutes in duration. All customers supplied by the Glenburnie and Wiltondale Terminal Stations experienced unplanned outages of one hour and 39 minutes in duration. The outage was caused by a tree coming into contact with transmission line TL226. The tree broke a conductor between Rocky Harbour and Wiltondale Stations. Rocky Harbour customers were restored from Berry Hill whilst Wiltondale and Glenburnie customers were restored from Deer Lake. The conductor was repaired on December 27.

On December 30, all customers supplied by the Rocky Harbour, Glenburnie, and Wiltondale Terminal Stations experienced an unplanned outage of two minutes in duration. The outage was caused by heavy snow build-up on transmission line TL226.

On December 30, all customers supplied by the Rocky Harbour, Glenburnie, and Wiltondale Terminal Stations experienced another unplanned outage of 49 minutes in duration. Similar to the events on December 26, the outage was caused by a tree contacting transmission line TL226. The tree broke a conductor between Rocky Harbour and Wiltondale Stations. Rocky Harbour customers were restored from Berry Hill while Wiltondale and Glenburnie customers were restored from Deer Lake. The conductor was repaired on December 31.

Planned

On November 4, all customers supplied by the Main Brook and Roddickton Terminal Stations experienced a planned outage of five hours and 14 minutes in duration. The outage was required to perform maintenance on Bus B1 PTs and install disconnect switch SST-1 at the St. Anthony Airport Terminal Station. Customers in the St. Anthony area were supplied by the St. Anthony Diesel plant.

On November 22, Newfoundland Power customers supplied by the Doyles Terminal Station experienced a planned outage of two hours and 50 minutes in duration. The outage was required to remove jumpers from circuit breaker B1L15 and to install a bypass around this breaker, to facilitate its replacement. Newfoundland Power customers in the Port Aux Basque area were supplied by local Newfoundland Power generation.

On December 31, all customers supplied by the Rocky Harbour Terminal Station experienced a planned outage of three minutes in duration. The short outage was required to restore TL226 following the completion of repairs to the conductor, broken during the previous day.

As previously reported, Hydro's planned outage durations tend to be longer than the national average. This is due to the relatively high number of delivery points on the Hydro system that do not have alternative supply options such as multiple station transformers or greater distribution system integration. This was a contributing factor to the planned outages on the GNP where station maintenance required customer outages for which there is no alternate supply point or local generation.

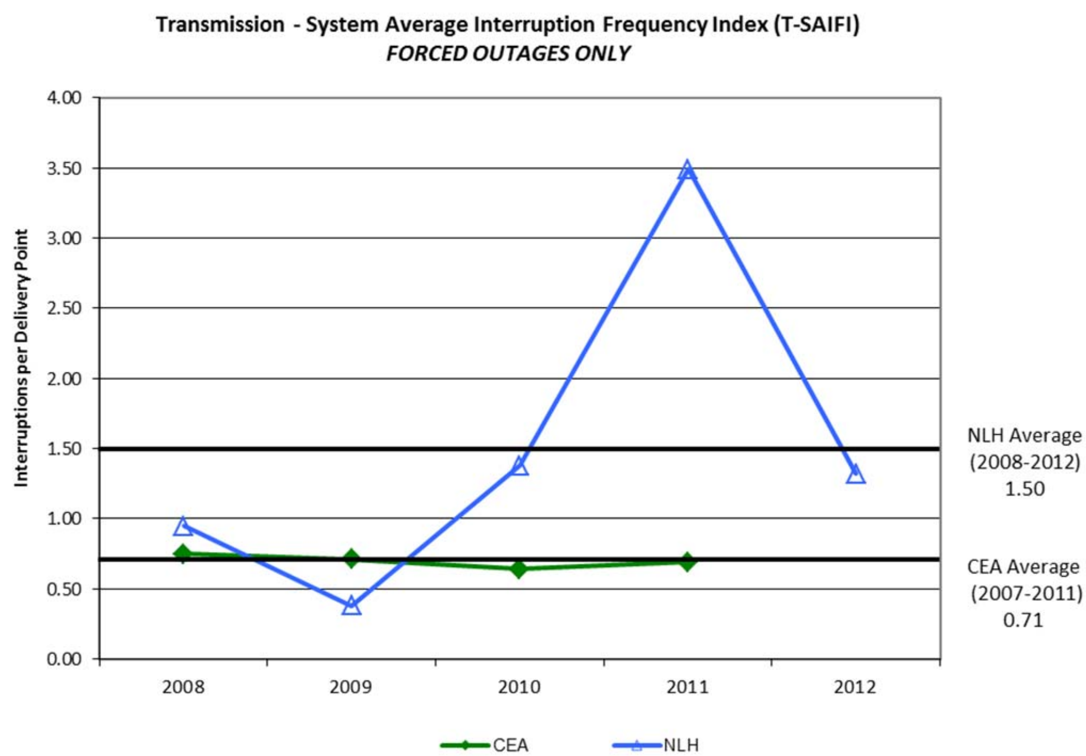
Appendix C1 lists all of the significant transmission events in 2012. Significant events are identified as those resulting in forced outages with an unsupplied energy of greater than 1,000 MW-mins. Unsupplied energy is a calculation of the outage duration multiplied by the load, in MW, at the delivery point before it was interrupted. This measures the energy that could have been supplied if the delivery had not been interrupted.

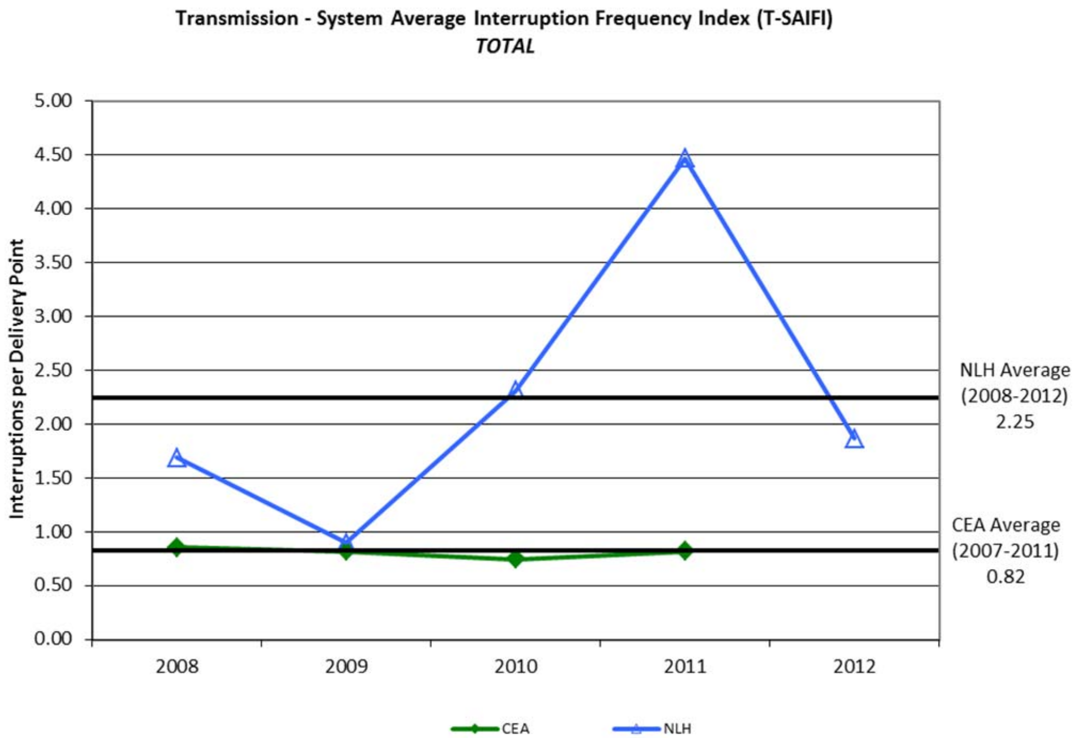
3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 0.52 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.45 and 0.07, respectively. In comparison, the 2011 fourth quarter T-SAIFI was 2.71 outages per bulk delivery point. The decrease in outage frequency was the result of a lower number of forced outages this quarter.

The overall 2012 T-SAIFI was 1.88 outages per bulk delivery point which is significantly lower than last year's average of 4.52 outages per delivery point, a decrease of 58%. The 2012 target was 2.00 outages per bulk delivery point and this target was met. The number of forced outages per delivery point in 2012 (1.32) decreased 62% from 2011 (3.49). The frequency of planned outages per delivery point decreased by 46%; to 0.55 in 2012.

The frequency of Hydro's forced delivery point outages has been generally higher than the national average. This result is expected and can generally be attributed to the number of delivery points that are supplied by a single transmission line. The most severe example is on the Great Northern Peninsula, where one line, TL-239, supplies up to nine delivery points. There are a number of other locations where a single line supplies three delivery points.



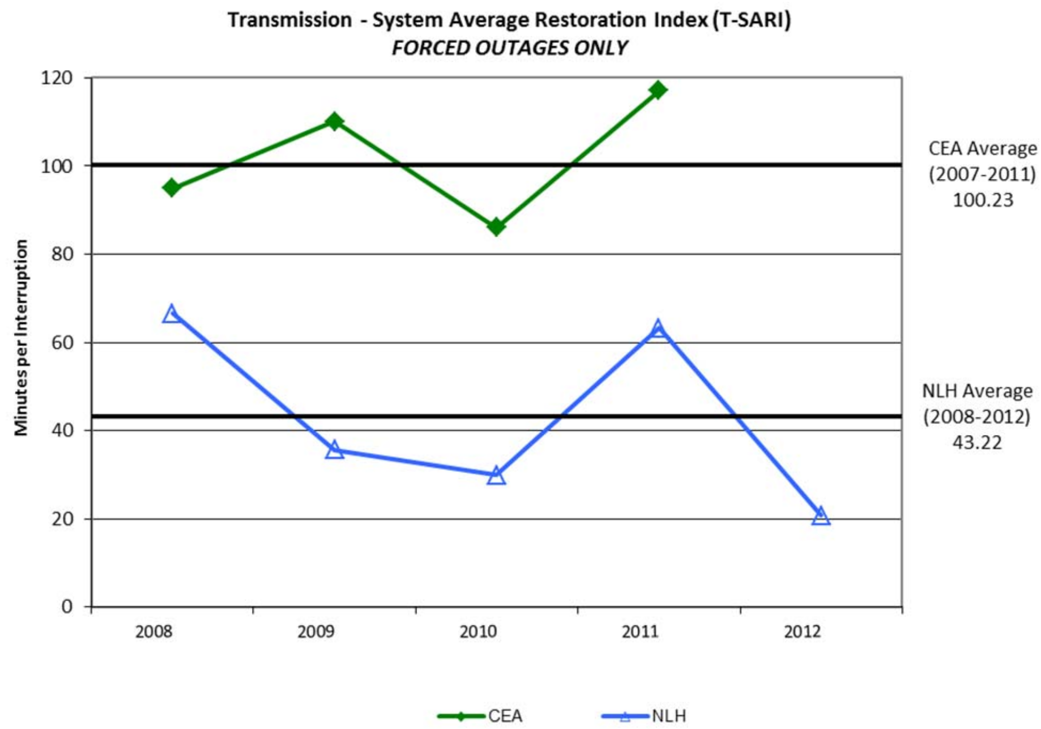


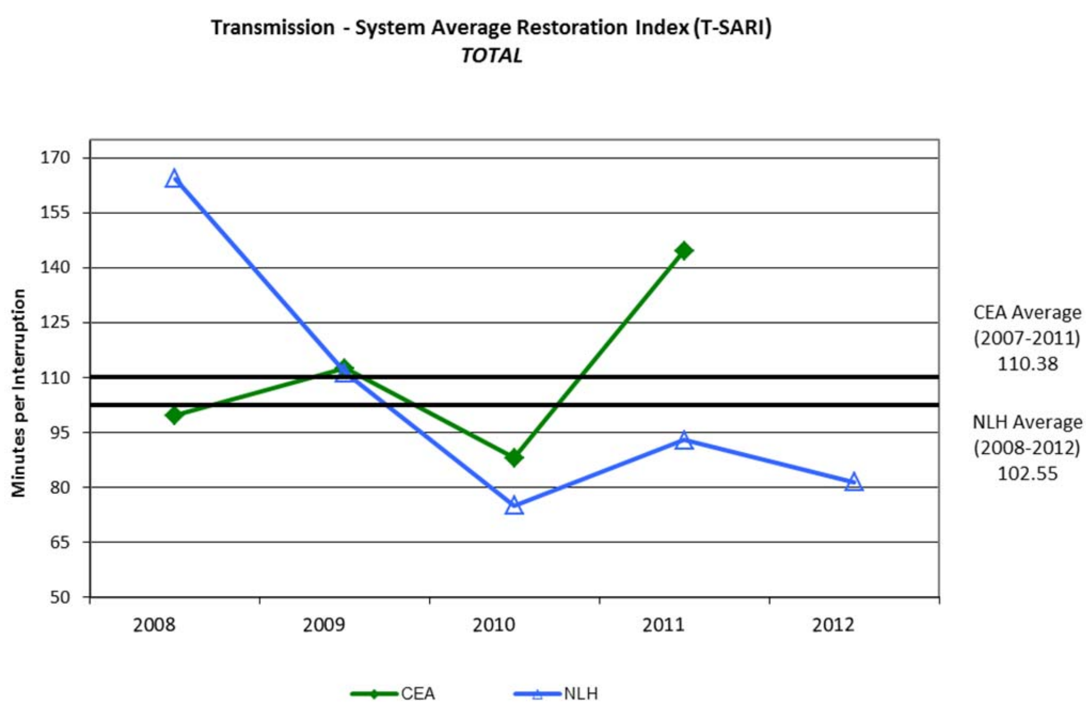
3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's total transmission T-SARI was 62.4 minutes per interruption for the fourth quarter of 2012 compared to 98.4 minutes per interruption during the same quarter in 2011, a 37% decrease. The forced outage component of T-SARI was 40.8 minutes per interruption compared to 79.8 minutes per interruption in 2011. The planned outage component of T-SARI was 200.4 minutes per interruption which is 6% higher than during the fourth quarter of 2011.

Hydro's 2012 total transmission T-SARI was 90 minutes per interruption, compared to 94 minutes in 2011 and a 2012 target of 133 minutes. The forced outage component of T-SARI was 34.8 minutes per interruption, a decrease of 44% over 2011. The planned outage component of T-SARI was 226 minutes per interruption, which is an increase of 9% over 2011. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase is driven by greater increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance continues to be better than the latest five-year national average. This can be seen in the chart below.


Transmission - System Average Restoration Index (T-SARI)
FORCED OUTAGES ONLY
Minutes per Interruption
120
100
80
60
40
20
0
2008
2009
2010
2011
2012
CEA Average
(2007-2011)
100.23
NLH Average
(2008-2012)
43.22
CEA
NLH

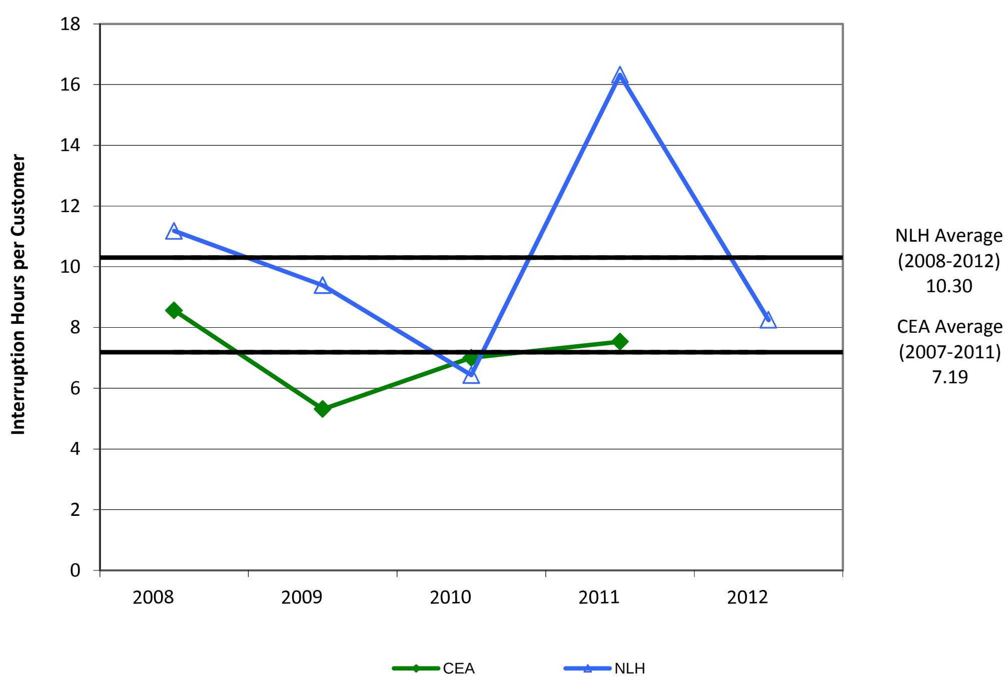

Transmission - System Average Restoration Index (T-SARI)
TOTAL
Minutes per Interruption
170
155
140
125
110
95
80
65
50
2008
2009
2010
2011
2012
CEA Average
(2007-2011)
110.38
NLH Average
(2008-2012)
102.55
CEA
NLH

3.1.3 Reliability KPI: Distribution

3.1.3 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2012, the SAIDI was 3.41 hours per customer, compared to 9.57 hours per customer during the same quarter of 2011. The total 2012 SAIDI was 8.25 hours per customer, compared to 16.32 hours per customer in 2011. The performance in 2012 was worse than the annual target of 5.90 hours per customer but showed a considerable improvement over the previous year.

Service Continuity - System Average Interruption Duration Index (SAIDI)



A summary of the major interruptions during the fourth quarter is as follows:

- On October 6, all customers (166) in Rigolet, Labrador experienced an unplanned power outage. The outage occurred when Diesel Units 2065 and 2051 experienced mechanical problems with their actuators. All customers were restored at 1340 hours. Outage duration was five hours and 40 minutes.

- On November 4, 146 customers serviced by Line 18 in Labrador City experienced two emergency planned power outages. The outages were requested by the local emergency response team due to a fire in an unfinished apartment building. Total customer outage time was nearly six hours.

- On November 25, all customers (105) in Black Tickle, Labrador experienced an unplanned power outage. The outage occurred after mobile generator 2 tripped off-line. All customers were restored at 1838 hours. The cause of the mobile tripping could not be determined. The total customer outage duration was five hours and 48 minutes.

- On December 6, 95 customers in Nain, Labrador experienced an unplanned power outage. The outage occurred when a vehicle hit and broke a utility pole. A community wide outage was required to isolate the affected area to perform maintenance. During this outage all Nain customers (452) experienced an unplanned power outage from 0300 hours to 0310 hours. The damaged pole was repaired and all the 95 customers initially impacted were restored. The total customer outage duration was 15 hours and 30 minutes.

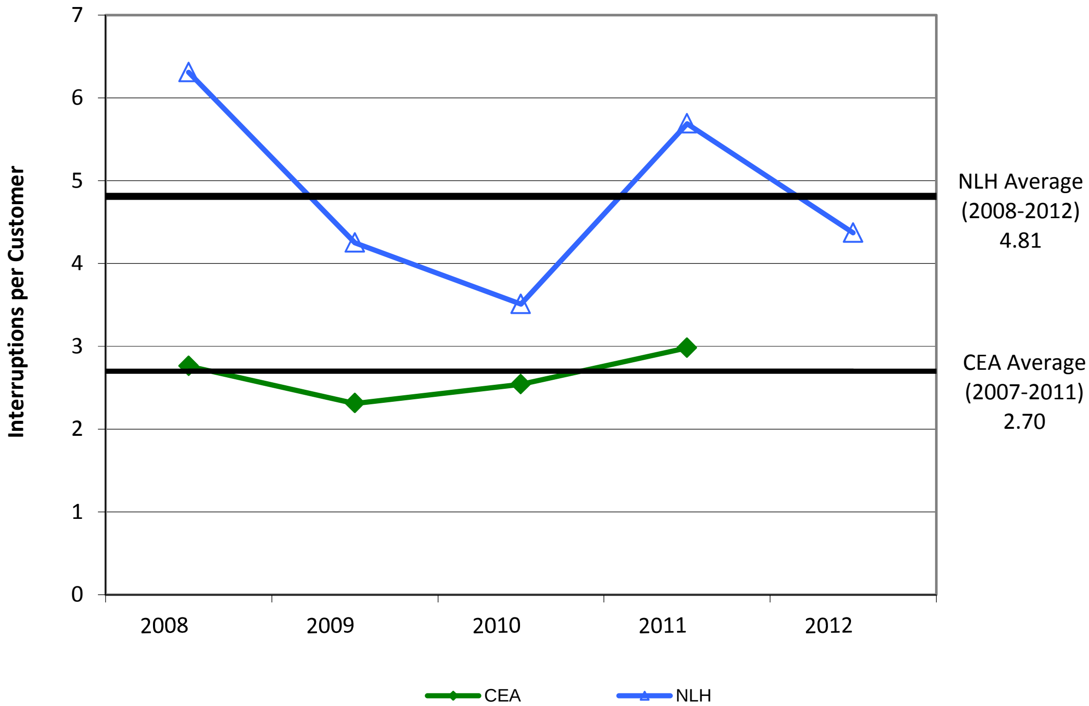
- On December 16, at 0000 hours (Labrador time), 50 customers in Nain, Labrador experienced an emergency planned power outage. The outage was required to repair an after cooler on Unit 2085. All customers were restored at 0640 hours with Unit 2085. The total customer outage duration was six hours and 40 minutes.

The remainder of the significant events in 2012, which affected the distribution systems (i.e., outages generally to a complete system with duration of greater than five hours), are contained in Appendix C2.

3.1.3 b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter the SAIFI was 1.64 interruptions per customer, compared to 1.85 interruptions per customer during the same quarter of 2011, an 11% decrease. The total 2012 SAIFI was 4.37 interruptions per customer compared to 5.70 interruptions per customer in 2011, a 23% decrease. The 2012 target of 3.7 interruptions per customer was not met; however, the performance in 2012 shows an improvement from 2011.

Service Continuity - System Average Interruption Frequency Index (SAIFI)



3.1.3.1 Additional Information

This section provides more detailed information in three tables with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	**Fourth Quarter 2012**	**Fourth Quarter 2011**	**12 Mths to Date 2012**	**12 Mths to Date 2011**	**5 Year Average**
Central					
Interconnected	0.89	7.80	2.08	2.91	3.00
Isolated	0.32	1.19	0.88	6.22	3.19
Northern					
Interconnected	2.31	2.94	4.81	6.38	4.54
Isolated	5.03	1.11	8.65	5.26	6.34
Labrador					
Interconnected	1.10	2.07	5.44	8.17	6.34
Isolated	3.51	2.73	9.59	8.28	11.35
Total	1.64	1.85	4.37	5.70	4.86

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	**Fourth Quarter 2012**	**Fourth Quarter 2011**	**12 Mths to Date 2012**	**12 Mths to Date 2011**	**5 Year Average**
Central					
Interconnected	2.31	10.71	4.98	16.86	9.99
Isolated	0.87	0.99	2.02	3.83	2.38
Northern					
Interconnected	5.73	16.78	11.05	25.21	11.11
Isolated	5.36	0.61	6.89	3.84	5.97
Labrador					
Interconnected	2.17	5.01	9.28	11.34	11.23
Isolated	4.92	1.17	15.11	10.92	15.51
Total	3.41	9.57	8.25	16.32	10.47

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)

Area	Fourth Quarter 2012	Fourth Quarter 2011	12 Mths to Date 2012	12 Mths to Date 2011	5 Year Average
Loss of Supply – Transmission	0.23	0.68	1.40	2.59	1.85
Loss of Supply – NF Power	0.00	0.01	0.01	0.01	0.01
Loss of Supply – Isolated	0.20	0.12	0.49	0.50	0.57
Loss of Supply – L'Anse au Loup	0.00	0.03	0.03	0.05	0.05
Distribution	1.20	1.01	2.45	2.53	2.38
Total	1.64	1.85	4.37	5.70	4.86

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)

Area	Fourth Quarter 2012	Fourth Quarter 2011	12 Mths to Date 2012	12 Mths to Date 2011	5 Year Average
Loss of Supply – Transmission	0.23	3.44	1.70	6.12	3.48
Loss of Supply – NF Power	0.00	0.49	0.00	0.49	0.14
Loss of Supply – Isolated	0.08	0.02	0.27	0.13	0.24
Loss of Supply – L'Anse au Loup	0.00	0.01	0.00	0.03	0.03
Distribution	3.10	5.61	6.26	9.55	6.58
Total	3.41	9.57	8.25	16.31	10.47

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.32	1.16	0.57	1.15	0.89	2.31
Isolated	0.16	0.05	0.16	0.82	0.32	0.88
Northern						
Interconnected	0.73	1.84	1.58	3.90	2.31	5.73
Isolated	0.32	0.57	4.71	4.79	5.03	5.36
Labrador						
Interconnected	0.47	1.66	0.63	0.52	1.10	2.17
Isolated	0.88	2.87	2.64	2.05	3.51	4.92
Total	0.49	1.50	1.14	1.91	1.64	3.41

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.4 Reliability KPI: Other

3.1.4 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were three underfrequency events during the fourth quarter of 2012, summarized as follows:

On October 17, Holyrood Generating Unit #1 tripped due to a faulty vibration probe on the unit's Turbine Instrumentation System. With the removal of generation (approximately 71 MW) the system frequency dropped to 58.58 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 706 MW. A total of 1,278 Hydro customers were restored nine minutes after the event occurred, and 16,545 Newfoundland Power customers were reported to be restored within eleven minutes after the event occurred. Customers were restored in stages after capacitor banks on the Avalon were placed in service.

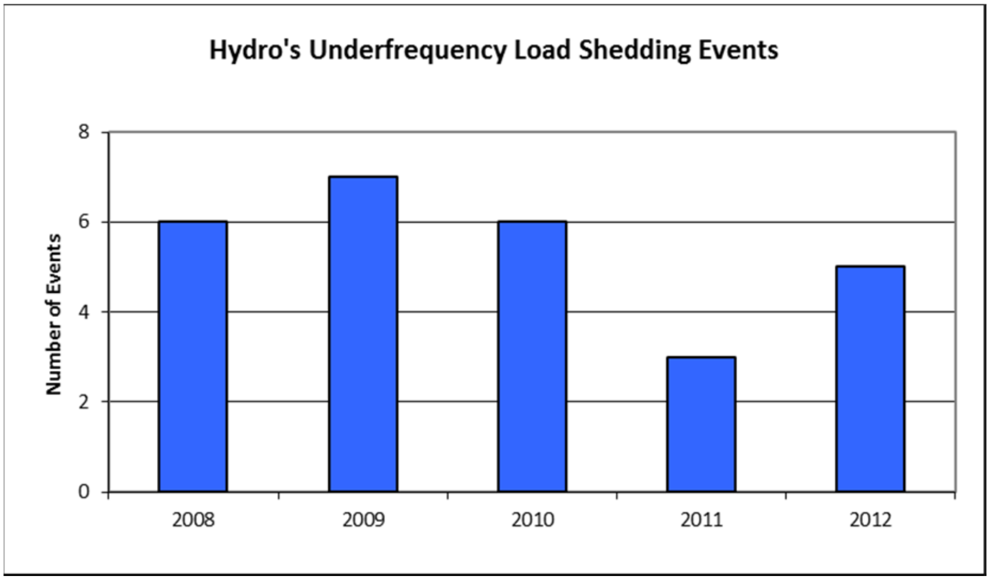
Load Shed:	Hydro: 4 MW
	Newfoundland Power: 39 MW
	Total Load Shed: 43 MW

On November 21, at 1438 hours, Holyrood Generating Unit #2 tripped. With the removal of generation (approximately 98 MW) the system frequency dropped to 58.55 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 903 MW. Hydro customers (1,282) were restored ten minutes after the event occurred, (50 MW-mins). Newfoundland Power customers (12,071) were reported to be restored within two to fourteen minutes after the event occurred, (399 MW-mins).

Load Shed:	Hydro: 5 MW
	Newfoundland Power: 54 MW
	Total Load Shed: 59 MW

On November 25, at 1124 hours Holyrood Generating Unit #2 tripped again. With the removal of generation (approximately 60 MW) the system frequency dropped to 58.79 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 722 MW. Newfoundland Power customers (6,660) were reported to be restored within sixteen minutes after the event occurred. The load was 16 MW for 91.5 MW-mins.

In total, there were five UFLS events in 2012. This represents two more events than what were experienced in 2011, but below the five-year average of 5.4 events. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The following table compares the UFLS events in the fourth quarter of 2012 to the same quarter in 2011.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter 2012	Fourth Quarter 2011	Year to Date 2012	Year to Date 2011	5 Year Average (2008–2012)
NF Power	3	1	5	3	5.4
Industrials	0	0	1	0	2.8
Hydro Rural*	2	0	3	0	2.8
Total Events	3	1	5	3	5.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter 2012	Fourth Quarter 2011	Year to Date 2012	Year to Date 2011	5 Year Average (2008–2012)
NF Power	920	24	3,194	324	1,643
Industrials	0	0	140	0	217
Hydro Rural*	86	0	107	0	44
Total Events	1,006	24	3,440	324	1,904

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

The details of the previous two UFLS events in 2012 are summarized in Appendix C3.

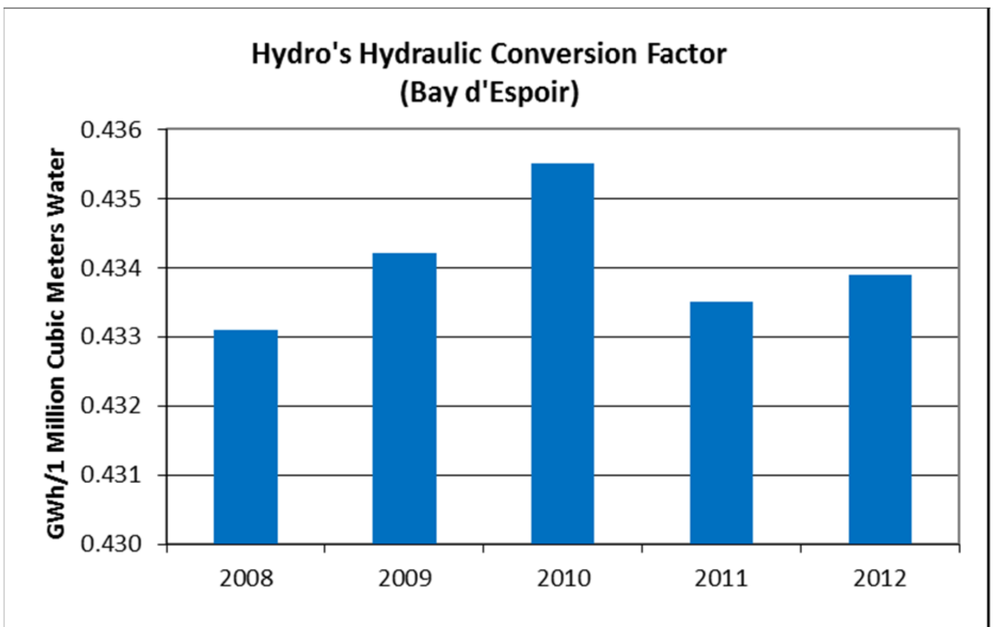
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2012, Hydro's hydraulic conversion factor for Bay d'Espoir was 0.4339 GWh/MCM. The performance in 2012 improved slightly from that in 2011, primarily due to reservoir storages which had returned to normal levels and allowed for more efficient operation of the hydro-electric generation. In 2011, reservoirs were very high and there was a significant amount of spill which required that generation be operated at high levels in order to minimize the same.

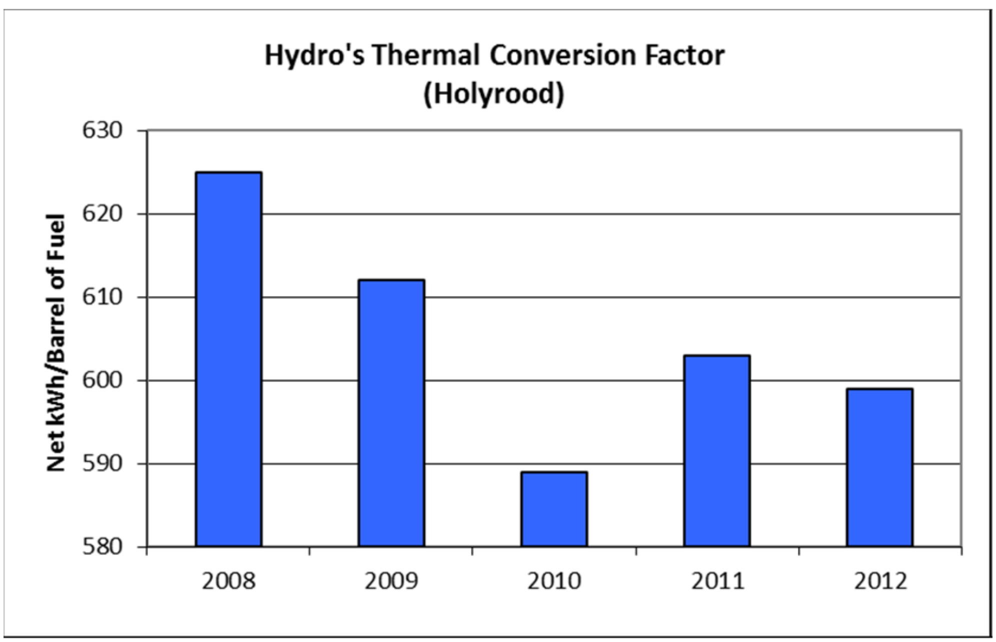


3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is directly proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. In turn, the output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production, quantity of power purchases, customer energy requirements and system security requirements.

In 2012, Hydro's net thermal conversion factor was 599 kWh per barrel, which is significantly below the 2012 target of 630 kWh per barrel. This reduction is primarily related to operating the plant at lower generating levels due to the high volume of water resources and energy receipts relative to the system load requirements. The experience in 2012 declined slightly from an improvement in 2011.

Production at Holyrood was kept to a minimum in 2012 with units dispatched only as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 80 MW, up from 75 MW in 2011. Overall, net production from Holyrood for 2012 was 856 GWh, a 3.3% decrease from 2011 production levels.



3.3 Financial Performance Indicators [complete section updated]

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[5]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8 (2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the fifth year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix C. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[6] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year-over-year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

[5] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.
[6] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

3.3.1 Financial KPI: Corporate

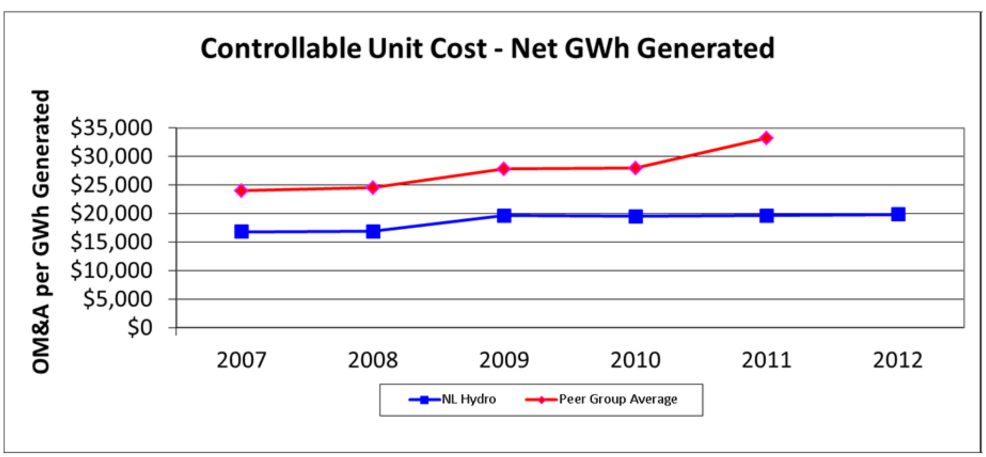
3.3.1 a) Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs increased from $106.9 million in 2011 to $108.7 million[7] in 2012, resulting in a Controllable Unit Cost of $14.93 per MWh delivered for 2012.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2007-2011 have therefore been herein restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $19.79 per MWh during 2012, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very steady trend as compared to an upward trend for the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.



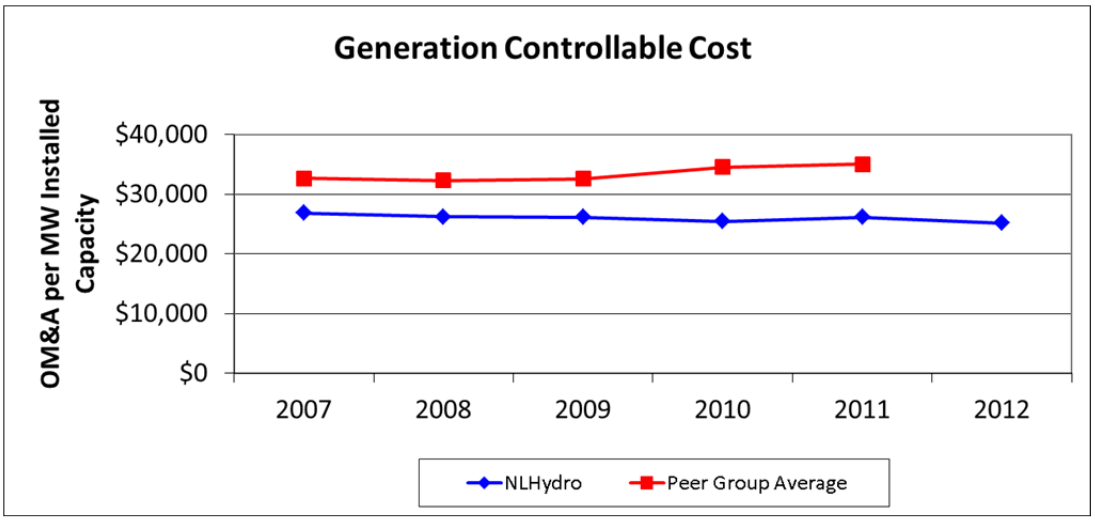
[7] This $108.7 million was calculated in the 2012 Cost of Service study and includes a $2.2 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $2.2 million was excluded when the $106.5 million regulated amount was reported on the Statement of Income – Regulated Operations for 2012, filed as part of the December 31, 2012 Quarterly Regulatory Report.

3.3.2 Financial KPI: Generation

3.3.2 a) Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $25,131 per MW for 2012 compared with $26,169 in 2011 a decrease of $1,038 per MW. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program concluded during 2012.

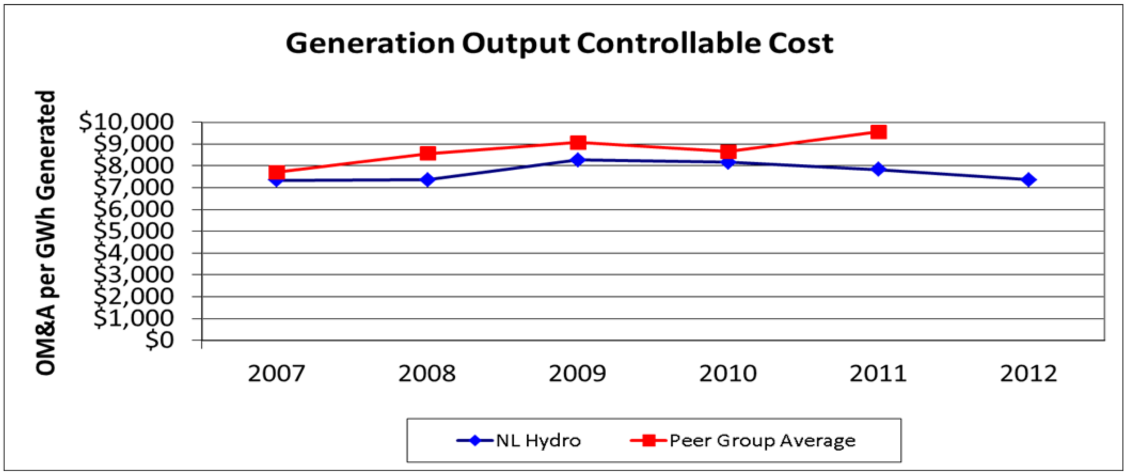
The peer group used to benchmark Generation Controllable Costs appears to be experiencing an increase in OM&A per MW installed capacity while Hydro is relatively stable.



3.3.2 b) Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2012, Hydro's Generation Output Controllable Cost of $7,358 per GWh, was lower than the $7,833 in 2011. There was a decrease in the Generation Costs component of approximately $2.2 million from 2011 to 2012 offset by an increase of 60 GWh in the Net Energy Generated.

From 2007 through 2010, Hydro's Generation Output Controllable Costs were primarily in line with and trending in a similar direction as those of the peer group with a moderate decline for Hydro in 2011.

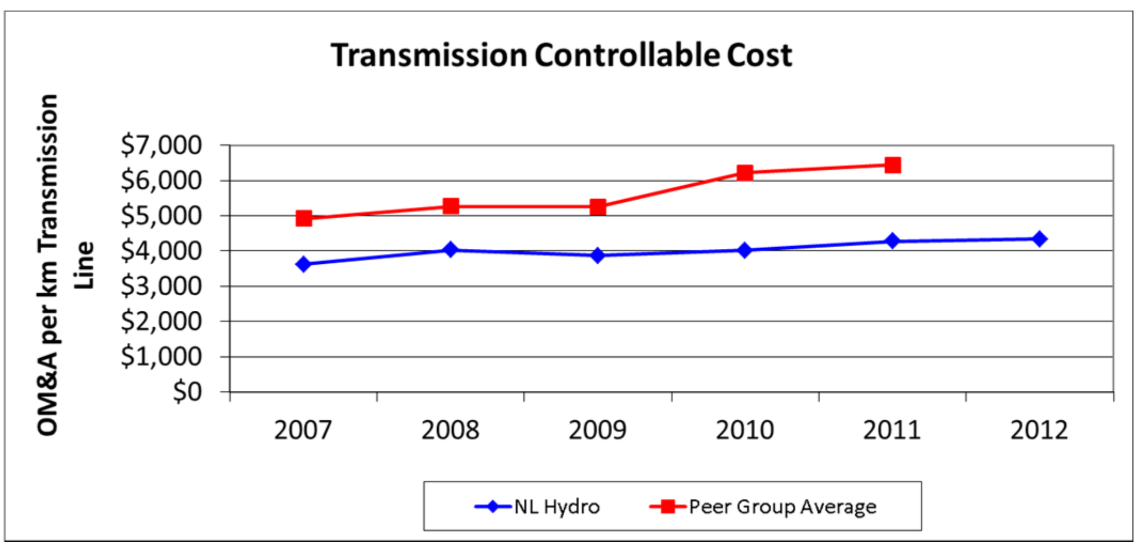


3.3.3 Financial KPI: Transmission

3.3.3 a) Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2012, Hydro's Transmission Controllable Cost was $4,335 per km of transmission, an increase of 1.4% over 2011.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



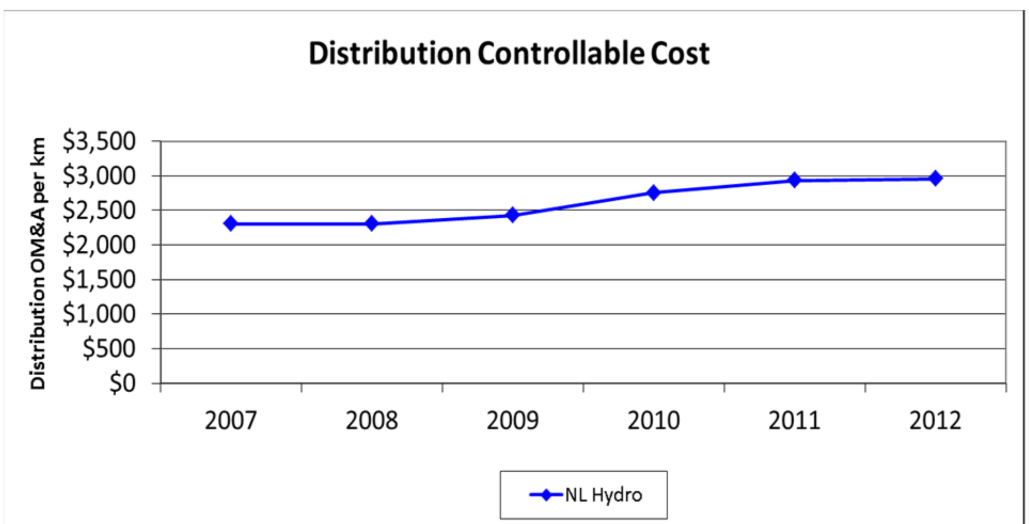
3.3.4 Financial KPI: Distribution

3.3.4 a) Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres[8].*

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

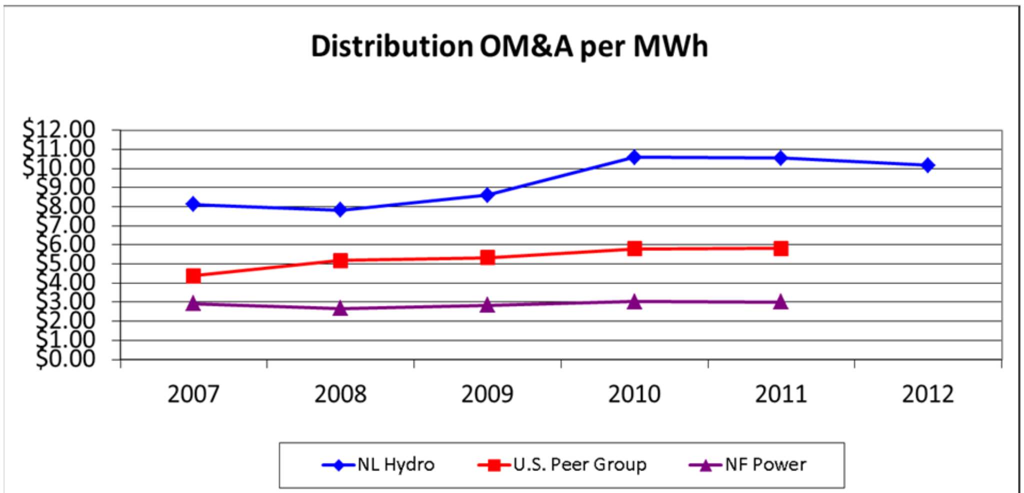
The distribution cost per km of circuit length will continue to be reported for year-over-year trend analysis.

At $2,960 per circuit km Hydro's Distribution Controllable Cost of 2012 increased from the $2,934 that was recorded in 2011. This is in line with the upward trend in this cost that was seen between 2007 and 2011.



[8] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.

As expected, Hydro's distribution costs of $10.16 in 2012 trend higher than those of its peers in the table below. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs per MWh are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.



3.4 Customer-Related Performance Indicators

3.4.1 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI*[9]*.*

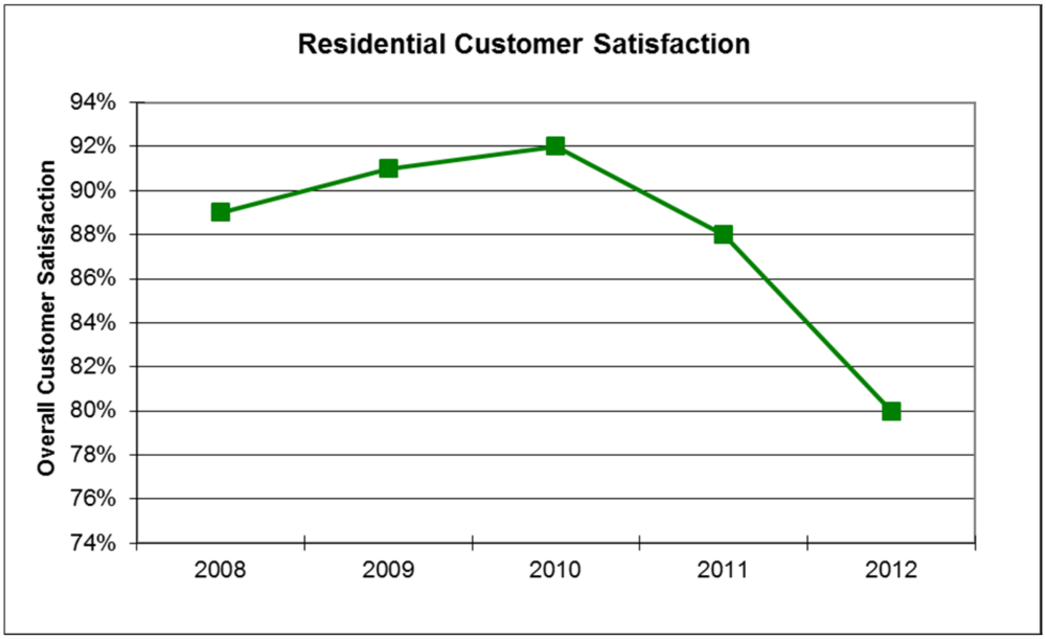
The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

Hydro targeted a 2012 residential satisfaction rate of $\geq$90%, up two points from the 2011 actual results of 88%. The 2012 residential customer satisfaction survey shows that the majority of customers (80%) are either *very satisfied* (46% provided a rating of 9 or 10, on a scale of 1 to 10) or *somewhat satisfied* (34% provided a rating of 7 or 8, on a scale of 1 to 10) with Hydro. Compared with 2011, the proportion of customers who provided a rating of 9 or 10 held steady at 46%, while the proportion that provided a rating of 7 or 8 decreased from 42% in 2011 to 34% in 2012.

Overall in 2012, there was a slippage in the proportion of customers who provided a rating of 7 or 8 and an increase in the proportion of customers who provided a rating of 5 or 6. Customer

[9] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.

satisfaction with the reliability of service appears to be the indicator for the slippage.



4 Data Table of Key Performance Indicators

Key Performance Indicators' targets for 2013 were established in the same manner as in previous years. Any future changes in methodology will be included as such a change occurs.

Newfoundland and Labrador Hydro
Key Performance Indicators (KPI)
Results for 2012 plus Targets/Budgets for 2013[1]

KPI	Measure Definition	Units	2008	2009	2010	2011	2012	2013T
Reliability								Target
Generation								
Weighted Capability Factor[2]	Availibility of Units for Supply	%	82.3	82.0	83.4	83.3	82.9	84.0
Weighted DAFOR[2]	Unavailibility of Units due to Forced Outage	%	5.0	4.5	1.8	2.7	2.3	2.8
Transmission[6,]								
T-SAIDI	Outage Duration per Delivery Point	Minutes / Point	278	100	173	432	171	203
T-SAIFI	Number of Outages per Delivery Point	Number / Point	1.7	0.9	2.3	4.5	1.9	1.7
T-SARI	Outage Duration per Interuption	Minutes / Outage	164	111	75	96	90	122
Distribution								
SAIDI	Average Outage Duration for Customers	Hours / Customer	11.2	9.4	6.6	16.3	8.3	5.9
SAIFI	Number of Outages for Customers	Number / Customer	6.3	4.3	3.5	5.7	4.4	3.6
Under Frequency Load Shedding								
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	7	6	3	5	6
Operating								
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.434	0.436	0.434	0.434	0.433
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	625	612	589	603	599	607
Financial (Regulated)								
Controllable Unit Cost[5]	Controllable OM&A$ / Energy Deliveries	$/MWh	$14.05	$14.91	$14.25	$14.96	$14.93	N/A
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,217	$26,138	$25,465	$26,169	$25,131	N/A
	Generation OM&A$ / Net Generation	$ / GWh	$7,362	$8,267	$8,159	$7,833	$7,358	N/A
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit Km	$ / Km	$4,023	$3,870	$4,021	$4,275	$4,335	N/A
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,305	$2,429	$2,755	$2,934	$2,960	N/A
Other								
Percent Satisfied Customers (Residential)	Satisfaction Rating	Max = 100%	89%	91%	92%	88%	80%	$\geq$90%

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For the Bay d'Espoir hydroelectric plant.
4. For the Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for AC Stephenville mill closure.
6. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.

Appendices

Appendix A: Rationale for Hydro's 2012 KPI Targets

KPI	Comment on KPI 2012 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2012 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2012 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2012 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is set using the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2012 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	Per Board Order No. P.U. 14 (2004)
Financial	
[ ]	N/A
[ ]	N/A
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1-\frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events - 2012

- On May 26, all customers served by the Happy Valley Terminal Station experienced an unplanned power outage of one hour and 31 minutes in duration. At the time there was a planned outage underway to transmission line L1301 and the Happy Valley Gas Turbine was in service supplying customers. A gas alarm occurred on the gas turbine unit transformer - T3. The planned work was cancelled on L1301, but before the line could be restored, the gas turbine tripped. Customers were restored after L1301 was returned to service. **Unsupplied Energy: 1,456 MW-mins.**

- On September 11, all Newfoundland Power customers east of the Western Avalon Terminal Station experienced an unplanned outage due to the high winds of Hurricane Leslie which tracked over the Avalon Peninsula. The following table provides additional detail:

Delivery Point Interruptions on Sept 11, 2012

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Hardwoods (Outage 1)	Sep 11, 2012 08:09	Sep 11, 2012 08:38	29.00	73.35	2,127.15
Hardwoods (Outage 2)	Sep 11, 2012 08:52	Sep 11, 2012 09:06	14.00	42.00	588.00
Oxen Pond	Sep 11, 2012 08:09	Sep 11, 2012 09:19	70.00	94.28	6,599.60
Holyrood - 38L (1)	Sep 11, 2012 08:09	Sep 11, 2012 08:48	39.00	9.82	382.98
Holyrood - 38L (2)	Sep 11, 2012 08:52	Sep 11, 2012 10:20	88.00	5.84	81.76
Holyrood - 39L (1)	Sep 11, 2012 08:09	Sep 11, 2012 08:35	26.00	0.00	0.00
Holyrood - 39L (2)	Sep 11, 2012 08:52	Sep 11, 2012 09:16	24.00	0.00	0.00
Western Avalon 64L (1)	Sep 11, 2012 08:01	Sep 11, 2012 08:05	4.00	0.00	0.00
Western Avalon 64L (2)	Sep 11, 2012 08:09	Sep 11, 2012 08:29	20.00	32.06	641.20
Western Avalon 64L (3)	Sep 11, 2012 08:31	Sep 11, 2012 08:34	3.00	3.43	10.29
Western Avalon 64L (4)	Sep 11, 2012 08:52	Sep 11, 2012 08:59	7.00	27.65	193.55
Western Avalon 64L (5)	Sep 11, 2012 09:14	Sep 11, 2012 09:29	15.00	33.22	66.44
Western Avalon Bus 2	Sep 11, 2012 08:09	Sep 11, 2012 09:58	109.00	2.10	228.90
		Total	448.00	211.61	10,919.87

The initial outage was caused by multiple faults that occurred on NP’s 138 kV loop between the Western Avalon and Holyrood Terminal Stations. Combined with other system conditions and the nature and duration of these faults, the protection equipment on Hydro’s 230 KV transmission lines responded and tripped. Investigation has determined that there was no fault on the 230 kV transmission system during this time and system stability was not lost. The slow clearing 138 kV faults created a severe 230 kV voltage dip and caused the protection operations which led to the outage.

A second outage occurred after transmission line TL237 faulted between the Come by Chance and Western Avalon Terminal Stations. This fault was also caused by the hurricane force winds resulting in the line conductors slapping together. **Total Unsupplied Energy: 10,541 MW-mins.**

Appendix C1: Significant Transmission Events – 2012 (Cont'd)

- On October 24, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of 32 minutes in duration. This outage occurred after transmission line L1301 tripped due to the operation of the lockout relay on transformer T31 at Churchill Falls. Personnel were working on the transformer, which was out of service, but the gas pressure relay was not blocked. This relay should have been blocked prior to starting work on the transformer. **Unsupplied Energy: 1,186 MW-mins.**

Appendix C2: Significant Distribution Events – 2012 (Excluding Fourth Quarter)

- On February 12, there was an unplanned outage affecting approximately 20 customers in La Poile. The outage occurred during a high wind and heavy rain storm. Due to the poor visibility caused by the weather conditions (high winds which later caused snow squalls), attempts to bring in a crew by helicopter were delayed until February 14. The cause of the outage was a blown fuse at a pole-mounted disconnect switch, associated with the customer feeder. Total outage time to the customers was more than 51 hours.

- On March 14, all customers (105) in Black Tickle experienced a lengthy power outage caused by a fire in the diesel plant. The fire damaged most of the overhead electrical conductors in the power plant engine hall. Power was restored to the community on March 15 after the maintenance personnel successfully and safely completed the temporary repairs to one of the three generator units damaged in the fire. A mobile unit was transported to the site and used to supply customers.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

- On January 14, Holyrood Generating Unit # 1 and Unit # 2 tripped due a fault on the 66 kV line supplying station service to the generating plant. With the removal of generation (approximately 142 MW) the system frequency dropped below 58.3 Hz resulting in the activation of the underfrequency protection at Newfoundland Power (18,940 customers), Hydro (2,200 Customers) and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,055 MW. Hydro indicated to Newfoundland Power and Corner Brook Pulp and Paper that power could be restored ten minutes after the event occurred and power was restored to all customers affected by the underfrequency in 40 minutes.

- On May 22, Cat Arm Generating Unit # 1 tripped after the fire protection deluge system operated on the unit transformer, T1. Personnel investigated, however, there was no fire or indication of a fire found at the transformer. With the removal of generation (approximately 60 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the underfrequency protection at Newfoundland Power. This underfrequency event affected 6,046 Newfoundland Power customers for up to four minutes for a total load loss of 48 MW-mins. Total system load at the time of the incident was 570 MW.

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.

Provincial Electrical Systems

June 2013

Table of Contents

Page

1.0 Overview

Hydro owns and operates two interconnected power systems, one on the Island and the other in Labrador. As well, Hydro owns and operates 21 isolated generation and distribution systems located around coastal Newfoundland and Labrador, and numerous distribution systems on the Island Interconnected System, primarily on the Great Northern Peninsula (GNP), the South Coast and the White Bay-Baie Verte area, as well as the Labrador Interconnected System.

1.1 Island Interconnected

On the Island Interconnected System, power and energy are provided by Hydro through a mix of hydroelectric and fossil-fired generation, as well as power purchases. This production, along with the transmission system, is managed by Hydro's Energy Control Centre (ECC) to ensure the economic and reliable dispatch of available resources.

The general location of Hydro's Island facilities is indicated in Schedule 1. A single line diagram of the Island Interconnected System is provided in Schedule 2. Since the last General Rate Application, additions and removals have been made to the Island Interconnected System. These will be assigned to the Cost of Service areas consistent with Board Order No. P.U. 14(2004) and are as follows:

2012-2013

- A 230/13.8 kV Terminal Station at the Vale Newfoundland and Labrador (Vale) processing facility and a 2.64 km extension of transmission line TL-208 from Western Avalon to the Vale processing facility - specifically assigned to Vale; and
- Removal of the Long Harbour Terminal Station and associated equipment due to the installation of the Terminal Station at the Vale facility.

Hydro's Island Interconnected production facilities consist of 14 generating stations, varying in size from 360 kW to 592 MW. As well, there are power purchase agreements in place to purchase power from Non-Utility Generators. The total from all power purchases will provide approximately 15% of Hydro's Island Interconnected total net energy supply in 2013. The Island Interconnected net installed capacity, including power purchase contracts is 1,686.3 MW. Schedule 3 outlines the provincial interconnected generation capability.

On the Island Interconnected System, Hydro owns and maintains 3,473 km of high voltage lines, and more than 50 high voltage terminal stations operating at 230, 138 and 69/66 kV which connect to the generation and the delivery points for Newfoundland Power, the Industrial Customers and Hydro's rural distribution systems.

1.2 Labrador Interconnected

Virtually all power and energy for the Labrador Interconnected System is purchased from Churchill Falls (Labrador) Corporation Ltd. Hydro has a total of 300 MW and 2,362 GWh available annually, and any power surplus to Labrador requirements is sold to external markets. Hydro also maintains gas turbine and diesel assets in the Labrador Interconnected System with a combined capacity of 32.1[1] MW.

Hydro owns and maintains 269 km of 138 kV transmission line and the associated terminal stations in Labrador, interconnecting Happy Valley/Goose Bay to Churchill Falls. Hydro also owns and maintains over 30 km of 46 kV sub-transmission lines in Labrador West. In Labrador West, Hydro has an arrangement with Twin Falls Power Corporation Limited, owner of the 230 kV transmission facilities connecting Churchill Falls to Labrador West, for the wheeling of electrical energy from Churchill Falls.

The general location of Hydro's facilities in Labrador is indicated on Schedule 1. A single line diagram of the Labrador Interconnected System is provided in Schedule 4. Since the last General Rate Application the following additions were made or are planned to be made to the Labrador Interconnected System.

[1] The Happy Valley North Plant has been de-rated to 5 MW due to a fire in January 2012.

2010-2013

- The completion of a distribution upgrade and voltage conversion at Labrador City from 4,160 V to 25 kV to meet expected load growth. This includes replacements of insulators, conductor, poles, and distribution transformers. As well, the plan is to have new 46/25 kV terminal stations go into service in 2012/2013 to replace five existing 46/4.16 kV terminal stations and provide the necessary 25 kV distribution voltage. There is also remaining distribution upgrading work planned for 2013;
- Installation of a new terminal station to provide construction power for Muskrat Falls, a new general service customer. This includes a new 30/40/50 MVA, 138/25 kV transformer, six 3.6 MVAR, 25 kV capacitor banks, and associated equipment – which will be fully contributed and is assigned as common due to the system capacity benefits associated with the capacitor banks and other terminal station equipment;
- Installation of a new 75/100/125 MVA, 230/138 kV transformer at Churchill Falls which will be fully contributed and is proposed to be assigned as a common asset; and
- At Wabush, IOC is installing a third synchronous condenser, SC #3, and constructing a seventh 46 kV feeder, connected to Bus 2. The synchronous condenser is rated for -60/+72 MVAR and requires a 27 MVAR shunt reactor to help ensure acceptable system voltages when starting the unit - proposed to be assigned to IOC.

1.3 Rural Interconnected Distribution

On the Island Interconnected Rural System, Hydro owns and maintains approximately 2,650 km of low voltage (up to 25 kV) distribution lines and 25 low voltage substations, which serve approximately 22,700 Rural Customers. These Rural Customers are served from distribution systems located in approximately 180 communities on the South Coast, Northeast Coast and along the GNP.

On the Labrador Interconnected System, Hydro owns and maintains approximately 350 km of low voltage distribution lines and seven substations, serving seven communities with approximately 10,500 Rural Customers.

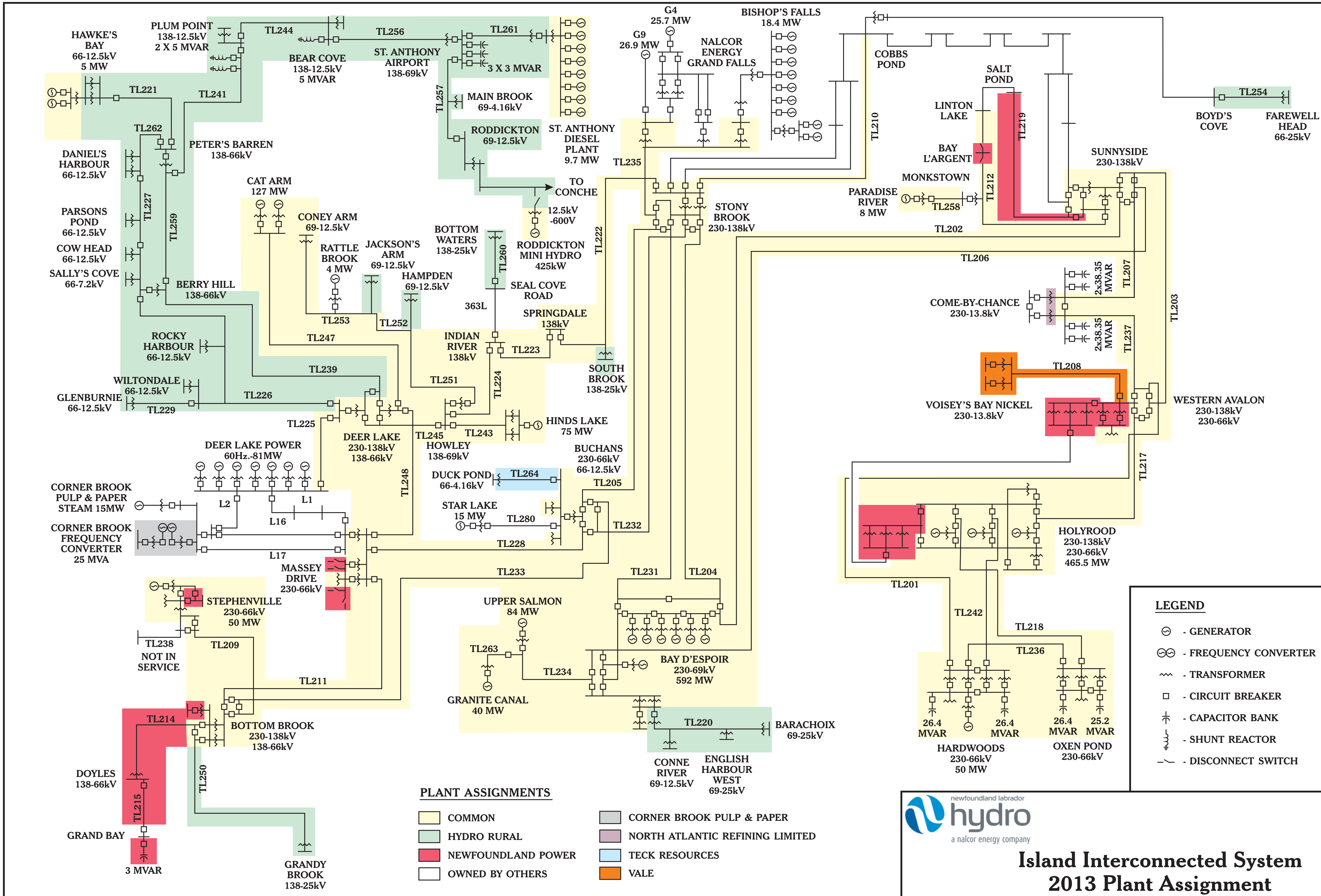
The general location of these service areas, as well as the isolated service areas is indicated in Schedules 5 and 6.

1.4 Hydro – Rural Isolated

Hydro owns and operates 21 isolated diesel generating and distribution systems serving approximately 4,400 customers (including L'Anse Au Loup) in over 40 communities throughout coastal Newfoundland and Labrador. Fifteen of these systems are located in Labrador and six are on the Island of Newfoundland.

Schedules 5 and 6 show the location of these isolated diesel generating plants and Schedule 7 provides a breakdown of their installed capacity as of December 31, 2011. The total installed capacity of Hydro's 21 diesel plants is approximately 32.4 MW.

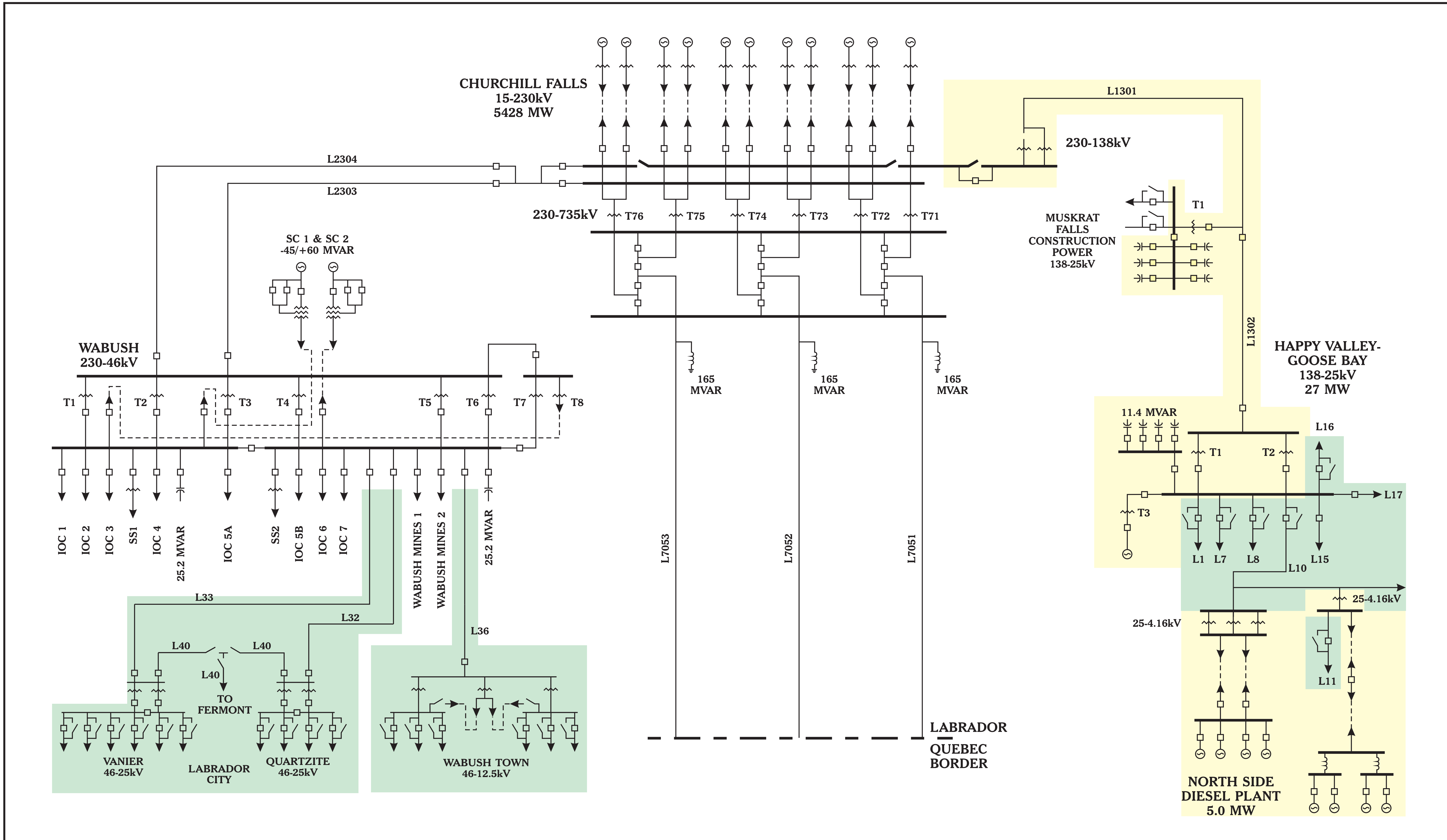

Exhibit 3 - Schedule 1
LEGEND
735 kV
230 kV
138 kV
69 kV
LOW VOLTAGE
CUSTOMER OWNED
HYDRO PLANT
THERMAL PLANT
TERMINAL STATION
DIESEL PLANT
GAS TURBINE
FREQ. CONVERTOR
NF. POWER
CORNER BROOK PULP AND PAPER
ALGONQUIN POWER
MUSHUAU 1st NATION
WIND GENERATION
OPERATED BY NALCOR
Labrador
Quebec
Atlantic Ocean
Gulf of St. Lawrence
Newfoundland
NAIN
NATUASHISH
HOPEDALE
MAKKOVIK
POSTVILLE
MENIHEK
RIGOLET
CHURCHILL FALLS
TWIN FALLS
NORTH WEST RIVER
GOOSE BAY
CARTWRIGHT
BLACK TICKLE
LABRADOR CITY
WABUSH
L1301
L1302
MUSKRAT FALLS
MUD LAKE
PARADISE RIVER
NORMAN BAY
CHARLOTTETOWN
WILLIAMS HR.
PORT HOPE SIMPSON
ST. LEWIS
MARY'S HR.
L'ANSE-AU-LOUP
RED BAY
L' ANSE-AU-LOUP
L' ANSE-AU-CLAIR
COOK'S HR.
L'ANSE AUX MEADOWS
ST. LUNAIRE
EDDIE'S COVE E.
ST. ANTHONY
BEAR COVE
TL256
TL261
GOOSE COVE
TL257B
ST. ANTHONY AIRPORT
MAIN BROOK
CROQUE
PLUM PT.
TL244
NEW FEROLLE
TL257A
CONCHE
RODDICKTON
RODDICKTON MINI-HYDRO
EDDIE'S COVE W.
TL241
ENGLEE
PORT AU CHOIX
HAWKES BAY
RIVER OF PONDS
TL221
BELLBURNS
PETER'S BARREN
DANIELS HR.
TL262
PORTLAND CREEK
CAT ARM
TL227
TL259
JACKSON'S ARM
FLEUR DE LYS
PARSONS POND
CONEY ARM
SEAL COVE
PACQUET
TL260
LA SCIE
COW HEAD
RATTLE BROOK
VENAM'S BIGHT
TL253
BOTTOM WATERS
SNOOK'S ARM
TL227
JACKSON'S ARM TAP
WEST-PORT
LITTLE BAY ISLANDS
CHANGE ISLANDS
SALLY'S COVE
TWILLINGATE
FOGO ISLAND
BERRY HILL
NORRIS PT.
HAMPDEN
TL252
NP
ROCKY HR.
WOODY PT.
SPRINGDALE
TRITON
FAREWELL HEAD
GLENBURNIE
TL229
TL239
HAMPDEN TAP
TL223
ROBERT'S ARM
BOYD'S COVE
TL254
TROUT RIVER
TL247
TL251
INDIAN RIVER
SOUTH BROOK
WILTONDALE
TL226
TL224
TL222
LEWISPORTE
GANDER BAY
WESLEYVILLE
TL225
BISHOP'S FALLS
BOTWOOD
CORNER BROOK
DEER LAKE
HOWLEY
TL245
TL243
GRAND FALLS
COBBS POND
FRENCHMAN'S COVE
HINDS LAKE
NP
GANDER
ST. BRENDAN'S
TL248
BUCHANS
TL205
TL210
COGENERATION
TL228
TL232
TL235
GLEN-WOOD
MASSEY DRIVE
SANDY BROOK
STONY BROOK
TL211
DUCK POND
GAMBO
STEPHENVILLE
TL264
R-FIELD TAP
TL209
TL238
NP
TL233
TL280
TL231
TL204
BONAVISTA
LOWER COVE
STAR LAKE
BOTTOM BROOK
N.S. DAM & SPILLWAY
TL263
LOOKOUT BROOK
MILTON
TL214
UPPER SALMON
TL250
GRANITE CANAL
TL234
CLARENVILLE
OLD PERLICAN
NEW CHELSEA
DOYLES
TL202
BAY D'ESPOIR
SUNNYSIDE
CARBONEAR
TL215
LONG LAKE
GRANDY BK.
ST. ALBAN'S
TL220
TL206
ENGLISH HR. WEST
TL207
TL219
TL212
OXEN POND
LAPOILE
PARADISE RIVER
TL203
WESTERN AVALON
TL218
TL236
GRAND BAY
GRAND BRUIT
BURGEO
BARACHOIX
COME BY CHANCE
TL237
HOLY-ROOD
HARDWOODS
PORT AUX BASQUES
McCALLUM
RENCONTRE EAST
MONKSTOWN
TL208
TL201
TL242
GREY RIVER
FRANCOIS
GAULTOIS
VOISEY BAY
TL217
RAMEA
PASS IS.
BELLEORAM
SEAL COVE
HERMITAGE
HR. BRETON
TL219
PETIT FORTE
SOUTH EAST BIGHT
NICKEL
TL212
GARNISH
LINTON LAKE
MARYSTOWN
CLARKE'S POND
GRAND BANK
SALT POND
CAPE BROYLE
LAWN
FALL POND
FERMEUSE
ST. LAWRENCE
TREPASSEY
0
50
100
KILOMETRES
Provincial Generation and Transmission Grid
Updated November 26, 2012


HAWKE'S BAY 66-12.5kV 5 MW
PLUM POINT 138-12.5kV 2 X 5 MVAR
TL244
TL256
TL261
BEAR COVE 138-12.5kV 5 MVAR
ST. ANTHONY AIRPORT 138-69kV
3 X 3 MVAR
TL221
TL241
TL257
MAIN BROOK 69-4.16kV
TL262
RODDICKTON 69-12.5kV
ST. ANTHONY DIESEL PLANT 9.7 MW
DANIEL'S HARBOUR 66-12.5kV
PETER'S BARREN 138-66kV
TO CONCHE
12.5kV -600V
RODDICKTON MINI HYDRO 425kW
CAT ARM 127 MW
CONEY ARM 69-12.5kV
PARSONS POND 66-12.5kV
TL227
TL259
RATTLE BROOK 4 MW
JACKSON'S ARM 69-12.5kV
BOTTOM WATERS 138-25kV
TL260
COW HEAD 66-12.5kV
SALLY'S COVE 66-7.2kV
BERRY HILL 138-66kV
HAMPDEN 69-12.5kV
SEAL COVE ROAD
TL253
TL252
363L
SPRINGDALE 138kV
ROCKY HARBOUR 66-12.5kV
TL247
INDIAN RIVER 138kV
TL223
SOUTH BROOK 138-25kV
TL239
TL251
TL224
WILTONDALE 66-12.5kV
GLENBURNIE 66-12.5kV
TL226
TL229
TL225
DEER LAKE 230-138kV 138-66kV
TL245
TL243
HOWLEY 138-69kV
HINDS LAKE 75 MW
DEER LAKE POWER 60Hz.-81MW
BUCHANS 230-66kV 66-12.5kV
DUCK POND 66-4.16kV
TL264
TL248
TL205
CORNER BROOK PULP & PAPER STEAM 15MW
L2
L1
L16
STAR LAKE 15 MW
TL280
TL232
CORNER BROOK FREQUENCY CONVERTER 25 MVA
TL228
L17
MASSEY DRIVE 230-66kV
TL233
TL231
TL204
STEPHENVILLE 230-66kV 50 MW
UPPER SALMON 84 MW
TL238 NOT IN SERVICE
TL209
TL263
TL234
BAY D'ESPOIR 230-69kV 592 MW
GRANITE CANAL 40 MW
TL211
TL214
BOTTOM BROOK 230-138kV 138-66kV
TL220
BARACHOIX 69-25kV
DOYLES 138-66kV
TL250
CONNE RIVER 69-12.5kV
ENGLISH HARBOUR WEST 69-25kV
TL215
GRAND BAY
3 MVAR
GRANDY BROOK 138-25kV
G4 25.7 MW
G9 26.9 MW
BISHOP'S FALLS 18.4 MW
NALCOR ENERGY GRAND FALLS
COBBS POND
TL235
STONY BROOK 230-138kV
TL222
TL210
SALT POND
LINTON LAKE
TL219
TL254
BOYD'S COVE
FAREWELL HEAD 66-25kV
BAY L'ARGENT
SUNNYSIDE 230-138kV
MONKSTOWN
TL212
PARADISE RIVER 8 MW
TL258
TL202
TL206
2x38.35 MVAR
TL207
COME-BY-CHANCE 230-13.8kV
TL203
2x38.35 MVAR
TL237
TL208
VOISEY'S BAY NICKEL 230-13.8kV
WESTERN AVALON 230-138kV 230-66kV
TL217
HOLYROOD 230-138kV 230-66kV 465.5 MW
TL201
TL242
TL218
TL236
26.4 MVAR
26.4 MVAR
26.4 MVAR
25.2 MVAR
HARDWOODS 230-66kV 50 MW
OXEN POND 230-66kV
LEGEND
- GENERATOR
- FREQUENCY CONVERTER
- TRANSFORMER
- CIRCUIT BREAKER
- CAPACITOR BANK
- SHUNT REACTOR
- DISCONNECT SWITCH
PLANT ASSIGNMENTS
COMMON
HYDRO RURAL
NEWFOUNDLAND POWER
OWNED BY OTHERS
CORNER BROOK PULP & PAPER
NORTH ATLANTIC REFINING LIMITED
TECK RESOURCES
VALE
newfoundland labrador hydro
a nalcor energy company
Island Interconnected System
2013 Plant Assignment

NEWFOUNDLAND AND LABRADOR HYDRO
GENERATING CAPACITY – 2013

Plant	Net Capacity (MW)	Average Annual Energy[1] (GWh)	Firm Annual Energy (GWh)
Island Interconnected System			
Newfoundland and Labrador Hydro			
Hydroelectric	927.3	4,528.7	3,961.0
Thermal[2]	580.2	2,996.0	2,996.0
Non-Utility Generation	178.8	1,021.5	865.6
Total Capability	1,686.3	8,546.2	7,822.6
Customer Generation	259.8	1,310.1	1,117.0
Total Island Interconnected System	1,946.1	9,856.3	8,939.6
Labrador Interconnected System			
Happy Valley Gas Turbine	27.0	-	-
Goose Bay North Plant, Mud Lake[3]	5.1	-	-
CF(L)Co Contract	300.0	2,362.0	2,362.0
Total	332.1	2,362.0	2,362.0

[1]Results from simulation using full hydrology record and 2013 load.
[2]Since the last GRA the Hardwoods and Stephenville Gas Turbines have been de-rated from 54 MW to 50 MW and the Holyrood Gas Turbine (10 MW) has been taken out of service.
[3] The Happy Valley North Plant has been de-rated to 5 MW due to fire in January 2012.



LEGEND

- GENERATOR
- TRANSFORMER
- CIRCUIT BREAKER
- DISCONNECT SWITCH
- RECLOSER
- CAPACITOR BANK
- SHUNT REACTOR
- CABLE

PLANT ASSIGNMENTS

- COMMON
- HYDRO RURAL
- OWNED BY OTHERS

newfoundland labrador hydro
a nalcor energy company

Labrador Interconnected System
2013 Plant Assignment

Exhibit 3 - Schedule 4

Exhibit 3 - Schedule 5

T.R.O. Communities Served by Interconnected Systems & Diesel Systems

T.R.O. Communities Served by Interconnected Systems & Diesel Systems

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED RURAL SYSTEMS
INSTALLED GENERATING CAPACITY – kW

Plant Location	Individual Unit Sizes						Firm Capacity	Installed Capacity
Labrador								
Black Tickle	300	455	250				550	1,005
Cartwright	450	720	450	600			1,500	2,220
Charlottetown	300	725	759	545	910		2,329	3,239
Hopedale	545	569	448				993	1,562
L'Anse Au Loup[1]	600	600	800	1,100	1,000	1,825	4,100	5,925
Makkovik	450	620	635				1,070	1,705
Mary's Harbour	545	545	820				1,090	1,910
Nain	865	865	1,275				1,730	3,005
Norman Bay	40	50	70				90	160
Paradise River	50	48	50				98	148
Port Hope Simpson	455	455	455				910	1,365
Postville	252	365	275				527	892
Rigolet	320	455	545				775	1,320
St. Lewis	365	455	250				615	1,070
Williams Harbour	210	80	90				170	380
SUBTOTAL							**16,547**	**25,906**
Island								
Francois	275	136	210				346	621
Grey River	136	136	250				272	522
Little Bay Islands	450	275	450	205			930	1,380
McCallum	136	210	100				236	446
Ramea[2]	925	925	925				1,850	2,775
St. Brendan's	277	210	225				435	712
SUBTOTAL							**4,069**	**6,456**
TOTAL INSTALLED CAPACITY								**32,362**

Notes:
1. Excludes Hydro Quebec interconnected capacity at 4,000 kW.
2. Excludes power purchase capacity of 390 kW from Frontier Power and Nalcor Wind Hydrogen capacity.

Corner Brook Pulp and Paper Generation Credit

June 2013

Table of Contents

SUMMARY

In April of 2009[1] the Board of Commissioners of Public Utilities (the Board) approved a pilot supply agreement between Newfoundland and Labrador Hydro (Hydro) and Corner Brook Pulp and Paper (CBPP) whereby CBPP will, under normal circumstances, be free to operate its generating units to most efficiently convert water to energy. The intent is to allow the Deer Lake Power (DLP) 60 Hz generators to be operated at their most efficient load settings. This is a similar benefit provided to Newfoundland Power[2] through its rate from Hydro whereby its level of generation output does not affect its demand costs. Operation under the pilot supply agreement commenced on April 30, 2009.

In June 2011, and in December 2011, Hydro completed assessments of the demand credit rate structure for the CBPP Service Agreement and determined that it provides hydraulic energy production efficiencies that permit lower energy production from Hydro's Holyrood Thermal Generating Station. Reports with Hydro's findings were submitted to the Board with the request that the pilot agreement be permanently instated.

In subsequent orders[3] the Board approved extensions to the Service agreement and requested that the analysis include additional considerations. In its latest ruling, the Board has requested that another updated report be filed with the 2013 General Rate Application, with the following:

> *…analysis in relation to potential and actual fuel savings at Holyrood, the efficiency factor at the Holyrood Thermal Generating Station, the Rate Stabilization Plan, and the allocation of costs in revenue requirement.*

---

[1] Order No. P.U. 17(2009)

[2] Newfoundland Power's generation credit is applied to its demand in determining cost of service allocations.

[3] Order No.'s P.U. 15(2011) and P.U. 4(2012)

In this update to the December 2011 report, the study period was extended to include the actual DLP operating experience from November 2011 to April 2012. The benefit improves from 3.36 to 3.60 GWh/year.

Although the energy benefit remains lower than anticipated[4], the total energy benefit since the pilot implementation to the end of 2013 produces a potential for significant fuel savings at Holyrood (approximately 27,600 bbls at a savings of $2.58 million) and reductions in greenhouse gas emissions of 14,200 tonnes. Since 2009, Hydro's reservoir storage levels have been high and the increased generation at DLP has resulted in little to no displacement of fuel consumption at the Holyrood generating station. It has resulted in displacement of Hydro's hydraulic production resulting in the storage of water in Hydro's reservoirs which will, in the future, result in reduced Holyrood production. The benefit to CBPP over the pilot period and ending in 2013 from the improved water utilization and reduction in firm purchases is determined to be $657,000. The impact on Holyrood efficiency for analysis was assumed to occur in 2013. It is insignificant, at less than one kWh/bbl because the energy benefit represents only 0.3% of the forecast 2013 Test Year production requirements at Holyrood. The impact on the Rate Stabilization Plan (RSP) for the 2009 to 2013 period is a net benefit of $1.85 million, which is comprised of a $714,000 benefit to all customers through the No. 6 fuel price variation component and $1.14 million to the load variation component. It should be noted that in this analysis, the proposed 2013 Test Year Industrial Customer firm energy rate of $0.04782 has been used.

The sensitivity of the contract change was checked under the scenario that CBPP was able to use it to reduce non-firm power purchases and convert them to firm power purchases. CBPP's average non-firm energy purchases for the five years prior to implementation of the agreement (3.46 GWh) were tested against the provisions of the pilot agreement. The results indicate a net savings to CBPP of $2.10 million in converting non-firm energy costs to firm energy costs. The net impact to the RSP of this

[4] Refer to June 2011 report for the explanation as to why the benefits fall short of original expectations.

change is an amount owing to customers of $71,000. However, there is an impact to Hydro's revenue in this case resulting from a loss of the ten percent administration fee on non-firm purchases of $248,000.

In a review of the impact of the energy benefit applied to the 2013 Test Year cost of service allocation, it was determined that the overall cost benefit to all customers is $663,000. The savings are shared among all customer groups with the allocation as follows; $426,000 for NP, $203,000 for the Industrials, and $34,000 for Hydro Rural customers.

Based on this review, it is recommended that the pilot agreement be permanently instated. There is significant benefit identified for CBPP in firm and potentially non-firm power costs and benefits to the other customers through the mechanisms of the RSP and Test Year cost of service allocation**.**

1.0 INTRODUCTION

In order to more efficiently operate the DLP generators, in April of 2009 the Board approved a pilot supply agreement between Hydro and CBPP whereby CBPP, under normal circumstances, is free to operate its units to most efficiently convert water to energy. The intent is to allow the Deer Lake 60 Hz generators to be operated at fixed output levels matching the generators' combined most efficient load as the customer gets credit for its generation capacity regardless of whether it is operated. The units would no longer be adjusted to follow the mill's load. This is similar to the benefit provided to Newfoundland Power, through its rate from Hydro, where Newfoundland Power's level of generation output does not affect its demand costs. Operation under the pilot supply agreement commenced on April 30, 2009.

Hydro completed an initial assessment of the demand credit rate structure for the CBPP Service Agreement following two years of operation of the pilot and determined that it provides hydraulic energy production efficiencies that permit lower energy production from Hydro's Holyrood Thermal Generating Station. The rate structure achieves these energy savings by providing an incentive for CBPP to operate its hydraulic generation resources in a manner which provides more efficient energy production as opposed to operating those resources so as to ensure that CBPP can maintain power production at levels that avoid the incurring of additional capacity charges. The initial report with Hydro's findings was submitted to the Board in June 2011, with the request that the pilot agreement be permanently instated.

In July 2011[5], the Board approved an extension of the Service Agreement on a pilot basis and requested that an updated report be filed with the proposed 2012 General Rate Application (GRA), with an extension of the analysis.

Although a GRA was not filed, in December 2011 Hydro completed a second assessment of the demand credit rate structure and a report with the updated findings was submitted to the Board, again with the request that the pilot agreement be permanently instated.

In February 2012[6], the Board approved another extension of the Service Agreement on a pilot basis and requested that another updated report be filed with the 2013 General Rate Application, with the following considerations:

> *…analysis in relation to potential and actual fuel savings at Holyrood, the efficiency factor at the Holyrood Thermal Generating Station, the Rate Stabilization Plan, and the allocation of costs in revenue requirement.*

2.0 METHODOLOGY

The determination of the water utilization benefit remains the same as in the June/December 2011 analyses except that the dataset was extended to include the additional months of November 2011 to April 2012. The water utilization following implementation of the pilot agreement improves slightly, from 5.571 m^3/kWh to 5.569

[5] Order No. P.U. 15(2011)
[6] Order No. P.U. 4(2012)

m^3/kWh. The annual energy benefit also indicates an increase, from 3.36 GWh/year to 3.60 GWh/year.

3.0 BENEFIT ANALYSIS

3.1 Generating Plant Efficiency Improvements

The analysis of the benefit resulting from increased water utilization at the Deer Lake Power Plant covers the period from the implementation of the pilot agreement (May, 2009) to the end of 2013 (the assessment period). The following tables outline the potential fuel savings at the Holyrood Thermal Plant for this period. Table 1 considers only Test Year Holyrood fuel conversion efficiencies, with the efficiency for 2013 as proposed in Hydro's current GRA. Table 2 considers only actual and forecast efficiencies.

Table 1
Potential Fuel Savings Arising from the Demand Credit Contract
May 2009 - December 2013
Using Test Year Fuel Conversion Rates

	Energy (kWh)	Conversion (kWh/bbl)	Fuel Savings (bbls)	Average Fuel Price ($/bbl)	Cost Savings ($$$)
2009-2011	9,888,000	630	15,700	$ 79.31	$ 1,245,167
2012	3,708,000	630	5,890	$ 115.56	$ 680,648
2013	3,708,000	612	6,060	$ 108.74	$ 658,975
Totals	**17,304,000**		**27,650**		**$ 2,584,790**

Table 2
Potential Fuel Savings Arising from the Demand Credit Contract
May 2009 - December 2013
Using Actual and Forecast Fuel Conversion Rates

	Energy (kWh)	Conversion (kWh/bbl)	Fuel Savings (bbls)	Average Fuel Price ($/bbl)	Cost Savings ($$$)
2009-2011	9,888,000	596	16,590	$ 79.31	$ 1,315,753
2012	3,708,000	602	6,160	$ 115.56	$ 711,850
2013	3,708,000	612	6,060	$ 108.74	$ 658,975
Totals	**17,304,000**		**28,810**		**$ 2,686,578**

Three percent has been added to the energy benefit to reflect the reduction in transmission losses. Both tables indicate a significant benefit in the order of $2.6 to $2.7 million. In addition, there is a potential environmental benefit of a reduction in CO_2 emissions of 14,200 tonnes. This uses the latest three year average emissions intensity factor at Holyrood of 0.819 kg/kWh.

It should be noted that, throughout the study period, the storage levels in Hydro's reservoirs have been high. Therefore the increase in Deer Lake Power generation has resulted in little to no displacement of fuel consumption at the Holyrood generating station to date. It has resulted in displacement of Hydro's hydraulic production and is reflected as an increase in the storage of water in Hydro's reservoirs which will, in the future, be used to produce hydroelectric energy, resulting in reduced Holyrood production.

The potential benefit to CBPP resulting from the energy improvement at its 60 HZ generation over the assessment period is $657,000. This total benefit is determined by applying the 2007 Test Year Industrial Customer firm rate of $0.03676 for the period of 2009 – 2012 and the proposed Test Year firm rate of $0.04782 for 2013.

3.2 Impact on Other Customers

The potential benefit to other customers through the fuel price and load variation Components of the RSP over the assessment period is as outlined in Tables 3 and 4.

Table 3 - Rate Stabilization Plan
No. 6 Fuel Variation - CBPP Demand Credit Contract

	2009-2011		
1.	CBPP Firm Sales Reduction[1] (KWh)	(9,600,000)	CBPP water utilization benefit
2.	Actual Quantity No. 6 Fuel[2] (bbl)	(15,238)	Line 1/630
3.	Actual Quantity No. 6 Fuel for Non-firm Sales (bbl)	-	
4.	Net Quantity No. 6 Fuel (bbl)	(15,238)	Line 2 - Line 3
5.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
6.	Actual Average No. 6 Fuel Cost ($Can/bbl)	79.31	May 2009 - December 2011 Average fuel pric
7.	Cost Variance ($Can/bbl)	24.20	Line 6 - Line 7
8.	No. 6 Fuel Variation ($000)	(369)	Line 4 * Line 7
	2012		
1.	CBPP Firm Sales Reduction[1] (KWh)	(3,600,000)	CBPP water utilization benefit
2.	Actual Quantity No. 6 Fuel[2] (bbl)	(5,714)	Line 1/630
3.	Actual Quantity No. 6 Fuel for Non-firm Sales (bbl)	-	
4.	Net Quantity No. 6 Fuel (bbl)	(5,714)	Line 2 - Line 3
5.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
6.	Actual Average No. 6 Fuel Cost ($Can/bbl)	115.56	2012 Forecast Average fuel price
7.	Cost Variance ($Can/bbl)	60.45	Line 6 - Line 7
8.	No. 6 Fuel Variation ($000)	(345)	Line 4 * Line 7
	2013		
1.	CBPP Firm Sales Reduction[1] (KWh)	(3,600,000)	CBPP water utilization benefit
2.	Actual Quantity No. 6 Fuel[3] (bbl)	(5,882.35)	Line 1/612
3.	Actual Quantity No. 6 Fuel for Non-firm Sales (bbl)	-	
4.	Net Quantity No. 6 Fuel (bbl)	(5,882)	Line 2 - Line 3
5.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	108.74	Average 2013 Test Year price of fuel
6.	Actual Average No. 6 Fuel Cost ($Can/bbl)	108.74	2013 Forecast Average fuel price
7.	Cost Variance ($Can/bbl)	-	Line 6 - Line 7
8.	No. 6 Fuel Variation ($000)	-	Line 4 * Line 7

Notes: 1. Load reduction possible due to improved water utilization at the DLP 60 Hz Plant
2. 2007 Test Year Holyrood Operating Efficiency of 630 kWh/bbl
3. Proposed Test Year Holyrood Operating Efficiency of 612 kWh/bbl

Table 4 - Rate Stabilization Plan
Industrial Load Variation- CBPP Demand Credit Contract

	2009-2011		
1.	CBPP Firm Sales Reduction[1] (KWh)	(9,600,000)	CBPP water utilization benefit
2.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
3.	Firm Energy Rate ($/kWh)	0.03676	Industrial firm rate (2007 test year)
4.	Industrial Load Variation[2] ($000)	(487)	Line 1 * (Line 2/630 - Line 3)

	2012		
1.	CBPP Firm Sales Reduction[1] (KWh)	(3,600,000)	CBPP water utilization benefit
2.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
3.	Firm Energy Rate ($/kWh)[4]	0.03676	Industrial firm rate (2007 test year)
4.	Industrial Load Variation[2] ($000)	(183)	Line 1 * (Line 2/630 - Line 3)

	2013		
1.	CBPP Firm Sales Reduction[1] (KWh)	(3,600,000)	CBPP water utilization benefit
2.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	108.74	Average 2013 Test Year price of fuel
3.	Firm Energy Rate ($/kWh)[4]	0.04782	Industrial firm rate (2013 test year)
4.	Industrial Load Variation[3] ($000)	(468)	Line 1 * (Line 2/612 - Line 3)

Notes:
1. Load reduction possible due to improved water utilization at the DLP 60 Hz Plant
2. 2007 Test Year Holyrood Operating Efficiency of 630 kWh/bbl
3. Proposed 2013 Test Year Holyrood Operating Efficiency of 612 kWh/bbl
4. Proposed IC Rates for 2013 Test Year of $0.04782/kWh

The tables indicate that the total projected impact to the RSP is a decrease or benefit of $1.85 million, with $714,000 benefiting all customers through the No. 6 fuel price variation and $1.14 million benefiting Industrial Customers through the Industrial load variation.

3.3 Sensitivity Impact of a Reduction of Non-Firm Power Purchases by CBPP

3.3.1 Benefits to Corner Brook Pulp and Paper Limited

As indicated in the June, 2011 report, CBPP has benefited and will continue to benefit from the pilot agreement through a reduction in the amount of energy it purchases at non-firm energy prices[7]. With the new agreement, CBPP no longer has to purchase non-firm energy for reductions in DLP generation unless it occurs when Hydro requests the generation for system purposes. The total benefit of this change remains difficult to quantify as DLP generation reduction can occur at any time due to a number of factors (e.g. equipment breakdown, planned shutdowns for capital refurbishment, low water levels, frazil ice). In the five years prior to the implementation of the pilot contract, CBPP purchased, on average, 3.46 GWh of energy at non-firm rates that would have been subject to firm rates if the provisions of this pilot contract were in place. Over the period from May 2009 to December 2013, using actual fuel prices, this amount of energy is projected to cost $2.732 million at non-firm rates. If the equivalent energy is all supplied under the firm power block rates, it is at a reduced cost to CBPP of $632,000. This results in net savings to CBPP of $2.100 million, exclusive of the savings of $657,000 achieved through the improved water utilization.

3.3.2 Impacts on Other Customers

As demonstrated in the previous reports, a reduction in energy at non-firm rates and a corresponding increase in energy at firm rates will have an impact on the fuel and load variation components of the RSP. Tables 5 and 6 illustrate this impact over the entire period of 2009-2013, using CBPP's average non-firm usage (3.46 GWh) during the five years prior to implementation of the pilot contract in combination with the base efficiency improvements described in Section 3.1.

[7] Refer to the June 2011 report for a more detailed description of the non-firm energy savings to CBPP.

Table 5 - Rate Stabilization Plan
No. 6 Fuel Variation - CBPP Demand Credit Contract
Sensitivity Analaysis - Reduction in CBPP Non-Firm Energy Usage

	2009-2011		
1a.	CBPP Firm Sales Reduction(1) (KWh)	(9,600,000)	CBPP water utilization benefit
1b.	CBPP Firm Sales Increase(2) (KWh)	9,226,667	CBPP 5-year average non-firm usage
2.	CBPP Net Firm Sales Increase/(Reduction)	(373,333)	Line 1a + 1b
3.	Actual Quantity No. 6 Fuel(3) (bbl)	(593)	Line 2/630
4.	Actual Quantity No. 6 Fuel for Non-firm Sales (bbl)	-	No recovery through non-firm rates
5.	Net Quantity No. 6 Fuel (bbl)	(593)	Line 3 - Line 4
6.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
7.	Actual Average No. 6 Fuel Cost ($Can/bbl)	79.31	May 2009 - December 2011 Average fuel p
8.	Cost Variance ($Can/bbl)	24.20	Line 7 - Line 6
9.	No. 6 Fuel Variation ($000)	(14)	Line 5 * Line 8
	2012		
1.	CBPP Firm Sales Reduction(1) (KWh)	(3,600,000)	CBPP water utilization benefit
1b.	CBPP Firm Sales Increase(2) (KWh)	3,460,000	CBPP 5-year average non-firm usage
2.	CBPP Net Firm Sales Increase/(Reduction)	(140,000)	Line 1a + 1b
3.	Actual Quantity No. 6 Fuel(3) (bbl)	(222)	Line 2/630
4.	Actual Quantity No. 6 Fuel for Non-firm Sales (bbl)	-	No recovery through non-firm rates
5.	Net Quantity No. 6 Fuel (bbl)	(222)	Line 3 - Line 4
6.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
7.	Actual Average No. 6 Fuel Cost ($Can/bbl)	115.56	2012 Forecast Average fuel price
8.	Cost Variance ($Can/bbl)	60.45	Line 7 - Line 6
9.	No. 6 Fuel Variation ($000)	(13)	Line 5 * Line 8
	2013		
1.	CBPP Firm Sales Reduction(1) (KWh)	(3,600,000)	CBPP water utilization benefit
1b.	CBPP Firm Sales Increase(2) (KWh)	3,460,000	CBPP 5-year average non-firm usage
2.	CBPP Net Firm Sales Increase/(Reduction)	(140,000)	Line 1a + 1b
3.	Actual Quantity No. 6 Fuel(4) (bbl)	(228.76)	Line 2/612
3.	Actual Quantity No. 6 Fuel for Non-firm Sales (bbl)	-	No recovery through non-firm rates
4.	Net Quantity No. 6 Fuel (bbl)	(229)	Line 3 - Line 4
5.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	108.74	Average 2013 Test Year price of fuel
6.	Actual Average No. 6 Fuel Cost ($Can/bbl)	108.74	2013 Forecast Average fuel price
7.	Cost Variance ($Can/bbl)	-	Line 7 - Line 6
8.	No. 6 Fuel Variation ($000)	-	Line 5 * Line 8

Notes: 1. Load reduction possible due to improved water utilization at the DLP 60 Hz Plant
2. Energy that would have been charged at non-firm is now firm
3. 2007 Test Year Holyrood Operating Efficiency of 630 kWh/bbl
4. Proposed 2013 Test Year Holyrood Operating Efficiency of 612 kWh/bbl

Table 6 - Rate Stabilization Plan
Industrial Load Variation- CBPP Demand Credit Contract
Sensitivity Analaysis - Reduction in CBPP Non-Firm Energy Usage

	2009-2011		
1a.	CBPP Firm Sales Reduction[1] (KWh)	(9,600,000)	CBPP water utilization benefit
1b.	CBPP Firm Sales Increase[2] (KWh)	9,226,667	CBPP 5-year average non-firm usage
2.	CBPP Net Firm Sales Increase/(Reduction)	(373,333)	Line 1a + 1b
3.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
4.	Firm Energy Rate ($/kWh)	0.03676	Industrial firm rate (2007 Test Year)
5.	No. 6 Fuel Variation(2) ($000)[3]	(19)	Line 2 * (Line 3/630 - Line 4)

	2012		
1a.	CBPP Firm Sales Reduction[1] (KWh)	(3,600,000)	CBPP water utilization benefit
1b.	CBPP Firm Sales Increase[2] (KWh)	3,460,000	CBPP 5-year average non-firm usage
2.	CBPP Net Firm Sales Increase/(Reduction)	(140,000)	Line 1a + 1b
3.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	55.11	Average 2007 Test Year price of fuel
4.	Firm Energy Rate ($/kWh)	0.03676	Industrial firm rate (2007 Test Year)
5.	No. 6 Fuel Variation(2) ($000)[3]	(7)	Line 2 * (Line 3/630 - Line 4)

	2013		
1a.	CBPP Firm Sales Reduction[1] (KWh)	(3,600,000)	CBPP water utilization benefit
1b.	CBPP Firm Sales Increase[2] (KWh)	3,460,000	CBPP 5-year average non-firm usage
2.	CBPP Net Firm Sales Increase/(Reduction)	(140,000)	Line 1a + 1b
3.	Cost of Service No. 6 Fuel Cost ($Can/bbl)	108.74	Average 2013 Test Year price of fuel
4.	Firm Energy Rate ($/kWh)[5]	0.04782	Industrial firm rate (2013 Test Year)
5.	No. 6 Fuel Variation(2) ($000)[4]	(18)	Line 2 * (Line 3/612 - Line 4)

Notes: 1. Load reduction possible due to improved water utilization at the DLP 60 Hz Plant
2. Energy that would have been charged at non-firm is now firm
3. 2007 Test Year Holyrood Operating Efficiency of 630 kWh/bbl
4. Proposed 2013 Test Year Holyrood Operating Efficiency of 612 kWh/bbl
5. Proposed IC Rates for 2013 Test Year of $0.04782/kWh

The tables indicate that, with the assumed reduction in energy at non-firm rates, the total projected impact to the RSP is a net decrease of $71,000 with $27,000 through the No. 6 fuel price variation and $44,000 through the load variation.

3.3.3 Impact on Hydro

In addition to the RSP impacts, there would be an impact to Hydro's revenue with a reduction in non-firm sales, as this would result in a corresponding reduction in the ten percent administration fee applied to non-firm rates. At CBPP's five year average (firm eligible) non-firm power purchases of 3.46 GWh, actual and forecast fuel prices for 2009-2013, and 2007 Test Year and proposed 2013 Test Year operating efficiencies, the reduction in Hydro's revenue is approximately $248,000.

3.4 Cost of Service Impact

The Board requested that Hydro determine the impact of the potential and resulting changes in the allocation of costs in the revenue requirement for any test year included in the period from the commencement of the pilot contract to the end of 2013. The following table outlines the benefits of the improved water utilization at CBPP's 60 Hz generators when applied to the 2013 Test Year cost allocation.

Table 7
Newfoundland and Labrador Hydro
CBPP Generation Credit
Load Reduction Impacts

Based on 2013 Load			
	Existing (MWh Required)	**Adjustment (Note 1)**	**Revised (MWh Required)**
Newfoundland Power	5,594,300		5,594,300
Industrial - Firm	408,400	(3,600)	404,800
Industrial - Non-Firm	-		-
Rural	447,300		447,300
Losses	230,800	(130)	230,670
Total	6,680,800	(3,730)	6,677,070
	($000)	Note 2	($000)
Estimated Energy Costs	308,208	(663)	307,545
Cost Allocation			
Newfoundland Power	267,319	(426)	266,893
Industrial - Firm	19,515	(203)	19,312
Industrial - Non-Firm	-	-	-
Rural	21,374	(34)	21,340
Total	308,208	(663)	307,545

Note 1: Energy benefit of 3.60 GWh plus losses of 3.6%
Note 2: Holyrood Costs Savings (3.60 GWh @ 3.6% losses, 612 kWh/bbl, $108.74/bbl)

As indicated in the table, using the proposed Test Year conversion rate of 612 kWh/bbl and average fuel costs of $108.74/bbl, the total cost of service benefit is $663,000 allocated among all the customer groups.

3.5 Holyrood Efficiency Impact

In its latest order, the Board requested that Hydro determine the impact on Holyrood efficiency resulting from the provisions of the CBPP Demand Credit rate structure. In the 2013 Test Year, Hydro is proposing a Holyrood efficiency factor of 612 kWh. As outlined in Hydro's 2013 GRA application, this is determined from an analysis which inputs the forecast monthly average generation requirements for Holyrood into a regression equation. The regression equation is developed using the past 10 years of generation and fuel consumption data for the facility.

If the Holyrood energy requirements in 2013 are increased by 3.71 GWh[8], the impact on the efficiency using this method is an increase of only 0.2 kWh/bbl. This would be considered insignificant given the level of precision of the proposed Test Year efficiency (rounded to the nearest whole kWh/bbl).

4.0 CONCLUSIONS AND RECOMMENDATIONS

The pilot agreement intended to allow Deer Lake Power to operate its generation at more efficient fixed output levels has brought benefit to the customer and will result in displaced oil consumption at Holyrood following a return to normal reservoir levels and expected system load growth. The annual generation benefit to DLP is estimated to be 3.60 GWh when considering the historical water usage. This represents a savings to CBPP of $657,000 over the period of May 2009 to December 2013 in firm power purchases. It should be noted that in this analysis the proposed Test Year Industrial Customer firm energy rate of $0.04782 was assumed for 2013. In addition, there is a potential annual displacement of approximately 27,600 barrels of oil usage at an associated fuel savings of $2.58 million. Environmentally, there is a potential reduction of 14,200 tonnes of greenhouse gas emissions at Holyrood.

A sensitivity check performed determines the impact to CBPP, the RSP and Hydro's revenue, namely the impact of a decrease in non-firm sales to CBPP as the provisions of the pilot agreement allow for energy that would have traditionally been purchased as Interruptible or Generator Outage power to now be purchased as firm. CBPP's five year

[8] This is the equivalent energy benefit realized by improved water utilization at DLP's 60 HZ turbines, plus 3% losses, and represents 0.3% of the 2013 Holyrood forecast energy requirements.

average non-firm purchases which would be eligible for firm energy pricing under the provisions of the pilot were used for this analysis.

The following table summarizes the impact under each scenario.

Table 8
June 2009-December 2013
Summary of Impacts

Cost Savings Calculation	
Holyrood Greenhouse Gas Reduction (tonnes)	14,200
Energy Sales Reduction (GWh)	16.80
System Loss Reduction @ 3% (GWh)	0.50
Total Energy Reduction (GWh)	17.30
Holyrood Fuel Usage Reduction (bbls)(1)	27,600
Holyrood Fuel Cost Reduction ($000)(2)	2,584

Stakeholder Impacts

	Base Case CBPP Improved Water Utilization	**Sensitivity CBPP Reduced Non-Firm Usage**
CBPP Firm Energy Purchases ($000)	$ (657)	$ (657)
CBPP Non-Firm Energy Purchases ($000)	$ -	$ (2,100)
RSP No. 6 Fuel Variation Component ($000)	$ (714)	$ (27)
RSP Load Variation Component ($000)	$ (1,138)	$ (44)
Hydro Revenue Loss ($000)(3)(4)	$ (75)	$ 248
Total Impact(5)	$ (2,585)	$ (2,580)

Notes:
1. Assumes Holyrood operating efficiency of 630 kWh/bbl 2009-2012 and 612 kWh/bbl for 2013
2. Uses actual and projected fuel prices 2009-2013
3. Hydro gains revenue from reduced system losses
4. Hydro loses revenue due to reduction in 10% administration charge on non-firm rates
5. Differences in Total Stakeholder Impact vs. Holyrood Fuel Cost Reduction is due to rounding

In its review of the impact of the energy benefit to the 2013 Test Year cost allocation, realized through improved water utilization at CBPP's 60 Hz generating units, Hydro determined that the overall costs savings are $663,000. These savings are allocated among all customer groups with $426,000 for NP, $203,000 for the Industrial Customers and $34,000 for Hydro Rural customers.

The impact on Holyrood efficiency is minimal and determined to be less than one kWh/bbl in the 2013 Test Year. This is due to the magnitude of the DLP water utilization benefit relative to the Test Year Holyrood requirements (0.3%).

As a result of this review it is recommended that the pilot agreement be permanently implemented. There is significant benefit identified for CBPP in firm and potentially non-firm power costs and benefits to the other customers through the mechanisms of the RSP and Test Year cost of service allocation.

Suite 500, 4342 Queen Street
Niagara Falls, Ontario, Canada L2E 7J7
Tel. 905 374 5200 ◆ Fax: 905 374 1157 ◆ www.hatch.ca

August 19, 2011

Joanna Barnard
Newfoundland and Labrador Hydro
Hydro Place
500 Columbus Drive
St. John's, NL A1B 4K7

Dear Ms. Barnard:

Subject: Modelling Approach for Determining System Capability

Introduction

Hatch (formerly Acres International) has provided Newfoundland and Labrador Hydro with modelling tools and support for decades, including advice on models and methodology to determine the average hydroelectric capabilities of its facilities (Island Hydrology Review, SGE Acres, 2003 and letter to D. Harris, May 2005). This letter summarizes recent enhancements in Hatch's suite of modelling tools and provides an update to the recommended approach to determining the average capability of the hydroelectric system.

Hatch has been developing and applying computer simulation tools to model complicated water resource systems since the 1970s. These computer models have been successfully applied to a large number of systems around the world and studies ranging from power system investment planning to water resource management studies and, more recently, decision support for operations. The modelling tools continue to evolve and new capabilities are constantly being added. The earliest modeling tool, referred to as Acres Reservoir Simulation Package (ARSP), was a water resource system simulation model. The ARSP model was capable of representing water resource systems in detail and allowed a range of license constraints, hydro electric facilities and consumptive demands. Later the ARSP model became a component in a System Simulation Model (SYSSIM) for simulating power system operations over long periods of time. SYSSIM was capable of representing load and other generation resources, such as thermal plants, in addition to the detailed hydroelectric system representation offered by the ARSP model. In the early 1990s the development of a 3rd generation of models started, referred to as the *Vista* Decision Support System (*Vista* DSS™) suite of models, and has gradually replaced both ARSP and SYSSIM for studies. In fact, SYSSIM is no longer being used or maintained by Hatch. In the development of the *Vista* DSS™ model the focus was a common modelling platform that could be used for study purposes as well as for operational use.

The SYSSIM and *Vista* DSS™ models are compared below, and as can be seen from the comparison, *Vista* DSS™ essentially evolved from ARSP and SYSSIM and retains most of their features, but exceeds the capability of SYSSIM in many areas. One important difference is the solution technique. In the ARSP model, a linear programming (LP) Network solver is employed and it solves a single time step at a time, starting at the beginning and moving forward through the study time horizon. This solution technique had important limitations; in particular it could not prepare for upcoming scheduled outages and/or water resource constraints. In *Vista* DSS™, this limitation has been overcome by the use of an iterative and/or piecewise LP solution technique, which obtains a simultaneous solution for the entire time horizon.

An important feature of *Vista* DSS™ that ARSP and SYSSIM did not have, is greater flexibility in defining how reservoirs are modelled, in particular the options available for specifying end condition; features that are very useful when modelling hydroelectric systems with large seasonal and multi-seasonal reservoirs.

Model Comparison

	SYSSIM/ARSP	***Vista***
Time Step	Monthly	Flexible, hourly and up.
Water Resource System	Network Representation	Network Representation
Power Plants	Single Composite Unit	Individual Units
Tailwater Levels	Function of Head and Discharge	Function of head and discharge.
Spill Structures	Gates, Weirs, Orifices	Gates, weirs, orifices and flashboards etc.
Channel Routing	Muskingum	Muskingum
Water Resource Constraints	Limited	Extensive
Hydrology	Historic	Historic or Forecast
Other Generation Resources	Thermal	Thermal, wind, external.
Market Representation	No	Purchase and sales by customer.
Load	Single load, energy/capacity with load duration curves.	Multiple loads, chronological.
Transmission System	No	Load buses, tie-lines and losses.
Transmission Constraints	No	Yes
Data Structures	Flat Files	Relational Database
Study Environment	Limited Menus	Menu driven windows environment.
Solution Technique	Single time step solve.	Iterative linear programming optimization.
Reporting	Limited	Report Module

Recommended Approach

The *Vista* DSS™ suite of models has been set up, tested and implemented at Newfoundland and Labrador Hydro for both operational decision support and studies, including wind integration and interconnection studies. Therefore, we recommend that Newfoundland and Labrador Hydro use the long-term planning module (LT *Vista)* to determine the average annual energy capabilities of the hydroelectric system. Given the similarity between the ARSP component of SYSSIM and LT *Vista,* the use of LT *Vista* does not constitute a radical change in modelling methodology, but rather a progression to a more capable model.

Several other utilities have used LT *Vista* for similar study purposes. PacificCorp of Portland, Oregon routinely uses LT *Vista* to determine the capabilities of the hydroelectric facilities and provide the results to a number of Public Utility Commissions in their service area for the purposes of rate applications. Tacoma Power in Washington State has also used LT *Vista* for Integrated Resource Planning. Bonneville Power Administration (BPA), a US federal agency, also uses LT *Vista* extensively for power and energy studies. LT *Vista* is also being used for studies involving the interconnection of Newfoundland's Island system with Labrador and Nova Scotia.

The main challenges in determining the expected average hydroelectric capabilities of the Newfoundland and Labrador Hydro system include

- hydrologic variability
- the multi-year storage capability of Meelpaeg reservoir
- how to minimize the effects of assumptions regarding start and end conditions on the results.

The recommended methodology for using LT *Vista* to determine average annual hydroelectric energy is similar to the method used with the SYSSIM model in earlier studies, as summarized below.

1. The study period for the analysis should be five or more years plus a two-year warm-up period. More specifically, if the forecast year is 2012, the analysis should start on January 1, 2010 and continue until December 31, 2016 at the earliest.
2. The 2012 forecast year demand should be populated into each of the study years.
3. To capture the hydrologic variability, the analysis should be performed using all available historic hydrology from 1950 to date. The first sequence would start in 1950, the second in 1951, etc. A total of 61 sequences is available.
4. The average annual hydroelectric energy production should be calculated as the average for the years in the study period, not including the warm up years and omitting the last year(s) if it appears that end conditions are affecting the results, as long as at least five years are used for the average.

In the SYSSIM approach used previously, the analysis was repeated multiple times with different sets of matching start and end water levels. This repetition should not be necessary with LT *Vista*. By simulating a two year warm-up period, multiple start levels are not needed, since the analysis will start from actual January 1, 2010 levels, and the 2012 start levels will be a representative simulated set. For the end condition, LT *Vista* has the option of using the end-of-period value of water in storage or target levels. The end-of-period value of water option should be used for the average annual energy runs as it reduces the likelihood that the end conditions will influence the modelled water management decisions leading up to the end of the simulation.

Yours faithfully,

Dr. Tryggvi Olason
Modeling Specialist

Stuart G. Bridgeman
Director, Power and Water Optimization

TO/SGB:kln

ALLOWED RANGE OF RETURN

ON

RATE BASE

for

NEWFOUNDLAND

AND

LABRADOR HYDRO

Prepared by

KATHLEEN C. MCSHANE

foster associates

JULY 2013

INTRODUCTION

My name is Kathleen C. McShane and my business address is 1 Church St., Suite 101, Rockville, Maryland 20850. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and am a Chartered Financial Analyst (1989). I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, pipelines, water utilities and telephone companies in more than 200 proceedings in Canada and the U.S., including the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB" or "Board"). My qualifications are attached as Appendix A.

I have been requested by Newfoundland and Labrador Hydro ("NLH") to evaluate the need for changes to its allowed range of return on rate base. This report presents the results of my analysis and recommendations.

BACKGROUND

As background for the analysis, some history regarding NLH's regulated cost of capital is useful. In 2003, NLH filed its second General Rate Application ("GRA") pursuant to full PUB regulation. In Order No. P.U. 14(2004) dated May 2004, the PUB:

(1) Established NLH's cost of equity at the company's marginal cost of debt;

(2) Determined that implementing a range of return on rate base and an "*excess earnings*" account was appropriate; and

(3) Directed NLH to submit a proposal for a range of return on rate base and a definition of an *"excess earnings"* account.

In June 2004, NLH filed a proposal for a range of return on rate base of 48 basis points (+/-24 basis points) and a definition of excess earnings. NLH's proposed range of return on rate base was in part designed to accommodate the significant fluctuations in return which can occur in the normal course of business, variations in short-term interest rates, the achievement of the target capital structure,[1] the lack of an automatic adjustment mechanism for cost of capital, and to operate as an incentive to effectively manage costs.

In Order No. P.U. 40(2004), dated October 2004, the PUB accepted NLH's definition of excess earnings, subject to its determination that the range of return on rate base should be 30 basis points (+/-15 basis points). In arriving at its decision on the range of return on rate base, the PUB found:

(1) It had already considered the fact that there are certain risks present for NLH in setting its ROE; the presence of those risks does not justify a particular range of return on rate base;

(2) The use of a range is intended to, in part, capture the uncertainty in forecasting operating conditions and allow for some financial flexibility in responding to those uncertainties;

(3) The range may also provide an incentive mechanism to contain costs by improving productivity, benefiting ratepayers in the long term.

[1] At the time, NLH's target capital structure was comprised of 80% debt and 20% equity.

In March 2009, the provincial government issued the following directive:

> Under the authority of Section 5.1 of the Electrical Power Control Act, 1994, the Lieutenant Governor in Council is pleased to direct the Board of Commissioners of Public Utilities to adopt policies as follows for all future General Rate Applications by Newfoundland and Labrador Hydro, commencing with the first General Rate Application by Newfoundland and Labrador Hydro after January 1, 2009:
>
> i. In calculating return on rate base for Newfoundland and Labrador Hydro, to set the target return on equity as was most recently set for Newfoundland Power through a General Rate Application or calculated through the Newfoundland Power Automatic Adjustment Mechanism;
>
> ii. That Newfoundland and Labrador Hydro is entitled to earn annually, a rate of return equal to the weighted average cost of capital, as ordered from time to time, on the entire rate base as fixed and determined by the Board of Commissioners of Public Utilities, including amounts used solely for the provision of service to its rural customers;[2] and
>
> iii. That the capital structure approved for Newfoundland and Labrador Hydro should be permitted to have a maximum proportion of equity as was most recently approved for Newfoundland Power.

Since its last GRA, NLH has adopted a corporate capital structure target of 75% debt/25% equity[3] for the regulated business and has strengthened its actual capital structure to conform to that target by means of dividend management, a waiver by the province of the debt guarantee fee in 2008-2010 and a $100 million equity infusion by the province in 2009.

---

[2] Previously, NLH was allowed to earn only the weighted average cost of debt (% of debt in regulated capital structure x embedded cost of debt) on the rural assets.

[3] NLH's corporate regulated capital structure calculation incorporates Standard and Poor's analytical adjustments to reported amounts of debt and equity. In applying the S&P approach, NLH includes accumulated other comprehensive income as a component of equity and excludes asset retirement obligations from the capital structure. Employee future benefits are also treated differently under the S& P approach to calculating capital structure than they are for rate making purposes. As a result, the percentage of debt in the regulated capital structure for rate making purposes is somewhat lower than 75%.

NLH's 2013 GRA includes a return on rate base of 7.83%, calculated as follows:

Table 1

Capital Structure Component	**% of Average Capital Structure**	**Cost Rate**	**Weighted Component**
Debt	70.1%	8.01%	5.62%
Employee Future Benefits	4.4%	0.0%	0.0%
Asset Retirement Obligation, Funded	0.4%	0.0%	0.0%
Equity	25.1%	8.80%	2.21%
Return on Rate Base			7.83%

The 8.80% cost rate for equity represents the most recent (for 2013) approved ROE for Newfoundland Power ("NP").[4]

ALLOWED RETURN ON RATE BASE VERSUS ROE

As noted above, in Order No. P.U. 40(2004), the PUB set NLH's range of allowed return on rate base at +/-15 basis points. The focus on the range of rate of return on rate base, rather than return on equity (or ROE), arises from the manner in which NLH is regulated.

Newfoundland and Labrador is unique in regard to the focus on the allowed return on rate base. With few exceptions,[5] other regulatory jurisdictions in Canada focus on return on equity and evaluate the profitability of utilities on the same basis. For purposes of assessing the reasonableness of the existing range of allowed return (1) in light of the change in NLH's circumstances and (2) relative to what is allowed for other utilities, it is useful to express the range of allowed return on rate base in terms of return on equity.

[4] Newfoundland & Labrador Board of Commissioners of Public Utilities, *In The Matter Of A General Rate Application Filed By Newfoundland Power In., Decision And Order Of the Board Order No. P.U. 13(2013)*, April 17, 2013.

[5] One notable exception was the March 2009 decision of the National Energy Board, *Reasons for Decision, Trans Quebec & Maritimes Pipelines Inc., RH-1-2008*. The decision adopted a new cost of capital methodology for TQM, which, instead of specifying separate capital structure and ROE components, expressed the allowed return as an overall after-tax return. The NEB did, however, provide calculations of the ROE implied at different capital structures to facilitate comparisons with what it referred to as the "traditional" capital structure/ROE approach.

When the PUB adopted NLH's +/-15 basis point allowed range of return on rate base in 2004, NLH's capital structure contained approximately 12.25% equity. With a capital structure containing approximately 12.25% equity, a +/- 15 basis point range of return on rate base is approximately equivalent to a range of return on equity of 2.4% (+/-120 basis points). Schedule 1 attached illustrates how the range of return on equity was derived.[6]

With the improvement in NLH's capital structure since Order No. P.U. 40(2004) to an equity ratio of approximately 25%, the previously approved range of return on rate base of +/- 15 basis points is equivalent to an ROE range of approximately +/- 60 basis points (See Schedule 1).

The only other utility in Canada whose allowed return is expressed as a range of return on rate base is NP. NP's allowed range of return on rate base, adopted in Order No. P.U. 19(2003), dated June 30, 2003, is 36 basis points (+/-18 basis points). Given NP's capital structure (approximately 45% common equity), the +/- 18 basis points range of return on rate base is approximately equal to a range of +/- 40 basis points of return on equity, as illustrated in the table below.[7]

[6] At the time of Order No. P.U. 14(2004), the return on the rural assets at the time was limited to the weighted average cost of debt, resulting in an effective allowed return on equity that was lower than the ROE specified in the decision. With no change to the test year embedded cost of debt, the implied range of return on equity was approximately +/-1.2% around the lower effective allowed ROE.

[7] For illustrative purposes, based on parameters approved for NP for 2010. For simplicity, preferred shares were ignored. Assumes the cost of debt remains unchanged from forecast. The indicated plus or minus 40 basis points on ROE is consistent with the PUB's findings in Order No. P.U. 19(2003), page 76, which concluded that the increase in the allowed range of return on rate base to 36 basis points (+/- 18 basis points) implied a range of return on common equity of 81 basis points (i.e., approximately +/- 40 basis points).

Table 2

Allowed Return on Rate Base:			
	%	**Cost**	**Weighted Cost**
Debt	55%	7.7%	4.24%
Equity	45%	9.0%	4.05%
Return on Rate Base			8.29%
Range of Return on Rate Base (+/18 basis points):			
Upper End			8.465%
Lower End			8.105%
ROE at Upper End of the Range:			
	%	**Cost**	**Weighted Cost**
Debt	55%	7.7%	4.24%
Equity	45%	**9.4%**	4.23%
Return on Rate Base			8.465%

BUSINESS AND FINANCIAL RISK AND THE IMPACT ON EARNED RETURNS

As the PUB noted in Order No. P.U. 40(2004), the range of allowed return on rate base is intended to serve two purposes: (1) capture the uncertainty in forecasting operating conditions and allow for some financial flexibility in responding to those uncertainties; and (2) provide an incentive mechanism to contain costs by improving productivity, benefiting ratepayers in the long term.

With respect to the first purpose, the range of the allowed return on rate base should, in my view, reflect the extent to which the uncertainty in forecasting future operating conditions can impact the earned returns on rate base and equity due to the utility's specific circumstances. The higher the probability that the earned return on rate base or equity will vary from the allowed return on rate base or target equity return, the wider the allowed range of return on rate base should be. This is particularly true when it is recognized that operation of the allowed return on rate base range for NLH is asymmetric. In other words, if the utility earns a return above the upper end of the range, the excess earnings are to the account of the ratepayers. If the utility earns below the lower end of the allowed range, under-earnings are to the account of the shareholder.[8] When the allowed return on rate base range is relatively narrow and asymmetric, but the potential range of earned returns on equity above and below the target ROE is relatively wide (and symmetric), over time, the utility is more likely to earn an average ROE that falls short of the target ROE.

Risk is the probability that the earned return will fall short of the required return. The risk that the actual return will fall short of the required return has both short-term and long-term aspects. The short-term aspect relates primarily to the annual variability of returns.[9] With respect to the annual volatility of returns, potential volatility can arise from both business risk and financial risk.

Business risk arises from demand, competitive, supply, operating, political and regulatory factors. Regulatory risk relates to the framework that determines how the fundamental demand, competitive, supply and operating risks are allocated between ratepayers and shareholders. In NLH's case, for example, the existence of the Rate Stabilization Plan ("RSP") mitigates the utility's short-term business risks. The combination of the stability of revenues and costs, the regulatory model and the utility's operating leverage effectively determine the extent to which the utility faces short-term business risks. Operating leverage reflects the extent to which annual returns can vary due to the relationship between expenses and capital. All other things equal, the higher the expense to capital ratio, the higher is the operating leverage and the greater the impact of a

[8] If the utility expects to continue to earn returns below the lower end of the allowed range, it has the right to file a general rate application, but ratepayers are not responsible for returns that fall below the bottom end of the allowed return on rate base range.

[9] Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon.

reduction in revenues or an increase in expenses will have on the earned return on rate base or capital.

For NLH, when compared to other Canadian electric utilities, the operating leverage, measured as non-energy expenses[10] to net plant or total capital, is slightly lower than that of the typical electric utility.[11] On average, from 2007-2011, the ratio of NLH's non-energy expenses to capital was approximately 10.5%. By comparison, the 2011 median non-energy expense to capital ratio for other Canadian electric utilities was approximately 11.8%.[12] NLH's slightly lower operating leverage would not, in isolation, materially lower the sensitivity of its earned returns to unanticipated changes in revenues or operating expenses relative to other Canadian utilities.[13]

Financial risk relates to the risk borne by the equity shareholder because the utility uses debt to finance a portion of its assets. The issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return. The potential variability of the equity shareholder's return rises as more debt is added to the capital structure.

To illustrate, as set out on Schedule 2, assume two utilities with similar operating leverage (non-energy expense to capital ratios of approximately 10.50%, similar to NLH). Both are tax-exempt. Utility A has a debt/equity capital structure of 55% debt/45% equity (similar to NP) and Utility B has a debt/equity capital structure of 75%

[10] Expenses include O&M, depreciation and amortization, and taxes other than income, but exclude energy-related expenses, since a number of Canadian electric utilities either do not incur energy-related expenses or they have regulatory mechanisms which flow through most or all of energy-related expenses to customers.

[11] An example of very high operating leverage is Ontario Power Generation's regulated nuclear operations, where the assets are significantly depreciated, but the operating expenses are relatively high. Integrated electric utilities whose generating capability is largely hydro-electric tend to have lower operating leverage than utilities whose generating capability is largely thermal (e.g., Nova Scotia Power or SaskPower).

[12] Newfoundland Power's 2011 non-energy expense to capital ratio of 11.4% is similar to the industry median.

[13] An unanticipated increase in expenses of 1% for a tax-exempt utility with an expense to rate base ratio of 10.50% would lower the earned return on rate base by 10.50 basis points; for a tax-exempt utility with an expense to rate base ratio of 11.50%, a 1% unanticipated increase in expenses would lower the earned return on rate base by 11.50 basis points (see Utility C on Schedule 2 attached).

debt/25% debt (similar to NLH). For Utility B, an unanticipated 1% increase in expenses reduces the earned return on equity by 0.23%. For Utility B, the same 1% unanticipated increase in expenses reduces the earned return on equity by 0.4%, i.e., by almost twice as much.

IMPACT OF TAX-EXEMPT STATUS ON RETURN ON RATE BASE AND ROE

The example above ignores the impact of income taxes on the variability of returns. When utilities which pay corporate income taxes or make special payments in lieu of income taxes (e.g., Ontario Crown and municipal electric utilities) experience an anticipated increase in expenses (or reduction in revenues), the impact of the increase (or reduction) is shared with the taxing authorities. In other words, corporate taxability effectively tempers volatility in returns, i.e., the impact on both return on rate base and return on equity of a one percent unanticipated increase in expenses is reduced by the tax rate (29% in Newfoundland and Labrador based on the 2013 combined federal/provincial corporate income tax rate).[14]

COMBINED EFFECTS OF BUSINESS RISK, FINANCIAL RISK AND TAX STATUS

The table below combines the approximate effects on the return on rate base and return on equity of differences in operating leverage, capital structure and income taxes for utilities with the characteristics of NLH and NP. As the table below indicates, when the two utilities face a similar percentage increase in expenses, the potential impact on a utility like NLH is much greater due to its higher debt ratio and tax-exempt status. Specifically, a 1% unanticipated increase in expenses would reduce NLH's return on

[14] The Alberta Utilities Commission has recognized the higher volatility of earnings and risk of tax-exempt or *de facto* non-taxability status by adopting thicker deemed common equity ratios for tax-exempt and *de facto* non-taxable utilities than for otherwise similarly situated taxable utilities.

equity by more than twice as much as it would reduce the return on equity for a utility like NP which has a stronger capital structure and is taxable.[15]

Table 3

	NLH	NP
Expense to Capital Ratio	10.50%	11.50%
Equity Ratio	25%	45%
Tax Status	Tax-exempt	Taxable at 29%
Capital/Rate Base	$1,000.0	$1,000.0
Expenses	$ 105	$ 115
Capital Structure:		
Debt	$ 750.0	$ 550.0
Equity	$ 250.0	$ 450.0
1% increase in expense	$ 1.05	$ 1.15
Reduction in Return on Capital/Rate Base	0.1050%	0.0817%
Reduction in Return on Equity	0.4200%	0.1814%

Source: Schedule 2

Similarly, a 1% reduction in revenues due to lower than anticipated electricity sales, with no offsetting reduction in operating expenses (which are largely fixed in nature), would have the same relative impact on the earned return on equity.

For the 2013 test year, NLH forecasts that its average common equity balance will be approximately $364 million. With a $364 million equity balance, a variance in net income of approximately $3.6 million equates to a variance in earned ROE of one percentage point. There is a high likelihood that NLH's annual earned ROE will vary by at least one percentage point from the target ROE given the multi-year rate regime that exists in the Province.

[15] To provide some perspective on the relative variability of NLH's regulated return on equity, I compared the range and standard deviation of its earned ROEs over the five-year period 2007-2011to those of a broad range of Canadian utilities. Between 2007 and 2011, NLH's actual regulated ROE ranged from 1.4% to 6.6% (a range of 5.2 percentage points); the standard deviation of the earned ROEs was 2.4%. For a sample of 23 Canadian utilities, the average range of earned ROE over the most recent five years available was 2.1 percentage points with a standard deviation of earned returns of approximately 1%.

The principal factors that can cause NLH's earned ROE to vary from the target ROE are higher or lower than expected electricity sales, operating expenses, costs of diesel fuel which are not covered by the RSP,[16] the Holyrood generating plant efficiency factor, and interest expense. Annual variances in each of these factors have the ability to cause the earned ROE to fall short of or exceed the target ROE by more than one percentage point. For example, in 2009, the contraction of the pulp and paper industry and lower secondary energy sales to the Canadian Forces Base in Goose Bay resulted in an approximately $3 million reduction in net revenue not covered by the RSP. In 2011, net demand/secondary and rural customer revenues were $3.4 million less than in 2010. Operating and maintenance expenses in 2007 were $8 million higher than in 2006, arising largely from two factors: expenses related to a major overhaul at Holyrood and increases in salaries and benefits. The Abitibi Bowater Grand Falls Mill closure in 2009 resulted in bad debt expense of $3.7 million. Diesel fuel expense in 2008 was $3.6 million higher than in 2007 due to higher fuel prices. At recent prices of No. 6 fuel oil, variances in the Holyrood generating plant efficiency factor can result in additional annual fuel expense or savings (not covered by the RSP) in excess of $3 million.

RANGE OF RETURN ON RATE BASE AS INCENTIVE MECHANISM

With respect to the incentive mechanism purpose of the range on the allowed return on rate base, the multi-year rate regime in Newfoundland and Labrador implicitly incorporates features of formal incentive regulation or performance-based regulation plans. Effectively, by introducing regulatory lag, i.e., increasing the time between general rate applications, a utility's incentives to lower costs in order to achieve a compensatory return are increased. The PUB recognized that the multi-year rate regime in the Province bears similarities to incentive or performance-based regulation, when, in its Newfoundland Power Order No. P.U. 43(2009), page 28, it supported "the comments of Mr. Todd in his report" where he stated "The existing multi-year regime serves two

[16] NLH intends to apply for a recovery mechanism to capture differences between forecast and actual diesel costs, but at present there is no mechanism in place.

purposes that are similar to the incentive regulation and performance based regulation regimes that have been adopted in some other jurisdictions: they reduce regulatory cost by reducing the frequency of GRA's and they provide an incentive for the Company to pursue productivity gains in the non-GRA years." In this context, a review of the extent to which Canadian utilities subject to formal performance-based regulation have been permitted to earn returns above the allowed ROE is informative.[17]

If the point at which earnings above the authorized ROE may trigger a review of the plan is interpreted as an ROE cap, the median overearnings in the plans referenced in Table 4 below is equivalent to the authorized ROE + 2%. The minimum is equivalent to the authorized ROE + 0.875% (Gaz Métro).[18]

[17] For many Canadian utilities still regulated on the basis of traditional cost of service regulation, and whose rates are reset on an annual basis or on a multiple test year basis where costs are separately forecast and approved for each of the test years, there is no range on the allowed ROE. All earnings above or below the allowed ROE are to the account of the shareholder. This is true, for example, for both investor-owned and government-owned utilities in Alberta, British Columbia, Ontario and Québec that are not subject to incentive regulation. There are three electric utilities subject to traditional cost of service regulation whose allowed ROEs are either expressed as a maximum or within a range. Maritime Electric's allowed ROE of 9.75% is expressed as a maximum. Nova Scotia Power's rates, per its most recent settlement, are set on a 9.0% ROE on 37.5% common equity, with an ROE range of 8.75% to 9.25%, and the ability to earn up to a 9.25% ROE on 40% equity. New Brunswick Power Transmission's allowed ROE is 9.5%, with a range of 8.5% to 10.5%. None of the three utilities has a formal process or mechanism (e.g., excess earnings account) to dispose of earnings above the maximum or outside the prescribed range. To my knowledge, none of these utilities has been required to refund excess earnings to ratepayers.

[18] Assuming Gaz Métro elects to share productivity gains at the time of year-end review. If the utility opts for sharing at the time of their rate application, it has the ability to earn the authorized ROE + 1.75%.

Table 4

Utility	Regulator	Utility Type	Earnings Sharing
Electricity Distributors	OEB	Electricity Distribution	• None; all earnings above or below authorized ROE to account of utility • ROE more than 3% above or below authorized ROE may trigger review and termination of plan
Enbridge Gas	OEB	Gas Distribution	• ROE in excess of 1% of AAM ROE shared 50/50 utility/ratepayer • ROE more than 3% above or below authorized ROE will trigger review of the incentive plan
Alberta Distribution Utilities Ex. Enmax[19]	AUC	Distribution	• No sharing. • Review triggered: • If actual ROE +/- 3.0% above/below target ROE for 2 years or +/- 5.0% above/below target ROE for one year.
Enmax	AUC	Electricity Transmission & Distribution	• ROE in excess of 1% of authorized ROE shared 50/50 utility/ratepayer • Review triggered : same as Alberta utilities
FortisBC Inc.	BCUC	Integrated Electric	• Authorized ROE +/-2% to account of utility • Outside +/- 2% collar shared 50/50 utility/ratepayer
Gazifère	Régie	Gas Distribution	• First 1.0% over authorized ROE shared 75/25 utility/ratepayer • Next 2.5% over authorized ROE shared 50/50 utility/ratepayer • 100% over 3.5% above authorized ROE to ratepayers
Gaz Métro	Régie	Gas Distribution	• 50/50 or 25/75 sharing utility/ratepayer of ROE over authorized ROE due to productivity gains • Higher proportion to utility if sharing occurs at time of rate case application • Lower proportion to utility if sharing occurs at year-end review • 100% over 3.5% above authorized ROE to ratepayers
Union Gas	OEB	Gas Distribution	• Up to 2% over AAM ROE 100% to utility • Between 2% to 3% shared 50/50 • Over 3%, shared 10/90 utility/ratepayer • ROE more than 3% above or below authorized ROE will trigger review of the incentive plan

Source: Various Regulatory Decisions.

[19] Includes distribution operations of the following companies: ATCO Electric; FortisAlberta; EPCOR Distribution and Transmission; ATCO Gas and Pipelines Ltd. and AltaGas Utilities.

CONCLUSIONS

The allowed range of return on rate base is, as the PUB indicated in P.U. 40(2004), intended to (1) capture the uncertainty in operating conditions and allow for some flexibility in responding to them; and (2) to act as an incentive to contain costs and improve productivity. Given the change in NLH's circumstances, specifically its improved capital structure and new approach to setting the target return on equity, it is timely to reconsider whether the allowed range of return on rate base remains appropriate.

Despite significant improvement, NLH's forecast 25.1% rate making equity ratio is still at the lower end of the range of equity ratios maintained by the universe of Canadian electric utilities and significantly lower than NP's 45% common equity ratio. The potential annual swings in revenues, operating and maintenance expenses and/or fuel costs that are not captured by the RSP, in conjunction with NLH's low equity ratio, and to a lesser extent, with its tax-exempt status, have the potential to produce relatively wide variances between the target ROE and the earned ROE. Experienced annual variances in revenues and expenses indicate the potential for NLH's earned returns on equity to vary from the target ROE by one or more percentage points. The potential variability in earned ROEs should be accommodated in the allowed range of return on rate base. This is especially true given the asymmetric nature of the allowed return on rate base range, i.e., where excess returns are to the account of ratepayers but shortfalls from the allowed range are borne by shareholders. The size of the allowed return on rate base range should fairly balance the potential to earn ROEs above and below the target ROE. Based on NLH's specific circumstances, an allowed range of return on rate base compatible with an implied range of return on equity of +/- one percentage point (100 basis points) would be reasonable.

The reasonableness of an allowed range of return on rate base consistent with the ability to earn an ROE of one percentage point above the target ROE can be evaluated by reference to the ROE parameters incorporated into the incentive regulation plans that have been adopted for Canadian utilities. Those plans indicate that the ability to achieve an ROE of one percentage point higher than the authorized ROE is conservative.

At NLH's forecast 2013 test year capital structure , the implied allowed range of return on rate base required to accommodate a range of return on ROE of plus or minus one percentage point is approximately plus or minus 0.25% (25 basis points), as illustrated in the table below.

Table 5

	%	**Return**	**Weighted Return**
Debt	70.1%	8.01%	5.62%
Employee Future Benefits	4.40%	0.00%	0.00%
ARO, Funded	0.40%	0.00%	0.00%
Equity	25.1%	8.80%	2.21%
Allowed Return on Rate Base			7.83%
	%	**Return**	**Weighted Return**
Debt	70.1%	8.01%	5.62%
Employee Future Benefits	4.40%	0.00%	0.00%
ARO, Funded	0.40%	0.00%	0.00%
Equity	25.1%	9.80%	2.46%
Upper End of Range			8.08%
	%	**Return**	**Weighted Return**
Debt	70.1%	8.01%	5.62%
Employee Future Benefits	4.40%	0.00%	0.00%
ARO, Funded	0.40%	0.00%	0.00%
Equity	25.1%	7.80%	1.96%
Lower End of Range			7.58%

While a range of return on rate base of +/- 25 basis points represents an increase from the +/- 15 basis points previously authorized by the PUB in Order No. P.U. 40(2004), the implied range of return on equity of +/- 100 basis points is narrower. This is due to NLH's higher 2013 test year common equity ratio compared to its 2003 common equity ratio (approximately 25% versus 12.25%). As discussed above, at NLH's 2003 capital structure containing approximately 12.25% equity, the +/-0.15 basis points range of return on rate base implied a range of return on common equity of approximately +/- 120 basis points, or 1.2%.

I recommend that NLH propose an allowed range of return on rate base of +/- 25 basis points. Other than the change in the range of return on rate base from +/-15 basis points to +/-25 basis points, there would be no change in the definition of excess earnings from what was approved by the PUB in Order No. P.U. 40(2004). When the earned return on the rate base exceeds the allowed return on rate base by more than 25 basis points, where the rate base is equal to the actual average annual rate base, the excess earnings would be recorded in an excess earnings account as a liability. The balance in the excess earnings account will be disposed of in the manner determined by the PUB. Although not specified in Order No. P.U. 40(2004), to the extent that the earned return on rate base falls below the bottom end of the allowed range, shortfalls remain to the account of the shareholder.

As discussed above, variations from the forecast cost of debt, in isolation, do not impact the earned return on rate base but do impact the earned ROE. If NLH exhibits a consistent ability to earn an ROE more than one percentage point above the target ROE, while still earning a return on rate base within the allowed range, as a result of a reduction in its cost of debt, ratepayers should be provided the opportunity to share the benefits of that cost reduction. As a result, I recommend that, when the regulated earned ROE exceeds the target ROE by more than one percentage point, NLH include in its annual return filing an explanation of the variance between the actual embedded cost of debt and the cost forecast for the test year and the variance between the earned and target ROE.[20] The information would provide the PUB with the opportunity to determine whether a review, e.g., a general rate application, is required.

[20] This requirement would be similar to that implemented by the PUB for Newfoundland Power in Order No. P.U. 19(2003).

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. MCSHANE

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian electric utilities, gas distributors and pipelines, and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, financial performance measures, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service.

She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

PUBLICATIONS, PAPERS AND PRESENTATIONS:

- *Utility Cost of Capital: Canada vs. U.S.*, presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.
- "The Fair Return", (co-authored with Michael Cleland), *Energy Law and Policy*, Gordon Kaiser and Bob Heggie, eds., Toronto: Carswell Legal Publications, 2011.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Alberta Natural Gas
1994

Alberta Utilities
Generic Cost of Capital
2011

AltaGas Utilities
2000

Ameren (Central Illinois Public Service)
2000, 2002, 2005, 2007 (2 cases),
2009 (2 cases)

Ameren (Central Illinois Light Company)
2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Illinois Power)
2004, 2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Union Electric)
2000 (2 cases), 2002 (2 cases), 2003,
2006 (2 cases)

ATCO and AltaGas Utilities
Generic Cost of Capital, Alberta
2003

ATCO Electric
1989, 1991, 1993, 1995
1998, 1999, 2000, 2003

ATCO Gas
2000, 2003, 2007

ATCO Pipelines
2000, 2003, 2007, 2011

ATCO Utilities
Generic Cost of Capital
2008

Bell Canada
1987, 1993

Benchmark Utility Cost of Capital
(British Columbia)
1994, 1999, 2012

Canadian Western Natural Gas
1989, 1996, 1998, 1999

Centra Gas B.C.
1992, 1995, 1996, 2002

Centra Gas Ontario
1990, 1991, 1993, 1994, 1995

Direct Energy Regulated Services
2005

Dow Pool A Joint Venture
1992

Electricity Distributors Association

2009

Enbridge Gas Distribution
1988, 1989, 1991, 1992, 1993, 1994
1995, 1996, 1997, 2001, 2002

Enbridge Gas New Brunswick
2000, 2010

Enbridge Pipelines (Line 9)
2007, 2009

Enbridge Pipelines (Southern Lights)
2007

EPCOR Water Services Inc.
1994, 2000, 2006, 2008, 2011

FortisBC Inc.
1995, 1999, 2001, 2004, 2013

FortisBC Energy Inc.
1992, 2005, 2009, 2011, 2013

FortisBC Energy (Whistler) Inc.
2008, 2013

Gas Company of Hawaii
2000, 2008

Gaz Métro
1988

Gazifère
1993-1998, 2010

Heritage Gas
2004, 2008, 2011

Hydro One
1999, 2001, 2006 (2 cases)

Insurance Bureau of Canada (Newfoundland)

2004

Laclede Gas Company
1998, 1999, 2001, 2002, 2005

Laclede Pipeline
2006

Mackenzie Valley Pipeline
2005

Maritime Electric
2010

Maritime Link
2013

Maritimes NRG (Nova Scotia and New Brunswick)
1999

MidAmerican Energy Company
2009

Multi-Pipeline Cost of Capital Hearing (National Energy Board)
1994

Natural Resource Gas
1994, 1997, 2006, 2010

New Brunswick Power Distribution
2005

Newfoundland & Labrador Hydro
2001, 2003

Newfoundland Power
1998, 2002, 2007, 2009, 2012 (2 cases)

Newfoundland Telephone
1992

Northland Utilities
2008 (2 cases)

Northwestel, Inc.
2000, 2006

Northwestern Utilities
1987, 1990

Northwest Territories Power Corp.
1990, 1992, 1993, 1995, 2001, 2006

Nova Scotia Power Inc.
2001, 2002, 2005
2008, 2011, 2012

Ontario Power Generation
2007, 2010

Ozark Gas Transmission
2000

Pacific Northern Gas
1990, 1991, 1994, 1997
1999, 2001, 2005, 2009, 2013

Plateau Pipe Line Ltd.
2007

Platte Pipeline Co.
2002

St. Lawrence Gas
1997, 2002

Southern Union Gas
1990, 1991, 1993

Stentor
1997

Tecumseh Gas Storage
1989, 1990

Telus Québec
2001

TransCanada PipeLines
1988, 1989, 1991 (2 cases), 1992, 1993

TransGas and SaskEnergy LDC
1995

Trans Québec & Maritimes Pipeline
1987

Union Gas
1988, 1989, 1990, 1992
1994, 1996, 1998, 2001

Westcoast Energy
1989, 1990, 1992 (2 cases), 1993, 2005

Yukon Electrical Company
1991, 1993, 2008

Yukon Energy
1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
Greater Toronto Airports Authority	Financial Performance Measures	2012
Heritage Gas	Criteria for a Mature Utility	2011
Alberta Utilities	Management Fee on CIAC	2011
ATCO Electric	Construction Work in Progress (CWIP) Recovery of Future Income Tax (FIT)	2010
Maritimes & Northeast Pipeline	Return on Escrow Account	2010
Nova Scotia Power	Calculation of ROE	2009
Alberta Oilsands Pipeline	Cash Working Capital	2007
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998

Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Métro/Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

Range of Return on Equity Implied by Allowed Range of Return on Rate Base of +/- 0.15%: Impact of Change in Capital Structure

	Capital Structure P.U. 40				Capital Structure Forecast 2013		
	%	**Cost**	**Weighted Cost**		**%**	**Cost**	**Weighted Cost**
Debt	86.04%	8.01%	6.89%	**Debt**	70.10%	8.01%	5.62%
Employee Benefits	1.70%	0.00%	0.00%	**Employee Future Benefits Funded**	4.40%	0.00%	0.00%
				Asset Retirement Obligation, Funded	0.40%	0.00%	0.00%
Equity	12.26%	8.80%	1.08%	**Equity, excluding AOCI**	25.10%	8.80%	2.21%
WACC			7.97%	**WACC**			7.83%

	Range of Return on Rate Base		Range of Return on Rate Base	
Range on Return on Rate Base	7.97% + .15%	8.12%	7.83% + .15%	7.98%
	7.97% - .15%	7.82%	7.83% - .15%	7.68%

	Rate Base	Rate Base
	$ 1,500,000	$ 1,500,000

Maximum Return on Rate Base

	P.U. 40	Forecast 2013
Return on Rate Base	$ 121,810.26	$ 119,700.00
Less Interest Expense	$ 103,377.06	$ 84,225.15
Net Income	$ 18,433.20	$ 35,474.85
Equity	$ 183,900.00	$ 376,500.00
ROE	10.02%	9.42%
Deviation from Target ROE	1.22%	0.62%

Minimum Return on Rate Base

	P.U. 40	Forecast 2013
Return on Rate Base	$ 117,310.26	$ 115,200.00
Less Interest Expense	$ 103,377.06	$ 84,225.15
Net Income	$ 13,933.20	$ 30,974.85
Equity	$ 183,900.00	$ 376,500.00
ROE	7.58%	8.23%
Deviation from Target ROE	-1.22%	-0.57%

Note:
For purposes of estimating the impact of the change in capital structure on the range of ROE at an allowed range of return on rate base of +/- 0.15%, all variables other than the capital structure ratios were assumed to be identical (i.e., costs of debt and equity and rate base).

Impact on Return on Rate Base and Return on Equity of Increased Operating Expenses

	Utility A	Utility B	Utility C	Utility D
Expense to Capital Ratio	10.50%	10.50%	11.50%	11.50%
Equity Ratio	45%	25%	45%	45%
Tax Status	Tax-exempt	Tax-exempt	Tax-exempt	Taxable at 29%
Capital/Rate Base	1,000.00	1,000.00	1,000.00	1,000.00
Expenses	105.00	105.00	115.00	115.00
Capital Structure				
Debt	550.00	750.00	550.00	550.00
Equity	450.00	250.00	450.00	450.00
1% increase in expense	1.05	1.05	1.15	1.15
Reduction in Return on Capital/Rate Base	0.105%	0.105%	0.115%	0.082%
Reduction in Return on Equity	0.233%	0.420%	0.256%	0.181%

Note: Utility B is similar to NLH; Utility D is similar to Newfoundland Power

Non-Regulated Operations

June 2012

Table of Contents

PURPOSE OF DOCUMENT

The purpose of this document is to outline the non-regulated operations within Newfoundland and Labrador Hydro (Hydro). Activities conducted by Hydro staff on behalf of other Nalcor lines of business are non-regulated and are recorded in a business unit designated as a cost recovery business unit as outlined in Section 8 below.

DEFINITION

Non-regulated costs are defined as all costs associated with any asset which is not used and useful in the generation, transmission and distribution of electrical power and energy by Hydro within the Province of Newfoundland and Labrador (Province); activities exempted by specific legislation; and costs specifically identified by the Board of Commissioners of Public Utilities as being non-recoverable from rate payers.

LIST OF NON-REGULATED ACTIVITIES

To date, the following activities/costs have been determined to be non-regulated:

1. All activities associated with the following subsidiary companies:
    a) Churchill Falls (Labrador) Corporation Limited (Churchill Falls) (CF(L)Co);
    b) Lower Churchill Development Corporation Limited (LCDC);
2. Supply of power to the Iron Ore Company of Canada (IOC);
3. Export Sales;
4. Natuashish;
5. Star Lake;
6. Ramea Wind-Hydrogen project;
7. Conservation and Demand Management – Labrador;

8. Cost Recovery Business Units;
9. Other Specific Non-Regulated Costs; and
10. Dividends.

1. SUBSIDIARY COMPANIES

a) Churchill Falls

The services provided to Churchill Falls by Hydro are provided in accordance with the CF(L)Co – NLH Services Agreement dated January 1, 2010. The Agreement provides for the provision of services by Hydro to Churchill Falls and outlines the manner in which those services will be charged and paid by Churchill Falls. The agreement is outlined in Appendix A. Any employee providing services to this entity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

b) LCDC

Although this corporation is primarily inactive[1], minimal costs such as external audit fees are being incurred and Business Unit (BU) 1953 is used to capture these costs. Any employee providing services to this entity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

2. SUPPLY OF POWER TO THE IRON ORE COMPANY OF CANADA (IOC)

Power and energy sales to IOC are a non-regulated activity. IOC is a customer on the Labrador Interconnected System and consequently, the costs associated with this customer is derived from the Cost of Service model. Rates charged to this customer are based on a negotiated contract and are not regulated. Any employee providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

[1] This company is not participating in Nalcor's ongoing Lower Churchill project.

All revenues and expenses associated with this activity are captured in BU 1952 and are excluded from the determination of regulated net income. Any employee providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

3. EXPORT SALES

Hydro meets the power and energy requirements for the Labrador Interconnected System primarily through an agreement with Churchill Falls. Under that agreement, Hydro purchases recall power and energy up to a maximum of 300 MW and 2,362 GWh annually. Power and energy surplus to meeting the needs of the Labrador Interconnected System is sold by Hydro to external markets.

All revenues and expenses associated with this activity are captured in BU 1950 and are excluded from the determination of regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

4. NATUASHISH

Hydro has been operating and maintaining the plant in the community of Natuashish on behalf of the Federal Government on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery.

All revenues and expenses associated with this activity are captured in BU 1405 and are excluded from the determination of regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

5. STAR LAKE

Hydro is operating the Star Lake plant on behalf of Nalcor who is acting as an agent for the Province.

All revenues and expenses associated with this activity are captured in BU 1970 and are excluded from the determination of regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

6. RAMEA PROJECT

In accordance with Board Order No. P.U. 31(2007), no costs associated with the construction of the wind-hydrogen diesel generation project at Ramea will be borne by ratepayers in the implementation, operation or abandonment of the facility. All expenses associated with this activity are captured in BU 1406 and are excluded from the determination of regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

7. CONSERVATION DEMAND MANAGEMENT

In accordance with Board Order No. P.U. 7(2008), Hydro and Newfoundland Power will undertake energy conservation initiatives. All expenses associated with this activity in Labrador West are captured in BU 1949 and are excluded from the determination of regulated income. Employees providing services to this activity will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

8. COST RECOVERY BUSINESS UNITS

Hydro maintains a number of cost recovery business units to capture costs incurred by Hydro personnel on behalf of other lines of business. These costs are billed on a monthly basis to the lines of business and are excluded from the determination of Hydro regulated income. Any employee providing services to these business units will charge their time in accordance with Nalcor's Intercompany Transaction Costing Guidelines as outlined in Exhibit 8.

9. OTHER SPECIFIC NON-REGULATED COSTS

From time to time, costs related to the Hydro legal entity are incurred but are not charged to regulated customers. These costs are recorded in BU 1955 and include the following:

a) <u>Contributions and Donations</u>

Expenditures for charitable donations, community and charitable advertisements, street light subsidy and scholarships are not considered to be regulated expenses.

b) <u>Advertising</u>

Regulated advertising expenses are limited to matters relating to conservation, safety and consumer information. Advertising for corporate image building is not a regulated expense.

c) <u>Companion Travel Costs</u>

On occasion, management approves the cost of a Hydro employee's companion attending a corporate function. These costs are not considered regulated expenses.

d) <u>Bad Debt Expense</u>

Bad debt expenses incurred for uncommon reasons may be designated as non-recoverable and are excluded from the determination of regulated income.

10. DIVIDENDS

On a monthly basis, net cash associated with non-regulated activities, with the exception of items in Sections 6 through 9 of this policy, are paid to Nalcor as a dividend. Any residual amounts that are not subject to the dividend policy are retained within the Hydro legal entity but are reported as non-regulated costs.

THIS AGREEMENT is made at St. John's, in the Province of Newfoundland and Labrador as of the 1st day of January, 2010.

BETWEEN : **CHURCHILL FALLS (LABRADOR) CORPORATION LIMITED,** a company incorporated under the laws of Canada and having its head office at Hydro Place, St. John's, in the Province of Newfoundland and Labrador (hereinafter referred to as "CF(L)Co") of the first part.

AND: **NEWFOUNDLAND AND LABRADOR HYDRO**, a body corporate existing pursuant to the *Hydro Corporation Act, 2007* being Chapter H-17 of the Statutes of Newfoundland and Labrador, 2007 (hereinafter referred to as "Hydro") of the second part.

(CF(L)Co and Hydro are hereinafter individually referred to as "Party" and collectively as the "Parties")

WHEREAS CF(L)Co has requested Hydro to provide certain corporate services to CF(L)Co;

AND WHEREAS the Parties wish to enter into an Agreement with respect to the determination and payment of the costs associated with the provision of such services;

<u>NOW THEREFORE THIS AGREEMENT WITNESSETH</u> that the Parties hereto, each, in consideration of the premises and of the covenants, agreements and declarations made herein by the other, covenant, agree and declare as of the date hereof as follows:

ARTICLE 1 – INTERPRETATION

1.01 (a) "Services" means corporate services, including but not limited to, management, general accounting, treasury, purchasing, legal, information systems and technology, human resources, safety and health, engineering, project execution and administration or as otherwise agreed to by the Parties; and

(b) "Operating Bill Rate" means a cost-based charge based on an employee's base rate plus employee benefits, allowances and other pays as applicable, as determined by the following formula:

Operating Bill Rate =

Base salary + employee benefits + allowances + other pays as applicable

(divided by) Average total available working hours

ARTICLE 2 – PAYMENT FOR SERVICES

2.01 Hydro shall provide the Services to CF(L)Co.

2.02 All costs associated with the provision of the Services shall be charged to, and paid for by, CF(L)Co in accordance with the following:

i) Subject to 2.02 ii), CF(L)Co shall be charged the Operating Bill Rate for time spent by any Hydro employee in providing the Services. In addition, a fixed charge for each hour of regular labour billed, up to a maximum of eight hours per day, shall be added to cover the additional cost, beyond those costs included in the Operating Bill Rate, of having an employee available to provide the Services. This cost-based charge shall be calculated at a corporate level and shall cover costs such as office space, telephone, computer and other such overhead costs.

ii) From time to time, certain departments may be identified as common service departments and costs associated with such departments shall be allocated to Nalcor Energy's various lines of business, including CF(L)Co, on an appropriate basis.

2.03 Prior to December 15th of each calendar year, Hydro will provide CF(L)Co with a list of the Services to be provided by Hydro to CF(L)Co during the following calendar year (the "Year"), as well as an estimate of the costs to be recovered from CF(L)Co by Hydro for the provision of said Services. Hydro shall bill CF(L)Co monthly for the costs commencing in January of the Year. If necessary, an adjustment shall be made by the Parties after the actual costs for the Year have been determined to the satisfaction of both Parties.

ARTICLE 3 – MISCELLANEOUS

3.01 Hydro agrees to provide the Services in a skilful and professional manner in accordance with its own methods and practices and will diligently carry out its obligations under this Agreement.

3.02 In carrying out the Services, Hydro shall not be responsible or liable for the consequences of any of its acts or omissions other than those attributable to its wilful misconduct or gross negligence or that of its employees.

3.03 Nothing contained herein shall constitute Hydro as an agent of CF(L)Co and Hydro shall not be entitled to contract in the name or on behalf of CF(L)Co or otherwise to incur obligations for or on behalf of CF(L)Co, unless the Parties otherwise agree.

3.04 Neither Party shall be permitted to assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

3.05 This Agreement shall be governed by the laws of Newfoundland and Labrador.

3.06 This Agreement shall remain in effect until such time as it is terminated by the mutual agreement of the Parties or it is terminated by either Party, in which case such Party shall provide the other party with six (6) months written notice of its intention to terminate the Agreement.

3.07 The doctrine of *contra proferentem* shall not apply in the interpretation of this Agreement.

IN WITNESS WHEREOF each of the Parties hereto has caused this Agreement to be executed by its officers or representatives duly authorized in that behalf.

CHURCHILL FALLS (LABRADOR) COPORATION LIMITED

Per:____________________

Witness

Title: President & CEO

Per:____________________

Witness

Title: General Counsel & Corporate Secretary

NEWFOUNDLAND AND LABRADOR HYDRO

Per:____________________

Witness

Title: VP, Finance & CFO

Per:____________________

Witness

Title: Assistant Corporate Secretary

Intercompany Transaction Costing Guidelines

June 2012

Table of Contents

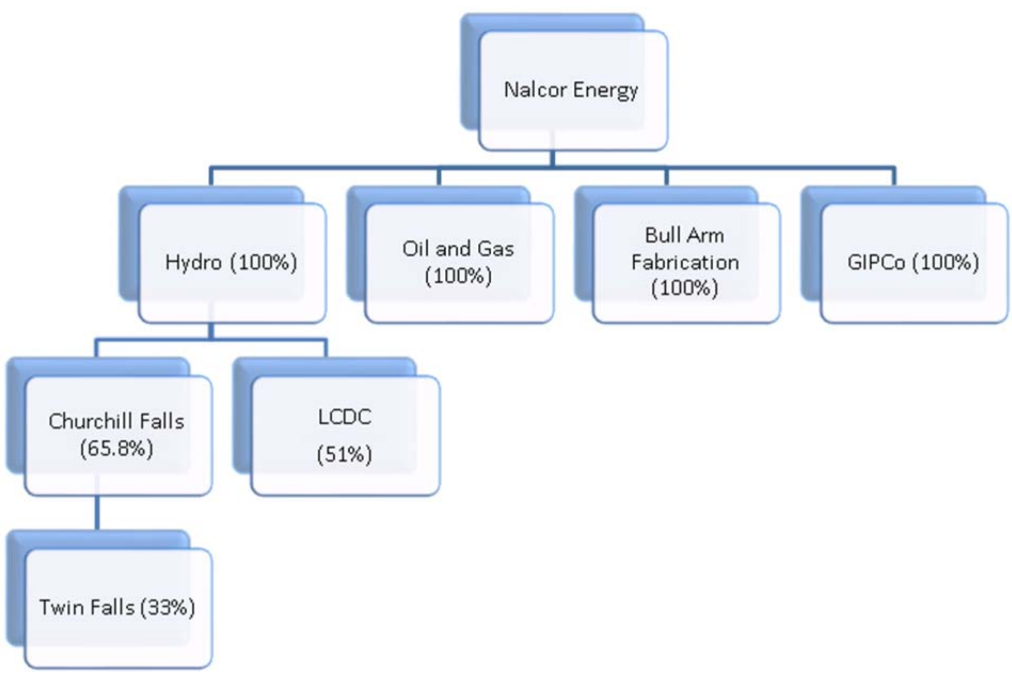
1.0 PURPOSE

This document is intended to outline the guidelines for charging costs across the lines of business within Nalcor Energy (Nalcor or the Company).

2.0 INTRODUCTION

Nalcor is a Crown corporation that was established in 2007 as part of one of the key initiatives of Newfoundland and Labrador's Energy Plan. The Company, which is wholly owned by the Government of Newfoundland and Labrador, was established to take a lead role in the development of the province's energy resources. The Nalcor legal entity structure is outlined below:

Figure 1



Nalcor's business includes the development, generation, transmission and distribution of electricity; the exploration, development, production and sale of oil and gas; industrial fabrication and energy marketing. These intercompany transaction costing guidelines apply to both intra-company and intercompany transactions. That is, the guidelines are applied to transactions between regulated and non-regulated Hydro, as well as to transactions between Nalcor and CF(L)Co, for instance.

The guidelines are based on the principle of cost based recovery. There is no profit component and, where practicable, employees track time worked to specific lines of business using a weekly time sheet. Costs associated with the operations of certain departments that provide common services available to all lines of business are allocated through an administration fee as outlined in this document.

3.0 CORPORATE SERVICES

Certain departments provide corporate services (or shared services) to other lines of business within Nalcor. These services include management, general accounting, treasury, purchasing, legal, information systems and technology, human resources, safety and health, engineering and project execution and administration. Transactions associated with these services are governed by these guidelines. Intercompany transactions operate on the premise that all transactions are billed at cost. The costing framework covers transactions from corporate or shared services groups as well as common services that are allocated through an administration fee process.

There are two main types of costs which are charged:

- Type 1 - Common Service Costs (via administration fee); and
- Type 2 - Costs related to the provision of Corporate Services.

3.1 Type 1 – Common Service Costs

Certain departments, which are based within Hydro, provide common services to various lines of business. Hydro recovers costs through an administration fee as described below.

Table 1

Common Service Departments	Allocation Basis
Human Resources	FTE
Safety and Health	FTE
Information Systems (IS)	Average Users
Office space and related costs	Square footage
Telephone and Local Area Network (LAN) costs	Average Users

3.1.1 Human Resources

Human Resources is responsible for the administration and coordination of all employee related services including payroll, recruitment, employee benefit programs, pensions, training and the rewards and recognition program as well as the maintenance of the human resources database. Human Resources also administer the performance appraisal system, salary surveys and maintain organization charts. Operating costs incurred in providing Human Resources services are allocated to the lines of business on a full time equivalent (FTE) basis.

3.1.2 Safety and Health

The Safety and Health department provides Occupational Health services including coordinating corporate efforts with regard to employee safety as well as wellness, disability and sick leave management, and medical screening. Operating costs incurred in providing safety and health services are allocated to the lines of business on an FTE basis.

3.1.3 Information Systems

Information Systems (IS) provides assistance and support in the areas of Software Applications, Planning and Integration and Business Solutions. This department is also responsible for the maintenance and administration of the company-wide computer infrastructure and network and provides technical support. Operating costs incurred in providing IS services are allocated to the lines of business on an average user basis. Depreciation expense and a return on rate base at the weighted average cost of capital (WACC) for costs capitalized such as servers and software are allocated to each line of business on an average user basis. Costs that are incurred solely for a particular line of business, rather than shared among the lines of business are charged to that line of business and are excluded from the determination of shared costs.

3.1.4 Office Space

Each line of business occupying floor space at Hydro Place is charged a rental charge for floor space. The square footage rental rate reflects the average annual capital and operating cost for Hydro Place as determined by the following formula:

$$\frac{\text{Hydro Place operating costs + return on rate base + annual depreciation}}{\text{Hydro Place total square footage}}$$

The cost based rate includes the following expenses for Hydro Place:

- Annual depreciation for all common assets;
  - Common assets include:
    - Furniture for offices, cubicles and common areas;
    - Fitness equipment;
    - Cafeteria equipment;
    - Printers and fax machines;
    - Mailroom equipment; and
    - Network services equipment.
- System Equipment Maintenance expenses and operating projects;
- Expenses relating to salaries, fringe benefits, group insurance and employee future benefits for Office Services, Building Maintenance and Transportation;
- Heat and Light;
- Office Supplies;

- Postage;
- Safety Supplies;
- Consulting expenses for projects at Hydro Place;
- Security Card Maintenance Contract; and
- Return on rate base at WACC for all common assets.

3.1.5 Telephone Infrastructure (PBX) Costs

All lines of business are charged their share of Telephone Infrastructure (PBX) costs including long distance charges. The Local Area Network (LAN) costs provided by Network Services are divided by the total number of LAN ports to derive a cost per user. The telephone costs provided by Network Services are divided by the number of telephone, fax, and modem lines to derive a cost per telephone per user. The average number of users for each line of business will be the allocator.

3.2 Type 2 – Corporate Costs

Corporate costs incurred within various lines of business are charged to the appropriate line of business as described below.

3.2.1 Employee Labour Costs

All employees of Nalcor are required to charge time by completing time sheets which allocate labour to work orders based on activity. The guiding principle is that where an employee spends time on specific tasks and work activities for another entity or line of business, time is to be charged at cost. Cost, or the bill rate, is defined as labour costs, fringe benefits (including time off) and other direct costs. See Appendix A for a detailed listing of the components of the bill rate.

The operating bill rates are reviewed annually and updated accordingly.

3.2.2 Overtime

Overtime will be charged according to policy and no further mark-up or fixed charge is applied.

3.2.3 Time Sheets

All employees are required to complete weekly time sheets on a timely basis. All work hours must be coded to work orders in order to adequately track hours to the appropriate business unit. Time is coded in 30 minute increments.

3.2.4 Corporate Services Functions

The functions and departments that share services across entities include:

a) Leadership Team

Executive management provides strategic oversight and general management.

b) Legal

General Counsel's responsibilities include the provision of legal and corporate secretary services.

c) Internal Audit

The Internal Audit Department provides auditing services as determined in an annual audit plan as part of the annual update of the Five-Year Internal Audit Plan.

d) Project Engineering and Technical Services

This division provides services in all engineering disciplines and covers such items as:

a) Design, construction and project management;

b) Engineering studies, technical specifications and construction coordination;

c) Tender preparation and analysis including interaction with consultants; and

d) Review and resolution of maintenance problems.

e) Environmental Services

The Environmental Services department's activities include auditing for compliance with government regulations and corporate policy, obtaining permits and approvals for proposed programs and advising on environmental matters.

f) Labour Relations

Labour Relations department provides services relating to the negotiation and administration of collective agreements, the resolution of grievances and all union/management communications.

g) Financial Planning

Investment Evaluation department provides services to facilitate the production, review and distribution of annual long-term financial plans. As well, they provide long-term financial planning and analyses for various activities and scenarios.

h) Risk and Insurance

Risk and Insurance department provides services related to the placement, policy and claims administration, risk control and risk financing of the corporate insurance program.

i) Finance

The Finance department provides accounting and treasury services including external financial reporting.

j) Supply Chain Management

The Supply Chain Management department coordinates all efforts related to the procurement process activities including tendering, purchasing and contract administration.

3.2.5 Fixed Charge

In addition to labour costs, a fixed rate will be applied to each hour of regular labour charged to lines of business. The fixed charge accounts for the additional cost, beyond basic salary and benefit costs, of having an employee available to provide service. The fixed charge recovers costs originally charged in the Administration Fee as well as other employee related costs, including:

- Telephone and fax;
- Books and subscriptions;
- Memberships and dues;
- Conferences;
- Training; and
- Employee expenses (e.g. overtime meal allowance).

While most employees who provide intercompany services are located in Hydro Place, this rate will also be used as a proxy for employees working from other locations

The fixed charge rate is reviewed annually and updated accordingly.

3.2.6 Materials Costs

Materials issued from inventory will be charged at cost to the applicable line of business.

3.2.7 Vehicle Costs

Vehicles utilized across lines of business will be charged a rental rate which is based upon the type of vehicle utilized. The rental charge is calculated by multiplying the usage time by the daily or hourly rental rate for the applicable vehicle. The rental rates are updated annually.

3.2.8 Computers

Computers are charged directly to the applicable line of business.

3.2.9 Cost of Equipment

Equipment will be charged to each line of business at a cost based rate as determined and maintained by the Capital Assets Accounting department.

4.0 BILLING AND COLLECTION

Invoices for the recovery of intercompany transactions are to be issued on a monthly basis. Billings to and from related entities shall be undertaken within 30 days of the service, resource or asset being provided. Receivables between related companies are paid upon invoice receipt from a related entity. If the invoice is not paid in full within 30 days from the date of invoice, Treasury and Risk Management will calculate an intercompany interest charge. The amount of the charge will be such that there is no net financing impact on the Company to which the balance is owed. Finance charges are calculated by applying a rate to the intercompany balance(s) that is equal to the cost of short-term financing for the Company to which the balance is owed. If the Company to which the balance is owed is Hydro, then the rate applied to such balances is the last approved WACC, which is currently 7.53% (2006 GRA).

APPENDIX A
OPERATING BILL RATE COMPONENTS

Components of the operating bill rate are as follows:

Salary Cost Components:

- Salaries & Temporary Salaries including the payroll code for Easeback/Return to Work
- Other Salary Costs - Retroactive Pay

Mark Up Components:

- Fringe Benefit Costs
  - Canada Pension Plan
  - Employment Insurance
  - Public Service Pension Plan
  - Group Money Purchase Plan
  - Prior Service Matched PSPP
  - Workplace Health Safety and Compensation Premiums

- Insurances
  - Life Insurances
  - A D&D Insurance
  - Medical Insurance
  - Dental Insurance

- Company Costs
  - Employee Future Benefits expense
  - Payroll Taxes
  - Other Salary Costs - Bonus, Performance Contracts & Signing Bonus

- Leave
  - Training Hours
  - Short-Term Sick Leave
  - Long-Term Sick Leave
  - Medical Travel
  - Medical Appointments
  - Annual Leave
  - Floaters
  - Family Leave
  - Compassion Leave
  - Jury Duty
  - Statutory Holiday
  - Union Leave
  - Banked Overtime

Exhibit 9

Final Report

Cost of Service Study / Utility and Industrial Rate Design Report

Prepared for

Newfoundland and Labrador Hydro

newfoundland labrador hydro

a nalcor energy company

July 7, 2013

Lummus Consultants International

DISCLAIMER NOTICE

This document was prepared by Lummus Consultants International, Inc. ("Consultant") for the benefit of Newfoundland and Labrador Hydro ("Company"). With regard to any use or reliance on this document by any party other than Company and those parties intended by Company to use this document ("Additional Parties"), Consultant, its parent, and affiliates: (a) make no warranty, expressed or implied, with respect to the use of any information or methodology disclosed in this document; and (b) specifically disclaims any liability with respect to any reliance on or use of any information or methodology disclosed in this document.

Any recipient of this document, other than Company and the Additional Parties, by their acceptance or use of this document, releases Consultant, its parent, and affiliates from any liability for direct, indirect, consequential, or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability of Consultant.

LUMMUS CONSULTANTS
INTERNATIONAL

Robert D. Greneman, P.E.
Associate Director
Lummus Consultants International, Inc.
150 Royall Street
Canton, MA 02021

At the hearing into Newfoundland and Labrador Hydro's General Rate Application, the Cost of Service Report will be adopted by Robert D. Greneman, P.E., Associate Director with Lummus Consultants International, Inc. (Lummus Consultants) (formerly Shaw Consultants). Mr. Greneman will also offer evidence with regard to Newfoundland Power (NP) rate design and Industrial Customer rate design. A witness profile for Mr. Greneman is included in Appendix 4. The topics addressed in the evidence are enumerated below.

1.) **<u>Cost of Service (COS)</u>** - *Summary of the cost of service process and its consistency with the Board approved methodology, along with rationale for any proposed changes.*

    - COS Study
    - COS Process
    - Systemization
    - Functionalization
    - Classification
    - Allocation
        - Energy Allocation Factors
        - Demand Allocation Factors
        - Customer Allocation Factors
    - Changes Other Than Methodology
        - CDM Systemization, Functionalization and Classification
    - Organization of the COS Study
    - Study Results

2.) **<u>Newfoundland Power Rate Design</u> -** *Review of the 2008 report and a recommendation that a Consumer Advocate (CA) proposed change in NP's generation credit not be made until further explored. Also a significant change in the mechanics of Hydro's invoices to NP, since using the 2013 cost of fuel of approximately 18 cents/kWh) would result in unnaturally low first block energy charges, and substantially impact cash flows of both utilities.*

    - Outstanding Issue from April 2008 review of Demand Billing to Newfoundland Power
        - Whether NP's curtailable load should be treated in a manner similar to NP's existing generation credit

- NP's 2013 Rate Structure
  - Principles for the rate structure
- Revenue requirement recovery
- Revenue Stream to reflect monthly costs/billings
- Demand rate
- First Block Size
- First Block Rate
- Tail Block Rate

3.) **<u>Industrial Customer (IC) Rate Design</u>** **-** *Review of the 2008 report and recommendations for the implementation of a two block rate structure for the IC; how blocks will be sized; and how the RSP will be impacted.*

- Outstanding Issues from February 2008 review of Industrial Customer Rate Design
  - Methodology for calculating first block
  - Monthly block sizing in unusual operating circumstances
  - RSP adjustment timing
- Industrial Customer 2013 Rate Structure
  - Two Block Energy Rate Structure
  - Tail Block pricing
  - Modifications to First Block Size
  - New Customers coming onto system
  - Demand Charges

4.) **<u>CDM Recovery Mechanism</u>** – *Recommended treatment of Hydro's Conservation and Demand Management costs.*

Table of Contents

List of Figures & Tables

1 Cost of Service

1.1 Cost of Service Study

A Cost of Service (COS) study is the industry standard against which rates are judged to be equitably distributed among customer classes and hence, non-discriminatory. Newfoundland and Labrador Hydro's (Hydro) COS continues to be a key tool in setting rates to its customers. The 2013 test year COS study incorporates methodologies that have been approved by the Board. The following sections provide an overview of the existing methodologies.

1.2 Cost of Service Process

The COS study is based on Hydro's embedded costs for the 2013 forecast year. As in its prior studies, Hydro first systemizes costs into its five discrete systems. For each system, a three-step approach of functionalization, classification and allocation is used.

This widely used three-step process facilitates the determination of a revenue requirement for each class by function, and the development of unit costs, which serve as an important guide in the rate design process.

The procedures used throughout the study are in accordance with those accepted by this Board and, based on my review, are consistent with industry practice.

The procedures that were used are discussed below.

1.3 Systemization

Hydro performs a COS study for each of the five geographic areas it serves. The five areas are: Island Interconnected, Island Isolated, Labrador Isolated, L'Anse au Loup and Labrador Interconnected. In general, plant that is located within each area along with its associated expenses is directly assigned to that area. Customer-related costs are systemized using customer ratios. Costs, such as Administrative and General (A&G) expenses, which are generally not identifiable with a specific service area or function, are systemized based on plant or expense ratios, as appropriate to the nature of the expense.

1.4 Functionalization

Functionalization takes the costs in each system and assigns them to the various steps in the process of producing, transmitting, distributing and billing for electricity. These steps, or functional categories, are generally defined in a cost study either to track costs associated with a particular function (e.g., generation or transmission) or to allow a different allocation factor to be applied to sub-functions within a function (e.g., distribution primary vs. distribution secondary).

Most plant and operating expenses are readily identifiable such that functionalization of these costs is rather straightforward. However, A&G expenses and general plant are indirect in nature and require different treatment. A&G expenses are functionalized using either plant or expense ratios, based on the nature of the expense.

In performing a COS study, a distinction is made between plant from a physical versus operational perspective. An example is transmission lines that function as generator leads to integrate the source of power with the backbone transmission system. These lines are assigned to the generation function for cost study purposes.

Distribution lines are assigned between primary and secondary functions based on an analysis of the type of poles and conductor that are installed for each voltage level. Distribution expenses are generally functionalized based on plant. Services, meters and street lighting plant are directly assigned to their respective functions.

1.5 Classification

The second step in the costing process is classification. In this step, each functionalized cost group is separated into demand, energy and customer-related components based on the predominant factor for cost causation.

Some costs are related to the quantity of energy produced or sold. These are known as energy-related costs. The cost of fuel and the energy component of purchased power are examples of energy-related costs.

Demand or capacity-related costs are those associated with the maximum rate at which energy is produced or consumed. Significant portions of generation, transmission and distribution facilities are considered to be demand-related because the investment in these facilities is related to the size of the facility, and facilities are generally sized to provide service under peak demand conditions.

Customer-related costs are those that are associated with serving customers regardless of either the amount of energy used or the maximum demand. For example, every customer has a meter and a service and the costs associated with metering and billing are not related to consumption. These costs are commonly considered to be allocable on factors that are related to the number of customers.

1.6 Allocation

The third step, allocation of costs, is the process of cost assignment whereby each class of service receives a proportionate cost responsibility for each of the functionalized and classified cost groups. This is accomplished by a combination of direct assignment and by allocation factors that are based on the ratio of the amount of demand, energy produced, or number of customers for each class of service to the system total. Customer classes in the COS study generally correspond with the rate schedules in each of Hydro's systems.

1.6.1 Energy Allocation Factors

Energy factors are developed by starting with forecast sales by customer class within each system and adding losses to reflect the input to each system.

1.6.2 Demand Allocation Factors

Demand factors are developed for each voltage level based on a measure of the maximum load imposed at that voltage level, recognizing:

- Customer load served at each voltage level;
- The level of diversity at each voltage level; and
- Losses.

The demand components of generation and transmission costs are allocated to classes using a 1 CP factor as approved by the Board. Lines and terminal station assets that exclusively serve Newfoundland Power (NP) or Industrial Customers (IC) are directly assigned.

Distribution substations and the demand component of distribution primary and secondary lines in each system are also allocated using the 1 CP method in accordance with the approved methodology.

1.6.3 Customer Allocation Factors

The customer component of primary and secondary distribution lines, transformers, and customer accounting expenses are allocated based on the number of distribution customers in each system. Distribution services and meter expenses are allocated based on weighted customers.

Revenues from non-firm sales customers are credited to the firm customers' revenue requirement.

1.7 Changes Other Than Methodology

1.7.1 Conservation and Demand Management (CDM)

Hydro requested that Lummus Consultants review its CDM costs to determine the appropriate treatment of both CDM program costs and non-program costs. Non-program costs related to CDM, which are the costs of administering the CDM efforts, including non-specific advertising, salary costs, and the like, are included in Hydro’s 2013 test year revenue requirement. The total non-program CDM costs forecast for 2013 are $0.36 Million. These costs are considered by Hydro to be administrative and general (A&G) in nature, allocated among systems using number of customers, and functionalized as all-expense related A&G expenses. I agree with this treatment, as these costs are not directly associated with a particular system or function. Program costs are discussed in Section 4, below.

1.8 Organization of the COS Study

The COS study is included in Hydro’s Application as Exhibit 13, and is organized into the following sections:

- Schedule 1.1 — Revenue Requirement and Return on Rate Base
- Schedule 1.2 — Revenue to Cost Ratios
- Schedule 1.3 — Unit Costs (all systems)
- Schedule 1.4 — Rate Calculations for Newfoundland Power
- Schedule 1.5 — Calculation of Newfoundland Power Thermal Generation Credit
- Schedule 1.6 — Calculation of Firming Up Charge
- Schedule 1.7 — Calculation of Transmission Wheeling Charge
- Schedules 2.1-2.6 — Functionalization and Classification by System
- Schedules 3.1-3.3 — Allocation by System
- Schedule 4.1 — Functionalization and Classification Ratios
- Schedule 4.2 — System Load Factor
- Schedule 4.3 — Holyrood Capacity Factor
- Schedule 4.4 — Power Purchases – Total System

1.9 Study Results

Hydro's revenue requirement includes return on rate base. The rates of return for each system are shown in Schedule 1.1, Page 2 of 2. The system revenue requirements based on the target rates of return are contained in Schedule 1.1, Page 1 of 2. Schedule 1.2 develops revenue to cost coverage ratios as forecast revenues divided by allocated costs. The rural deficit in the cost study is allocated to Newfoundland Power and to Rural Labrador Interconnected Customers.

Unit costs for each customer class, before and after the deficit allocation, are shown in Schedule 1.3. These unit costs, which are expressed in terms of $/kW, $/kWh and $/bill, are not rates per se, but serve a key role in the design of Hydro's proposed rates.

It should be noted that the return on rate base in the 2013 COS study now includes return on equity for rural assets in all systems, as discussed in the Finance evidence. In previous years, there was no return on equity in the Island Isolated, Labrador Isolated, and L'Anse au Loup COS studies or for Island Interconnected assets serving Rural Customers. In the 2013 test year, Hydro has appropriately functionalized and allocated the return on equity in the same manner as return on debt in these systems.

2 Newfoundland Power Rate Design

2.1 Outstanding Issue from April 2008 Review of Demand Billing to Newfoundland Power

Should NP's curtailable load be treated in a manner similar to NP's existing generation credit?

2.1.1 Background

In April 2008, Hydro filed a report with the Board titled Review of Demand Billing to Newfoundland Power (NP Demand Billing Report), (attached as Exhibit 11 to Hydro's GRA evidence) which was completed as a result of an October 20, 2006 Agreement in Hydro's 2006 GRA on Cost of Service, Rate Design and Rate Stabilization Plan. The parties reached agreement as follows:

- It was recommended that the current demand billing approach be continued. While alternate rate designs are available, the current methodology used to calculate billing demand from Hydro to NP reasonably balances Hydro's operating and planning demand requirements with revenue stability and rate practicality considerations. It was judged that the costs of implementation and ongoing administration of alternative approaches would exceed potential benefits.
- Significant changes in marginal costs, system configuration, or other considerations may warrant a further review of the rate structure for the sale of power and energy from Hydro to NP. In addition, the CA recommended that the wholesale rate design be revisited if deemed a deterrent to the province's demand management and energy conservation initiatives.

It was also acknowledged in the April, 2008 report that one outstanding issue remained to be resolved[1], i.e., the recommendation that curtailable load be treated in a manner similar to NP's existing generation credit based on its perspective that service interruptions were causing undue hardship to curtailable service customers with limited system benefit. Hydro and NP recommended that this issue be reviewed at Hydro's next GRA, including cost of service implications, which may be of interest and subject to intervention by other affected customers, such as the Industrial Customers, if it resulted in any change in revenue responsibility.

2.1.2 Current Demand Billing Approach and Effects

Under the current rate structure, NP's annual demand charges are billed based on its highest 15-minute demand in the months of December through March (Native Peak). The billing demand equals the Native Peak, adjusted to reflect normal peak day weather, less the credit for NP's generation (Generation Credit). The Generation Credit avoids the need for NP to operate its generation at the time of system peak in order to reduce its billing demand. The minimum billing demand is set at 99% of the test year billing demand to encourage conservation activities and to protect the ability of Hydro to recover its revenue requirement. The monthly demand charge is equal to the annual demand charge divided by 12 months. Several advantages of this demand rate structure were highlighted in the NP Demand Billing Report, including providing NP with:

- A price signal to encourage the deferral of new generation and transmission capital resources on the Island Interconnected System based on reducing system peak demand requirements.

[1] NP Billing Demand Report, page 1.

Deferral of new generation costs will act to reduce the overall costs of generating electricity on the Island Interconnected System.

- An incentive to conserve energy by shifting load from on-peak periods to off-peak periods.
- An incentive to implement passive load control alternatives, such as time-of-use rates for its retail customers.

In an effort to reduce its demand costs in response to the demand price signal, NP has responded by:

- Increasing participation in its curtailable service option. The number of participants increased from eight customers during the 2004-2005 winter season to 20 in 2007-2008.
- Enabling load curtailments at its own buildings and facilities during peak load periods.
- Developing procedures and voltage monitoring capabilities to enable expanded voltage control management during peak load periods.
- Reviewing its maintenance and operating practices for its generation plants to improve availability of its generation during winter high load periods.
- Continuing to enhance its customer and company facilities energy efficiency efforts.

These steps have resulted in NP's billing demand being below what it otherwise would have been, which contributed to purchased power savings.

Table 1: Newfoundland Power's Billed Demand 2005 - 2011

	2005	2006	2007	2008	2009	2010	2011
Test Year Peak Demand	1,180,000	1,180,000	1,203,500	1,203,500	1,203,500	1,203,500	1,203,500
Minimum Billing Demand[2]	1,044,005	1,044,005	1,074,714	1,074,714	1,074,714	1,074,714	1,074,714
Billed Demand	1,056,055	1,044,005	1,074,714	1,074,714	1,119,136	1,119,636	1,134,566

However effective, issues remain as to whether the incentive provided by the current billing method results in the most effective use of curtailable load to the system. The concerns highlighted in the NP Billing Report are noted below:

- On most peak days, the system has adequate generation available and customer curtailments are not required for system support, however, NP activates curtailment for economic reasons to reduce costs. It may be more efficient to have Hydro reflect a curtailable load credit in determining NP's billing demand and have Hydro request NP to curtail customer load only when the system requires it. This approach would parallel the approach used by Hydro and NP to

[2] Minimum Billing Demand is the Test Year Peak Demand minus the Generation Credit. For the period 2007-2012, the calculation is as shown below:

NP 2007 Test Year Native Load	1,203,500
Generation Credit	-117,930
Net NP Test Year Native Load	1,085,570
Applicable Percentage	0.99
Minimum Billing Demand	**1,074,714**

provide for the most efficient use of NP's generation during peak periods. Providing Hydro the responsibility to dispatch curtailable load when required would result in less inconvenience to customers that has been reported as a consequence of increased frequency in requests to curtail. Over the longer term, an increased number of curtailment requests may result in reduced participation and reduced curtailable load available when needed.

- The CA's perspective is that service interruptions to Curtailable Service customers cause undue hardship and cannot be justified when the interruptions do not coincide with system emergencies.

2.1.3 Discussion

In considering the proposal to implement a generation credit for NP's curtailable load, a number of issues are worthy of investigation. These are noted below:

- One is certainty as to the magnitude and firmness of the curtailable demand and year-to-year variability in its availability. In order to justify the Generation Credit, NP's installed generation is tested each winter season to confirm its availability and ability to produce the predetermined output. A significant portion of NP's curtailable load is at the discretion of its customers and not directly controllable by NP.
- NP's billing provides for a minimum demand of 99% of the test year demand. This was done in order to provide an incentive for NP to implement measures to reduce demand during potential winter peaks. If curtailable load is reformulated as a Generation Credit there would be a rationale to set the minimum billing demand at 100% of the test year value.
- If curtailable load is provided a Generation Credit treatment, Hydro and NP must address the concern that some load during peak periods could still be curtailed for economic reasons, thereby effectively resulting in a duplicate credit.
- If curtailable load is treated as a generation credit, penalty provisions may need to be implemented for non-compliance during annual performance verification or when called on for system benefit.

There is an argument to be made that if customers want to take advantage of opportunities to reduce their own costs through curtailment then there is no "inconvenience" as it is an economic decision. If NP and Hydro agree to have a program to curtail based on system emergencies, Hydro would have to assess the magnitude and firmness of the curtailable load and year-to-year variability in its availability. Additionally, Hydro would be the entity that would determine when such curtailable load is called upon for system emergencies. The present NP demand rate is seen to be working as intended – it encourages conservation, recovers Hydro's costs and ensures appropriate allocation of those costs to NP and the IC. In light if the above concerns, it is recommended that NP, the CA and other interested stakeholders propose options for treatment of NP curtailable load that addresses the concerns discussed above.

2.2 Newfoundland Power's 2013 Rate Structure

2.2.1 Background

The proper rate structure for service provided by Hydro to NP has been the subject of discussion for many years, going back as far as NP's 1989 Rate Hearing. The main focus of the discussion was whether NP should be billed under a demand and energy rate structure in order to provide a proper price signal rather than the energy-only rate that was in place. As a result of Hydro's 2003 GRA, the Board found that the introduction of a demand-energy rate by Hydro for NP's purchased power was appropriate, and in Order No. P.U. 14 (2004), directed that Hydro file, no later than July 31, 2004, an application for the demand-energy rate to be implemented for NP on January 1, 2005, addressing the following issues:

- The degree of risk to be assumed by Hydro;
- The expected relationship between the risk assumed by Hydro and the response in terms of conservation efforts by NP;
- An appropriate weather normalization mechanism, with quantification of the intrinsic error in the formula;
- The treatment of NP's generation;
- Appropriate costing and billing determinants;
- The use of adequate metering, or, in its absence at any supply points, an appropriate estimation formula;
- The effects of variations in NP's hydraulic generation and native load, individually and together; and
- The effects of varying levels of demand and energy rates for a range of usage patterns.

Hydro's July 30, 2004 Application proposed that a demand and energy rate structure for sales of power and energy to NP be implemented as of January 1, 2005 with the following features:

A demand rate ($/kW/month)

- With a minimum billing demand of 99% of NP's adjusted native load, and a weather adjustment true-up of the winter demand

A two-block inclining energy rate ($/kWh)

- With the first Block at 250 GWh/month
- And the second Block over 250 GWh /month and price reflective of the test year cost of Holyrood fuel oil.

The demand rate was anticipated to recover test year demand costs, with the 99% minimum billing demand assigning some risk to Hydro should NP achieve less demand than forecast. The first energy block of 250 GWh corresponded to the forecast minimum energy consumption that NP does not fall below in any month. A three-year phased-in implementation of the full demand cost recovery was proposed.

The Board, in Order No. P.U. 44 (2004), approved the proposed rate structure and three year implementation plan, and a reserve account for NP regarding variations in the cost of power purchased from hydro.

2.2.2 Hydro's 2006 Rate Hearing

The parties (Hydro, NP, the Consumer Advocate, and the Industrial Customers) negotiated many items from Hydro's 2006 *G*eneral Rate Application. Among these negotiated items was reducing the level of NP's demand charge per kW from the cost based $7.49 to $4.00. The rates were therefore determined as follows:

- Demand – negotiated
- Tail block – Test Year Holyrood Fuel price per barrel divided by Test Year Holyrood Efficiency Factor
- First block – (Total Revenue Requirement less forecast demand revenue less forecast tail block revenue) divided by First Block kWh

2.2.3 2008 Report: "Review of Demand Billing to Newfoundland Power"

A review Hydro's rate structure for the sale of power and energy to NP was completed in accordance with the Agreement on Cost of Service, Rate Design and Rate Stabilization Plan filed during Hydro's 2006 GRA. NP, CA and Hydro (the Parties) reached agreement as follows:

- The Parties recommend continuing with the current demand billing approach. While alternate rate designs are available, the current methodology used to calculate billing demand from Hydro to NP reasonably balances Hydro's operating and planning demand requirements with revenue stability and rate practicality considerations. It is judged that at this point in time that the costs of implementation and ongoing administration of alternative approaches would exceed potential benefits.
- Significant changes in marginal costs, system configuration, or other considerations may warrant a further review of the rate structure for the sale of power and energy from Hydro to NP. In addition, the CA recommends that the wholesale rate design be revisited if deemed a deterrent to the Province's demand management and energy conservation initiatives.

The review of the demand billing approach in NP's rate design considered the generally accepted rate design principles agreed to by all Parties in the 2006 Hydro GRA[3], as indicated below.

> Giving consideration to the generally accepted principles and past regulatory practice in this jurisdiction, the Industrial Customers and Newfoundland Power rate designs will be developed and implemented based on the following principles:
>
> A. Rates will be designed to recover the class revenue requirement derived in the embedded cost of service study.
>
> B. Rate design will give consideration to the fairness of embedded cost recovery from individual customers within classes.
>
> C. Capacity and energy rate components will reflect current forecasts of time varying marginal costs of system capacity and energy when the benefits resulting from more complex rate designs are judged to exceed the costs of implementation.
>
> D. The rate designs will take into account trends in marginal costs. For example, if system marginal capacity costs are expected to increase over time, they may be averaged over a number of years in the future in order to capture a portion of the expected increase. Trends and the relevance of future capacity additions may be given more or less weighting depending on the objectives at the time.

[3] Agreement on Cost of Service, Rate Design and Rate Stabilization Plan, Attachment A.

E. Rate designs will incorporate an element of revenue/price stability, certainty, predictability and understandability. This will include consideration of marginal costs over a number of years into the future.

2.2.4 Current Application

As fuel prices are rising, and Hydro has identified capacity constraints requiring investment in new transmission, the appropriate demand, first block and tail block rates to charge Newfoundland Power, as well as the appropriateness of the level of the first block kWh require review. To that end, Lummus Consultants was engaged to assess alternatives and prepare a recommendation.

Issues:

- Should NP's demand rate now be cost-based?
- Should the current focus on fuel-based pricing for the second energy block be given less importance, considering the uncertainty of demand and energy contract terms of the anticipated Labrador infeed?
- If the tail block of NP's energy rate is set at the price of Holyrood fuel oil (currently forecast to be $108.74/bbl) and recognizing that a portion of Hydro's non-fuel revenue requirement is collected in the tail block, the balance of the revenue requirement, to be collected in the first block, will become negative.

Hydro's latest Generation Planning Issues Report (July 2010) shows that, absent any action on Hydro's part, an Island Interconnected System capacity deficit would occur in 2015. Additionally, significant transmission line expenditures are planned for 2012-2016, which are also capacity-related expenditures. In short, there does not seem to be justification for muting the demand price signal by pricing NP's demand at less than the cost based rate.

Retaining the existing methodology for calculating NP's First block rate would result in a negative first block rate under current fuel oil prices. **Figure 1**, below, shows that NP's monthly usage pattern over the three year period 2009-2011 is relatively consistent and does not dip below the 250 GWh first energy block threshold in any summer month. Additionally, based on the forecast load growth for 2013-2015, NP's consumption in the summer months is expected to remain above 280 GWh.

Figure 1: Newfoundland Power Monthly Usage Pattern, 2009 – 2015

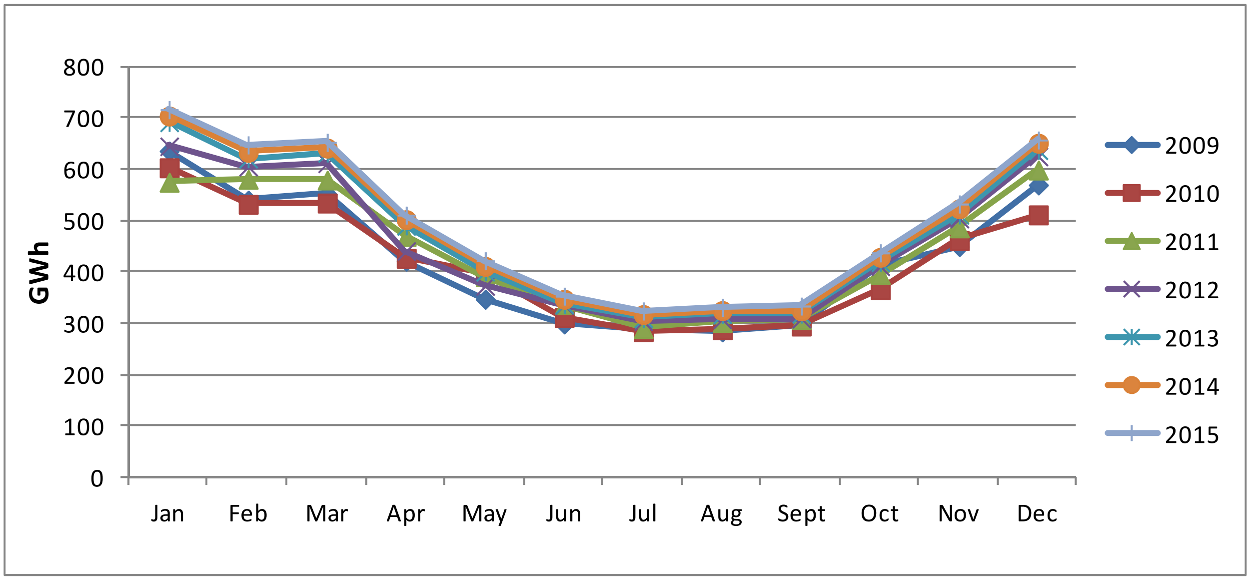


Table 2, below, which provides a sample rate calculation using 2013 forecast fuel assumptions, shows that at the test year price of fuel oil under the existing rate structure, the first block would be negative 45.00 mills per kWh, which results in a perverse price signal.

Table 2: Sample NP Rates - Existing Methodology

	Test Year Fuel Oil				
1	$/bbl	$ 108.74			
2	Holyrood Conversion Rate (kWh/bbl)	612			
3	Mills/kWh	$ 177.68			
4	Total Holyrood Fuel Costs	$ 200,692,615	Sch. 1.1, pg 1, Ln 2 Col. 3		
5	NP Energy Ratio	0.8673	Sch. 3.1A, Ln 14 Col 4		
	NP Revenue Requirement				
6	Total Revenue Requirement	$ 453,005,298	Sch. 1.2, pg 1, Ln 1, Col 7		
7	Demand Revenue Requirement	$ 127,044,995	Sch. 1.3.1, pg 1, Ln 1, Col 3		
8	Energy Revenue Requirement	$ 267,676,715	Sch. 1.3.1. pg 1, Ln 1, Col 4		
9	NP Allocated Holyrood Fuel Costs	$ 174,067,395	Ln 4 * Ln 5		
10	Non-Fuel Energy Costs	$ 93,609,320	Ln 8 - Ln 9		
	Rate	kW/kWh	Rate	Revenue	
		(A)	(B)	(C)	
11	Demand	13,929,036	$ 9.12	$ 127,044,995	kW: Sch 1.3.2, pg 1, Ln 1, Col 2; Revenue: Ln 7; Rate: Col C/Col A
12	Energy				
13	First block (First 250 GWh/mo.)	3,000,000,000	$ (0.04500)	(134,994,243)	kWh: 250 GWh * 12 * 1,000,000; Revenue: Ln 6 - Ln 7 - Ln 14; Rate: Col C/Col A
14	Second block (Over 250 GWh/mo.)	2,594,300,000	$ 0.17768	460,954,546	kWh: Ln 15, Col A - Ln 13 Col A; Rate: Ln 3/1,000; Revenue: Ln 6 - Ln 11 Col C - Ln 13 Col C
		-----------------		-----------------	
15	Total	5,594,300,000		$ 453,005,298	kWh: Sch. 1.3.2, pg 1, Ln 1, Col 3; Revenue: Sch. 1.3.1, pg 1, Ln 1, Col 6

The effect of a moderate increase to the first block from 250 GWh per month to 280 GWh in each of four summer months and 325 GWh per month in the non-summer months, results in a first block rate of negative 1.9 mills/kWh, or virtually zero, with any future increases in the price of test year fuel oil resulting in a more negative first block price. This is shown in **Table 3**, below.

Table 3: Sample NP Rates – Increase Summer Months to 280 GWh; Non-Summer Months to 325 GWh

	Test Year Fuel Oil				
1	$/bbl	$ 108.74			
2	Holyrood Conversion Rate (kWh/bbl)	612			
3	Mills/kWh	$ 177.68			
4	Total Holyrood Fuel Costs	$ 200,692,615	Sch. 1.1, Ln 2 Col. 3		
5	NP Energy Ratio	0.8673	Sch. 3.1A, Ln 14 Col 4		
	NP Revenue Requirement				
6	Total Revenue Requirement	$ 453,005,298	Sch. 1.2, pg 1, Ln 1, Col 7		
7	Demand Revenue Requirement	$ 127,044,995	Sch. 1.3.1, pg 1, Ln 1, Col 3		
8	Energy Revenue Requirement	$ 267,676,715	Sch. 1.3.1. pg 1, Ln 1, Col 4		
9	NP Allocated Holyrood Fuel Costs	$ 174,067,395	Ln 4 * Ln 5		
10	Non-Fuel Energy Costs	$ 93,609,320	Ln 8 - Ln 9		
	Rate	kW/kWh	Rate	Revenue	
		(A)	(B)	(C)	
11	Demand	13,929,036	$ 9.12	$ 127,044,995	kW: Sch 1.3.2, pg 1, Ln 1, Col 2; Revenue: Ln 7; Rate: Col C/Col A
12	Energy				
13	First block @ 280 GWh/mo. (June-Sept); 325 GWh (other months)	3,720,000,000	$ (0.00190)	(7,064,831)	kWh: (280 GWh*4 + 325*8)*1,000,000; Revenue: Ln 6 - Ln 7 - Ln 14; Rate: Col C/Col A
14	Second block (Over 280 GWh/mo.)	1,874,300,000	$ 0.17768	333,025,134	kWh: Ln 15, Col A - Ln 13 Col A; Revenue: Ln 6 - Ln 11 Col C - Ln 13 Col C; Rate: Ln 3/1,000
		----------------		----------------	
15	Total	5,594,300,000		$ 453,005,298	kWh: Sch. 1.3.2, pg 1, Ln 1, Col 3; Revenue: Sch. 1.3.1, pg 1, Ln 1, Col 6

The methodology used to date to calculate NP's rates therefore requires adjustment. The variables in the calculation of the rates are:

1.) Demand rate;
2.) First block kWh;
3.) First block energy rate; and
4.) Second block energy rate.

Assuming the recommendation regarding keeping the demand rate equal to cost holds true, the size of the first block and the energy rates become the adjustable variables.

Additional principles to consider here include:

- Monthly invoicing should be reflective of monthly costs;
- Cash flows of both utilities should not be unduly impacted; and
- Rate Stabilization Plan impacts should be minimized to the extent possible.

1. Monthly invoicing should be reflective of monthly costs

For monthly invoicing to be reflective of monthly costs, the first block pricing for low consumption months (typically August, followed by July and September) should be reasonably close to the average non-fuel cost of energy. For the purpose of this analysis, the average cost of energy, excluding Holyrood and demand costs, is approximately 2.8 cents/kWh. The first block rate should not materially slip below this threshold.

2. Cash flows of both utilities should not be unduly impacted

Setting the first block price materially below the non-fuel costs of Hydro (as above) could result in Hydro's cash flow stream during those low NP consumption months being inadequate to cover operating costs. That may influence borrowing, which could result in higher debt financing costs being passed to the rate payers.

As well, setting tail block prices for NP too high in high consumption months could adversely impact NP's cash flows, in that NP would be unable to pass along a particularly high price to most of its customers. In those high consumption months NP would therefore be paying power purchase costs that significantly exceed its cash flow.

The relative inability to get a reasonable first block rate by varying block sizes under condition of high fuel oil prices stems from the fact that there is unrecovered non-fuel energy revenue requirement in the second block. Since the second block contains the balance of the non-fuel energy revenue requirement, as the test year fuel oil price increases, Hydro's non-fuel revenue requirement balance in the second block also increases at the price of fuel oil, thereby applying downward pressure on the first block rate.

Table 4, below, maintains the same rate structure but sets the first block at 280 GWh in all months and targets recovery of 100% of the non-fuel energy revenue requirement in the first block and Holyrood fuel costs, the rural deficit and customer-related costs in the second block. This results in a first block rate of $0.02786/kWh and a second block rate of $0.10400/kWh.

Table 4: Sample NP Rates –Increase First Block Size to 280 GWh in all months; All Non-Fuel Energy Revenue Requirement Recovered in the First Block

	Test Year Fuel Oil							
1	$/bbl	$ 108.74						
2	Holyrood Conversion Rate (kWh/bbl)	612						
3	Mills/kWh	$ 177.68						
4	Total Holyrood Fuel Costs	$ 200,692,615	Sch. 1.1, Ln 2 Col. 3					
5	NP Transmission Allocation Ratio	0.8673	Sch. 3.1A, Ln 14 Col 4					
	NP Revenue Requirement							
6	Total Revenue Requirement	$ 453,005,298	Sch. 1.2, pg 1, Ln 1, Col 7					
7	Demand Revenue Requirement	$ 127,044,995	Sch. 1.3.1, pg 1, Ln 1, Col 3					
8	Energy Revenue Requirement	$ 267,676,715	Sch. 1.3.1. pg 1, Ln 1, Col 4					
9	NP Allocated Holyrood Fuel Costs	$ 174,067,395	Ln 4 * Ln 5					
10	Non-Fuel Energy Costs	$ 93,609,320	Ln 8 - Ln 9					
	Rate	kW/kWh	Rate	Revenue	127,032,808			
		(A)	(B)	(C)				
11	Demand	13,929,036	$ 9.12	$ 127,032,808	kW: Sch 1.3.2, pg 1, Ln 1, Col 2; Rate: Ln 7 / Ln 11 rounded; Revenue: Ln 11 Col A * Col B			
12	Energy							
13	First block (First 280 GWh/mo.)	3,360,000,000	$ 0.02786	93,609,600	kWh: 280 GWh * 12 * 1,000,000; Revenue: Ln 10; Rate: Col C/Col A			
14	Second block (Over 280 GWh/mo.)	2,234,300,000	$ 0.10400	232,362,890	kWh: Ln 15 Col A - Ln 13 Col A; Revenue: Ln 6 - Ln 11 Col C - Ln 13 Col C; Rate: Col C/Col A			
		-----------------		-----------------				
15	Total	5,594,300,000		$ 453,005,298	kWh: Sch. 1.3.2, pg 1, Ln 1, Col 3; Revenue: Sch. 1.3.1, pg 1, Ln 1, Col 6			

Although this rate recovers Hydro's full test year revenue requirement for NP, is reflective of monthly costs and does not unduly impact cash flows, there is an impact on the Load Variation component of the RSP due to the second block of the rate being significantly lower than the test year price of fuel. With a tail block price less than the Test Year fuel price per kWh, variations in NP's load will have a larger value than load variations had based upon the 2007 Test Year fuel prices and base rates.

As noted above, while the contract terms defining the demand and energy rate associated with the Labrador infeed is not certain at this time, by placing less emphasis on Holyrood fuel, this rate structure is seen to be moving towards closer alignment with the possible demand/energy relationship of the next least-cost supply resource.

3 Industrial Customer Rate Design

3.1 Background

Following Hydro's 2006 GRA, Hydro and the Industrial Customers entered into discussions, agreed upon during the GRA, for the purpose of developing a revised Island Industrial rate design that was consistent with a more focused set of objectives.

Meetings to discuss rate design alternatives were held during 2007 and a joint report detailing the results of those discussions, titled Review of Industrial Customer Rate Design (IC Rate Design Report), attached as Exhibit 12, was prepared by Hydro and filed with the PUB on February 5, 2008.

As discussed in that report, agreement between Hydro and the IC was reached on the following:

- A two-block rate structure for IC with a marginal cost based second block could improve price signals and economic efficiency.
- The tail block or second block should be priced at Hydro's Test Year marginal cost of supply.
- An IC would be able to apply to Hydro to have their first block energy adjusted to take into account significant changes to their business or output. Industrial Customers entering the Island Interconnected System between rate hearings would l be charged a Test Year average energy charge, in addition to regular IC demand charges for all kWh. The difference between the cost of fuel and the energy revenue received should be recoverable by Hydro through an automatic rate adjustment.
- Hydro would continue to bill IC embedded cost-based demand charges for their full Power on Order.
- Industrial Customer generation should not affect the two-block rate structure, and vice versa.

Areas in which agreement was not reached include:

- The method to be used to calculate the size of the first block.
- In situations such as strikes or temporary plant shutdowns, whether unused kWh in the first block should be carried forward to succeeding months.
- The treatment of automatic fuel related adjustments when a new customer enters the Island Interconnected System between test years or when an existing industrial customer is given an increased first block size by virtue of a qualified increase in load.

Issues that were discussed in detail, but deferred for final decision subject to further studies and reports are:

- DSM and conservation initiatives; and
- The continued need for a load variation provision in the RSP depending upon which method was used to calculate the size of the first block.

There is also the question as to whether it is appropriate to consider if the recommendations still make sense in light of the potential Labrador interconnection.

3.2 Current Industrial Customer Rate Design

The current Industrial Customer (IC) firm rate design consists of a single demand charge applied to all Power on Order each month and a single energy charge applied to all firm energy consumed. Non-firm energy is usually priced at the cost of fuel at Holyrood.

3.2.1 Current Application

For the 2013 Application, additional issues to be considered are:

- Is the two block rate structure still appropriate given the Industrial Customers CDM program?
- Is a two block rate structure still appropriate in light of the proposed 2017 Labrador Interconnection?
- How would the rate structure affect the billing of the construction load of Vale Newfoundland and Labrador Limited (Vale)?

3.2.2 Industrial Customer Energy Conservation Initiatives

At the time of the discussions with the IC in 2007, one of the IC concerns was the economic payback period for implementing CDM programs, where the energy rate for payback was the average cost of energy (3.676 cents/kWh approved base rates from 2007). Since that time, Hydro has made available a CDM program for IC which provides incentives for qualified conservation projects. The program includes: a High Level Energy Audit of the IC which will be fully funded by Hydro and a Feasibility Study of a potential project which will be 50% funded by Hydro, up to a maximum of $50,000 at a project development level. A Project Development Agreement is entered into, where the IC and Hydro have a formal agreement outlining the project deliverables, expected energy savings, incentives to be provided by Hydro, and obligations of both parties. Incentives are determined on a case by case basis based on maximums for either project costs first year energy savings or payback period. The economic tests used to determine these thresholds are CDM economic tests used by utilities across North America.

This program has effectively addressed concerns over incentives being available to the IC for CDM, thereby mitigating the need for a two block rate structure.

3.2.3 Labrador Interconnection

Hydro's current least cost generation plan is the Labrador Interconnection. At this point, the contract terms, demand and/or energy constraints, and resultant cost of service methodology are uncertain. The appropriate marginal price signal is therefore uncertain. Adjusting the IC rate structure at this time for a fuel price signal, expected to no longer be required within the relatively near term, and in light of the CDM requirements being addressed as discussed previously, does not appear to be prudent.

3.2.4 Vale Construction Power requirements

The 2013 Test Year load forecast shows Vale taking service with a maximum monthly Power on Order of 25 MW. This is a construction period for Vale, and the average monthly Power on Order will increase to 40.6 MW in 2014, 70.1 MW in 2015, 75.3 MW in 2016 and stabilizing at 77.6 MW in 2017, at which time it will be Hydro's largest IC. As discussed previously, one concern with a two block energy rate structure under increasing load for an IC, is the requirement to adapt the two block rate structure to that increasing load. The planned load for Vale would add a level of complexity, and a lack of transparency, to the block sizes under a two block rate structure, for the customer in each year after the 2013 test year. The Vale load is anticipated to stabilize around the time of the Labrador Interconnection, where a different rate structure may be more appropriate. This suggests that implementation of a two block energy rate structure at this time may not be advisable.

In light of the foregoing, it is recommended that the existing flat energy rate for the IC continue.

4 CDM Recovery Mechanism

4.1 Background

As part of its 2006 GRA, Hydro committed to determine the available opportunities for cost effective demand side management/conservation. The resultant five-year plan for electricity conservation was filed with the Board on June 27, 2008, and a NP/Hydro (the Utilities) partnership was developed in this area.

The justification of the Utilities' CDM programs has been on system energy savings that benefit all customers on the Island interconnected System, including: Hydro Rural, IC and NP. The CDM savings funded by Hydro to date have been only through the programs offered to its Rural Customers. A custom IC program has also been operating. The IC program has resulted in minimal energy savings to date. Additional applications for rebates are being processed with installations expected in 2012 and 2013.

4.1.1 Treatment of CDM Costs

Hydro has asked Lummus Consultants to review and recommend the most appropriate way to assign CDM costs to its customer groups and how best to recover these costs. Two potential methods for assigning the costs to customer groups are:

- To directly assign and recover only the costs of the programs from each customer class that are offered to that class; or
- To allocate all CDM program costs and recover those costs from all customer classes on the same basis.

Allocation of CDM costs direct to specific customer classes

Using the Island Interconnected System as an example, if Hydro assigned CDM costs to those customer classes that directly benefited from the specific program measures, the rural and IC class would each be assigned their respective CDM costs that were incurred by Hydro. The costs directly assigned to the Rural Customers would, as a practical matter, be allocated to each Rural Customer class, regardless of whether or not each customer received a direct CDM program benefit.

If costs are assigned to the customer class that received the CDM funding, the following is true:

- Customers within a class that do not receive the CDM benefit will subsidize those that do. Spreading CDM costs among the customers in only one class tends to amplify the effect of any cross-subsidies as compared with spreading all CDM costs among all customers.
- Direct assignment does not recognize that energy savings by any of Hydro's customer classes results in lower fuel oil costs, which benefits all customer classes. Direct assignment of CDM costs to the targeted classes acts to mitigate the savings to those classes.

It is therefore recommended that Hydro consider the CDM program costs as common costs, applicable to all customer classes consistent with the anticipated fuel savings from the programs.

As common costs, the next issue is to determine the most appropriate method of allocation to rate classes, i.e., energy or demand. Since Hydro's impetus for funding the existing CDM programs is to achieve overall fuel savings, the most appropriate treatment is to allocate these costs on an energy basis. Allocation on a common energy basis:

- Recognizes that all customer classes derive benefits from less fuel oil burned, which manifests itself as a larger percentage of less costly hydraulic resources available to all customers;
- Is consistent with the COS allocation of fuel oil to all of Hydro's customer classes. The avoided fuel costs as a result of the CDM programs results in less fuel cost for all customers, regardless of which class was responsible for the savings. On the Island Interconnected System, NP, by virtue of its relative size would derive the greatest benefit of avoided fuel oil costs; and
- Is administratively straightforward.

While the focus of Hydro's current CDM programs is to achieve fuel oil savings, it is possible that future CDM program measures could focus on peak demand reduction. Also, while the terms of the Labrador in-feed remain uncertain at this time, peak demand might also impose an operational or economic constraint in the future.

In order to provide flexibility in addressing the focus of future CDM measures, a recommended option is to implement a common allocation methodology that incorporates both energy and demand components, in which the weighting of each component could change from time to time as a function of the then-current program measures.

- For Hydro's current CDM programs, the weighting would be 100% common energy and 0% common demand.
- Hydro would petition the Board for approval in the change in weightings, if and when circumstances warranted.

4.1.2 Recovery Mechanism for CDM Costs

Hydro's 2009, 2010, 2011 and 2012 CDM program expenditures received Board approval for deferral and a CDM Cost Deferral Account was established. The definition of this account is attached as Appendix 1.

Table 5, below, shows the balance forecast in this deferral account at December 31, 2012:

Table 5: Deferred CDM Costs

	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Grand Total
CDM Deferred Account	$ 159,313	$ 412,024	$ 473,926	$ 1,384,548	$ 2,429,811

NP, in its 2010 GRA, proposed that its deferred 2009 CDM costs, which were approved by the Board for deferral in a manner similar to Hydro's costs, be amortized over the remaining four years of the five-year Energy Conservation Plan, beginning January 1, 2010[4].

Although NP and Hydro share the same CDM programs, NP began recovery of its deferred CDM costs approximately two and a half years before Hydro's application for recovery in this proceeding. Also, **Table 5** shows that Hydro's CDM expenditures are more heavily weighted during the last two years of the CDM program If Hydro were to recover its deferred CDM costs through its revenue requirement to the end of the initial five-year study period, it could result in a significant increase during the remaining two years. For these reasons it is recommended that Hydro amortize its deferred CDM costs over a somewhat longer period in order to provide a more even recovery of these costs.

One must consider whether the CDM costs should be recovered through the revenue requirement (in base rates) or through a rate rider.

Hydro's CDM costs have varied significantly from budget costs, as seen in **Table 6** below for a variety of reasons as described in its annual CDM reporting to the Board. The magnitude of expenditures expected to be proposed through the IC CDM program ($0.1 Million to $0.5 Million per individual project) and the low frequency with which such expenditures are anticipated to occur, is anticipated to result in a relatively uneven annual expenditures. Hydro also anticipates that emerging technologies and new CDM programs may result in the justifiable need for increased CDM expenditures between test years. To ensure the customers are not over-paying for less than anticipated annual CDM program as well as to account for the potential costs of viable new programs, it is recommended that the CDM costs deferred to date, as well as future CDM program costs, be recovered through the use of a rate rider rather than including them in the 2013 test year revenue requirement. The advantages of a rate rider are that it results in a proper matching of cost recovery with cost incurrence and is administratively straight-forward and transparent. Hydro's proposed CDM Deferred Cost Plan Rules are attached as Appendix 2.

Table 6: CDM Portfolio Spending ($'000)

	2009		2010		2011		2012	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Insulation	$ 132	$ 40	$ 100	$ 60	$ 88	$ 140	$ 28	$ 126
Windows	96	44	93	48	69	80	27	117
Thermostats	65	13	16	19	22	31	7	47
Coupon Program	0	0	0	140	136	135	-	-
Commercial Lighting	78	13	41	12	36	59	23	20
Industrial	1,466	57	2,018	221	830	103	1,772	173
Isolated Custom Commercial	0	0	0	0	0	0	-	93
Isolated Community Direct Install	0	0	0	0	0	0	596	858
Block Heater Timer	0	0	0	0	0	0	63	31
Total	$ 1,837	$ 167	$ 2,268	$ 500	$ 1,181	$ 548	$ 2,516	$ 1,464

[4] In its 2013 GRA, filed in September 2012, NP requested that the PUB allow recovery of its CDM costs over a seven year period, commencing in the year following the year in which the CDM Cost Deferral is charged to its Conservation and Demand Management Cost Deferral Account.

For these reasons it is recommended that Hydro amortize its deferred CDM costs over a somewhat longer seven-year period in order to provide a more even recovery of these costs. Seven years is seen as being reasonable as it is not so short as to cause significant price bumps due to uneven expenditures, nor so long as to cause intergenerational equity issues. This seven year recovery period is also consistent with the recovery period that NP is proposing in its current GRA application.

Hydro's regulated CDM costs are incurred for customers on the Island Interconnected, L'Anse au Loup, Island Isolated and Labrador Isolated Systems. From a COS perspective, the costs incurred for Rural Customers would form part of the rural deficit if included in Hydro's revenue requirement. The rural deficit is allocated among Newfoundland Power and the Labrador Interconnected Rural Customers. Additionally, non-test year rate changes to Hydro's Rural Customers in these systems are included in Hydro's Rural Rate Alteration provision of the Rate Stabilization Plan (RSP). As a practical matter, it is recommended that the CDM costs for the Island Interconnected customers (both rural and industrial) be allocated among the same customer groups and in the same manner as are fuel costs in the RSP. That is, the CDM costs for the Island Interconnected customers should be allocated to Newfoundland Power, the Industrial Customers, and Rural Island interconnected customers based on year-to-date energy sales. The Rural Island Interconnected portion should be added to the CDM costs for the L'Anse au Loup, Island Isolated and Labrador Isolated Systems, and allocated to Newfoundland Power and the Labrador Interconnected Rural customers. As with the RSP costs, the Labrador Interconnected portion would not be recovered.

It is recommended that the amortized costs in each year be recovered from NP and the Island Industrial customers through a separate CDM rider beginning July 1, 2013. This differs from the RSP, which has an effective date of January 1st for the IC and July 1st for NP. However, since the CDM deferral account is separate and distinct from the RSP, no basis is seen for having separate effective dates. For Hydro's current CDM program, the mid-year July 1st date would coincide with NP's CDM recovery mechanism. The proposed mechanism is attached as Appendix 3.

Appendix 1 – Conservation and Demand Management (CDM) Cost Deferral Account Definition

Historic Costs (2009 to 2012):

This account shall be charged with the deferred costs incurred to date from 2009 to 2012 related to Hydro's CDM programs and incentives offered to its Residential and Industrial customers. It will exclude administrative and general expenses necessary to coordinate, advertise and monitor the program. It will also exclude any expenditure related to programs or incentives that are fully recoverable from other parties, including government. Where a program or initiative is partially funded by other parties, the amount funded will be used to reduce the appropriate expenditures.

Costs associated with Labrador Interconnected customers will be tracked separately from costs associated with the other customers, as programs for the latter are based upon a cost structure which is significantly different from the Labrador Interconnected System and future disposition may be treated separately.

Hydro proposes to amortize the account balance (and future year spending) over seven years to provide for more even cost recovery. The resultant annual expense will not be included in the revenue requirement in Hydro's Test Year Application. Rather, it will be disposed of using an annual rate rider beginning July 1, 2014, applicable to Newfoundland Power and Hydro's Industrial customers. The detailed recovery mechanism is provided in the CDM Deferred Cost Recovery Plan Rules.

Appendix 2 – CDM Deferred Cost Recovery Plan Rules

NEWFOUNDLAND AND LABRADOR HYDRO

CONSERVATION AND DEMAND MANAGEMENT DEFERRAL ACCOUNT RECOVERY PLAN

The Conservation and Demand Management Cost Recovery Plan (the Plan) of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to recover Hydro's Conservation and Demand Management (CDM) program expenditures.

The CDM Recovery account shall be charged with the costs incurred in implementing the CDM Program Portfolio. The costs will include such items as detailed program development, promotional materials, advertising, pre and post customer installation checks, application and incentive processing, incentives, trade ally training, employee training, and program evaluation costs associated with programs in the CDM Program Portfolio.

The account will exclude any expenditure properly chargeable to plant accounts. The account shall also exclude conservation expenditures that are general in nature, such as costs associated with providing energy conservation awareness, responding to customer inquiries, planning, research and general supervision that are not associated with a specific program in the CDM Program Portfolio.

The account will exclude any expenditure related to programs or incentives that are fully recoverable from other parties, including government. Where a program or initiative is partially funded by other parties, the amount funded will be used to reduce the appropriate expenditures.

Costs associated with Labrador Interconnected customers will not be included for recovery, as programs for this system are based upon a cost structure which is significantly different from the other systems, and energy savings result in more energy being available for non-regulated sales.

Transfers to, and from, the proposed account will be tax-effected.

Hydro's program expenditures for 2009, 2010, 2011 and 2012 received Board approval for deferral. Additional expenditures will be recorded as incurred.

Recovery/Adjustment Period

The Plan balance as at March each year shall be recovered over a period of seven (7) years.

Plan Balance

The Plan Balance will be maintained separately for the Island Interconnected and Other Systems.

Assignment of Customer Balance for Recovery

The March 31 Plan balance to be removed from the plan and recovered (Recoverable Amount) in the next July 1- to June 30 period is calculated using the following formula:

A/7

Where,

A = March 31 Plan balance
7 = Recovery period in years

The Island Interconnected Recoverable Amount will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the Island Interconnected Recoverable Amount which is initially allocated to Rural Island Interconnected will be added to the Other Plan Recoverable Amount, and then re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Labrador Interconnected Recoverable Amount shall be written off to Hydro's net income (loss).

The Plan Balance will be reduced by the Recoverable Amount.

Recovery Mechanism

Newfoundland Power:
The adjustment rate for each year will be determined as follows:
B = (C ÷ D)

Where,

B = adjustment rate ($ per kWh) for the 12-month period commencing the following July 1
C = Recoverable Amount assigned to Newfoundland Power as at March 31
D = energy sales (kWh) (firm and firmed-up secondary) to Newfoundland Power for the most recent 12 months ended March 31

Island Industrial Customers:
The adjustment rate for each year will be determined as follows:
E = (F ÷ H)

Where,

E = adjustment rate ($ per kWh) for the 12-month period commencing the following July 1
F = Recoverable Amount assigned to Island Industrial customers as at March 31
H = firm energy sales (kWh) to Industrial Customers, for the most recent 12 months ended March 31

Appendix 3 – CDM Recovery Plan Mechanism

Newfoundland and Labrador Hydro

Pro forma Conservation and Demand Management Recovery

31-Mar-13

Line No		A 2009 ($)	B 2010 ($)	C 2011 ($)	D 2012 ($)	2013 Budget, Jan - Mar ($)	E Total (S)	F Recoverable Amount (Col E/7)
1	Island Interconnected Plan Deferred Costs	(159,313)	(412,024)	(473,926)	(1,384,548)	(641,145)	(3,070,956)	(438,708)
2	Other Plan Deferred Costs						0.00	0.00
	Allocation of Island Interconnected Recoverable Amount	**Total**		**Newfoundland Power**	**Island Industrial Customers**	**Rural**	**Labrador Interconnected**	
3	Recoverable Amount, Line 1, Col F	(438,708)						
4	Customer Allocation Ratio , Lines 10 to 12			0.86493	0.06335	0.07172		
5	Allocated Amount, Line 3 * Line 4			(379,451)	(27,794)	(31,463)		
6	Reallocate Rural Portion[1]			(28,034)		31,463	(3,429)	
7	Total Recoverable Amount			(407,485)	(27,794)	0	(3,429)	
8	12 months to date sales, Lines 10 to 11			5,379,834,205	394,061,387			
9	Recovery Rate, Line 7 / Line 8 * 1000 (mills/kWh)			-0.07574	-0.07053			
	Calculation of Customer Allocation Ratios	kWh[2]	**Percent of Total**					
10	12 months to date Utility Sales	5,379,834,205	86.49%					
11	12 months to date Industrial Customers Sales	394,061,387	6.34%					
12	12 months to date Rural Bulk Energy	446,084,468	7.17%					
13	Total	6,219,980,060	100.00%					

(1) The deferred amount allocated to Rural is reallocated to Newfoundland Power and Labrador Interconnected in the same proportion as the Rural deficit, 89.1% and 10.9% respectively.
(2) Twelve months to date sales as at March 31, 2013.
(3) 2012 Island Interconnected Plan cost has actuals to December.

Appendix 4 – Witness Profile of Robert D. Greneman

A witness profile for Mr. Greneman is as follows:

- From 1973 through 1978 Mr. Greneman was employed by Alan J. Schultz, Consulting Engineer (later Casazza, Schultz & Associates), a firm that specialized in economic studies and rate work for electric, gas and water utilities. In 1978 he joined Stone & Webster Consultants, where, as a consultant he has assisted utility companies in rate and regulatory matters. From 1983 to 1986 he was employed by the Brooklyn Union Gas Company in the Rate and Regulatory Department where he was responsible for conducting the Company's cost of service studies, rate design and the review of gas purchase contracts. In 1986 he rejoined Stone & Webster Consultants as an executive consultant in the Rate and Regulatory Services Department.
- Mr. Greneman has prepared and reviewed cost of service and rate design studies for an extensive number of clients including:

  Canada:

  Centra Gas British Columbia (Terasen Gas), Centra Gas Manitoba, Inc., Gaz Metropolitan, Inc. (Montreal), Halifax Regional Municipality, Newfoundland and Labrador Hydro, ICG Utilities (Toronto) and Winnipeg Hydro

  U.S. and Other:

  Alpena Power Company (MI), Barbados Light & Power Company, Ltd., Blackstone Valley Electric Company, Brockton Edison Company, Central Illinois Light Company, Chesapeake Utilities Corporation, China Light & Power Company, Ltd. (Hong Kong), Citizens Utilities Company, City of Westfield, MA, Colorado Electric Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Dayton Power & Light Company, Delmarva Power & Light Company, Delta Natural Gas Company, Edison Sault Electric Company, El Paso Electric Company, Energy Services of Pensacola, Equitable Gas Company, Fall River Electric Light Company, Florida Public Utilities Company, Gas del Estado (Buenos Aires), Green Mountain Power Company, Guam Public Utilities Commission, Guyana Electricity Corporation, Holyoke Department of Gas & Electric (MA), Jamaica Water Supply Company (NY), Lake Superior District Power Company, Louisville Gas & Electric Company, Northern Indiana Public Service Company, Montana-Dakota Utilities Co., Midland Electric Power Cooperative (IA), Newport Electric Corporation, Roseville Electric (CA), Tampa Electric Company, South Jersey Gas Company, Southwest Louisiana Electric Membership Corporation, Southern Indiana Gas and Electric Company, Suffolk County Water Authority (NY), Valley Gas Company (RI), and Washington Natural Gas Company
- Mr. Greneman has provided expert testimony before the Delaware Public Service Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Commonwealth of Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board and the Federal Energy Regulatory Commission.
- Mr. Greneman is a licensed professional engineer in the states of New York and New Jersey.

- Robert Greneman appeared before the Board during Hydro's 2003 and 2006 General Rate Applications

Headquarters:
1430 Enclave Parkway
Houston, TX 77077-2023
Tele: 281.368.3000
Fax: 281.368.4488

Issuing office:

Canton, MA

Other Offices:

Centennial, CO
Dubai
Milton Keynes, UK
Singapore

LUMMUS CONSULTANTS
INTERNATIONAL

NEWFOUNDLAND AND LABRADOR HYDRO

CAPITAL CARRYOVER REPORT
YEAR ENDING DECEMBER 31, 2006

Filed with the Public Utilities Board
February/2007

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL CARRYOVER REPORT
For Year Ending December 31, 2006

TABLE OF CONTENTS

Page

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

OVERVIEW

	Revised PUB App Budget 2006	Actuals 2006	From 2006 Variance	Carryover Amount
GENERATION	7,951	5,913	2,038	2,038
TRANSMISSION & RURAL OPERATIONS	6,182	4,058	2,124	2,124
GENERAL PROPERTIES	5,529	4,661	868	868
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	49	14	35	35
TOTAL CAPITAL BUDGET	19,711	14,646	5,065	5,065

Exhibit 10 (2006 Report)

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

SUMMARY BY CATEGORY

	Revised PUB App Budget 2006	Actuals 2006	From 2006 Variance	Carryover Amount
GENERATION				
NEW GENERATION SOURCE				
Generation Projects	1,523	1,135	388	388
HYDRO PLANTS				
Construction Projects	3,393	2,972	421	421
THERMAL PLANT				
Construction Projects	3,035	1,806	1,229	1,229
TOTAL GENERATION	7,951	5,913	2,038	2,038
TRANSMISSION & RURAL OPERATIONS				
TRANSMISSION	1,779	625	1,154	1,154
SYSTEM PERFORMANCE & PROTECTION	35	29	6	6
TERMINALS	201	43	158	158
DISTRIBUTION	958	830	128	128
GENERATION	3,196	2,531	665	665
GENERAL				
Tools & Equipment	13	0	13	13
TOTAL TRANSMISSION & RURAL OPERATIONS	6,182	4,058	2,124	2,124
GENERAL PROPERTIES				
INFORMATION SYSTEMS & TELECOMMUNICATIONS	5,052	4,250	802	802
ADMINISTRATIVE	477	411	66	66
TOTAL GENERAL PROPERTIES	5,529	4,661	868	868
PROJECTS APPROVED FOR LESS THAN $50,000	49	14	35	35
TOTAL CAPITAL BUDGET	19,711	14,646	5,065	5,065

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

GENERATION

PROJECT DESCRIPTION	Revised PUB App Budget 2006	Actuals 2006	Variance	Carryover Amount	Carryover Explan. Ref. No.
GENERATION PROJECTS					
Island Pond Development - Feasibilty Update	1,003	895	108	108	1
Portland Creek Development -Final Feasibility Study	520	240	280	280	2
TOTAL GENERATION PROJECTS	1,523	1,135	388	388	
HYDRO PLANTS					
CONSTRUCTION PROJECTS					
Replace Penstock - Snook's Arm Generating Station	2,233	1,941	292	292	3
Replace Unit 1 Governor Controls - Cat Arm	883	851	32	32	
Replace Underground Fuel Tanks - Cat Arm Powerhouse	149	134	15	15	
Provide Remote Operation By-Pass Fisheries Comp. Valve - Granite Canal	128	46	82	82	4
TOTAL CONSTRUCTION PROJECTS	3,393	2,972	421	421	
TOTAL HYDRO PLANTS	3,393	2,972	421	421	
THERMAL PLANT					
CONSTRUCTION PROJECTS					
Upgrade Control System - Holyrood	616	561	55	55	5
Purch/Inst Anti-Fouling System for Cooling Water Systems - Holyrood	326	310	16	16	
Addition of Disconnecting Means to 600 Volt MCC Branch Feeders - Holyrood	1,116	728	388	388	6
Fire Protection Upgrades - HRD	369	28	341	341	7
Replace Superheater Unit 2 - Holyrood	319	4	315	315	8
Study of Regeneration Waste Treatment - HRD	172	137	35	35	
Modify Boiler Protection and Control - HRD	117	38	79	79	9
TOTAL CONSTRUCTION PROJECTS	3,035	1,806	1,229	1,229	
TOTAL THERMAL PLANTS	3,035	1,806	1,229	1,229	
TOTAL GENERATION	7,951	5,913	2,038	2,038	

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

TRANSMISSION & RURAL OPERATIONS

PROJECT DESCRIPTION	Revised PUB App Budget 2006	Actuals 2006	Variance	Carryover Amount	Carryover Explan. Ref. No.
TRANSMISSION					
Upgrade Corner Brook Frequency Converter	862	186	676	676	10
Replace Insulators TL231 - (230kV Bay d'Espoir - Stoney Brook)	917	439	478	478	11
TOTAL TRANSMISSION	1,779	625	1,154	1,154	
SYSTEM PERFORMANCE & PROTECTION					
Upgrade Breaker Controls - BDE/BUC Terminal Station	35	29	6	6	
TOTAL SYSTEM PERFORMANCE & PROTECTION	35	29	6	6	
TERMINALS					
Replace Air Compressor and Dryer - Grand Falls Frequency Converter Station	68	20	48	48	
Replace Air Compressors - Holyrood T.S.	80	4	76	76	12
Install Transformer Oil Monitoring System - Upper Salmon	53	19	34	34	
TOTAL TERMINALS	201	43	158	158	

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

TRANSMISSION & RURAL OPERATIONS

PROJECT DESCRIPTION	Revised PUB App Budget 2006	Actuals 2006	Variance	Carryover Amount	Carryover Explan. Ref. No.
DISTRIBUTION					
Upgrade Distribution Feeders - St. Anthony	778	743	35	35	
Distribution Line Pole Replacements - Nain	180	87	93	93	13
TOTAL DISTRIBUTION	958	830	128	128	
GENERATION					
Construct New Diesel Plant - St. Lewis	2,254	1,885	369	369	14
Replace Diesel Generating Units - Various Locations	701	555	146	146	15
Replace Control Panel - Rigolet	135	66	69	69	16
Install Nox Monitor - Little Bay Islands	106	25	81	81	17
TOTAL GENERATION	3,196	2,531	665	665	
TOOLS & EQUIPMENT					
Purchase & Replace Tools & Equipment Less than $ 50,000					
Confined Space Entry Equipment	13	0	13	13	
TOTAL TOOLS & EQUIPMENT	13	0	13	13	
TOTAL TRANSMISSION & RURAL OPERTIONS	6,182	4,058	2,124	2,124	

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

GENERAL PROPERTIES

PROJECT DESCRIPTION	Revised PUB App Budget 2006	Actuals 2006	Variance	Carryover Amount	Carryover Explan. Ref. No.
INFORMATION SYSTEMS & TELECOMMUNICATIONS					
NETWORK SERVICES					
INFRASTRUCTURE REPLACEMENT					
Replace VHF Mobile Radio System	5,619	5,131	488	488	18
Cost Recovery - WST	(1,620)	(1,620)	0	0	
Replace Power Line Carrier TL240 - Churchill Falls - Goose Bay	105	81	24	24	
Microwave Site Refurbishing - Bay D'Espoir Hill & Blue Grass Hill	407	251	156	156	19
Replace Battery System - Multiple Sites	404	312	92	92	20
Westcoast Communications System - Study	137	95	42	42	
TOTAL NETWORK SERVICES	5,052	4,250	802	802	
ADMINISTRATION					
Construct New Warehouse - Port Saunders	477	411	66	66	21
TOTAL ADMINISTRATIVE	477	411	66	66	
TOTAL GENERAL PROPERTIES	5,529	4,661	868	868	

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

OTHER APPROVED FUNDS

PROJECT DESCRIPTION	Revised PUB App Budget 2006	Actuals 2006	Variance	Carryover Amount	Carryover Explan. Ref. No.
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO					
Install Oil Water Separators - Various Stations	49	14	35	35	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	49	14	35	35	

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

GENERATION

---

1. **Island Pond Development - Feasibility Update**

   This project is on budget however there was a delayed start date due to internal labor availability which subsequently resulted in a delayed completion by the consultant. This project is expected to be complete by the end of February, 2007.

2. **Portland Creek Development - Final Feasibility Study**

   The draft report is completed with the final report expected in January. This project is expected to be $276,000 less than the $796,000 due to a scope change resulting in less field investigation work.

3. **Replace Penstock - Snook's Arm Generating Station**

   The Penstock went into service on December 20, 2006. Some design changes were required in order to more appropriately suit site topography and other physical conditions resulting in increased material and construction costs. This project is expected to be complete by July 31, 2007 at a cost of $2,311,000 up from $2,110,000 in the 2006 Capital Budget submission. Work left to be completed includes epoxy coating of welded joints as well as site upgrading and landscaping.

4. **Provide Remote Operation By-Pass Fisheries Comp. Valve - Granite Canal**

   This project was to be completed in August of 2006 however changes in personnel as well as scheduling issues have delayed the completion of this project until May 2007. The cost is estimated to be $128,000 up from the $107,000 due to additional labour costs for designing and testing the system.

5. **Upgrade Control System - Holyrood**

   This project is in-service however training has to be provided for Hydro personnel in the operation and the design of the system. The overall cost of the project has increased to $3,281,000 due installation problems that resulted in additional motor logic and installation work.

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

GENERATION

---

6. **Addition of Disconnecting Means to 600 Volt MCC Branch Feeders - HRD**

   This is a multi-year project expected to be complete by December of 2007. The total estimated capital cost remains unchanged.

7. **Fire Protection Upgrades - HRD**

   This is a multi-year project to be completed by the end of 2007. Due to delays in receiving technical clarifications for requested fire protection improvements and other work commitments the bulk of the work will be completed in 2007. The total estimated capital cost remains unchanged.

8. **Replace Superheater Unit 2 - Holyrood**

   This is a multi-year project to be completed in the fall of 2007. The contract has been awarded and the material ordered. The project is estimated to be on time and budget.

9. **Modify Boiler Protection and Control - HRD**

   Late in the project Hydro was informed that the consultant's proposal was patented by another company. The fee to use the patented information is too high so alternate methods are being explored therefore the project has to be delayed to next fall to allow for the next available outage season.

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

TRANSMISSION & RURAL OPERATIONS

---

10. Upgrade Corner Brook Frequency Converter

Recent increases in the cost of steel and copper, along with increased demand, have led to significant increases in the cost of power transformers therefore the cost of this project has increased to $ 862,000 from $ 617,000. An outage could not be scheduled in 2006 in order to install the new transformer therefore the project is now scheduled to be complete by the end of April 2007.

11. Replace insulators TL231 - (230kV Bay d'Espoir - Stoney Brook)

Project completion has been delayed until April 2007 due to the tendered contract quotes being higher than budgeted. This work will now be completed by Regulated Operations within budget.

12. Replace Air Compressors - Holyrood T.S.

Due to a labour dispute at the manufacturing plant where the compressors are fabricated, delivery was delayed until late December. Installation manpower was not available until the New Year. This project is expected to be completed by the end of February 2007 within budget.

13. Distribution Line Pole Replacements

Part of this job was pole replacements for Nain and the tenders received for this job was much higher than anticipated. Therefore this work will be done internally in the first half of the 2007.

14. Construct New Diesel Plant - St. Lewis

The St. Lewis Diesel Plant is in service in manual mode. Automation of the Plant and correction of contract deficiencies will be completed in the first quarter of 2007. The cost of this project increased by approximately $238,000 due to higher than expected contract costs.

15. Replace Diesel Generating Units - Various Location

This project includes the replacement of two generating units at Rigolet and one at Black Tickle. The Black Tickle job has been carried over into 2007 because the contractor was unable to deliver the unit before the end of the shipping season. The units at Rigolet are on site and the mechanical installation is complete.

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

TRANSMISSION & RURAL OPERATIONS

16. **Replace Control Panel - Rigolet**

The installation of the control panel has been delayed until the replacement of generating units is completed. The total budget remains unchanged.

17. **Install Nox Monitor - Little Bay Islands**

This project was late getting started due to other work commitments. It will be completed in the first quarter of 2007 on budget.

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
YEAR ENDING DECEMBER 31, 2006
($000)

GENERAL PROPERTIES

---

18. Replace VHF Mobile Radio System

Based on the cost and scope of the selected tender for the mobile radio system, the original labour, materials and contract budget estimates have decreased since the system will be contractor owned with Hydro and the Department of Transportation and Works as anchor tenants. This project is expected to be completed by the end of March with a total cost of approximately $4.0 million compared to the original estimate of $8 million.

19. Microwave Site Refurbishing - Bay d'Espoir & Blue Grass Hill

Due to limited labour resources, this project will be completed by March 2007. The total budget remains unchanged.

20. Replace Battery Systems - Multiple Site

Due to an extended delivery time for the batteries combined with limited labour availability, this project will be completed by March 2007 within budget.

21. Construct New Warehouse - Port Saunders

A geotechnical investigation of the site revealed that extensive unforeseen excavation and concrete foundation work was required in order to ensure that the new building would maintain its integrity. This additional work increased the cost by $46,000 as well as delayed the completion date until the end of the first quarter of 2007.

NEWFOUNDLAND AND LABRADOR HYDRO

CAPITAL EXPENDITURES AND CARRYOVER REPORT

YEAR ENDING DECEMBER, 2007

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Quarter Ending December 31, 2007

TABLE OF CONTENTS

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
OVERVIEW

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007
GENERATION	12,057	4,531	9,366	(2,691)
TRANSMISSION AND RURAL OPERATIONS	21,266	8,158	18,241	(3,025)
GENERAL PROPERTIES	8,391	3,393	6,811	(1,580)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	150	743	(257)
PROJECTS APPROVED BY PU BOARD	231	202	202	(29)
NEW PROJECTS APPROVED FOR LESS THAN $50,000	359	191	306	(53)
TOTAL CAPITAL BUDGET	43,304	16,625	35,669	(7,635)

2007 Capital Budget Approved by Board Order No. P.U. 35 (2006)	37,684
Carryover Projects 2006 to 2007	5,065
New Projects Approved by Board Order No. P.U. 25 (2007)	231
2007 New Projects Approved for less than $50,000	324
TOTAL APPROVED CAPITAL BUDGET	43,304

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
OVERVIEW

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007
GENERATION				
NEW GENERATION SOURCE				
Generation Projects	421	0	356	(65)
HYDRO PLANTS				
Construction Projects	1,813	501	1,400	(413)
Property Additions	0	0	0	0
Tools and Equipment	83	24	84	1
THERMAL PLANT				
Construction Projects	8,262	3,186	6,523	(1,739)
Property Additions	599	326	434	(165)
Tools and Equipment	42	6	33	(9)
GAS TURBINES				
Construction Projects	837	488	536	(301)
TOTAL GENERATION	12,057	4,531	9,366	(2,691)

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007
TRANSMISSION AND RURAL OPERATIONS				
TRANSMISSION	7,046	2,111	5,661	(1,385)
SYSTEM PERFORMANCE AND PROTECTION	261	104	184	(77)
TERMINALS	1,617	671	1,320	(297)
DISTRIBUTION	7,746	4,112	8,296	550
GENERATION	2,145	142	977	(1,168)
GENERAL				
Metering	811	267	308	(503)
Properties	655	381	559	(96)
Tools and Equipment	985	370	936	(49)
TRANSMISSION AND RURAL OPERATIONS	21,266	8,158	18,241	(3,025)

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007
GENERAL PROPERTIES				
INFORMATION SYSTEMS AND TELECOMMUNICATIONS	3,999	1,344	3,459	(540)
ADMINISTRATIVE	4,392	2,049	3,352	(1,040)
TOTAL GENERAL PROPERTIES	8,391	3,393	6,811	(1,580)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	150	743	(257)
PROJECTS APPROVED BY PU BOARD	231	202	202	(29)
PROJECTS APPROVED FOR LESS THAN $50,000	359	191	306	(53)
TOTAL CAPITAL BUDGET	43,304	16,625	35,669	(7,635)

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERATION

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2,007	Variance Explan. Ref. No.
NEW GENERATION SOURCE						
GENERATION PROJECTS						
Island Pond Development - Feasibilty Update	108	0	80	(28)	-26%	
Portland Creek Development - Final Feasibility Study	280	0	276	(4)	-1%	
Wind Generation Inventory Study	33	0	0	(33)	-100%	
TOTAL GENERATION PROJECTS	**421**	**0**	**356**	**(65)**		
HYDRO PLANTS						
CONSTRUCTION PROJECTS						
Replace Penstock - Snook's Arm Generating Station	292	6	129	(163)	-56%	1
Replace Unit 1 Governor Controls - Cat Arm	32	0	34	2	6%	
Replace Underground Fuel Tanks - Cat Arm Powerhouse	15	0	15	0	0%	
Provide Remote Operation By-Pass Valve - Granite Canal	82	41	83	1	1%	
Upgrade Access Road - Upper Salmon	675	15	650	(25)	-4%	
Upgrade Access Road - Burnt Dam	309	274	289	(20)	-6%	
Upgrade Cooling Water System Unit 1 and 2 - Bay d'Espoir	112	0	0	(112)	-100%	2
Replace Station Service Control - Bay d'Espoir	105	62	66	(39)	-37%	
Replace Air Dryer - Cat Arm	76	38	41	(35)	-46%	
Replace Bridge Paradise Access Rd	66	41	64	(2)	-3%	
Stator Windings Design Review - Bay d'Espoir	49	24	29	(20)	-41%	
TOTAL CONSTRUCTION PROJECTS	**1,813**	**501**	**1,400**	**(413)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERATION

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
PROPERTY ADDITIONS						
TOTAL PROPERTY ADDITIONS	**0**	**0**	**0**	**0**		
TOOLS AND EQUIPMENT						
Tools and Equipment Less than $50,000	83	24	84	1	1%	
TOTAL TOOLS AND EQUIPMENT	**83**	**24**	**84**	**1**		
TOTAL HYDRO PLANTS	**1,896**	**525**	**1,484**	**(412)**		
THERMAL PLANT - HOLYROOD						
CONSTRUCTION PROJECTS						
Upgrade Control System	55	0	217	162	295%	3
Purch/Inst Anti-Fouling System for Cooling Water Systems	16	0	81	65	406%	
Addition of Disconnecting Means to 600 Volt MCC Branch Feeders	1,138	294	772	(366)	-32%	4
Fire Protection Upgrades	1,797	503	578	(1,219)	-68%	5
Replace Superheater Unit 2	3,133	2,256	3,065	(68)	-2%	
Study of Regeneration Waste Treatment	35	0	19	(16)	-46%	
Modify Boiler Protection and Control	79	77	81	2	3%	
Turbine and Generator Upgrade Unit 3	1,654	55	1,705	51	3%	
Contaminated Water Treatment	276	0	0	(276)	-100%	6
UPS Battery Monitoring Program	79	1	5	(74)		
TOTAL CONSTRUCTION PROJECTS	**8,262**	**3,186**	**6,523**	**(1,739)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERATION

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
PROPERTY ADDITIONS						
Air Preheater Steam Condenser Pumps - Unit 3	599	326	434	(165)	-28%	7
TOTAL PROPERTY ADDITIONS	**599**	**326**	**434**	**(165)**		
TOOLS AND EQUIPMENT						
Tools and Equipment Less than $50,000	42	6	33	(9)	-21%	
TOTAL TOOLS AND EQUIPMENT	**42**	**6**	**33**	**(9)**		
TOTAL THERMAL PLANTS	**8,903**	**3,518**	**6,990**	**(1,913)**		
GAS TURBINES						
CONSTRUCTION PROJECTS						
Replace Fuel Piping - Hardwoods, Stephenville	530	302	312	(218)	-41%	8
Gas Turbine Assessments - Hardwoods, Stephenville	307	186	224	(83)	-27%	
TOTAL GAS TURBINE PLANTS	**837**	**488**	**536**	**(301)**		
TOTAL GENERATION	**12,057**	**4,531**	**9,366**	**(2,691)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
TRANSMISSION						
Upgrade Corner Brook Frequency Converter - 2006	676	119	823	147	22%	9
Replace Insulators TL231 - (230kV Bay d'Espoir - Stoney Brook)	478	0	466	(12)	-3%	
Replace Wood Poles - Transmission - 2007	2,148	1,168	2,214	66	3%	
Replace Insulators - TL251, TL252 and TL234	2,118	707	1,769	(349)	-16%	10
Upgrade Corner Brook Frequency Converter - 2007	1,320	25	26	(1,294)	-98%	11
Supply and Install Bridge - South West River	212	2	273	61	29%	
Install Deadend Structure - Conne River Tap TL220	94	90	90	(4)	-4%	
TOTAL TRANSMISSION	**7,046**	**2,111**	**5,661**	**(1,385)**		
SYSTEM PERFORMANCE AND PROTECTION						
Upgrade Breaker Controls - BDE/BUC Terminal Station	6	0	3	(3)	-50%	
Upgrade 138kV Protection Upgrades - Springdale, Howley, Indian River	215	101	169	(46)	-21%	
Upgrade Breaker Controls - OPD/SSD Terminal Station	40	3	12	(28)	-70%	
TOTAL SYSTEM PERFORMANCE AND PROTECTION	**261**	**104**	**184**	**(77)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
TERMINALS						
Replace Air Compressor and Dryer - Grand Falls Frequency Converter	48	12	42	(6)	-13%	
Replace Air Compressors - Holyrood Terminal Station	76	0	54	(22)	-29%	
Install Transformer Oil Monitoring System - Upper Salmon	34	12	13	(21)	-62%	
Safety and Reliability Upgrade - Hawkes Bay Terminal Station	349	191	204	(145)	-42%	12
Replace Insulators - Various Stations	313	159	298	(15)	-5%	
Upgrade Breakers - Various Stations	258	(54)	146	(112)	-43%	13
Replace Breaker B7C1 - Hardwoods	136	129	143	7	5%	
Replace Instrument Transformers - Various Stations	80	29	80	0	0%	
Replace Compressors - Various Stations	78	64	67	(11)	-14%	
Replace Battery Banks - Various Stations	72	20	68	(4)	-6%	
Replace Battery Chargers - Various Stations	72	65	70	(2)	-3%	
Replace Surge Arrestors - Various Stations	71	29	85	14	20%	
Install RIGD (Remote Ice Growth Detection) Beam - Various Stations	30	15	50	20	67%	
TOTAL TERMINALS	**1,617**	**671**	**1,320**	**(297)**		
DISTRIBUTION						
Upgrade Distribution Feeders - Various Locations	1,418	429	1,129	(289)	-20%	14
Service Extensions	2,085	1,755	2,800	715	34%	15
Distribution Upgrades	2,035	762	2,224	189	9%	
Replace Distribution Lines - South Brook, Harbour Breton	741	538	783	42	6%	
Distribution Line Pole Replacements	837	299	845	8	1%	
Upgrade Unit 290 and Upgrade Fuel Storage - Williams Harbour	479	244	277	(202)	-42%	16
Grey River Stack Modifications	151	85	108	(43)	-28%	
Interconnect - Rencontre East	0	0	130	130		17
TOTAL DISTRIBUTION	**7,746**	**4,112**	**8,296**	**550**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
GENERATION						
Construct New Diesel Plant - St. Lewis	369	20	527	158	43%	18
Replace Diesel Generating Units - Various Location	146	85	189	43	29%	
Replace Control Panel - Rigolet	69	0	90	21	30%	
Install Nox Monitor - Little Bay Islands	81	17	82	1	1%	
Purchase Spare Transformer - Upper Salmon	1,366	13	19	(1,347)	-99%	19
Replace Diesel Unit Breakers - Mary's Harbour	114	7	70	(44)	-39%	
TOTAL GENERATION	**2,145**	**142**	**977**	**(1,168)**		
GENERAL						
METERING						
Automatic Meter Reading	696	195	201	(495)	-71%	20
Purchase Meters and Equipment - Rural Systems	94	65	100	6	6%	
Purchase Metering Spares	21	7	7	(14)	-67%	
TOTAL METERING	**811**	**267**	**308**	**(503)**		
PROPERTIES						
Installation of Fall Arrest Equipment - Hydro facilities	251	110	245	(6)	-2%	
Upgrade Fuel Storage - Norman Bay	222	156	164	(58)	-26%	
Installation of Card Access System - Bishop Falls and Whitbourne	131	97	102	(29)	-22%	
Legal Survey of Distribution Line Right-of-Ways	51	18	48	(3)	-6%	
TOTAL PROPERTIES	**655**	**381**	**559**	**(96)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
TOOLS AND EQUIPMENT						
Confined Space Entry Equipment	13	0	11	(2)	-15%	
Replace Off Road Track Vehicle - Unit 7696 - Cow Head	307	352	352	45	15%	
Replace Light Duty Mobile Equipment Less than $ 50,000	241	0	244	3	1%	
Replace Doble Relay Test Equipment - St. Anthony, Happy Valley	174	3	132	(42)	-24%	
Replace Off Road Track Vehicle - Unit 7734 - Flowers Cove	139	0	91	(48)	-35%	
Tools and Equipment Less than $ 50,000	111	15	106	(5)	-5%	
TOTAL TOOLS AND EQUIPMENT	**985**	**370**	**936**	**(49)**		
TOTAL GENERAL	**2,451**	**1,018**	**1,803**	**(648)**		
TOTAL TRANSMISSION AND RURAL OPERTIONS	**21,266**	**8,158**	**18,241**	**(3,025)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERAL PROPERTIES

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
NEW INFRASTRUCTURE						
Applications Enhancements	149	74	148	(1)	-1%	
Cost Recovery CF(L)Co	(27)	(11)	(28)	(1)	4%	
Upgrade of Technology						
Corporate Application Environment	377	73	107	(270)	-72%	21
Cost Recovery CF(L)Co	(75)	(6)	(21)	54	-72%	
TOTAL SOFTWARE APPLICATIONS	**424**	**130**	**206**	**(218)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERAL PROPERTIES

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
Enterprise Storage Capacity Upgrade	186	168	182	(4)	-2%	
Cost Recovery CF(L)Co	(37)	(11)	(36)	1	-3%	
End User Infrastructure Evergreen Program	395	176	394	(1)	0%	
NEW INFRASTRUCTURE						
Peripheral Infrastructure Replacement	139	15	141	2	1%	
Security Information Management System	73	14	75	2	3%	
Cost Recovery CF(L)Co	(15)	(5)	(15)	0	0%	
UPGRADE OF TECHNOLOGY						
Server Technology Program	82	39	79	(3)	-4%	
TOTAL COMPUTER OPERATIONS	**823**	**396**	**820**	**(3)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERAL PROPERTIES

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Replace VHF Mobile Radio System	2,185	637	1,712	111	22%	22
Cost Recovery of Works and Transporation	(1,680)	(547)	(1,096)			
Replace Power Line Carrier TL240 - Churchill Falls - Goose Bay	24	0	35	11	46%	
Microwave Site Refurbishing - Bay d'Espoir Hill and Blue Grass Hill	156	28	114	(42)	- 27%	
Replace Battery Systems - 2006 - Multiple Sites	92	0	107	15	16%	
Westcoast Communications System - Study	42	0	46	4	10%	
Replace Battery Systems - 2007 - Multiple Sites	485	138	279	(206)	- 42%	23
Microwave Site Refurbishing	364	158	184	(180)	- 49%	24
Replace Remote Terminal Units - Multiple Sites	321	74	276	(45)	- 14%	
Replace VHF Radio Communications - Burnt Dam	226	139	222	(4)	- 2%	
Replace Radomes - Multiple Sites	27	9	9	(18)	- 67%	
Network Infrastructure						
IRIG-B Distributions	103	86	105	2	2%	
Communications Network Technology	102	55	122	20	20%	
Test Equipment	49	9	52	3	6%	
Hydro Place Wireless	44	7	51	7	16%	
UPGRADE OF TECHNOLOGY						
MWIC Quad - Diversity Upgrade	114	0	116	2	2%	
Network Management Tools	49	19	48	(1)	- 2%	
Upgrade Site Facilities	49	6	51	2	4%	
TOTAL NETWORK SERVICES	**2,752**	**818**	**2,433**	**(319)**		
TOTAL INFORMATION SYSTEMS AND TELECONTROL	**3,999**	**1,344**	**3,459**	**(540)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
GENERAL PROPERTIES

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From Budget 2007	Percentage Variance From Budget 2007	Variance Explan. Ref. No.
ADMINISTRATIVE						
VEHICLES						
Replace Vehicles - Hydro System - 2007	2686	1,530	2,218	(468)	-17%	25
Purchase Trucks, Snowmobiles, lifts, storage bldings- Labrador Coast	842	331	798	(44)	-5%	
ADMINISTRATION						
Construct New Warehouse - Port Saunders	66	0	74	8	12%	
Security Assessment of System Operations	668	131	137	(531)	-79%	26
Replace Storage Ramp - Bishop's Falls	62	13	63	1	2%	
Replace Administration Office Equipment less than $50,000	68	44	62	(6)	-9%	
TOTAL ADMINISTRATIVE	**4,392**	**2,049**	**3,352**	**(1,040)**		
TOTAL GENERAL PROPERTIES	**8,391**	**3,393**	**6,811**	**(1,580)**		

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From 2007 Budget	Percentage Variance From 2007 Budget
ALLOCATION FOR UNFORESEEN EVENTS					
Cartwright Distribution - Upgrade Sleet Storm	113	0	105	(8)	-7%
Daniel's Harbour Distribution Line Re-Route	81	0	78	(3)	-4%
Ice Storm Damage - Northern	231	0	245	14	6%
Replace Insulators on TL221	252	0	165	(87)	-35%
Replace Structure 34 on TL212 (Sunnyside to Linton Lake)	203	150	150	(53)	-26%
Unused Allocation for Unforeseen Events	**120**	**0**	**0**	(120)	-100%
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	**1,000**	**150**	**743**	**(257)**	
PROJECTS APPROVED BY PU BOARD					
NEW					
Replace Atomic Absorption with ICP Mass Spectrometer - Order No. P.U. 25 (2007)	231	202	202	(29)	-13%
TOTAL PROJECTS APPROVED BY PU BOARD	**231**	**202**	**202**	**(29)**	

NEWFOUNDLAND & LABRADOR HYDRO
2007 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS

FOR THE QUARTER ENDING DECEMBER 31, 2007
($000)

	PUB Approved Budget 2007	4th Quarter Actuals 2007	Total Actual Expend. 2007	Variance From 2007 Budget	Percentage Variance From 2007 Budget
NEW PROJECTS APPROVED FOR LESS THAN $50,000					
Install Oil Water Separators - Various Stations	35	4	23	(12)	-34%
Replace Annuciator - Come By Chance Terminal Station	49	48	65	16	33%
Replace Battery Charger - Hawkes Bay	4	0	3	(1)	-25%
Purchase High Angle Rescue Equipment	4	0	3	(1)	-25%
Vibration Monitoring Systems Upgrade - Hardwoods and Stephenville	49	32	34	(15)	-31%
Transfer and Overhaul Diesel Unit 2058 - Little Bay Islands	49	(7)	52	3	6%
Replace Portable Oil Dielectric Test Set - Happy Valley	8	7	7	(1)	-13%
Replace Lube Oil Storage Tank - St. Anthony	6	6	6	0	0%
Replace 125 V DC Battery Charger System - L'Anse au Loup	14	10	10	(4)	-29%
Purchase Office Furniture - Hydro Place	22	20	20	(2)	-9%
Install Corporate Emergency Response Centre - Hydro Place	49	23	35	(14)	-29%
Energy Audit - Hydro Place	28	17	17	(11)	-39%
Upgrade Operator Console - Hardwood Gas Turbine	42	31	31	(11)	-26%
TOTAL PROJECTS APPROVED FOR LESS THAN $50,000	**359**	**191**	**306**	**(53)**	

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

1. **Replace Penstock - Snook's Arm Generating Station**

   The project was substantially complete in December of 2006 with only site cleanup and landscaping to be done in 2007; however the contractor claimed that they were owed additional amounts due to design changes and site conditions. The final agreement with the contractor was for $131,000 less than expected. This reduction resulted in less overhead and no contingency being utilized.

2. **Upgrade Cooling Water System Unit 1 and 2 - Bay d'Espoir**

   The anticipated cost of this project had escalated considerably since the proposal was prepared early in 2006, partially due to the unusually high price escalation of stainless steel piping, pipe fittings and equipment, therefore it was cancelled and resubmitted in the 2008 Capital Budget Application. This project was approved for $264,000 in Board Order No. P.U. 30 (2007).

3. **Upgrade Control System - Holyrood**

   The cost of the project increased by $170,000 due to unanticipated difficulties in system compatibility that resulted in additional programming, testing and training. There was no change in scope nor was a cost benefit analysis originally prepared for the installation of this system. In addition, this project remains the least cost alternative.

4. **Addition of Disconnecting Means to 600 Volt Motor Control Centre (MCC) Branch Feeders - Holyrood**

   The project is under budget primarily due to the cost for the contracted portion of the work being less than estimated in the original budget. At the time the budget was prepared, the exact outage schedules for the Holyrood plant were not known, so assumptions were made when estimating the contract portion of the project. Worst case scenarios were used, estimating outages over an extended timeframe, which increased the length and cost of the project. Once outage schedules for the plant were confirmed, and included in the tender documents, the tenders were less than the estimates included in the budget.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

5. Fire Protection Upgrades - Holyrood

Due to delays in receiving technical clarification from the corporation's insurers for requested fire protection improvements and other work commitments, the bulk of the work will be completed in 2008. The total estimated capital cost remains unchanged.

6. Contaminated Water Treatment - Holyrood

The Contaminated Water Treatment Study is deferred until the long-term future of the Holyrood Plant has been determined.

7. Air Preheater Steam Condenser Pumps - Unit 3 - Holyrood

This project was under budget due to the installation contract being significantly less than the amount estimated in 2006. The successful contractor submitted a very favourable tender because of work shortage at the time. The original estimate for the major component of the work was approximately $342,000, while the actual contract cost was approximately $227,000, resulting in savings of $115,000. These reductions also resulted in less overhead and no contingency being utilized.

8. Replace Fuel Piping - Hardwoods, Stephenville

On December 11, 2007, during excavation operations for this project at Stephenville Gas Turbine, the contractor struck an electrical cable causing a delay in this project. The location of the cable was not shown on any existing Hydro drawings. When excavation work resumes it will be performed manually, without the use of an excavator. Due to the manual digging, this work will have to take place when there is no frost in the ground. As well, a complete unit shutdown is required, with all equipment in the area de-energized to minimize the possibility of striking another live wire. This work is scheduled to be completed in the summer of 2008, within budget.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

9. Upgrade Corner Brook Frequency Converter - 2006

The 2006 work was delayed in starting due to negotiations with Corner Brook Pulp & Paper concerning ownership of the facility. The project costs exceeded the budget primarily for three reasons:

- The pressure relief valve on the new transformer was damaged when the transformer arrived on site. Delays and extra work were incurred while waiting for and installing the replacement valve.
- The tenders for the upgrades to the compressed air system were higher than estimated because there were no contractors in the Corner Brook area that submitted tenders and the contract was awarded to a contractor based in St. John's. There were extra costs incurred in mobilizing this contractor to the work site.
- There were no competitive tenders received for the upgrades to the ventilation systems. The systems had to be redesigned twice, in order to attract competitive bids.

These delays and extra work required additional engineering and project management and also increased the overhead and interest expenses for the project. The scope and justification for the project has not changed from the original project proposal. The execution of the work is still being done at the least costs available in the marketplace.

10. Replace Insulators - TL251, TL252 and TL234

There were efficiencies gained and costs saved because additional work crews and equipment were deployed to the area at the time this project was executed. This also resulted in less overhead costs and contingency not being utilized. Both the material and the contract costs were less than estimated by approximately $149,000. In addition, the work was completed in less time than originally budgeted causing the construction labour to be approximately $93,000 under budget.

11. Upgrade Corner Brook Frequency Converter - 2007

This project is expected to be completed within budget. The 2007 project work was delayed due to delays in the 2006 upgrade work (the reasons for which are outlined in (9) above); consequently, the 2007 project is being carried over to 2008.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

12. Safety and Reliability Upgrade - Hawkes Bay Terminal Station

The 2007 work was delayed due to a system planning analysis which indicated potential modifications to the station. Consequently, work on the project did not start until the early summer of 2007. This left only enough time to complete the general civil works in 2007. The tenders for the civil works were higher than estimated due to local contractors not being available, the time of the year when the tender was called and the general cost of grounding materials. It is not yet confirmed whether this increase in the civil costs will result in an increase in the overall project costs. The electrical portion of the upgrades is currently planned for the summer of 2008. There may be some long delivery times on some electrical equipment, which may further delay final project completion.

13. Upgrade Breakers - Various Stations

This project was budgeted to upgrade four breakers but due to outage and resource unavailability only two breakers were upgraded. This resulted in less overhead costs and the contingency amount not being utilized.

14. Upgrade Distribution Feeders - Various Locations

The budget estimates for upgrading distribution feeders are based on contracted out labour, since internal labour availability was unknown at the project proposal stage. The use of internal labour resulted in an overall reduction of project costs. As well, each project is estimated individually, however, efficiencies were gained and costs were reduced due to work crews being deployed to areas and working on multiple projects concurrently.

15. Service Extensions

The budgeted amount is an annual allotment based on the average of the annual expenditures for services extensions over the last five years. It is not based on a summary of specific projects. There was a $330,000 increase from the estimate in the Labrador Interconnected System as well as a new North West Arm Cottage Development expenditure of $310,000 and Pine Cove Interconnection expenditure of $103,000.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

16. Upgrade Unit 290 and Upgrade Fuel Storage - Williams Harbour

This was a pooled project to upgrade Unit 290 and upgrade the fuel storage. The upgrade Unit 290 portion will be carried over into 2008. During testing it was discovered that the genset to be supplied by the winning bidder was not in compliance with the specification. The deficiencies could not be corrected and the order was cancelled. The genset supply must be retendered which will delay completion until approximately September, 2008. Additional costs will be incurred for retendering, acceptance testing of the new genset, training for a potentially new make of genset, and rewiring/recertification of the control panel to suit an alternative genset. The budget for this portion of the project has increased from $290,000 to $370,000.

17. Interconnect - Rencontre East

This project was completed in 2006 however a contract claims settlement resulted in an additional $130,000 being required for this project.

18. Construct New Diesel Plant - St. Lewis

During construction, extra labor charges associated with plant automation and commissioning as well as other in-house work resulted in an increased cost of $136,000 for the new St. Lewis Diesel Plant. Along with this, increased cost of steel and copper components resulted in an increased cost of $22,000.

A cost benefit analysis performed in June 2005 determined that the construction of a new diesel plant at St. Lewis was the preferred option over the other alternative which was to construct an interconnection to Port Hope Simpson. The Net Present Value (NPV) for the new diesel plant was $530,732 in January 2005 dollars. With the discount rate of 8.4% used in the original cost benefit analysis, the $158,000 equals $124,042 in January 2005. Thus, the original NPV benefits have been reduced by $124,042 to $406,690, remaining the least cost alternative.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

19. Purchase Spare Transformer - Upper Salmon

Transformer manufacturers are experiencing significant increases in demand for new transformers which has extended manufacturing time from less than one year to eighteen months. The resultant extended delivery times for large power transformers has changed the project in-service date to December, 2008. The total project cost is still forecast at $2.2 million, of which $1.36 million was budgeted to be spent in 2007 with the remainder to be spent in 2008.

20. Automatic Meter Reading

The cost of the Automatic Meter Reading (AMR) project has increased from $696,000 to $1,135,000 due to additional requirements identified during the detailed project design in 2007, including costs related to the interface between the AMR system and the existing Customer Billing system and receivers required in each distribution system. Additional time is also required to replace the required meters, therefore this project will be carried over with a completion date of October, 2008.

With respect to cost, the projected operating cost per meter for the Bay d'Espoir and St. Anthony service areas for 2007 is $35 per meter. The implementation of AMR will lower the cost to $10 per meter. The cumulative present worth analysis of AMR and the current system has a positive net present value starting in 2017 (11 years), and totals approximately $266,000 in 2022.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

21. Corporate Application Environment

This project consisted of an operating system upgrade and JD Edwards software upgrade. The software upgrade was required because the vendor support for the current release of JD Edwards was terminating. Subsequently, the vendor decided to support Hydro's current software until 2013 therefore it was decided to delay this upgrade, reducing the net budget by $267,000.

22. Replace VHF Mobile Radio System

The cost overrun can be attributed to increased costs incurred with respect to the work and material associated with our user equipment such as VHF radios, Energy Control Centre interface, installation, testing, and training. Issues encountered during the transition phase caused by faulty user equipment required the old VHF radio system to operate three months longer than anticipated while all units in service were reprogrammed to work with the new system. There was no change in the scope and the project remains the least cost solution. The two tenders received had approximately the same capital cost however the chosen solution had a considerably lower operating cost over the 15 year life span. The increased cost of approximately $111,000 on the total project budget of approximately $7.1 million (1.5%) has minimal impact on the NPV calculation.

23. Replace Battery System - Multiple Sites

The material and contract costs were $162,000 less than budgeted for three reasons:

- One battery and charger system originally included in the 2007 budget was replaced in 2006 because additional capacity was needed at that time.
- The tendering process resulted in more competitive bids for installation services than in previous years.
- The contingency of $40,000 was not used.

24. Microwave Site Refurbishing

The original budget of $360,000 was based on a deficiency report generated by Tiller Engineering in 2005. Between that time and the start of this job, some of the items included in the budget had already been replaced. Other items were operating costs and therefore removed from the list. This resulted in the actual expenditure being significantly below the original budget.

NEWFOUNDLAND & LABRADOR HYDRO
2007 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2007
(Greater than $100,000)

25. Replace Vehicles - Hydro System - 2007

The remainder of this budget has been carried over to 2008 for the boom remount project dealing with stability issues on two boom trucks V4483 and V4486. This includes supply and installation of two new booms on the old chassis. The lead time to supply the new booms is 18 months.

26. Security Assessment of System Operations

The work completed in 2007 consisted of installing anti-climb devices on communication towers throughout the system, purchasing high voltage and personal protective equipment signage for installation throughout the system, and the initiation of a telecommunication design review. In 2008, the work scope consists of purchasing, and installing a card reader, surveillance camera and alarm equipment throughout the system. As well, upgrades to fencing, area lighting and signage will begin. The requirements for these upgrades were outlined in a summary document produced in 2007, however, the schedule for this work has not yet been finalized. The work will be completed through a combination of external contracts and some work by Hydro Operations. This project will be carried over into 2008 with a scheduled completion date of December, 2008 within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 1998 - 2007
AS AT DECEMBER 31
($000)

Year	Budget	Actual Expenditures	Variance	Percentage Variance
1998	47,522	28,017	19,505	41.0%
1999	38,142	29,684	8,458	22.2%
2000	43,824	38,569	5,255	12.0%
2001	55,897	47,501	8,396	15.0%
2002	44,660	40,217	4,443	9.9%
2003	36,122	32,506	3,616	10.0%
2004	31,435	27,984	3,451	11.0%
2005	47,760	33,952	13,808	28.9%
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%

It should be noted that the above variances include amounts related to the carryover of projects from year to year. Variances from budget for completed projects are 8% and 5% for 2006 and 2007 respectively, well within acceptable ranges. Project carryovers worsened considerably in 2005, with retirements, transfers and reassignments, primarily as a result of the reorganization of Hydro's engineering function. Since then, improvements have been made, and efforts are underway to further improve the completion of projects on schedule. These efforts include:

- more two-year schedules to accommodate the construction seasons rather than the calendar year;
- more two-year schedules to allow adequate lead time on materials, such as that now required for the purchase of power transformers, as identified in the variance explanation for the Upper Salmon transformer, which contributed to the 2007 carryover amount;
- newly hired engineers obtaining the experience and knowledge required to be able to more independently complete assignments;

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 1998 - 2007
AS AT DECEMBER 31
($000)

- capital budget preparation now including review of staff availability. The internal 2008 Capital Budget review resulted in a deferral of projects which remain necessary, but could not be completed with existing staff. This type of deferral, however, contains a risk to the reliability of Hydro's aging infrastructure, which will be mitigated when the maintenance plan is completed.

It is not anticipated that carryovers of capital projects will ever be eliminated. There are frequently sound or unavoidable reasons for delay in project completion, such as in 2007, when projects were delayed due to:

- consideration of the prudence of a particular project under changing circumstances, such as the delay experienced in the safety and reliability upgrades at Hawkes Bay. The project was delayed pending analysis of a reconfiguration of the terminal station to address a separate problem, and work proceeded once it was determined that such a reconfiguration was not required.
- consideration of the requirements of the customer. The Corner Brook frequency converter project was delayed due to discussions with the customer to whom the converter is specifically assigned concerning possibly transferring ownership.

NEWFOUNDLAND & LABRADOR HYDRO
CARRY OVER REPORT
FOR THE YEAR ENDED DECEMBER 31
($000)

	PUB Approved Budget	Revised Budget	Actuals	Carryover Amount	Variance Explan. Ref. No.
Replace Station Service Control - Bay d'Espoir	105	124	66	58	
Stator Windings Design Review - Bay d'Espoir	49	49	29	20	
Fire Protection Upgrades - Holyrood	1,797	1,797	578	1,219	5
UPS Battery Monitoring Program - Holyrood	79	79	5	74	
Replace Fuel Piping - Hardwoods and Stephenville[1]	530	242	145	97	
Upgrade Corner Brook Frequency Converter - 2007	1,320	1,320	26	1,294	11
Upgrade 138kV Protection - Springdale, Howley, Indian River	215	215	169	46	
Upgrade Breaker Controls - OPD/SSD Terminal Station	40	40	12	28	
Safety and Reliability Upgrade - Hawkes Bay Terminal Station	349	349	204	145	12
Upgrade Unit 290 and Upgrade Fuel Storage - Williams Harbour[2]	479	370	92	278	16
Purchase Spare Transformer - Upper Salmon	665	665	19	646	19
Automatic Meter Reading	696	1,135	201	934	20
Installation of Card Access System - Bishop's Falls and Whitbourne	131	131	102	29	
Replace Vehicles - Hydro System - 2007	2,686	2,686	2,218	468	25
Security Assessment of System Operations	668	668	137	531	26
Vibration Monitoring System Upgrade - Hardwoods and Stephenville	49	49	34	15	
TOTAL CARRYOVER	**9,858**	**9,919**	**4,037**	**5,882**	

[1]This was a pooled project to replace fuel piping in the Hardwoods and Stephenville terminal stations. The Hardwoods portion of the job is complete.

[2]This was a pooled project to upgrade Unit 290 and the fuel storage system in William's Harbour. The fuel storage system replacement is complete.

Exhibit 10 (2008 Report)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CAPITAL EXPENDITURES AND CARRYOVER REPORT

For Year Ending December 31, 2008

March 2009

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Quarter Ending December 31, 2008

TABLE OF CONTENTS

Page

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
OVERVIEW
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008
GENERATION	8,965	5,823	9,460	495
TRANSMISSION AND RURAL OPERATIONS	27,617	10,730	23,931	(3,686)
GENERAL PROPERTIES	10,698	3,994	7,565	(3,133)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	779	933	(67)
PROJECTS APPROVED BY PU BOARD	5,182	338	4,260	(922)
NEW PROJECTS APPROVED FOR LESS THAN $50,000	117	84	97	(20)
TOTAL CAPITAL BUDGET	53,579	21,748	46,246	(7,333)

Projects Approved by PU Board	
2008 Capital Budget Approved by Board Order No. P.U. 30 (2007)	42,398
New Projects Approved by Board Order No. P.U. 17 (2008)	4,542
New Projects Approved by Board Order No. P.U. 23 (2008)	420
New Projects Approved by Board Order No. P.U. 25 (2008)	220
New Projects Approved by Board Order No. P.U. 26 (2008)	0
New Projects Approved by Board Order No. P.U. 30 (2008)	0
Carryover Projects 2007 to 2008	5,882
2008 New Projects Approved for Less than $50,000	117
TOTAL APPROVED CAPITAL BUDGET	53,579

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008
GENERATION				
HYDRAULIC PLANTS	4,052	3,494	5,025	973
THERMAL PLANT	4,065	2,162	3,767	(298)
GAS TURBINES	143	94	181	38
TOOLS AND EQUIPMENT	705	73	487	(218)
TOTAL GENERATION	8,965	5,823	9,460	495
TRANSMISSION AND RURAL OPERATIONS				
TERMINAL STATIONS	4,065	1,518	2,478	(1,587)
TRANSMISSION	5,977	3,118	6,606	629
DISTRIBUTION	9,265	3,838	9,745	480
GENERATION	1,956	631	1,287	(669)
PROPERTIES	2,409	565	813	(1,596)
METERING	1,593	240	1,543	(50)
TOOLS AND EQUIPMENT	2,352	820	1,459	(893)
TOTAL TRANSMISSION AND RURAL OPERATIONS	27,617	10,730	23,931	(3,686)

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008
GENERAL PROPERTIES				
INFORMATION SYSTEMS	3,444	1,192	3,317	(127)
TELECONTROL	2,817	1,270	1,750	(1,067)
TRANSPORTATION	2,294	877	1,508	(786)
ADMINISTRATIVE	2,143	655	990	(1,153)
TOTAL GENERAL PROPERTIES	10,698	3,994	7,565	(3,133)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	779	933	(67)
PROJECTS APPROVED BY PU BOARD	5,182	338	4,260	(922)
PROJECTS APPROVED FOR LESS THAN $50,000	117	84	97	(20)
TOTAL CAPITAL BUDGET	53,579	21,748	46,246	(7,333)

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
HYDRAULIC PLANTS						
Replace Station Service Control - Bay d'Espoir	58	33	189	131	226%	1
Stator Windings Design Review - Bay d'Espoir	20	7	9	(11)	-55%	
Upgrade Spherical Valve Maintenance Seals - Cat Arm	1,060	1,628	1,969	909	86%	2
Replace Governor Controls Unit 2 - Cat Arm	975	677	1,096	121	12%	3
Arc Flash Analysis - Various Sites	342	217	259	(83)	-24%	
Replace Cooling Water Systems Units 1 and 2 - Bay d'Espoir	264	69	198	(66)	-25%	
Replace 40 kW Diesel Generator - Burnt Dam	157	135	148	(9)	-6%	
Install Meteorological Stations - Various Locations	222	99	225	3	1%	
Hydraulic Structure Life Study - Bay d'Espoir	196	109	123	(73)	-37%	
Replace Cooling Water Piping System - Hinds Lake	193	81	143	(50)	-26%	
Salmon Spillway Stoplog Handling System	141	154	207	66	47%	
Upgrade Intake No. 4 Gate Controls - Bay d'Espoir	116	2	134	18	16%	
Replace Back-Up Air Dryer - Bay d'Espoir	73	52	53	(20)	-27%	
Replace Communications Room Air Conditioner - Bay d'Espoir	64	51	51	(13)	-20%	
Upgrade Access Trail - Venam's Bight	64	91	100	36	56%	
Replace Fire Alarm System - Cat Arm	54	70	82	28	52%	
Replace Auxiliary Service Water Pump - Cat Arm	53	19	39	(14)	-26%	
TOTAL HYDRAULIC PLANTS	**4,052**	**3,494**	**5,025**	**973**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
THERMAL PLANT						
Fire Protection Upgrades - Holyrood	1,219	438	1,085	(134)	-11%	4
UPS Battery Monitoring Program - Holyrood	74	2	80	6	8%	
Tank Farm Upgrade	500	775	776	276	55%	5
Replace Unit 2 High Pressure Heater	20	56	62	42	210%	
Replace Unit 1 and 2 Condenser Valve Actuators	313	66	236	(77)	-25%	
Replace Unit 2 Electromechanical Trip Device	305	174	345	40	13%	
Precipitator and Scrubber Installation Study	272	221	247	(25)	-9%	
Replace 4160 Volt Motor Relays	172	63	128	(44)	-26%	
Replace Unit 2 Main Steam Stop Valve	171	0	190	19	11%	
Environmental Effects Monitoring Study of Waste Water	73	26	31	(42)	-58%	
Upgrade Ambient Monitoring Station	128	11	91	(37)	-29%	
Soot Blowing Controls Study	123	95	107	(16)	-13%	
Stack Breeching Study	115	37	42	(73)	-63%	
Install Safety Egress Lighting	97	15	20	(77)	-79%	
Auto Synchronizing Units 1 and 2	93	44	46	(47)	-51%	
Install Stator Ground Fault Protection	85	57	118	33	39%	
Upgrade Meteorological Station	75	15	59	(16)	-21%	
Construct Beta Attenuation Meter (BAM) Unit Enclosure	60	0	0	(60)	-100%	
Programmable Logic Controller Replacement Study	58	7	41	(17)	-29%	
Motor Control Centres Assessment	43	20	23	(20)	-47%	
Install UV Domestic Water Treatment	36	15	15	(21)	-58%	
Jetty Building Ventilation	33	25	25	(8)	-24%	
TOTAL THERMAL PLANTS	**4,065**	**2,162**	**3,767**	**(298)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
GAS TURBINES						
Replace Fuel Piping -Stephenville	97	58	114	17	18%	
Vibration Monitoring System Upgrade - Hardwoods and Stephenville	15	37	38	23	153%	
Gas Turbine Electrical Assessment - Holyrood	31	(1)	29	(2)	-6%	
TOTAL GAS TURBINE PLANTS	**143**	**94**	**181**	**38**		
TOOLS AND EQUIPMENT						
Replace Champion Grader V-9797 - Bay d'Espoir	404	0	239	(165)	-41%	6
Purchase Grounding Trucks	61	0	55	(6)	-10%	
Tools and Equipment Less than $50,000	240	73	193	(47)	-20%	
TOTAL TOOLS AND EQUIPMENT	**705**	**73**	**487**	**(218)**		
TOTAL GENERATION	**8,965**	**5,823**	**9,460**	**495**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
TERMINAL STATIONS						
Upgrade Breaker Controls - Oxen Pond and Sunnyside Terminal Stations	28	27	35	7	25%	
Safety and Reliability Upgrade - Hawkes Bay Terminal Station	145	230	521	376	259%	7
Purchase Spare Transformer - Upper Salmon	2,198	375	416	(1,782)	-81%	8
Replace Battery Banks and Chargers - Various Locations	430	282	473	43	10%	
Replace Disconnect Switches - Cow Head and Daniel's Harbour	368	237	284	(84)	-23%	
Upgrade Circuit Breakers - Various Locations	315	143	295	(20)	-6%	
Replace Digital Fault Recorder - Buchans	130	51	104	(26)	-20%	
Replace Compressors - Buchans	94	61	74	(20)	-21%	
Replace Instrument Transformers - Various Locations	74	(2)	75	1	1%	
Replace Surge Arrestors - Various Locations	67	2	73	6	9%	
Upgrade Station Services - Hardwoods	59	1	1	(58)	-98%	
On-Line Dewpoint Monitoring - Bay d'Espoir	38	27	34	(4)	-11%	
Replace Control Building Roof - Doyles	34	20	22	(12)	-35%	
Secondary Air Line for Switchgear - Cat Arm	33	14	14	(19)	-58%	
Replace Breaker Control Panels - Western Avalon	32	25	28	(4)	-13%	
Replace Equipment Concrete Foundation - Stoney Brook	20	25	29	9	45%	
TOTAL TRANSMISSION	**4,065**	**1,518**	**2,478**	**(1,587)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
TRANSMISSION						
Upgrade Corner Brook Frequency Converter - 2007	1,294	494	1,185	(109)	-8%	
Upgrade 138kV Protection - Springdale, Howley and Indian River	46	0	55	9	20%	
Wood Pole Line Management Program	2,188	1,274	2,393	205	9%	
Replace Insulators TL232 and TL253	848	115	878	30	4%	
Upgrade Corner Brook Frequency Converter - 2008	495	905	943	448	91%	9
Upgrade Line TL212 - (Sunnyside to Linton Lake)	464	6	474	10	2%	
Construct Transmission Line Equipment Off-Loading Areas	302	261	305	3	1%	
Replace Insulators - Various Locations	294	47	324	30	10%	
Install Remote Ice Growth Detection Beam - Various Locations	46	16	49	3	7%	
TOTAL TERMINALS	**5,977**	**3,118**	**6,606**	**629**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
DISTRIBUTION						
Replace Diesel Unit No. 290 - William's Harbour	278	191	218	(60)	-22%	
Upgrade Distribution Systems - Various Locations	2,727	1,066	2,551	(176)	-6%	
Service Extensions	2,158	1,352	3,328	1,170	54%	10
Distribution Upgrades	2,293	635	2,236	(57)	-2%	
Replace poles - South Brook and Bay d'Espoir	701	394	588	(113)	-16%	11
Replace Insulators - Various Locations	623	124	572	(51)	-8%	
Replace Recloser Control Panels - Various Locations	223	38	134	(89)	-40%	
Reconfigure Feeders - Happy Valley	151	31	76	(75)	-50%	
Replace Submarine Cable Terminator - Gaultois	64	7	42	(22)	-34%	
Recloser Assessment - Happy Valley	47	0	0	(47)	-100%	
TOTAL DISTRIBUTION	**9,265**	**3,838**	**9,745**	**480**		
GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	335	4	8	(327)	-98%	12
Diesel Plant Automation - Makkovik and Rigolet	516	361	589	73	14%	
Increase Generation Capacity - Charlottetown	18	1	6	(12)	-67%	
Replace Switchgear - Cartwright	383	102	117	(266)	-69%	13
Replace Mufflers - L'Anse au Loup and St. Anthony	479	117	340	(139)	-29%	14
Replace Underground Fuel Lines - Little Bay Islands and Grey River	89	20	65	(24)	-27%	
Upgrade Meter House Equipment - Various Locations	75	25	87	12	16%	
Install Day Tank and Meter - Hopedale	61	1	75	14	23%	
TOTAL GENERATION	**1,956**	**631**	**1,287**	**(669)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
PROPERTIES						
Installation of Card Access System - Bishop Falls and Whitbourne	29	0	29	0	0%	
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	1,248	85	94	(1,154)	-92%	15
Upgrade Ventilation System - Makkovik - Project Cancelled	217	0	0	(217)	-100%	16
Construct Diesel Plant Extension - William's Harbour	177	0	11	(166)	-94%	17
Replace Fire Alarm System - Hopedale and Paradise River	168	122	139	(29)	-17%	
Install Storage Ramp - Holyrood and Port Saunders	136	127	132	(4)	-3%	
Install Chain Link Fencing - Port Hope Simpson	84	14	58	(26)	-31%	
Upgrade Parking Lot - Whitbourne	67	55	65	(2)	-3%	
Install Waste Oil Storage Tank - Cartwright	53	4	62	9	17%	
Survey of Hydro's Primary Right of Ways - Various Locations	52	47	54	2	4%	
Install Waste Oil Storage Tank - L'Anse au Loup - Changed to Charlottown	46	2	54	8	17%	
Construct Lube Oil Storage Ramps - Various Locations	44	34	37	(7)	-16%	
Install Pole Storage Ramp - Burgeo	43	47	49	6	14%	
Construct Storage Shed - Paradise River	30	17	18	(12)	-40%	
Transformer Storage Ramp-Port Saunders - St. Lewis Lube Oil Storage Ramp	15	11	11	(4)	-27%	
TOTAL PROPERTIES	**2,409**	**565**	**813**	**(1,596)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
METERING						
Install Automatic Meter Reading 2007 - Various Locations	934	102	967	33	4%	
Install Automatic Meter Reading 2008 - Various Locations	567	96	493	(74)	-13%	
Purchase Meters and Equipment	67	42	58	(9)	-13%	
Purchase Metering Spares	25	0	25	0	0%	
TOTAL METERING	**1,593**	**240**	**1,543**	**(50)**		
TOOLS AND EQUIPMENT						
Replace Off Road Track Vehicles - Bishop's Falls and Whitbourne	746	509	511	(235)	-32%	18
Replace Light Duty Mobile Equipment Less than $50,000	588	121	454	(134)	-23%	19
Installation of Fall Arrest Equipment - Various Locations	404	96	194	(210)	-52%	20
Replace Boom 6069 on Track Vehicle - Stephenville	236	0	0	(236)	-100%	21
Purchase Hydraulic Cutters and Presses - Various Locations	66	1	53	(13)	-20%	
Purchase Forklift for Salvage Stores - Bishop's Falls	49	0	37	(12)	-24%	
Tools and Equipment Less than $50,000	263	93	210	(53)	-20%	
TOTAL TOOLS AND EQUIPMENT	**2,352**	**820**	**1,459**	**(893)**		
TOTAL GENERAL	**6,354**	**1,625**	**3,815**	**(2,539)**		
TOTAL TRANSMISSION AND RURAL OPERATIONS	**27,617**	**10,730**	**23,931**	**(3,686)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
New Infrastructure						
Application Enhancements - Work Protection Code	678	54	676	(2)	0%	
Application Enhancements - Energy Systems Water Management	651	428	625	(26)	-4%	
Applications Enhancements Corporate Systems	373	281	365	(8)	-2%	
Cost Recovery CF(L)Co	(75)	(16)	(66)	9	-12%	
Application Enhancements - Energy Systems Optimum Power flow	216	19	115	(101)	-47%	22
Upgrade of Technology						
Corporate Application Environment	331	211	331	0	0%	
Cost Recovery CF(L)Co	(41)	(12)	(41)	0	0%	
TOTAL SOFTWARE APPLICATIONS	**2,133**	**965**	**2,005**	**(128)**		
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
End User Infrastructure Evergreen Program	451	22	457	6	1%	
Enterprise Storage Capacity Upgrade	327	5	326	(1)	0%	
Cost Recovery CF(L)Co	(65)	0	(65)	0	0%	
NEW INFRASTRUCTURE						
Peripheral Infrastructure Replacement	159	7	159	0	0%	
Video Conferencing	140	113	139	(1)	-1%	
Security Configuration Auditing	72	72	72	0	0%	
Cost Recovery CF(L)Co	(14)	(14)	(14)	0	0%	
UPGRADE OF TECHNOLOGY						
Server Technology Program	241	22	238	(3)	-1%	
TOTAL COMPUTER OPERATIONS	**1,311**	**227**	**1,312**	**1**		
TOTAL INFORMATION SYSTEMS	**3,444**	**1,192**	**3,317**	**(127)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Customer Service Application - Hydro Place	768	11	40	(728)	-95%	23
Replace Power Line Carrier TL212 - Sunnyside to Paradise River	466	311	369	(97)	-21%	
Replace Remote Terminal Units - Various Sites	319	100	281	(38)	-12%	
Refurbish Microwave Site - Gull Pond Hill	202	183	188	(14)	-7%	
Replace Dial Backup System - Various Sites	201	87	98	(103)	-51%	24
Install Recloser Remote Control - Change Islands	194	96	150	(44)	-23%	
Replace Radomes - Various Sites	124	111	111	(13)	-10%	
Network Infrastructure						
Replace Network Communications Equipment - Various Sites	131	87	144	13	10%	
Test Equipment - Hydro Place and Deer Lake	49	12	54	5	10%	
Wireless Networking - Various Sites	46	49	53	7	15%	
UPGRADE OF TECHNOLOGY						
Voice Communications Strategy Study - Hydro Place	190	85	118	(72)	-38%	
Replace Network Management Tools - Hydro Place	81	85	91	10	12%	
Upgrade Site Facilities - Various Sites	46	53	53	7	15%	
TOTAL TELECONTROL	**2,817**	**1,270**	**1,750**	**(1,067)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
TRANSPORTATION						
Replace Vehicles - Hydro System - 2007	468	0	317	(151)	-32%	25
Replace Vehicles - Hydro System - 2008	1,826	877	1,191	(635)	-35%	26
TOTAL TRANSPORTATION	**2,294**	**877**	**1,508**	**(786)**		
ADMINISTRATION						
Security Assessment of System Operations	531	333	579	48	9%	
Upgrade System Security - Various Sites	906	145	145	(761)	-84%	27
Purchase Spare Transformer - Hydro Place	87	47	51	(36)	-41%	
Install Computer Room Inergen Fire Protection System - Hydro Place	116	0	0	(116)	-100%	28
Safety Hazards Removal - Various Sites	252	117	131	(121)	-48%	29
Purchase and Replace Admin Office Equip less than $50,000	137	13	84	(53)	-39%	
Replace Humidifiers in Air Handling Units - Hydro Place	58	0	0	(58)	-100%	
Replace Air Conditioning Units - Hydro Place	56	0	0	(56)	-100%	
TOTAL ADMINISTRATIVE	**2,143**	**655**	**990**	**(1,153)**		
TOTAL GENERAL PROPERTIES	**10,698**	**3,994**	**7,565**	**(3,133)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
ALLOCATION FOR UNFORESEEN EVENTS						
Replace Structure No. 380 on TL212	65	0	67	2	3%	
Replace Air Compressors No. 4 and 5 - Holyrood	256	215	215	(41)	-16%	
Nain Diesel Plant Rehabilitation	0	291	304	304	0%	30
Install Midspan Structure - Roddickton	68	6	61	(7)	-10%	
Grounding Upgrades - Bottom Brook, Hinds Lake and Oxen Pond	0	267	286	286	0%	31
Allocation for Unforeseen Events	**611**	**0**	**0**	**(611)**		
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	**1,000**	**779**	**933**	**(67)**		
PROJECTS APPROVED BY PUB						
CARRYOVER						
NEW						
Replace Superheater Unit 1 - Holyrood	4,446	106	4,028	(418)	-9%	
Public Address System - Holyrood	96	3	3	(93)	-97%	
Condition Assessment and Life Extension Study - Holyrood	420	0	0	(420)	-100%	32
Replace Front End Loader V9614 - Bay d'Espoir	220	229	229	9	4%	
Install Neutral Grounding Resistors - Come by Chance	227	0	0	(227)	-100%	33
Cost Recovery - North Atlantic Refining Limited	(227)	0	0	227		
Relocate Transmisson Line TL227 and TL262 - Daniels Harbour	350	152	152	(198)	0%	34
Cost Recovery - Department Works and Transportation	(350)	(152)	(152)	198		
Coastal Labrador Alternative Energy Study	250	29	29	(221)	-88%	35
Cost Recovery - Department Works and Transportation	(250)	(29)	(29)	221		
TOTAL PROJECTS APPROVED BY PU BOARD	**5,182**	**338**	**4,260**	**(922)**		

NEWFOUNDLAND & LABRADOR HYDRO
2008 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

	PUB Approved Budget 2008	4th Quarter Actuals 2008	Total Actual Expend. 2008	Variance From Budget 2008	Percentage Variance From Budget 2008	Variance Explanation Ref. No.
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Electronic White Board - Hydro Place	14	0	13	(1)	-7%	
Install Water and Sewer System - Hopedale	49	45	45	(4)	-8%	
Replace Diesel Unit No. 562 - Norman Bay	17	17	17	0	0%	
Purchase Exercise Equipment - Corporate Wellness Strategy	21	14	14	(7)	-33%	
Purchase Office Furniture - Hydro Place	9	8	8	(1)	-11%	
Purchase Pressure Sealer - Hydro Place	7	0	0	(7)	-100%	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**117**	**84**	**97**	**(20)**		

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

1. Replace Station Services Control – Bay D'Espoir

Station Services is critical to the operation of the generating units in Bay d'Espoir Powerhouse 1. An outage to the Station Services would cause an outage to Units 1-6. Due to the critical nature of the Station Services, extra precautions and equipment, engineering time and plant personnel time were required to ensure the availability of the Station Services during the preliminary installation work, final installation work and commissioning. All of the cost increases are due to labour for both installation and commissioning.

2. Upgrade Spherical Valve Maintenance Seals - Cat Arm

The original estimate was based upon a preliminary design in a 2007 proposal by the manufacturer of the spherical valves to replace the existing maintenance seals with a new design. In early 2008, the manufacturer commenced detailed engineering and design and concluded that the proposed design would be ineffective. The manufacturer subsequently submitted a new proposal on March 26, 2008, with an improved design for the maintenance seal. This new design resulted in an increase of $279,000 to the contract.

In addition, the cost estimate was based upon availability of camp facilities on-site. The cookhouse and bunkhouse at Cat Arm was closed due to mould issues, as reported in Hydro's 2009 Capital Budget Application [1]. This resulted in additional costs associated with housing workers at the nearest available lodging in the community of Pollard's Point, as well as the additional labour incurred for workers travelling between Pollard's Point and Cat Arm. This resulted in increased costs of $145,000 due to labour, overtime and travel expenses. Furthermore, the scope of the project was expanded to include the construction of a cookhouse on-site to feed workers during the construction period at a cost of $102,000.

A further cost increase of $305,000 is attributed to the provision of additional in-house engineering to permit a more thorough review of the new design, more extensive factory acceptance testing, additional labour and materials to address a number of deficiencies in the contractor's design and work plan and to expedite the return of the generating units to service.

[1] Volume II, Tab 7, "*Cat Arm Hydro Generating Station Replacement of Accommodations*" report.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

3. Replace Governor Controls Unit 2 - Cat Arm

As stated previously, the on-site accommodations at Cat Arm have been closed. Personnel from Hydro and General Electric, the control system supplier, stayed at a motel during the installation and commissioning of the governor controls and its associated equipment. The budget variance is due to increased labour costs due to travel time plus the cost of accommodations.

4. Fire Protection Upgrades – Holyrood

The fire protection system is installed, however, there is some contractor work left to be completed resulting in this project being carried over into 2009. It is expected to be completed within budget.

5. Tank Farm Upgrade - Holyrood

The increase in the cost of this project is due to a contract cost for upgrading fuel storage tank No. 2 that was $306,000 greater than estimated. Factors contributing to the increased contract cost include an increase in material costs and the high demand for skilled labour which has increased contracting costs and a heightened awareness of safety hazards, requiring more involved mitigation procedures during construction.

6. Replace Champion Grader V-9797 – Bay d'Espoir

The budgeted price was developed following discussions with a single manufacturer. Competitive bidding and optimizing the specification resulted in the purchase of a machine which meets requirements at a lower cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

7. Safety and Reliability Upgrades – Hawkes Bay Terminal Station

This project was approved by Board Order No. P.U. 35(2006) as a one-year project and then subsequently carried over into 2007[2]. This delay resulted in a significant increase in costs for material and contracts. The contract cost increased by $149,000 as well as additional labour costs of $163,000.

8. Purchase Spare Transformer – Upper Salmon

In addition to the delay in this project reported in the 2007 Capital Expenditure Report (Page 23), there was a further three-month delay in production by the manufacturer, therefore, this project will be carried over into 2009. Due to the size of this equipment, transportation permits are required in order to get the transformer on site. The Department of Transportation does not usually grant these permits during the winter months, therefore the expected in service date has been extended until June 2009. The total budgeted expenditure remains unchanged.

9. Upgrade Corner Brook Frequency Converter - 2008

This is a multi-year project also reported in the 2007 Capital Expenditures Report (Page 20) and the original plan was to perform two rotor rewinds in separate years, requiring two outages. This plan was reviewed and it was decided to complete both of the rewinds in one longer outage period, therefore more work was done in 2008 than was originally planned. This project is expected to be completed on time and within budget.

10. Service Extensions

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

[2] Page 21 of the 2007 Capital Expenditure and Carryover Report

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

11. Replace Poles – South Brook and Bay d'Espoir

This is a pooled project for South Brook and Bay d'Espoir. The cost of the pole replacement for South Brook was underestimated by $47,000 and the one for Bay d'Espoir was underestimated by $66,000. This was due to contract bids that came in less than expected as well as savings in material costs. This resulted in less overheads and no contingency funds being required.

12. Replace Diesel Units – Norman Bay, Cartwright and Black Tickle

This is a pooled multiyear project. The bulk of the variance relates to Black Tickle, where $293,000 was budgeted to be spent for the purchase and delivery of the diesel unit. Due to other work commitments, this did not occur. This project is expected to be completed on time and within budget in 2009.

13. Replace Switchgear - Cartwright

This is a multiyear project to be completed in 2009. Initially the tendering and delivery of the switchgear was to be completed in 2008 however, scheduling issues with the Makkovik and Rigolet automation project, resulted in the delay of this work until 2009. This project is expected to be completed on time and within budget.

14. Replace Mufflers – L'Anse au Loup and St. Anthony

For the St. Anthony project, labour and travel costs were reduced as a result of using local area labour. The work in L'Anse au Loup had to be completed faster than planned due to low water levels in the Hydro Québec Lac Robertson system that required diesel system availability be restored as quickly as possible. The cost savings for both projects resulted in less overheads and as well as contingency amounts not being utilized.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

15. Construct New Office/Warehouse/Line Depot Facilities – Happy Valley

This project was reforecast as part of the 2009 Capital Budget application[3]. There was $358,000 to be spent in 2008 which included the land purchase and project design. The project design will now be completed early in 2009. The design process was extended due to a new requirement to construct the building to LEED (Leadership in Energy and Environmental Design) standard, preventing construction from beginning in 2008. The project is expected to be completed on time and within budget.

16. Upgrade Ventilation System - Makkovik

This project has been cancelled. There is an overall concern with the age and condition of many of Hydro's Diesel Plants. Therefore, before addressing any specific issues, it was decided to complete a comprehensive condition assessment of all the plants in question in order to prioritize recommendations for improvements.

17. Construct Diesel Plant Extension – William's Harbour

The bid prices obtained for this project were significantly over budget therefore it was decided to do some design modifications and re-tender the work early in 2009. This project will be completed late in 2009 and there is no change in the overall budget.

18. Replace Off Road Track Vehicles – Bishop's Falls and Whitbourne

The original specifications for these units included pricing for backhoes or booms that were not purchased. A thorough needs analysis permitted specifying vehicle with less auxiliary equipment than originally envisaged. There were also cost savings by purchasing two units with the same specifications and contingency amounts were not utilized.

[3] Page B40 of Hydro's 2009 Capital Budget Application

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

19. Replace Light Duty Mobile Equipment Less than $50,000

The reduction in cost for this project is mainly due to not purchasing several pieces of equipment that were included in this budget. A review of the condition of several pieces of equipment indicated that their useful operating lives could be extended and that replacement of two boom trailers, three boat trailers and a back hoe attachment were not required at this time. These cost reductions resulted in contingency not being utilized.

20. Installation of Fall Arrest Equipment – Various Locations

The cost of this project was less than budgeted for several reasons. Firstly, horizontal lifelines were purchased but not installed at Cat Arm, Hinds Lake and Paradise River. These will be installed using funds from the 2009 fall arrest project. Secondly, the initial plan was to install railings on the perimeter of the roof at the Holyrood Thermal Generating Plant however it was determined that railings were only required near the emergency ladders, resulting in cost savings. Thirdly, the installation of fall arrest equipment at the Nain Diesel Plant was delayed due to the fire.

21. Replace Boom 6069 on Track Vehicle – Stephenville

This project will be carried over into 2009 and was delayed due to the fact that a boom is to be installed on an existing unit. This unit had to be reconfigured and the resulting boom specially designed to fit the track unit therefore the order could not be completed and delivered before the end of the year. This project is expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

22. Application Enhancements – Energy Systems Optimum Powerflow

The vendor, Open Systems International, has been unable to supply all the required functionality in accordance with the originally planned timeline. This functionality was received early in 2009 and testing will take place up to the end of March. This project is expected to be completed within budget.

23. Customer Service Application – Hydro Place

This is a multiyear project to be completed by the end of 2009. There was very little money spent in 2008 due to an unsuccessful tendering process. The project was tendered twice, first with no responses and then the second resulting in one noncompliant bid. Hydro is currently working with vendors to arrive a solution that meets the requirements. This project is expected to be completed on schedule and within budget.

24. Replace Dial Backup System – Various Sites

No bids were received when the project was initially tendered therefore the project had to be retendered. This resulted in the project completion being delayed until the end of March 2009. This project is expected to cost $178,000 rather than $201,000 budgeted due to lower than expected contract costs.

25. Replace Vehicles – Hydro System – 2007

The remainder of this project was carried over from 2007 for the supply and installation of two new booms on existing chassis. The variance results from competitive bidding and not utilizing all of the contingency from this project.

26. Replace Vehicles – Hydro System - 2008

This project is being carried over into 2009 due to change in policy whereby custom built vehicles costing more than $200,000 will be inspected by Hydro staff on site before shipping, since it is time consuming and potentially costly to correct deficiencies after delivery. This situation pertains to two boom trucks budgeted in 2008. The project is still expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

27. Upgrade System Security – Various Sites

This project will be carried over into 2009 due to several factors. Because the Upgrade System Security 2007 was carried over into 2008, this increased the scope of work required for 2008. Also, the design and tendering stages of the new system-wide video surveillance program was extensive, largely due to the fact that significant research had to be done before the work could be tendered. This will be an interconnected system, using technologies new to Hydro. This project is expected to be completed within budget by the end of 2009.

28. Install Computer Room Inergen Fire Protection System – Hydro Place

This project was cancelled following a detailed review of the computer room and Hydro Place fire protection systems. A concern was identified that the replacement of the computer room existing sprinkler fire protection and replacement by a gas fire suppression system could compromise the overall building fire protection.

29. Safety Hazards Removal – Various Sites

The purpose of this project was to ensure that adequate capital funding was available to quickly address capital-related safety issues as they were identified. It was not based on specifically identified projects. The amount spent reflects the safety hazards identified and addressed using this funding.

30. Nain Diesel Plant Rehabilitation

The allocation for unforeseen events was used in order to address a fire that occurred at the Nain Diesel Plant in September 2008. In 2009, Hydro will be applying for approval of this project separately and will not continue to use this allocation for this project.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

31. Grounding Upgrades at Bottom Brook, Hinds Lake and Oxen Pond

Hydro obtained approval for Grounding Upgrades – Various Sites in Board Order No. P.U. 36 (2008) for a multi-year project to modify existing ground grids and install or modify gradient control mats. Subsequent to filing the 2009 Capital Budget Application, it was determined that the identified hazards at the sites listed above were serious enough that Hydro could not wait until 2009 to correct these hazards. The allocation for unforeseen events was used in last quarter of 2008 in order to rectify the identified hazards.

32. Condition Assessment and Life Extension Study – Holyrood

Hydro applied for approximately $4.0 million to do a condition assessment and life extension study for the Holyrood Thermal Generating Station, however, only $420,000 was approved by Board Order No. P.U. 23 (2008). This was an approval to begin the study involving the issuance of a request for proposals, evaluation of the proposals and the preparation of a detailed scope of work. Hydro feels that this approach is not a good use of funds and proposed an alternate methodology during a meeting with Board Staff on 2009-01-28, which was accepted in principal. Hydro is in the process of preparing a revised proposal and expects to submit this document in March.

33. Install Neutral Grounding Resistors – Come by Chance

This project is fully contributed by Hydro's customer North Atlantic Refining Limited (NARL) and it was initially going to be completed by the end of 2008 however it will now be completed in the spring of 2009. The project is delayed because NARL was late in approving the project that in turn delayed the design work and the delivery of the resistors.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2008
(Greater than $100,000)

34. Relocate Transmission Line TL227 and TL262 – Daniels Harbour

This project was approved late November by Board Order No. P.U. 30(2008). Even though Hydro intended to complete this work by the end of 2008, adverse weather conditions and the inability of the contractor to provide enough adequately trained individuals to complete this work in the required time frame resulted in this projected being carried over into 2009. This project is scheduled to be completed by the end of March 2009.

35. Coastal Labrador Alternate Energy Study

This project was announced by the Provincial Government in the 2008 Provincial Budget however the funds were not received by Hydro until October 2008. It will therefore be carried over into 2009. Hydro is in the process of preparing the project specifications and will file an application for approval in the near future.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 1999 – 2008
AS AT DECEMBER 31
($000)

Year	Budget	Actual Expenditures	Variance	Percentage Variance
1999	38,142	29,684	8,458	22.2%
2000	43,824	38,569	5,255	12.0%
2001	55,897	47,501	8,396	15.0%
2002	44,660	40,217	4,443	9.9%
2003	36,122	32,506	3,616	10.0%
2004	31,435	27,984	3,451	11.0%
2005	47,760	33,952	13,808	28.9%
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%

These variances include amounts related to the carryover of projects from year to year. Variances from budget for completed projects are 5% and 1% for 2007 and 2008 respectively, well within acceptable ranges. Staff retirements, resignations, transfers and reassignments, primarily as a result of the reorganization of Hydro's engineering function, were the cause of the significant 2005 carryover amounts. While Hydro has made improvements since then, and continues to make efforts to further improve the completion of projects on schedule, staffing challenges continue.

Project delivery has been improving since 2005. The apparent setback in 2007 can primarily be attributed to a single project, the purchase of a transformer to be used as a spare at Upper Salmon, Bay d'Espoir or Granite Canal. When originally proposed, the delivery cycle for such a transformer was ten months, however, when the project was initiated the international demand for transformers had increased substantially, resulting in a doubling of the delivery cycle, causing the carry over of this project to 2009. This single project accounts for approximately 3.0% of the 17.6% carry over for 2007 and 3.3% of the 13.7% of the carry over from 2008 to 2009.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 1999 – 2008
AS AT DECEMBER 31
($000)

The 13.7% actual carryover can be attributed principally to two factors:

1. The construction of new office/warehouse/line depot facilities at Happy Valley Goose Bay was delayed, as reported in Hydro's 2009 Capital Budget Application[4]. The approved proposal had construction beginning in 2008, with an expenditure of $1.25 million in that year. The September 2007 requirement that this building be constructed to Leadership in Energy and Environmental Design (LEED) standards which was not included in the proposal, delayed the project schedule while the building was redesigned from an architectural and engineering perspective. The delay of this project accounts for approximately 2.2% of the 13.7% carry over for 2008. In addition costs related to this project increased substantially, as reported in the 2009 Capital Budget Application.

2. In the fall of 2008 Hydro suffered two major losses, a fire at the Nain diesel plant and a failure of the dock at the Holyrood Thermal Generating Station. These emergencies required the diversion of staff from scheduled activities. The Nain fire required the reassignment of staff from Engineering Services and Regulated Operations to construct a temporary diesel pant and begin repairs to the existing plant. The Holyrood dock repairs required staff from Engineering Services to design and contract the implementation of emergency component replacements, to ensure that fuel was able to be received at Holyrood for the winter season. Both events caused delays to several capital projects.

[4] Pages B-40 and B-41 of Hydro's 2009 Capital Budget Application

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 1999 – 2008
AS AT DECEMBER 31
($000)

It is anticipated that some carryovers of capital projects will occur in most years as there are frequently unavoidable reasons for delay in project completion. Some examples of such delays which occurred in 2008 are:

1. Unforeseeable events interfering with scheduled activities, such as occurred following the Nain diesel plant fire and the failure at the Holyrood dock. This contributed to the carry over of capital projects such as Replace Fire Alarm System at Hopedale and Paradise River and Install Meteorological Stations – Various Sites.

2. Changes in market conditions between the time when a project is proposed, approved and implemented, such as happened with the delivery of the spare transformer for Upper Salmon, Bay d'Espoir and Granite Canal. Changes in market conditions can also significantly effect project costs as the escalating cost of commodities result in large price changes in goods (such as copper wire) and services. This applies as well to heavy equipment delivery when a supplier's manufacturing plant may have had capacity available at time of proposal but at time of tender they may be booked which can affect price and in particular delivery schedule.

3. Difficulties with new equipment which must be resolved with the manufacturer. Hydro installed approximately 6,500 meters as part of the Automatic Meter Reading – Various Systems project in 2008, of which about 500 do not perform as they should, requiring collaboration between the meter supplier and the AMR vendor to sort out a software issue and preventing completion of the project. These meters contain an internal programming error, which must be remedied by the manufacturer, tested and reinstalled in the 500 meters, following which, the meters must be installed in the field, adding delays and some rework

Such events as these and others are outside the control of project managers and will result in the carry over of some projects in most years. Hydro continues to improve its project management practices and expects to continue to reduce the number of projects carried over. The project management practices, as reported in the 2007 Capital Expenditures and Carryover year-end report, include:

- more two-year schedules to accommodate the construction seasons rather than the calendar year.
- more two-year schedules to allow adequate lead time on materials, such as that now required for the purchase of power transformers,

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 1999 – 2008
AS AT DECEMBER 31
($000)

- newly hired engineers obtaining the experience and knowledge required to be able to more independently complete assignments; and
- Capital Budget preparation now including review of staff availability.

Project estimators and managers have been challenged in recent years by the rapidly changing costs of commodities, equipment and services. Staff are preparing project proposal estimates to the best of their abilities and the price fluctuations of recent years are beginning to abate somewhat, although there has not yet been a return to the relative stability of past years. These fluctuations have been manifested in a significant reduction in the number of projects completed within +/- 10% of the original cost estimate. We have been fortunate in that the number of projects completed over budget has been essentially equally compensated for by the number of projects completed under budget, conveniently cancelling each other, but this cannot be relied upon to happen consistently each year. It should be expected, that as has been experienced by other industries during these volatile times, Hydro's project completion costs for the next several years will probably vary from original estimated costs by amounts greater than in the past.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 CARRYOVER REPORT
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

Project Name[1]	PUB Approved Budget 2008	Revised Budget 2008	Total Actual Expend. 2008	Carryover Amount	Variance Explanation Ref. No.
Replace Governor Controls Unit 2 - Cat Arm	975	1,238	1,096	142	3
Replace 40 kW Diesel Generator - Burnt Dam	157	157	148	9	
Install Meteorological Stations - Various Locations	222	252	225	27	
Fire Protection Upgrades - Holyrood	1,219	1,219	1,085	134	4
Replace Unit 2 High Pressure Heater - Holyrood	20	20	62	(42)	
Environmental Effects Monitoring Study of Waste Water - Holyrood	73	73	31	42	
Install Safety Egress Lighting - Holyrood	97	112	20	92	
Auto Synchronizing Units 1 and 2 - Holyrood	93	93	46	47	
Construct Beta Attenuation Meter (BAM) Unit Enclosure - Holyrood	60	60	0	60	
Tools and Equipment Less than $50,000 - Generation[2]	240	24	0	24	
Purchase Spare Transformer - Upper Salmon	2,198	2,198	416	1,782	8
Replace Disconnect Switches - Cow Head and Daniel's Harbour	368	368	284	84	
Upgrade Station Services - Hardwoods	59	59	1	58	
Replace Insulators TL232 and TL253[3]	848	561	571	(10)	
Upgrade Corner Brook Frequency Converter - 2008	495	801	943	(142)	9
Reconfigure Feeders - Happy Valley	151	151	76	75	
Recloser Assessment - Happy Valley	47	47	0	47	
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	335	335	8	327	12
Diesel Plant Automation - Makkovik and Rigolet	516	516	589	(73)	
Increase Generation Capacity - Charlottetown	18	18	6	12	
Replace Switchgear - Cartwright	383	383	117	266	13

[1] Projects shaded in yellow are multi-year projects scheduled to be completed in future years.
[2] Comprised of a number of items of which a portion is being carried forward.
[3] Replace Insulators TL253 is complete. Replace Insulators TL232 is a multiyear project.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 CARRYOVER REPORT
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

Project Name[1]	PUB Approved Budget 2008	Revised Budget 2008	Total Actual Expend. 2008	Carryover Amount	Variance Explanation Ref. No.
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	1,248	358	94	264	15
Construct Diesel Plant Extension - William's Harbour	177	177	11	166	17
Replace Fire Alarm System - Hopedale and Paradise River	168	168	139	29	
Install Automatic Meter Reading 2007 - Various Locations	934	1,075	967	108	
Install Automatic Meter Reading 2008 - Various Locations	567	606	493	113	
Replace Boom 6069 on Track Vehicle - Stephenville	236	236	0	236	21
Application Enhancements - Energy Systems Water Management	651	651	625	26	
Application Enhancements - Energy Systems Optimum Power flow	216	216	115	101	22
Customer Service Application - Hydro Place	768	768	40	728	23
Replace Dial Backup System - Various Locations	201	201	98	103	24
Install Recloser Remote Control - Change Islands	194	194	150	44	
Replace Vehicles - Hydro System - 2008	1,826	1,826	1,191	635	26
Upgrade System Security - Various Locations	906	906	145	761	27
Purchase Spare Transformer - Hydro Place	87	87	51	36	
Purchase and Replace Admin Office Equipment less than $50,000[2]	137	50	0	50	
Replace Humidifiers in Air Handling Units - Hydro Place	58	58	0	58	
Replace Air Conditioning Units - Hydro Place	56	56	0	56	
Replace Air Compressors No. 4 and 5 - Holyrood	256	256	215	41	

[1] Projects shaded in yellow are multi-year projects scheduled to be completed in future years.

[2] Comprised of a number of items of which a portion is being carried forward.

NEWFOUNDLAND AND LABRADOR HYDRO
2008 CARRYOVER REPORT
FOR THE QUARTER ENDING DECEMBER 31, 2008
($000)

Project Name[1]	PUB Approved Budget 2008	Revised Budget 2008	Total Actual Expend. 2008	Carryover Amount	Variance Explanation Ref. No.
Nain Diesel Plant Rehabilitation	0	0	304	0	30
Public Address System - Holyrood	96	96	3	93	
Install Neutral Grounding Resistors - Come by Chance	227	227	0	227	32
Cost Recovery - North Atlantic Refining Limited	(227)	(227)	0	(227)	
Relocate Transmisson Line TL227 and TL262 - Daniels Harbour	350	350	152	198	
Cost Recovery - Department Works and Transportation	(350)	(350)	(152)	(198)	
Coastal Labrador Alternative Energy Study	250	250	29	221	33
Cost Recovery - Government Of Newfoundland and Labrador	(250)	(250)	(29)	(221)	
Total Carryover Amount	21,372	20,686	10,365	6,609	

[1] Projects shaded in yellow are multi-year projects scheduled to be completed in future years.

Exhibit 10 (2009 Report)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CAPITAL EXPENDITURES AND CARRYOVER REPORT

For Year Ending December 31, 2009

March 2010

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Quarter Ending December 31, 2009

TABLE OF CONTENTS

Page

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
OVERVIEW
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009
GENERATION	8,287	9,933	7,909	(378)
TRANSMISSION	11,154	5,300	10,732	(422)
RURAL SYSTEMS	20,038	10,364	19,634	(404)
GENERAL PROPERTIES	13,980	4,546	11,420	(2,560)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	109	672	(328)
PROJECTS APPROVED BY PU BOARD	6,915	1,749	3,618	(3,297)
NEW PROJECTS APPROVED FOR LESS THAN $50,000	171	129	167	(4)
TOTAL CAPITAL BUDGET	61,544	32,130	54,152	(7,392)

Approved Board Order No. P.U. 36 (2008) 2009 Capital Budget	47,856
Carryover Projects 2008 to 2009	6,609
New Project Approved by Board Order No. P.U. 4 (2009)	351
New Project Approved by Board Order No. P.U. 8 (2009)	1,093
New Project Approved by Board Order No. P.U. 10 (2009)	704
New Project Approved by Board Order No. P.U. 16 (2009)	0
New Project Approved by Board Order No. P.U. 23 (2009)	161
New Project Approved by Board Order No. P.U. 28 (2009)	1,210
New Project Approved by Board Order No. P.U. 31 (2009)	2,416
New Project Approved by Board Order No. P.U. 33 (2009)	291
New Project Approved by Board Order No. P.U. 34 (2009)	492
New Project Approved by Board Order No. P.U. 40 (2009)	197
2009 New Projects Approved For Less than $50,000	164
TOTAL APPROVED CAPITAL BUDGET	61,544

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009
GENERATION				
HYDRO PLANTS	1,712	789	1,847	135
THERMAL PLANT	5,862	3,072	5,264	(598)
GAS TURBINES	712	6,072	798	86
TOTAL GENERATION	8,287	9,933	7,909	(378)
TRANSMISSION				
TERMINAL STATIONS	5,291	2,049	4,863	(428)
TRANSMISSION	5,832	3,251	5,854	22
TOOLS AND EQUIPMENT	31	0	15	(16)
TOTAL TRANSMISSION	11,154	5,300	10,732	(422)
RURAL SYSTEMS				
CONSTRUCTION PROJECTS	11,982	6,176	13,786	1,804
GENERAL	6,752	3,982	5,096	(1,656)
METERING	745	52	229	(516)
TOOLS AND EQUIPMENT	560	154	523	(37)
TOTAL RURAL SYSTEMS	20,038	10,364	19,634	(404)

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009
GENERAL PROPERTIES				
INFORMATION SYSTEMS	1,760	363	1,786	26
TELECONTROL	4,683	1,173	2,650	(2,033)
TRANSPORTATION	4,110	1,544	3,620	(490)
ADMINISTRATIVE	3,426	1,466	3,364	(62)
TOTAL GENERAL PROPERTIES	13,980	4,546	11,420	(2,560)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	109	672	(328)
PROJECTS APPROVED BY PU BOARD	6,915	1,749	3,618	(3,297)
PROJECTS APPROVED FOR LESS THAN $50,000	171	129	167	(4)
TOTAL CAPITAL BUDGET	61,544	32,130	54,152	(7,392)

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
HYDRAULIC PLANTS						
Replace Governor Controls Unit 2 - Cat Arm	216	191	226	10	5%	
Replace 40 kW Diesel Generator at Spillway - Burnt Dam	112	(6)	138	26	23%	
Install Meteorological Stations 2008 - Various Locations	27	0	48	21	78%	
Replace Cooling Water Systems on Units 3 and 4 - Bay d'Espoir	287	12	192	(95)	-33%	
Install Meteorological Stations 2009 - Various Locations	253	144	268	16	6%	
Replace 50kW Diesel Generator - Bay d'Espoir	36	7	7	(29)	-81%	
Upgrade Intake Gate Controls - Hinds Lake	263	224	312	49	19%	
Replace Generator Oil Level System on Units 1 and 2 - Cat Arm	68	113	134	66	98%	
Purchase Spare Stator Windings Units 1 to 4 - Bay d'Espoir	37	5	131	95	259%	
Replace Service Water Piping Unit 7 - Bay d'Espoir	144	31	138	(6)	-4%	
Purchase Tools and Equipment Less Than $50,000	270	68	253	(17)	-6%	
TOTAL HYDRAULIC PLANTS	**1,712**	**789**	**1,847**	**135**	**8%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
THERMAL PLANT						
Fire Protection Upgrades - Holyrood	134	(54)	113	(21)	-16%	
Replace Unit 2 High Pressure Heater - Holyrood	877	203	946	69	8%	
Environmental Effects Monitoring Study of Waste Water	129	45	71	(58)	-45%	
Install Safety Egress Lighting	92	166	184	92	100%	
Construct Beta Attenuation Meter (BAM) Unit Enclosure	60	0	63	3	5%	
Automatic Synchroniziation Units 1 and 2	47	107	140	93	198%	
Replace No.'s 4 and 5 Air Compressors - Holyrood	41	0	47	6	15%	
Install Motorized Stack Winches - Holyrood	174	3	49	(125)	-72%	1
Replace Unit 2 Air Preheater Cold End - Holyrood	320	192	314	(6)	-2%	
Replace Unit 1 Hydrogen Emergency Vent Valves - Holyrood	214	3	213	(1)	0%	
Install Unit 1 CR Condensate Drains and HP Heater Trip Level - Holyrood	192	207	284	92	48%	
Replace Unit 3 Steam Seal Regulator - Holyrood	475	483	518	43	9%	
Install Marine Terminal Capstans Lifting Frames - Holyrood	93	79	122	29	31%	
Refurbish Fuel Storage Facility - Holyrood	2,867	1,556	2,086	(781)	-27%	2
Purchase Boom Style Hydraulic Lift - Holyrood	82	55	55	(27)	-33%	
Purchase Tools and Equipment Less Than $50,000	65	27	59	(6)	-10%	
TOTAL THERMAL PLANTS	**5,862**	**3,072**	**5,264**	**(598)**	**-10%**	
GAS TURBINES						
Upgrade Gas Turbine Plant Life Extension - Hardwoods	450	381	540	90	20%	
Replace Automatic Voltage Regulator on Gas Turbine - Stephenville	262	209	258	(4)	-2%	
TOTAL GAS TURBINE PLANTS	**712**	**6,072**	**798**	**86**	**12%**	
TOTAL GENERATION	**8,287**	**9,933**	**7,909**	**(378)**	**-5%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
TERMINAL STATIONS						
Purchase Spare Transformer - Upper Salmon	1,782	662	1,702	(80)	-4%	
Replace Disconnect Switches - Cow Head and Daniel's Harbour	84	41	277	193	230%	3
Upgrade Station Services - Hardwoods	58	30	89	31	53%	
Replace Insulators - Various Terminal Stations	391	219	427	36	9%	
Upgrade Circuit Breakers - Various Terminal Stations	422	87	365	(57)	-14%	
Replace Air Compressors - Sunny Side	96	99	108	12	13%	
Install Digital Fault Recorders - Oxen Pond, Massey Drive and St. Anthony	462	107	331	(131)	-28%	4
Replace 230kV Breaker Controls - Oxen Pond, Bay d'Espoir	100	25	60	(40)	-40%	
Upgrade Power Transformers - Various Terminal Stations	654	291	590	(64)	-10%	
Replace 69kV Breaker L51T2 - Howley	199	211	251	53	26%	
Replace Drainage System - Western Avalon	84	10	67	(17)	-20%	
Perform Grounding Upgrades - Various Terminal Stations	252	129	154	(98)	-39%	
Upgrade Great Northern Peninsula Protection - Various Locations	101	53	68	(33)	-32%	
Install 138kV Capacitive Voltage Transformer - St. Anthony Airport	71	4	42	(29)	-40%	
Install 69kV Capacitive Voltage Transformer - St. Anthony Diesel Plant	67	13	23	(44)	-66%	
New 25kV Terminal Station - Labrador City	283	79	101	(182)	-64%	5
Replace Instrument Transformers - Various Terminal Stations	107	7	128	21	20%	
Replace Surge Arrestors - Various Terminal Stations	81	(18)	80	(1)	-1%	
TOTAL TERMINAL STATIONS	**5,291**	**2,049**	**4,863**	**(428)**	**-8%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
TRANSMISSION						
Replace Insulators on 230kV Line TL-253 - Stony Brook, Buchans	960	866	1,017	57	6%	
Upgrade Corner Brook Frequency Converter - 2008	1,010	701	1,179	169	17%	6
Perform Wood Pole Line Management Program - Various Locations	2,256	1,211	2,613	357	16%	7
Construct Transmission Line Equip Off-Loading Areas - Various Locations	498	299	324	(174)	-35%	8
Construct Transmission Storage Ramps - Bay d'Espoir	75	45	45	(30)	-40%	
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	968	100	609	(359)	-37%	9
Install Remote Ice Growth Detector Beams - Various Locations	65	29	67	2	4%	
TOTAL TRANSMISSION	**5,832**	**3,251**	**5,854**	**22**	**0%**	
TOOLS AND EQUIPMENT						
Purchase and Replace Tools and Equipment Less than $50,000	31	0	15	(16)	-51%	
TOTAL TOOLS AND EQUIPMENT	**31**	**0**	**15**	**(16)**	**-51%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
DISTRIBUTION						
Provide Service Extensions - All Service Areas	2,439	1,988	4,011	1,572	64%	10
Upgrade Distribution Systems - All Service Areas	2,526	1,139	2,660	134	5%	
Replace Poles - Jackson's Arm and Hampton	697	291	660	(37)	-5%	
Replace Insulators - Jacksons Arm, Hampden and Little Bay	874	206	712	(162)	-19%	11
Reconfigure Feeders - Happy Valley	75	0	74	(1)	-1%	
Recloser Assessment - Happy Valley	47	23	27	(20)	-43%	
Replace Recloser Control Panels - Various Locations	132	33	107	(25)	-19%	
Replace Submarine Cable Terminator Kit - Change Islands/Fogo Island	96	2	81	(15)	-16%	
Purchase and Install Voltage Regulator Bank - English Harbour West	123	21	102	(21)	-17%	
Upgrade L7 Distribution System - St. Anthony	689	221	504	(185)	-27%	12
Replace Conductor on L2 - Rocky Harbour	325	(130)	348	24	7%	
Replace Line L36 - Wabush	498	222	466	(32)	-6%	
Upgrade Voltage Conversion Phase 1 - Labrador City	189	121	191	2	1%	
Purchase and Install Electronic Recloser - Cartwright	96	59	162	66	69%	
TOTAL DISTRIBUTION	**8,807**	**4,196**	**10,105**	**1,298**	**15%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	1,265	455	1,003	(262)	-21%	13
Replace Diesel Units - Norman Bay, Postville and Paradise River	170	220	469	299	176%	14
Diesel Plant Automation - Makkovik and Rigolet	306	157	627	321	105%	15
Increase Generation Capacity - Charlottetown (Project Cancelled)	589	0	(6)	(595)	-101%	16
Replace Switchgear - Cartwright	435	130	450	15	3%	
Replace Speed Increaser - Roddickton	125	132	141	16	13%	
Install Furnace Fuel Storage Tank - Williams Harbour (Project Cancelled)	59	0	0	(59)	-100%	
Increase Generation - L'Anse au Loup	23	775	783	760	3319%	17
Upgrade Fuel Storage - Cartwright	139	39	142	3	2%	
Install Meter Station for Fuel Reconcilation - Hawke's Bay	64	72	72	8	13%	
TOTAL GENERATION	**3,175**	**1,980**	**3,681**	**506**	**16%**	
TOTAL CONSTRUCTION PROJECTS	**11,982**	**6,176**	**13,786**	**1,804**	**15%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
GENERAL						
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	3,224	2,392	2,696	(528)	-16%	18
Construct Diesel Plant Extension - William's Harbour (Project Cancelled)	166	0	(11)	(177)	-107%	19
Replace Fire Alarm System - Hopedale and Paradise River	29	0	11	(18)	-62%	
Install Fall Arrest Equipment - Various Locations	322	132	303	(19)	-6%	
Legal Survey of Primary Distribution Line Right of Ways - Various Locations	56	(14)	55	(1)	-2%	
Install Air Conditioning at Training Centre - Bay d'Espoir	34	22	28	(6)	-19%	
Replace Accom, Septic Sys and Upgrade Plant Communications Sys - Cat Arm	1,254	683	733	(521)	-42%	20
Upgrade CEMS Room Ventilation - Holyrood	39	70	72	33	83%	
Build ATV/snowmobile Storage - Whitbourne	86	70	95	9	10%	
Replace Dock Lighting - Holyrood	33	26	26	(7)	-22%	
Replace Explosive Storage Magazines - Various Locations	293	30	143	(150)	-51%	21
Install Pole Storage Ramps - Various Locations	77	(27)	36	(41)	-53%	
Install Transformer Storage Ramps - Labrador	121	69	96	(25)	-20%	
Upgrade Ventilation System - Little Bay Islands Diesel Plant	186	153	196	10	5%	
Build New Maintenance Shop - St. Anthony	429	263	293	(136)	-32%	22
Install Waste Oil Storage Tanks - Mary's Harbour	84	21	70	(14)	-17%	
Install Water and Sewer System - Paradise River (Project Cancelled)	77	(4)	0	(77)	-100%	
Construct Sewage Disposal Field - Makkovik	50	44	45	(5)	-9%	
Install Storage Ramp - Whitbourne	41	52	55	14	33%	
Pave Parking Lots and Roadways - Bishops Falls	150	0	154	4	3%	
TOTAL GENERAL	**6,752**	**3,982**	**5,096**	**(1,656)**	**-25%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
METERING						
Install Automatic Meter Reading - Various Locations	108	21	123	15	14%	
Install Automatic Meter Reading - VariousLocations	113	30	105	(8)	-7%	
Install Automatic Meter Reading - Change Islands and Fogo Island	491	1	1	(490)	-100%	23
Purchase Meters and Equipment - Various Locations	33	0	0	(33)	-100%	
TOTAL METERING	**745**	**52**	**229**	**(516)**	**-69%**	
TOOLS AND EQUIPMENT						
Replace Boom 6069 on Track Vehicle - Stephenville	236	0	240	4	2%	
Purchase High Definition Infrared Camera - Central	87	1	79	(8)	-9%	
Tools and Equipment Less Than $50,000	237	153	204	(33)	-14%	
TOTAL TOOLS AND EQUIPMENT	**560**	**154**	**523**	**(37)**	**-7%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
NEW INFRASTRUCTURE						
Application Enhancements - Energy Systems Water Management	26	0	75	49	188%	
Application Enhancements - Energy Systems Optimum Powerflow	101	0	114	13	13%	
Application Enhancements - Perform Minor Application Enhancements	120	42	121	1	1%	
Cost Recoveries	(35)	(12)	(35)	(0)	0%	
Upgrade Intranet - Hydro Place	67	60	66	(1)	-1%	
Cost Recoveries	(19)	(6)	(19)	0	-2%	
Application Enhancements - Performance Management Software Budgeting Tool	127	0	130	3	2%	
Purchase Protection Relay Event Report Software - Hydro Place	54	22	31	(23)	-42%	
UPGRADE OF TECHNOLOGY						
Citrix Enhancement - Hydro Place	118	22	118	(0)	0%	
Cost Recoveries	(34)	(11)	(34)	0	-1%	
Corporate Application Environment Upgrade Showcase Strategy Suite - Hydro Place	158	75	160	2	1%	
Cost Recoveries	(46)	(15)	(46)	(0)	0%	
TOTAL SOFTWARE APPLICATIONS	**637**	**177**	**681**	**44**	**7%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
End User Evergreen Program - Various Locations	491	93	490	(1)	0%	
Replace Peripheral Infrastructure - Hydro Place	161	24	161	(0)	0%	
Perform Hawke Hill Improvements - Hawke Hill	50	36	37	(13)	-25%	
Replace Drafting Scanner/Plotter - Hydro Place	139	0	139	0	0%	
NEW INFRASTRUCTURE						
Security Smartcard and Disk Encryption for Laptops - Hydro Place	125	2	124	(1)	-1%	
Cost Recoveries	(36)	(12)	(36)	0	-1%	
UPGRADE OF TECHNOLOGY						
Upgrade Server Technology Program - Hydro Place	273	69	269	(4)	-1%	
Cost Recoveries	(79)	(26)	(79)	0	0%	
TOTAL COMPUTER OPERATIONS	**1,123**	**186**	**1,105**	**(18)**	**-2%**	
TOTAL INFORMATION SYSTEMS	**1,760**	**363**	**1,786**	**26**	**1%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Customer Service Application - Hydro Place	910	275	360	(550)	-60%	24
Replace Dial Backup System - Various Locations	103	22	60	(43)	-42%	
Install Recloser Remote Control - Change Islands	44	(11)	64	20	45%	
Public Address System - Holyrood	1,275	42	119	(1,156)	-91%	25
Replace Remote Terminal Units - Various Locations	278	120	258	(20)	-7%	
Replace Radomes - Various Locations	130	11	111	(19)	-14%	
Install Fibre Optic Cable - Hinds Lake	209	9	9	(200)	-96%	26
Replace Power Line Carrier on TL250 - Bottom Brook to Grandy Brook	473	62	476	4	1%	
NETWORK INFRASTRUCTURE						
Replace Network Communications Equipment - Various Locations	141	55	132	(9)	-6%	
Purchase Test Equipment - Various Locations	74	2	70	(4)	-5%	
Install Wireless Networking - Various Locations	45	39	39	(6)	-14%	
Replace Radio Tower - Ebbegunbaeg	179	112	124	(55)	-31%	
Replace Batteries and Chargers - Various Locations	729	409	776	47	7%	
UPGRADE OF TECHNOLOGY						
Replace Network Management Tools - Various Locations (Project Cancelled)	47	0	0	(47)	-100%	
Upgrade Site Facilities - Various Locations	47	26	52	5	10%	
TOTAL TELECONTROL	**4,683**	**1,173**	**2,650**	**(2,033)**	**-43%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
TRANSPORATION						
Replace Vehicles and Aerial Devices 2008 - Various Locations	635	0	449	(186)	-29%	27
Replace Vehicles and Aerial Devices 2009 - Various Locations	2,156	731	2,044	(112)	-5%	
Replace Light Duty Mobile Equipment Less Than $50,000 - Various Locations	561	216	530	(31)	-6%	
Replace Off Road Tracked Vehicles - Whitbourne and Bishop's Falls	758	597	597	(161)	-21%	28
TOTAL TRANSPORATION	**4,110**	**1,544**	**3,620**	**(490)**	**-12%**	
ADMINISTRATION						
Upgrade System Security 2008 - Various Locations	762	4	812	50	7%	
Upgrade System Security 2009 - Various Locations	767	232	488	(279)	-36%	29
Purchase Spare Transformer - Hydro Place	389	155	460	71	18%	
Replace Humidifiers in Air Handling Units 2008 - Hydro Place	58	20	20	(38)	-66%	
Replace Air Conditioning Units 2008 - Hydro Place	56	6	6	(50)	-89%	
Replace Humidifiers in Air Handling Units 2009 - Hydro Place	74	34	34	(40)	-54%	
Replace Air Conditioning Units 2009 - Hydro Place	37	30	30	(7)	-20%	
Energy Conservation Upgrades - Hydro Place	833	814	1,167	334	40%	30
Replace Fire Protection Panels - Hydro Place	89	94	104	15	17%	
Purchase and Replace Admin Office Equipment Less Than $50,000	361	77	243	(118)	-33%	
TOTAL ADMINISTRATION	**3,426**	**1,466**	**3,364**	**(62)**	**-2%**	
	13,980	**4,546**	**11,420**	**(2,560)**	**-18%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	PUB Approved Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
ALLOCATION FOR UNFORESEEN EVENTS						
Replace Diesel Engine - Mary's Harbour	569	5	454	(115)	-20%	31
TL 221 - Insulator Upgrade	192	104	218	26	14%	
Allocation for Unforeseen Events	**239**	**0**	**0**	**(239)**	-100%	
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	**1,000**	**109**	**672**	**(328)**	**-33%**	
PROJECTS APPROVED BY PUB						
CARRYOVER						
TL227/262 Upgrde Daniel's Harbour, Transmission Line Re-Location	198	(1)	295	97	49%	
Cost Recovery - Dept Works and Transportation	(198)	1	(295)	(97)	49%	
Install Neutral Grounding Resistors - Come By Chance	227	0	0	(227)	-100%	32
Cost Recovery - North Atlantic Refining Limited	(227)	0	0	227	-100%	
NEW						
Replace Programable Logic Controllers - Holyrood	1,093	283	877	(216)	-20%	33
Upgrade Continuous Emission Monitoring System - Holyrood	704	2	7	(697)	-99%	34
Condition Assessment and Life Extension Study - Holyrood	1,210	38	50	(1,160)	-96%	35
Nain Diesel Plant Rehabilitation	2,416	619	1,764	(652)	-27%	36
Replacement of Power Transformer - Wiltondale Terminal Station	351	70	70	(281)	-80%	37
Gas Turbine Refurbishment - Stephenville	291	0	0	(291)	-100%	38
Hinds Lake Powerhouse Slope Stabilization	492	667	704	212	43%	39
Microwave Replacement - Godaleich Hill	197	120	120	(77)	-39%	
Work Protection Code eLearning Program	227	92	92	(135)	-59%	40
Cost Recoveries	(66)	(28)	(66)	0	0%	
Hydro Place Parking Lot Extension	93	0	114	21	23%	
Cost Recovery - Nalcor Energy	(93)	(114)	(114)	(21)	23%	
TOTAL PROJECTS APPROVED BY PU BOARD	**6,915**	**1,749**	**3,618**	**(3,297)**	**-48%**	

NEWFOUNDLAND & LABRADOR HYDRO
2009 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

	Budget 2009	4th Quarter Actuals 2009	Total Actual Expend. 2009	Variance From Budget 2009	Percentage Variance From Budget 2009	Variance Explanation Ref. No.
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Pressure Sealer - Treasury	7	0	6	(1)	-14%	
Purchase Former Diesel Plant Property - Fogo Island	4	0	4	0	0%	
Replace Roof - Stony Brook Terminal Station	49	29	29	(20)	-41%	
Replace Roof - Bottom Brook Terminal Station	49	47	47	(2)	-4%	
Purchase Hydraulic Drill and Impact Wrench	5	4	4	(1)	-20%	
Test Console No's 1 and 2 Upgrade	41	41	41	0	0%	
Purchase Towable ATV Backhoe - Mud Lake	10	8	8	(2)	-20%	
Purchase Meters and Equipment	6	0	28	22	367%	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**171**	**129**	**167**	**(4)**	**-2%**	

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
GENERATION
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

1. Install Motor Stack Winches – Holyrood

Consultants were hired to complete the detailed engineering design for the stack winches and their respective restraint systems. The cost associated with the installation of this design was prohibitive. It was necessary to design a less elaborate restraint system while offering the same level of safety. Due to the timing and scheduling of other work during the fall, this project will be completed in 2010.

2. Refurbish Fuel Storage Facility - Holyrood

Better than expected competition for the civil site work and drainage system installation provided competitive bids resulting in an overall lower price for the work by approximately $250,000. Based on work performed on pipe supports several years ago, it was estimated that the pipe supports would require extensive modification to return them to serviceable condition, however, once the supports were exposed and detail design was completed, the work required was much less extensive than originally anticipated resulting in further savings of approximately $400,000. Corporate Overhead costs were less based on the reduced cost of the site, drainage and pipe support work. Additionally, the project contingency was not required.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

3. Replace Disconnect Switches – Cow Head and Daniel's Harbour

During installation of the disconnect switches in Cow Head, it was discovered that several poles and bus work needed to be replaced, increasing the scope, duration and cost of the project. Due to other work commitments and the increased scope, Hydro's crews were not able to perform all the work and it became necessary to prepare and tender a contract document to have the work performed by a contractor. This additional engineering work, site supervision and contract management was not anticipated in the original project scope, nor was the added cost of having the work performed by a contractor.

4. Install Digital Fault Recorders – Oxen Pond, Massey Drive and St. Anthony

Both the engineering design and installation of the digital fault recorders (DFR) required less time than budgeted resulting in less labour and travel costs. The same model of digital fault recorder was purchased for this project as was installed in Buchans in 2008 therefore the design and drawing preparatory effort was reduced since only modifications to the Buchan's design was required. Similarly, installation personnel were familiar with the Buchan's installation, which expedited the installation at these three locations. This also resulted in less overhead costs and contingency fund being required.

5. New 25kV Terminal Station – Labrador City

This is a multi-year project to be completed in 2011. There were issues which arose during the acquisition of the land required for the new terminal stations which delayed the finalization of the design and the ordering of equipment. These activities will now be completed during the first quarter of 2010. This project is expected to be completed on time within budget.

6. Upgrade Corner Brook Frequency Converter - 2008

The scope of this job included the replacement of the old liquid rheostat which is used to start and stop the frequency converter. The preliminary design and budget was based upon the replacement of the original liquid rheostat with a variable speed drive. During the finalization of the electrical design, it became evident that the use of a variable speed drive was not the preferred solution for this application and it was decided to simply replace the old liquid rheostat with a new one. During disassembly of this 40 year old machine it was also discovered that more remedial work was encountered than expected which increased the scope, duration and cost of the work.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

7. Perform Wood Pole Line Management Program – Various Locations

The wood pole line management program consists of a replacement program for deteriorated poles identified in previous inspections as well as new line inspections. During the 2009 inspection of TL-201, 29 poles were found to be in such condition that, for reliability and safety reasons, they had to be replaced immediately. These additional poles and the associated installation costs were unbudgeted and totaled approximately $500,000. This included the cost of utilizing a contractor and Hydro crews from across the island to complete the work during the limited outage time in November and December. There were also outage restrictions on TL-215 and TL-250 that resulted in additional costs due to the requirement to use of alternate generation and additional labour costs due to the compressed time frame to complete the work. These increased costs were offset by other refurbishment work that was deferred until 2010 and 2011, however, there was still an overall increase of approximately $360,000.

8. Construct Transmission Equipment Off-Loading Areas – Various Locations

The tenders received for construction of off-loading areas, prepared with estimates based on actual contract costs for the previous year, were lower than expected. In addition, the Department of Transportation and Works initially required new culvert installation at all sites but changed the final requirements to the installation of new culvert at sites on an as-needed basis only. They also initially requested that all sites on the Burin Peninsula highway be equipped with guard rails. They eventually concluded that guard rails provided no additional safety benefits to the public and could interfere with both the Department of Transportation and Works snow clearing operations and Hydro's off-loading operations, thus they were removed from the design. The reduced cost of construction work resulted in less engineering labour costs as well as less overhead costs and no contingency fund being required.

9. Upgrade Transmission Line TL-212 – Sunnyside to Linton Lake

Due to environmental constraints related to bog along parts of the line, several of the mid-span structures proposed for 2009 have been deferred until March 2010, to minimize the environmental damage. This multi-year project is to be completed in 2010 and is expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

10. Provide Service Extensions – All Service Areas

The budgeted amount is an annual allotment based on the average of the annual expenditures for service extensions over the last five years. It is not based on a summary of specific projects. There have been increases in expenditures in all service areas with the bulk pertaining to Labrador ($800,000) and Northern ($600,000) regions.

The increase in costs in Labrador is mainly due to housing developments in Happy Valley, Nain, Hopedale and Makkovik; a new school in Happy Valley, and a hotel in Labrador City. The increase in expenditures in the Northern region, which include Southern Labrador, is partly due to an increase in customers converting to electric heat causing a load increase on existing electrical infrastructure, requiring an increase in transformer and conductor sizing and, in certain cases, involves the installation and/or replacement of poles. In addition, there are new schools in Port Hope Simpson and Port Saunders, a wood pellet plant in Roddickton as well as the addition of the ice-making capacity for the Charlottetown Shrimp plant contributing to the increased costs for the Northern region.

11. Replace Insulators – Jacksons Arm, Hampden and Little Bay

The budget estimate for insulator replacement is based on contracted out labour, since internal labour availability was unknown at the project proposal stage. The use of internal labour resulted in an overall reduction of project costs. These factors resulted in less overhead costs and no contingency funds being required.

12. Upgrade L7 Distribution System – St. Anthony

The availability of internal labour to work on this project, which was not anticipated in the budget, resulted in a shorter outage duration therefore reducing labour costs. The contracted portion of the project was also less than expected. This resulted in less overhead costs and no contingency funds being required.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

13. Replace Diesel Units – Norman Bay, Cartwright and Black Tickle

The diesel unit replacement for Cartwright is complete however, the ones for Norman Bay and Black Tickle will be carried over and completed in 2010. Due to the design of the existing automatic controls for Norman Bay, extensive engineering for protection and control work would have to be done to temporarily integrate the new equipment with the existing gensets. A capital budget to replace two diesel units and automate the Norman Bay Plant was approved by Board Order No. P.U. 36 (2009). Rather than incur unnecessary costs for temporary configurations and mobilization, it is prudent to install all the equipment at the same time in 2010. The Black Tickle installation was scheduled for completion in late October of 2009. Due to delays in shipping from the manufacturer and further delays with the coastal ferry service, the genset did not arrive until early December, at which time there was no available manpower to complete the installation in 2009. The genset will be installed in the spring of 2010.

14. Replace Diesel Units – Norman Bay, Postville and Paradise River

This project is a multi-year project to be completed in 2010. Due to unforeseen work commitments such as the Nain fire and failures of generating sets at Postville and Mary's Harbour, which negatively impacted the resource availability of both Engineering Services and Operations personnel, there was limited work done on the Norman Bay and Paradise River replacements. However, the genset being replaced in Postville failed prematurely in the winter of 2009 leaving the town vulnerable to outages therefore this project was completed in 2009.

15. Diesel Plant Automation – Makkovik and Rigolet

Originally all project engineering work was to be done by Hydro personnel, however, due to resource constraints within Engineering Services, outside technical assistance was required for the automation design portion of the project. The work that was outsourced included onsite installation of this automation equipment as well as commissioning of the entire diesel plant automation systems followed by operator training. This increased the cost by approximately $185,000. Additionally, there was a significant disruption in the work schedule for operating crews as a result of the diesel plant fire at the Nain Plant in 2008 that affected the work schedule at Makkovik into 2009 resulting in an increase of approximately $100,000 in labour and travel costs.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

16. Increase Generation Capacity – Charlottetown *(Project Cancelled)*

The primary reason for the new generation to be installed at Charlottetown was to continue supporting the high summer load associated with the operation of the seasonal fish plant that was built in the community in 2000. In the fall of 2008, Hydro was advised by the owners of the fish plant that the installation of additional ice making capacity in 2009 would increase demand by 150 kW and that another similar addition could be expected in two to three years. This requires a reassessment of the long-term suitability of the existing generation plant. Hydro expects to have this assessment completed in time for the 2011 Capital Budget Application. The generation shortfall experienced during the summer when the fish plant is operating is being addressed with a temporary mobile generator relocated from L'Anse Au Loup. (See variance explanation 17.)

17. Increase Generation – L'Anse au Loup

This is a multi-year project, the original scope of which was to replace an existing 600 kW diesel generating set with a 1,100 kW unit. Load growth on this system has increased faster than expected and Hydro found it necessary to lease a 1,825 kW mobile generating set to provide sufficient capacity, following notification from Hydro-Québec that it might not be able to provide power from its Lac Robertson hydro facility due to low water levels and its own load requirements. Combined effects of increased demand on the L'Anse au Loup system and potentially less available energy from Hydro Québec has caused Hydro to change the scope of this project to procurement of the 1,825 kW mobile generating set which has been connected to the power system in a temporary fashion. During 2010 a more permanent interconnection will be completed and protection and control enhancements will be effected. This mobile can also be used as an emergency unit for other isolated diesel systems.

18. Construct New Office/Warehouse/Line Depot Facilities – Happy Valley

The office, warehouse and line depot facilities were completed in January 2010, however, pavement and landscaping cannot be completed until the spring and summer of 2010. Therefore this project will be carried over into 2010.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
TRANSMISSION AND RURAL OPERATIONS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

19. Construct Diesel Plant Extension – William's Harbour (*Project Cancelled)*

Project cancelled due to the potential relocation of the residents of William's Harbour to other communities.

20. Replace Accom, Septic Sys, and Upgrade Plant Communications Sys – Cat Arm

The six modular accommodations units were constructed and are at the Cat Arm Generating station waiting to be installed. The septic system and fencing has also been completed. The lowest acceptable tender for the installation was much greater than the estimated cost. The remaining work will be retendered early in 2010 and is expected to result in a more reasonable installation cost.

21. Replace Explosive Storage Magazines – Various Sites

This project came in under budget due to the magazines costing less than expected. The budget for this proposal was based on a quote of approximately $200,000 for the fourteen magazines. The actual contracted cost was approximately $90,000. This resulted in less overhead costs and no contingency fund being required.

22. Build New Maintenance Shop – St. Anthony

During excavation for the building foundations, organic material (bog) was encountered, requiring additional excavation and structural fill placement. Additional consultant time was also required to make the necessary geotechnical recommendations. This resulted in an increase in the overall budget by $171,000 as well as construction delays. This project will be completed in the first quarter of 2010.

23. Install Automatic Metering Reading – Change Islands and Fogo Island

This project was delayed as the economics were tied, in part, to the expected retirement of a meter reader. The meter reader provided notification later than expected, thus delaying implementation. The revised completion date is November 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

24. Customer Service Application – Hydro Place

The procurement phase of the project resulted in two unsuccessful tender calls, with no bids in the first and a single non-compliant bid in the second, thereby delaying the project by approximately three months. The decision was made to proceed with the non-compliant tenderer however, with a revised proposal, which will utilize purchased software for the Call Centre portion of the work. The refined bid and the time to negotiate the contract for the work has delayed the implementation by a further three months. Utilizing purchased software will lessen the risk associated with application development and reduce future operational costs for program design. This project will be completed within budget by the end of the second quarter in 2010.

25. Public Address System - Holyrood

The public tendering process resulted in a tender which significantly exceeded the budget allocation. The system was redesigned in a simpler configuration which provided similar functionality and will be retendered early in 2010 for installation during the summer.

26. Install Fibre Optic Cable – Hinds Lake

Due to resource limitations within the Engineering Division, this project was not started until the fall of 2009. Originally the right of way clearing and the purchase of equipment was to be done in 2009 before the winter season. This work is now scheduled to be completed as soon as the construction season begins again in the spring of 2010, with the remainder of the work such as pole line construction and fiber cable installation being completed by the fall of 2010. This project is expected to be completed within budget.

27. Replace Vehicles and Aerial Devices 2008 – Various Locations

The project was carried over from 2008 for the purchase of two boom trucks. The variance resulted from the favorable pricing due to the exchange rate in effect during the tendering process as well as the contingency not being required.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

28. Replace Off Road Tracked Vehicles – Whitbourne and Bishop's Falls

The project was carried over from 2008 to purchase two tracked units fitted for backhoe attachments. The tracked vehicles were purchased without the attachments due to a safety requirement, therefore reducing the cost. Additionally, the contingency was not utilized.

29. Upgrade System Security 2009 – Various Locations

This is a multi-year project that included a security camera contract for approximately $500,000 that was awarded in 2009. Due to design issues and internal labour shortages, only a small portion of this contract was completed. The remaining portion of this contract will be completed in 2010. This project is expected to be completed on time and within budget.

30. Energy Conservation Upgrades – Hydro Place

The majority of the cost overrun results from the higher than anticipated engineering consulting fees as well as the cost of the new energy management system components. This project was originally justified based on a payback of 9 years. The cost benefit analysis was recalculated using the new estimated cost. Results from the revised cost benefit analysis indicate that this project will now have a payback of 11 years, well within the 15 year expected service life of the upgrades.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

31. Replace Diesel Engine – Mary's Harbour

This project was initiated in March of 2009 following the sudden failure of generating unit 2048. High level estimates were developed for budgeting purposes. Due to various uncertainties concerning compatibility of the new equipment with the existing controls, and a high workload for the Protection and Control department, the Protection and Control estimate contained extensive engineering and the possibility of utilizing outside consultants which were ultimately not required.

32. Install Neutral Grounding Resistors – Come by Chance

This project is to be fully contributed by Hydro's customer North Atlantic Refining Limited (NARL) and was approved by Board Order No. P.U. 26 (2008). Hydro is waiting for NARL to approve the expenditure for this project.

33. Replace Programmable Logic Controllers - Holyrood

It was anticipated that a substantial amount of collaborative work involving engineering services and plant engineering and operations forces would have been needed during the development of the project but this was found not to be necessary. Installation costs were significantly less than anticipated. This resulted in less overhead costs and no contingency funds being required.

34. Upgrade Continuous Emission Monitoring System – Holyrood

This project was approved March 20, 2009 with estimated expenditures in 2008 and 2009. The project was scheduled to start in February 2009 with a closeout of March 2010. The majority of the tenders pertaining to this project were awarded late in 2009. However, due to longer than expected manufacturing time, the equipment will not arrive on site until March 2010. It is expected that the project will be completed by the end of the third quarter, 2010.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

35. Condition Assessment and Life Extension Study – Holyrood

This is a multi-year project to be completed in 2010. A consultant was selected in 2009 to do the condition assessment but the key members of the consultant's project team were not available until January 2010 to begin work. Therefore the bulk of the project costs will be incurred during 2010 and the project will be completed in 2010.

36. Nain Diesel Plant Rehabilitation

This is a multi-year project to be completed in 2010. The project schedule had the bulk of the plant automation work being done in the fall of 2009 to be completed by February of 2010. However, due to unavailability of Protection and Control staff for the plant automation, this work will not be completed until the last quarter of 2010.

37. Replacement of Power Transformer – Wiltondale Terminal Station

The original project scope was to upgrade a spare transformer owned by Hydro, and to transport and install it in Wiltondale. It was determined that it would be less costly to purchase a transformer, which had been borrowed from Newfoundland Power, and perform related modifications rather than to proceed with the original plan.

38. Gas Turbine Refurbishment – Stephenville

This is a multi-year project to be completed in 2010. The investigation, research and specifications preparation for this project was completed in late 2009. The majority of the budget for this project will now be spent in 2010.

39. Hinds Lake Powerhouse Slope Stabilization

This is a multi-year project to be completed in 2010. The 2009 final cost was higher than originally proposed due to design improvements and quantity variances during construction which resulted in additional rock removal adding $160,000 to the estimated cost of this activity. The additional work also resulted in increased labor cost of approximately $50,000. Hydro is currently reviewing the design and the required 2010 work to finalize the remaining scope and budget to complete the work.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE QUARTER ENDING DECEMBER 31, 2009
(Greater than $100,000)

40. Work Protection Code eLearning Program

This was an unbudgeted capital project that was approved on June 16, 2009 by Board Order No. P.U. 23 (2009). This project has a scheduled duration of at least 33 weeks, therefore it will be completed by the second quarter of 2010. This project is expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 2000 – 2009
AS AT DECEMBER 31
($000)

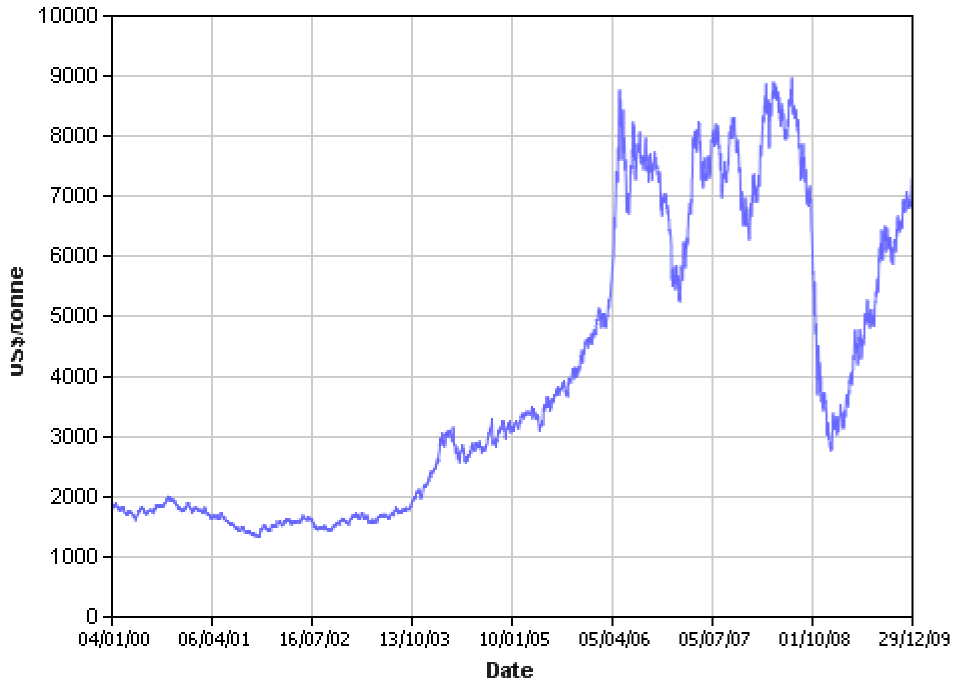
Table 1: CAPITAL BUDGET VERSUS EXPENDITURES 2000 – 2009

Year	Budget	Actual Expenditures	Variance	Percentage Variance
2000	43,824	38,569	5,255	12.0%
2001	55,897	47,501	8,396	15.0%
2002	44,660	40,217	4,443	9.9%
2003	36,122	32,506	3,616	10.0%
2004	31,435	27,984	3,451	11.0%
2005	47,760	33,952	13,808	28.9%
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%
2009	61,544	54,152	7,392	12.0%

These variances include amounts related to the carryover of projects from year to year. Total variances from budget for completed projects are 1% and 1% for 2008 and 2009 respectively, well within acceptable ranges, however the variances of individual projects completed in 2008 and 2009 tend to be greater than in previous years, due to continued high volatility in commodity prices, which are reflected in the cost of materials and manufactured goods. This period of unprecedented volatility began in mid 2005 and as long as it continues individual project variances will be greater than in years prior to 2005. To illustrate this volatility, the graph below indicates the price of copper for the 10 year period ending in December 2009.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 2000 – 2009
AS AT DECEMBER 31
($000)

Table 2: COPPER PRICES 2000 - 2009



The variances indicated in Table 1 for the years 2000-2009 are due almost entirely to under-spending as a result of not completing all projects approved each year. Hydro continues to have staffing issues, especially within the Engineering Services Division where the bulk of the capital budgets are managed. The maturing of this workforce has resulted in the loss of some of the most experienced staff to retirement and this, coupled with a number of resignations, resulted in the loss of about 30% of the technical staff and their replacement with younger and relatively inexperienced staff. This, combined with increased demand for technical support to deal with an aging infrastructure across the Hydro system, continues to present challenges to lowering the percentage variances as shown above.

It is anticipated that some carryovers of capital projects will occur in most years as there are frequently unavoidable reasons for delays in project completion. The Nain diesel plant fire had a significant affect on the success of the 2009 capital program. The burden it placed on Engineering Services and Operations personnel directly caused the carryover of two projects; Cartwright Switchgear Replacement and Black Tickle Generating Unit Replacement; and adversely affected the schedules of several other projects, contributing to their carryover. Several of the carryover projects missed their year end completion dates by only a few weeks. For example, Happy Valley/Goose Bay staff began moving into the new office building on January 18, and the installation of Meteorlogical Stations was completed in the first week of January.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS EXPENDITURES 2000 – 2009
AS AT DECEMBER 31
($000)

Hydro has also carried over to 2010 two projects which could have been completed in 2009, as we felt we would obtain lower cost tenders if the work was retendered. The Cat Arm Accommodations building was designed as a prefabricated building, ordered and delivered to site. The installation contract was tendered mid year and resulted in the receipt of bids for much greater than the estimated cost, a reflection of the high level of activity in that segment of the industry at the time. Hydro feels that the installation will be completed for a lower cost if retendered during the winter of 2009/10 for installation in the spring of 2010. The tenders for the Holyrood Paging System were also much higher than expected, the estimate for which was based on discussions held with equipment manufacturers when the budget proposal was prepared. Hydro has changed the design of the system to reduce cost while maintaining functionality. The completion of both these projects in 2010 should result in lower costs to our customers.

Hydro continues to improve its project management practices and expects to continue to reduce the percentage variance between the budget and actual expenditures as well as reduce the number of projects carried over.

NEWFOUNDLAND AND LABRADOR HYDRO
2009 CARRYOVER REPORT
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

Project Name	PUB Approved Budget 2009	Revised Budget 2009	Total Actual Expend. 2009	Carryover Amount	Variance Explanation Ref. No.	Original Completion Year
Install Meteorological Stations 2009 - Various Locations	253	253	268	(16)		2009
Install Motorized Stack Winches - Holyrood	174	174	49	125	1	2009
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	1,265	787	440	347	13	2009
Replace Switchgear - Cartwright	435	758	450	308		2009
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	3,224	3,224	2,696	528	18	2009
Replace Accom, Septic Sys and Upgrade Plant Communications Sys - Cat Arm	1,254	1,254	733	521	20	2009
Build New Maintenance Shop - St. Anthony	429	600	293	307	22	2009
Install Automatic Meter Reading - Change Islands and Fogo Island	491	491	1	490		2009
Purchase Meters and Equipment - Various Locations	33	33	0	33		2009
Tools and Equipment Less Than $50,000	237	28	0	28		2009
Customer Service Application - Hydro Place	910	1,140	360	780	24	2009
Public Address System - Holyrood	1,275	1,275	119	1,156	25	2009
Replace Vehicles and Aerial Devices 2009 - Various Locations	2,156	2,156	2,044	112		2009
Replace Light Duty Mobile Equipment Less Than $50,000 - Various Locations	561	561	530	31		2009
Purchase Spare Transformer - Hydro Place	389	481	460	21		2009
Replace Air Conditioning Units 2008 - Hydro Place	56	56	6	50		2009
Replace Fire Protection Panels - Hydro Place	89	114	104	10		2009
Install Neutral Grounding Resistors - Come By Chance	227	227	0	227	32	2009
Cost Recovery - North Atlantic Refining Limited	(227)	(227)	0	(227)		2009

NEWFOUNDLAND AND LABRADOR HYDRO
2009 CARRYOVER REPORT
FOR THE QUARTER ENDING DECEMBER 31, 2009
($000)

Project Name	Approved Budget 2009	Revised Budget 2009	Actual Expend. 2009	Carryover Amount	Variance Explanation Ref. No.	Original Completion Year
Replace 50kW Diesel Generator - Bay d'Espoir	36	36	7	29		2011
Purchase Spare Stator Windings Units 1 to 4 - Bay d'Espoir	37	37	131	(95)		2011
Upgrade Great Northern Peninsula Protection - Various Locations	101	101	68	33		2011
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	968	968	609	359	8	2011
Replace Diesel Units - Norman Bay, Postville and Paradise River	170	610	470	140	14	2011
Increase Generation - L'Anse Au Loup	23	1,002	783	219	17	2011
Install Fibre Optic Cable - Hinds Lake	209	209	9	200	26	2011
Upgrade System Security 2009 - Various Locations	767	767	488	279	29	2011
Upgrade Continuous Emission Monitoring System - Holyrood	704	704	7	697	34	2011
Condition Assessment and Life Extension Study - Holyrood	1,210	1,210	50	1,160	35	2011
Nain Diesel Plant Rehabilitation	2,416	2,416	1,764	652	36	2011
Gas Turbine Refurbishment - Stephenville	291	291	0	291	38	2011
Hinds Lake Powerhouse Slope Stabilization	492	492	704	(212)	39	2011
Work Protection Code eLearning Program	227	227	92	135	40	2011
Cost Recovery - Nalcor Energy, Churchill Falls	(66)	(66)	(66)	0		
New 25kV Terminal Station - Labrador City	283	283	101	182	5	2012
	21,098	**22,672**	**13,770**	**8,902**		

Exhibit 10 (2010 Report)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CAPITAL EXPENDITURES AND CARRYOVER REPORT

For Year Ending December 31, 2010

March 2011

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Year Ending December 31, 2010

TABLE OF CONTENTS

Page

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
OVERVIEW
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010
GENERATION	18,333	5,023	13,736	(4,597)
TRANSMISSION	11,276	5,930	10,654	(622)
RURAL SYSTEMS	16,133	5,941	17,361	1,228
GENERAL PROPERTIES	10,982	3,689	10,084	(898)
ALLOWANCE FOR UNFORESEEN EVENTS	1,694	325	851	(843)
PROJECTS APPROVED BY PU BOARD	4,731	1,079	2,762	(1,969)
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	148	56	105	(43)
TOTAL CAPITAL BUDGET	63,297	22,043	55,553	(7,744)

2010 Capital Budget Approved by Board Order No. P.U. 1 (2010)*	51,225
Carryover Projects 2009 to 2010	8,902
Changes to Multi-year Projects in 2009 affecting 2010**	(840)
New Project Approved by Board Order No. 31 (2009)	389
New Project Approved by Board Order No. 33 (2009)	1,795
New Project Approved by Board Order No. 34 (2009)	644
New Project Approved by Board Order No. 16 (2010)	0
New Project Approved by Board Order No. 21 (2010)	694
New Project Approved by Board Order No. 26 (2010)	120
New Project Approved by Board Order No. 29 (2010)	18
New Project Approved by Board Order No. 34 (2010)	202
2010 New Projects under $50,000 Approved by Hydro	148
TOTAL APPROVED CAPITAL BUDGET	63,297

* The total Capital Budget for $52,775 was approved less Upgrade Plant Acess Road - Bay d'Espoir for $1,550 that has been cancelled by Hydro since this cost cannot be recovered from its customers.

** **a)** Increase Generation - L'Anse au Loup was approved by Board Order No. P.U. 36 (2008) with a budget of $23,000 for 2009 and $821,000 for 2010. On August 20, 2009 Hydro filed documentation indicating a change in scope resulting in a budget increase for the project with $1,002,000 to be spent in 2009 and $517,000 in 2010. Therefore the 2010 budget is reduced by $304,000.

b) Replace Diesel Units - Norman Bay, Postville and Paradise River is a multi-year project to be completed in 2010, however, the genset being replaced in Postville failed prematurely and was replaced in 2009 reducing the 2010 budget by $536,000.

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010
GENERATION				
HYDRO PLANTS	10,057	1,135	6,722	(3,335)
THERMAL PLANT	6,637	3,178	6,228	(409)
GAS TURBINES	1,638	710	786	(852)
TOTAL GENERATION	18,333	5,023	13,736	(4,597)
TRANSMISSION				
TERMINAL STATIONS	5,768	2,881	4,730	(1,038)
TRANSMISSION	5,474	3,042	5,902	428
TOOLS AND EQUIPMENT	33	7	22	(11)
TOTAL TRANSMISSION	11,276	5,930	10,654	(622)
RURAL SYSTEMS				
DISTRIBUTION	8,512	3,632	10,478	1,966
RURAL GENERATION	3,032	1,488	2,810	(222)
GENERAL	2,396	601	2,770	374
METERING	558	157	453	(105)
TOOLS AND EQUIPMENT	1,636	63	850	(786)
TOTAL RURAL SYSTEMS	16,133	5,941	17,361	1,228

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010
GENERAL PROPERTIES				
INFORMATION SYSTEMS	2,008	514	1,811	(197)
TELECONTROL	5,105	1,937	4,485	(620)
TRANSPORTATION	2,299	656	2,060	(239)
ADMINISTRATIVE	1,570	582	1,728	159
TOTAL GENERAL PROPERTIES	10,982	3,689	10,084	(898)
OTHER APPROVED FUNDS				
ALLOWANCE FOR UNFORESEEN EVENTS	1,694	325	851	(843)
PROJECTS APPROVED BY PU BOARD	4,731	1,079	2,762	(1,969)
NEW PROJECTS APPROVED FOR LESS THAN $50,000	148	56	105	(43)
TOTAL CAPITAL BUDGET	63,297	22,043	55,553	(7,744)

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
GENERATION
FOR THE YEAR QUARTER AND ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
HYDRO PLANTS						
Install Meteorological Stations 2009 - Various Sites	(16)	0	9	25	-158%	
Replace 50 kW Diesel Generator - Bay d'Espoir	317	167	330	13	4%	
Purchase Spare Stator Windings Units 2 - Bay d'Espoir	2,711	(66)	1,655	(1,056)	-39%	1
Replace and Purchase Stator Winding - Bay d'Espoir	4,687	284	3,143	(1,544)	-33%	2
Upgrade Plant Access Road - Bay d'Espoir - (*Project Cancelled)*	0	0	0	0	0%	
Install Meteorological Stations 2010 - Various Sites -*(Project Cancelled)*	443	0	0	(443)	-100%	3
Upgrade Units 5 and 6 Cooling Water Systems - Bay d'Espoir	305	166	349	44	15%	
Upgrade Intake Gate Controls - Upper Salmon	284	42	328	44	15%	
Install Diesel Fuel Tank Monitoring System at Ebbegunbaeg - Bay d'Espoir	236	68	160	(76)	-32%	
Purchase Spare Spherical Valve Seal and Ring Assemblies - Bay d'Espoir	223	153	164	(59)	-26%	
Replace A/C Units in Control and Communications Room - Upper Salmon	197	61	67	(130)	-66%	4
Replace Human Machine Interface (HMI) Computer - Paradise River	158	51	82	(76)	-48%	
Upgrade Fuel Storage - Hinds Lake	149	80	167	18	12%	
Install Gain Heaters Gate 2 Burnt Dam Spillway - Bay d'Espoir	81	48	65	(16)	-20%	
Install Air Conditioning at Burnt Spillway - Bay d'Espoir	48	47	54	6	13%	
Replace 21 Inch Metal Cutting Lathe	80	0	0	(80)	-100%	
Purchase Tools and Equipment Less than $50,000	154	34	149	(5)	-3%	
TOTAL HYDRO PLANTS	**10,057**	**1,135**	**6,722**	**(3,335)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
THERMAL PLANT						
Install Motorized Stack Winches - Holyrood	125	209	272	147	117%	
Condition Assessment and Life Extension Study - Holyrood	1,846	484	1,278	(568)	-31%	5
Refurbish Fuel Storage Facility - Holyrood	2,500	1,275	2,560	60	2%	
Replace Programmable Logic Controllers - Holyrood	1,208	828	1,358	150	12%	6
Replace Pumphouse Motor Control Centres - Holyrood	50	15	99	49	97%	
Replace Steam Seal Regulator Unit 1 - Holyrood	335	12	16	(319)	-95%	7
Replace Diesel Fire Pump - Holyrood	112	1	28	(84)	-75%	
Install Cold Reheat Condensate Drains and High Pressure Heater Trip Level Units 1 and 3 - Holyrood	231	148	346	115	50%	8
Install Warm Air Make-up Access - Holyrood	170	206	219	49	29%	
Improve On Site Paving and Drainage - Holyrood	59	0	52	(7)	-12%	
Purchase Tools and Equipment Less than $50,000	0	0	0	0	0%	
TOTAL THERMAL PLANTS	**6,637**	**3,178**	**6,228**	**(409)**		
GAS TURBINES						
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	700	705	(600)	-46%	9
Upgrade Glycol Systems - Stephenville	261	2	3	(258)	-99%	10
Upgrade Fuel Tank Farm Controls - Happy Valley	72	8	78	6	8%	
TOTAL GAS TURBINE PLANTS	**1,638**	**710**	**786**	**(852)**		
TOTAL GENERATION	**18,333**	**5,023**	**13,736**	**(4,597)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
TRANSMISSION
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
TERMINAL STATIONS						
Upgrade Great Northern Peninsula Protection - Various Sites	124	45	196	72	58%	
New 25 kV Terminal Station - Labrador City	2,882	1,336	1,693	(1,189)	-41%	11
Upgrade Power Transformers - Various Sites	816	545	913	98	12%	
Upgrade Circuit Breakers - Various Terminal Stations	342	47	501	159	46%	12
Replace Insulators - Various Terminal Stations	399	227	324	(75)	-19%	
Replace Instrument Transformers - Various Sites	197	112	227	30	15%	
Replace Disconnects - Various Sites	199	91	97	(102)	-51%	13
Perform Grounding Upgrades - Various Sites	291	216	272	(19)	-7%	
Upgrade Trailer and Mobile Substation - Bishop's Falls	30	3	151	121	397%	14
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood	79	16	19	(60)	-76%	
Replace Surge Arrestors - Various Sites	73	10	72	(1)	-2%	
Install Digital Fault Recorder - Various Sites	166	111	128	(38)	-23%	
Replace Air Compressors - Various Sites	97	83	86	(11)	-11%	
Replace 230 kV Breaker Controls - Massey Drive and Buchans	73	39	51	(22)	-30%	
TOTAL TERMINAL STATIONS	**5,768**	**2,881**	**4,730**	**(1,038)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
TRANSMISSION
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
TRANSMISSION						
Upgrade Transmission Line TL-212 - Sunnyside to Linton Lake	1,323	1,068	1,804	481	36%	15
Construct Transmission Line Equipment Off-Loading Areas - Various Sites	990	912	984	(6)	-1%	
Perform Wood Pole Line Management Program - Various Sites	2,308	556	2,501	193	8%	
Replace Guy Wires TL-215 - Doyles to Grand Bay	301	281	326	25	8%	
Upgrade Line TL-244 - Plum Point to Bear Cove	141	0	0	(141)	-100%	16
Upgrade Anchors on C Structures TL-259 - Parson's Pond	353	171	225	(128)	-36%	17
Install Remote Ice Growth Detector Beams - Various Sites	58	54	62	4	7%	
TOTAL TRANSMISSION	**5,474**	**3,042**	**5,902**	**428**		
TOOLS AND EQUIPMENT						
Purchase Tools and Equipment Less than $50,000	33	7	22	(11)		
TOTAL TOOLS AND EQUIPMENT	**33**	**7**	**22**	**(11)**		
TOTAL TRANSMISSION	**11,276**	**5,930**	**10,654**	**(622)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
DISTRIBUTION						
Provide Service Extensions - All Service Areas	2,428	1,949	4,855	2,427	100%	18
Upgrade Distribution Systems - All Service Areas	2,572	519	2,299	(273)	-11%	19
Upgrade Line 2 Distribution Feeder - Glenburnie	267	64	110	(157)	-59%	20
Upgrade Distribution Lines - Various Sites	218	67	84	(134)	-61%	21
Replace Poles - Various Sites	1,083	468	1,005	(78)	-7%	
Voltage Conversion - Labrador City	1,089	238	1,525	436	40%	22
Replace Recloser Control Panels - Various Sites	603	189	370	(233)	-39%	23
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois	82	27	40	(42)	-51%	
Install New Voltage Regulators - Various Sites	170	111	190	20	12%	
TOTAL DISTRIBUTION	**8,512**	**3,632**	**10,478**	**1,966**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE YEAR QUARTER AND ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
RURAL GENERATION						
Replace Diesel Units - Norman Bay, Cartwright and Black Tickle	347	109	432	85	24%	
Replace Diesel Units - Norman Bay, Postville and Paradise River	1,304	1,079	1,497	193	15%	24
Replace Switchgear - Cartwright	308	64	412	104	34%	25
Increase Generation Capacity - L'Ance Au Loup	736	215	448	(288)	-39%	26
Replace Diesel Unit 2001 and Engine 566 - Francois	168	11	11	(157)	-93%	27
Replace Diesel Unit 2018 - McCallum	19	10	10	(9)	-48%	
Replace Main Bus Splitter - Postville - *(Project Cancelled)*	149	0	0	(149)	-100%	28
TOTAL RURAL GENERATION	**3,032**	**1,488**	**2,810**	**(222)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
GENERAL						
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	528	16	334	(194)	-37%	29
Replace Accom, Septic Sys and Upgrade Plant Communications Sys - Cat Arm	521	164	1,108	587	113%	30
Build New Maintenance Shop - St. Anthony	307	0	316	9	3%	
Upgrade Properties - Port Hope Simpson	71	49	52	(19)	-27%	
Install Fall Protection Equipment at Hydro Facilities - Various Sites	198	103	216	18	9%	
Install Pole Storage Ramps - Various Sites	90	3	78	(12)	-14%	
Legal Survey of Primary Distribution Line Right of Way - Various Sites	65	54	65	(0)	-1%	
Install Waste Oil Storage Tanks - Various Sites	84	43	91	7	8%	
Install Transformer Storage Ramps - Various Sites	89	59	84	(5)	-5%	
Upgrade Accommodations - Norman Bay and Ebbegunbaeg	196	6	302	106	54%	31
Upgrade Fire Protection System - Bishop's Falls	158	86	103	(55)	-35%	
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls	88	18	21	(67)	-76%	
TOTAL GENERAL	**2,396**	**601**	**2,770**	**374**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
METERING						
Purchase Meters and Equipment 2010 - Various Sites	34	30	30	(4)	-13%	
Install Automatic Meter Reading - Various Sites	490	127	390	(100)	-20%	32
Purchase Meters and Equipment 2009 - Various Sites	33	0	33	(0)	0%	
TOTAL METERING	**558**	**157**	**453**	**(105)**		
TOOLS AND EQUIPMENT						
Replace Off-Road Track Vehicles - Various Sites	685	0	1	(684)	-100%	33
Replace Light-Duty Mobile Equipment - Various Sites	554	8	518	(36)	-6%	
Replace Heavy-Duty Forklift - Unit 9799 - Bishop's Falls	166	0	118	(48)	-29%	
Tools and Equipment Less than $50,000	232	55	213	(19)	-8%	
TOTAL TOOLS AND EQUIPMENT	**1,636**	**63**	**850**	**(786)**		
TOTAL RURAL SYSTEMS	**16,133**	**5,941**	**17,361**	**1,228**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
INFRASTRUCTURE REPLACEMENT						
NEW INFRASTRUCTURE						
Perform Minor Application Enhancements - Hydro Place	121	61	123	2	2%	
Cost Recoveries	(36)	(33)	(42)	(6)	16%	
Work Protection Software Design	71	32	66	(5)	-7%	
Cost Recoveries	(21)	(17)	(22)	(1)	4%	
Upgrade Intranet - Hydro Place	66	60	66	(0)	0%	
Cost Recoveries	(20)	(19)	(23)	(3)	16%	
UPGRADE OF TECHNOLOGY						
Corporate Application Environment - Upgrade Microsoft Products	751	33	562	(189)	-25%	34
Cost Recoveries	(225)	(33)	(191)	34	-15%	
Upgrade Business Intelligence Toolset Software - Hydro Place	84	40	86	2	3%	
Cost Recoveries	(25)	(23)	(29)	(4)	16%	
TOTAL SOFTWARE APPLICATIONS	**765**	**101**	**596**	**(169)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
PC Replacement Program - Various Sites	406	63	404	(2)	-1%	
Replace Peripheral Infrastructure - Various Sites	222	27	227	5	2%	
Upgrade Enterprise Storage Capacity - Hydro Place	241	64	241	(0)	0%	
Cost Recoveries	(72)	(64)	(82)	(10)	13%	
NEW INFRASTRUCTURE						
Develop Learning Management System Safety Courses - Hydro Place	138	110	139	1	1%	
Cost Recoveries	(41)	(37)	(47)	(6)	14%	
Smart Card Implementation - Various Sites	133	117	133	0	0%	
Cost Recoveries	(40)	(35)	(45)	(5)	13%	
Upgrade Security SCADA Intrusion Prevention System - Hydro Place	62	66	68	6	10%	
Upgrade Security Vulnerability Management System - Hydro Place	81	70	70	(11)	-14%	
Cost Recoveries	(24)	(19)	(24)	0	-2%	
UPGRADE OF TECHNOLOGY						
Upgrade Server Technology Program - Various Sites	197	103	198	1	1%	
Cost Recoveries	(59)	(52)	(67)	(8)	14%	
TOTAL COMPUTER OPERATIONS	**1,243**	**413**	**1,215**	**(28)**		
TOTAL INFORMATION SYSTEMS	**2,008**	**514**	**1,811**	**(197)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Customer Service Application - Hydro Place	780	254	1,210	430	55%	35
Public Address System - Holyrood	1,156	500	540	(616)	-53%	36
Install Fibre Optic Cable - Hinds Lake	683	148	459	(224)	-33%	37
Replace Radomes - Various Sites	212	44	110	(102)	-48%	38
Upgrade Remote Terminal Units - Various Sites	190	(7)	398	208	109%	39
Purchase Tools and Equipment less than $50,000	109	40	89	(20)	-19%	
NETWORK INFRASTRUCTURE						
Replace Stationary Battery Banks and Chargers - Various Sites	717	315	559	(158)	-22%	40
Replace Network Communications Equipment - Various Sites	131	78	149	18	14%	
Install Mobile Communications - Port Hope Simpson, Charlottetown	208	182	202	(6)	-3%	
UPGRADE OF TECHNOLOGY						
Replace Radio Link with Fiber - Bay d'Espoir	489	32	375	(114)	-23%	41
Upgrade Private Automated Branch Exchange (PABX) - Various Sites	339	344	384	45	13%	
Upgrade Operator Training Simulator - Hydro Place	92	7	10	(82)	-89%	
TOTAL TELECONTROL	**5,105**	**1,937**	**4,485**	**(620)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
TRANSPORATION						
Replace Vehicles and Aerial Devices 2009 - Various Sites	112	0	28	(84)	-75%	
Replace Light Duty Mobile Equipment Less than $50,000 - Various Sites	31	0	35	4	12%	
Replace Vehicles and Aerial Devices 2010 - Various Sites	2,156	656	1,997	(159)	-7%	42
TOTAL TRANSPORATION	**2,299**	**656**	**2,060**	**(239)**		
ADMINISTRATION						
Upgrade System Security 2009 - Various Sites	981	355	1,295	314	32%	43
Purchase Spare Transformer - Hydro Place	21	0	12	(9)	-43%	
Replace Air Conditioning Units 2008 - Hydro Place	50	0	46	(4)	-8%	
Replace Fire Protection Panels - Hydro Place	10	0	8	(2)	-20%	
Remove Safety Hazards - Various Sites	252	160	208	(44)	-18%	
Replace Humidifiers in Air Handling Units - Hydro Place	75	5	14	(61)	-81%	
Purchase Tools and Equipment less than $50,000	180	62	145	(35)	-19%	
TOTAL ADMINISTRATION	**1,570**	**582**	**1,728**	**159**		
TOTAL GENERAL PROPERTIES	**10,982**	**3,689**	**10,084**	**(898)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
ALLOWANCE FOR UNFORESEEN EVENTS						
Structure Failure TL-208 - Long Harbour	249	3	340	91	37%	
Microwave Radio Site Ice Storm Damage - Four Mile Hill	445	131	320	(125)	-28%	44
Ice Storm - Southern Labrador	207	191	191	(16)	-8%	
Allowance for Unforeseen Events	**793**	**0**	**0**	**(793)**		
TOTAL ALLOWANCE FOR UNFORESEEN EVENTS	**1,694**	**325**	**851**	**(843)**		
PROJECTS APPROVED BY PUB						
CARRYOVER						
Install Neutral Grounding Resistors - Come By Chance	227	0	0	(227)	-100%	45
Cost Recovery - North Atlantic Refining Limited	(227)	0	0	227		
Upgrade Continuous Emission Monitoring System - Holyrood	697	177	614	(83)	-12%	
Nain Diesel Plant Rehabilitation	1,041	89	117	(924)	-89%	46
Gas Turbine Refurbishment - Stephenville	2,086	165	1,269	(817)	-39%	47
Hinds Lake Powerhouse Slope Stabilization	432	465	497	65	15%	
Work Protection Code Elearning Program	135	34	116	(19)	-14%	
NEW						
Voisey's Bay Nickel - Long Harbour Power Supply	3,605	931	1,332	(2,273)	-63%	48
Cost Recovery - Vale Inco	(3,605)	(931)	(1,332)	2,273		
Replace Fuel Tank - Bay d'Espoir Campsite	120	10	10	(110)	-92%	49
Confined Space Isolation (Blanks and Blinds) - Holyrood	202	139	139	(63)	-31%	
Replace Unit 565 - Little Bay Islands	18	0	0	(18)	-100%	
TOTAL PROJECTS APPROVED BY PUB	**4,731**	**1,079**	**2,762**	**(1,969)**		

NEWFOUNDLAND & LABRADOR HYDRO
2010 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2010
($000)

	PUB Approved Budget 2010	4th Quarter Actuals 2010	Total Actual Expend. 2010	Variance From Budget 2010	Percentage Variance From Budget 2010	Variance Explanation Ref. No.
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Replace Generator Unit 2066 - Black Tickle	18	12	18	0	0%	
Replace Domestic Water Pump - Upper Salmon - *(Project Cancelled)*	26	0	0	(26)	-100%	
Replace Drainage Piping - Stephenvill Gas Turbine	48	29	72	24	50%	
Replace Switch - Oxen Pond Terminal Station	38	0	0	(38)	-100%	
Purchase Test Equipment - Hydro Place	18	15	15	(3)	-17%	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**148**	**56**	**105**	**(43)**		

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

1. Purchase Spare Stator Windings Unit 2 – Bay d'Espoir

Budget: $2,711 **Actual:** $1,655 **Variance:** ($1,056)

This project has been carried over into 2011. When budgetary quotes were received in 2008 for the supply of stator windings, the material cost of the windings was budgeted at $2.3 million. Between the time the quote was provided and the contract was tendered, the price of copper declined. This, combined with favorable tenders, reduced the material cost of the windings to approximately $1.5 million. The reduction in material costs also resulted in less interest and overhead cost, and no contingency being required.

2. Replace and Purchase Stator Winding – Bay d'Espoir

Budget: $4,687 **Actual:** $3,143 **Variance:** ($1,544)

From the time that budgetary quotes were provided for this project in 2008, and the time the contract was tendered in 2010, the price of copper declined. This, combined with favorable tenders, reduced the material cost of the windings by approximately $700,000. Conversely, the contract cost for the installation came in approximately $350,000 higher than quoted. This project has been carried over to 2011 and is expected to be completed for approximately $500,000 less than budgeted.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

3. **Install Meteorological Stations 2010 – Various Sites** *(Project Cancelled)*

Budget: $443 **Actual:** $0 **Variance:** ($443)

Part of the Install Meteorological Stations project for 2008 approved by Board Order No. P.U. 30 (2007) included the installation of a remote station in the Cat Arm watershed with a snow water equivalent measurement device (snow pillow). This installation of the snow pillow was a first for Hydro and some problems were encountered with communication of the data from the site to Hydro's data collection center in St. John's. Although the gauge has been in place since 2008, difficulties with the satellite communications have prevented the use of this data. The 2010 program was to add more snow pillows (in remote locations in the watersheds of the Victoria, Long Pond, Hinds Lake and Meelpaeg reservoirs), however, because of the communication difficulties experienced with the Cat Arm snow pillow it was decided to cancel the 2010 project and resubmit it when there was certainty that the data collection issues were resolved and that the data received provides the intended benefit of improved inflow forecasting.

4. **Replace A/C Units in Control and Communications Rooms - Upper Salmon**

Budget: $197 **Actual:** $67 **Variance:** ($130)

This project has been carried over into 2011. The equipment supplier failed to approve required modification drawings on time resulting in a ten week delay in the fabrication and delivery of the air conditioning units which did not arrive on site until late December 2010. The budget for this project was prepared based on a supply and install contract, however, the project was executed with owner supply of equipment and installation by a separate contractor thus reducing the overall cost of the project. The cost of the project was reduced by approximately $41,000 as a result of favorable material and installation prices received during the public tender process. This project will be completed by the end of the first quarter of 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

5. Condition Assessment and Life Extension Study - Holyrood

Budget: **$1,846** **Actual:** **$1,278** **Variance:** **($568)**

This project was carried over into 2011 due to scope changes to include a more detailed condition assessment of the marine terminal, gas turbine plant and the stack breeching on Units 1 and 2. While completing this project, it was recognized that a more in depth analysis on the items listed above should be undertaken as part of this assessment. It was determined that there were sufficient funds within this project in order to complete this additional work therefore this project is still expected to be completed within budget.

6. Replace Programmable Logic Controllers – Holyrood

Budget: **$1,208** **Actual:** **$1,358** **Variance:** **$150**

This is a multiyear project scheduled to be completed in 2012. The burner management system controls for Units 1 and 2 were replaced during 2010. There were safety related deficiencies in the burner management control systems that were not identified during the preparation of this proposal. The modifications required to correct these deficiencies resulted in an additional $50,000 for completion and commissioning. As well, the tender for the engineering and supply of the burner management systems and the electrical systems were $100,000 greater than expected. In addition, the scope of this project has been changed to exclude the replacement of the control systems for the warm air makeup system. There are mechanical issues with this system that have to be addressed therefore it would not be prudent to replace the control systems at this time. Overall, this project is expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

7. Replace Steam Seal Regulator Unit 1 – Holyrood

Budget:	$335	Actual:	$16	Variance:	($319)

This is a multiyear project scheduled to be completed in 2011. The original plan for 2010 was to complete the project mechanical design requirements by the beginning of the second quarter and then engage a consultant to complete a pipe stress analysis which would then enable tender preparation and award by the third quarter and construction starting in the fourth quarter. However, due to the system operating conditions (extreme changes in temperature during operation) and piping configuration, the stress analysis required several iterations before acceptable thermal stress levels were achieved. As a result, the stress analysis was not completed until January 2011. The construction tender will now be issued in the first quarter of 2011. Also, the initial plan was to install flow meters in the steam lines that would enable measuring flow rates required for control valve sizing. Unfortunately, this was determined not possible due to the existing piping configuration. This information was later determined by locating another utility that had completed an identical project on a similar turbine to Holyrood Unit 1. As a result, the specification for control and manual isolation valves was not completed and tendered until January 2011. This project is expected to be completed within budget.

8. Install Cold Reheat Condensate Drains and High Pressure Heater Trip Level Units 1 and 3 - Holyrood

Budget:	$231	Actual:	$346	Variance:	$115

After capital budget approval, and during the detailed engineering design, it was determined that the installation of a maintenance platform and a more sophisticated electrical and controls package were required. This resulted in an increase in the cost of the installation contract by $70,000. This extra work also required an increase to the cost of in-house resources by $39,000. Also contributing to the increase in installation cost was a reduced unit outage duration which resulted in the contractor having to work overtime shifts to complete the work within the scheduled outage.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

9. Upgrade Gas Turbine Plant Life Extension – Hardwoods

Budget: **$1,305** **Actual:** **$705** **Variance:** **($600)**

This is a multiyear project scheduled to be completed in 2012. A major portion of the 2010 budget for this project was allocated to overhauling one gas turbine engine. The proposal assumed that a plant outage would occur early in the year so that the gas turbine engine could be removed, refurbished and returned to service before winter. The plant outage at Hardwoods did not occur until late in October. This did not allow sufficient time to have the engine overhauled and returned to service prior to the winter operation season. Depending on the outage schedule for 2011 and the degree of overhaul required once the engine is disassembled and inspected, the work planned for 2011 which involves the overhaul of another of the gas turbine engines may be delayed to 2012.

10. Upgrade Glycol System – Stephenville

Budget: **$261** **Actual:** **$3** **Variance:** **($258)**

This multiyear project was scheduled to start in 2010 with completion in 2011. Equipment scheduled to be ordered in 2010 has been rescheduled for ordering in the first quarter of 2011 due to unavailability of resources with project completion still anticipated for 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

11. <u>New 25 kV Terminal Station – Labrador City</u>

Budget: $2,882 **Actual: $1,693** **Variance: ($1,189)**

This is a multi-year project scheduled to be completed in 2012. There were issues which arose during the acquisition of the land required for the new terminal stations which delayed the finalization of the design and the ordering of equipment. The design and ordering of equipment is ongoing with scheduled completion during the first quarter of 2011. This project is expected to be completed within budget.

12. <u>Upgrade Circuit Breakers – Various Terminal Stations</u>

Budget: $342 **Actual: $501** **Variance: $159**

The original plan for the 2010 Upgrade Circuit Breaker program was to complete five overhauls during 2010. There was an unplanned replacement due to the failure of a 138 kV breaker at Bottom Brook. To help minimize the impact to the overall budget the plan was reduced to two replacements after the breaker failed at Bottom Brook in April. In June, a 230 kV Current Transformer failed at Holyrood Terminal Station that damaged an adjacent breaker, resulting in one phase of breaker B1B11 being replaced. Then in October we experienced a problem with breaker B4B5 at Bay d'Espoir and as a result, this originally deferred breaker overhaul had to be advanced. This action resulted in the cost of this project being approximately $160,000 greater than budgeted.

13. <u>Replace Disconnects – Various Sites</u>

Budget: $199 **Actual: $97** **Variance: ($102)**

This project has been carried over into 2011. The station post insulator specifications were updated in 2009 however the corresponding disconnect specifications were not updated. This resulted in delivery delays since the supplier had to procure insulators and switches to meet our new specification requirements. The disconnect switches were not delivered until September therefore it was not possible to schedule an outage in 2010 and this project will be completed in 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

14. Upgrade Trailer and Mobile Substation – Bishop's Falls

Budget: **$30** **Actual:** **$151** **Variance:** **$121**

The original budget estimate for this project was based on upgrading the trailer and replacing the circuit breaker of the existing mobile substation. An assessment of the condition of the existing trailer concluded that the trailer was near its maximum loading limits which had contributed to the deflection of its support beams and that the trailer should be replaced.

The purchase of a new trailer required that the power transformer be transferred from the existing trailer, function-tested and re-commissioned for service by a qualified contractor in a certified test shop. Given the need to go to a certified testing and fabrication shop, it was seen as an opportune time to perform other necessary work on the transformer. As a result all bushings cover gaskets (including the top cover), coolers, pumps and pipe work will be replaced. In addition all steel control panels will be replaced with lighter weight aluminum with upgrades to the control systems to meet current Nalcor standards. An additional set of CTs will be installed on the 69 kV winding of the transformer to provide increased versatility for the application of the substation, as this asset is essential to provide service to customers during planned and emergency work.

While replacement of the 25 kV oil filled circuit breaker with a lighter more environmentally friendly vacuum style breaker was included in the budget estimate, additional modifications are required to the breaker control system to connect it to the main control panel of the substation and bring it up to Nalcor standards, which were not budgeted. The tendered bids were all higher than anticipated.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

15. Upgrade Transmission Line TL-212 – Sunnyside to Linton Lake

Budget: $1,323 **Actual: $1,804** **Variance: $481**

The budget estimate for this project was based on tender pricing received during the 2007 and 2008 construction seasons. The tender pricing was higher than expected resulting in this project being over budget by approximately $480,000.

16. Upgrade Transmission Line TL-244 – Plum Point to Bear Cove

Budget: $141 **Actual: $0** **Variance: ($141)**

This project was submitted as a multiyear project to be completed in 2011. Due to the unavailability of resources in the Engineering discipline, it was decided to execute and complete this project in a single year, 2011. This project is expected to be completed within budget.

17. Upgrade Anchors on C Structures TL-259 – Parson's Pond

Budget: $353 **Actual: $225** **Variance: ($128)**

The planned scope of this project was to replace existing anchors that were deteriorated due to corrosion. Since anchor components are buried underground, no visual inspection or assessment can be performed at site during the budget preparation. As a result, a worst- case scenario was anticipated in which specially designed concrete gravity based anchors would be utilized to prevent any further deterioration due to corrosion.

During the excavation of the existing anchors, it was determined that the anchors were not as deteriorated as anticipated and it was decided to use standard anchor replacements with rock backfill instead of the concrete anchor design. Therefore, the final project cost was $128,000 less than budgeted.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

18. Provide Service Extensions – All Service Areas

Budget: **$2,428** **Actual:** **$4,855** **Variance:** **$2,427**

The increase in this budget is due to the growth in all areas serviced by Hydro. In the Labrador Interconnected system, there are three new subdivisions being developed in Happy Valley and Sheshatshui with an additional 90 homes being developed in total. Housing developments in the Labrador West area have resulted in an additional 130 new houses planned for that area as well as the connection of the new College of North Atlantic facility. In the Northern region, increased services were required as a result of customers converting from oil fired to electric heating systems. In addition, the interconnection of a wood pellet plant, a saw mill and a high school resulted in additional costs.

19. Upgrade Distribution Systems – All Service Areas

Budget: **$2,572** **Actual:** **$2,299** **Variance:** **($273)**

The Upgrade Distribution Systems budget is based on a five year average rather than specifically identified projects. The expenditures for this project were below average in the Labrador region.

20. Upgrade Line 2 Distribution Feeder – Glenburnie

Budget: **$267** **Actual:** **$110** **Variance:** **($157)**

This is a four year project and in first year, 2010, it was planned to complete a line assessment and environmental assessment. The environmental assessment cost was less than anticipated due to the limited number of environmental issues which were encountered. Due to other capital work commitments, the line assessment was delayed. The overall project is expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

21. Upgrade Distribution Lines – Various Sites

Budget: $218 **Actual: $84** **Variance: ($134)**

This is a multiyear project to be completed in 2011 for the communities of Makkovik and Roddickton. The under expenditure in 2010 is due primarily to the Roddickton portion of the project. The first year was designated for an assessment of the line to be completed. This assessment would have provided the necessary information required to order materials for the construction phase in 2011. The assessment was not completed in 2010, due to other work commitments, and therefore materials were not ordered for the project. Although there is an under expenditure for 2010, the project is expected to be completed within budget.

22. Voltage Conversion – Labrador City

Budget: $1,089 **Actual: $1,525** **Variance: $436**

This is a four year project. This first year of this project was designated for the ordering of materials and the upgrade of Harrie Lake Trailer Court to be 25 kV ready. The cost estimate for this project was created prior to an assessment of the line being performed. Once the assessment of the line was completed late in 2009, it was discovered that dual voltage distribution transformers were required to allow for the Harrie Lake 25 kV conversion. Although there is an over expenditure for the budget year 2010, the four-year project is expected to be completed within budget overall.

23. Replace Recloser Control Panels – Various Sites

Budget: $603 **Actual: $370** **Variance: ($233)**

This project has been carried over into 2011 due to the unavailability of resources to complete this work. A cable run is required to the terminal station equipment and the snow must be melted before this work can be completed in June 2011. Repeated recloser installations have decreased the engineering and install/commissioning time required to complete each recloser replacement. This project is expected to be completed under budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

24. Replace Diesel Units – Norman Bay, Postville and Paradise River

Budget: **$1,304** **Actual:** **$1,497** **Variance:** **$193**

Costs were higher than anticipated on this project for two reasons. Firstly, the budget was prepared in 2007 with cost estimates from a local vendor. The final tendered costs for gensets in 2009 and 2010 were approximately double the 2007 budget quotes, or $75,000 greater than budgeted. Secondly, the replacement of gensets was planned to take place while the plant remained in operation. This was not possible due to existing equipment constraints and, as a result, temporary generation was required to maintain service to the community while the work was performed. Additional costs of approximately $96,000 were incurred to rent and transport these gensets, and approximately $65,000 in labour and material costs to install and later remove them. These increases in cost were partially offset by a decrease in the protection and control equipment costs.

25. Replace Switchgear - Cartwright

Budget: **$308** **Actual:** **$412** **Variance:** **$104**

Originally, all project engineering work was to be done by Hydro personnel, however, due to resource constraints within Engineering Services, outside technical assistance was required to complete the automation portion of the project. The work outsourced included onsite installation of the automation equipment, commissioning of the switchgear system, and operator training. This increased the project cost by approximately $65,000. Project construction costs also increased by $25,000 due to additional changes required for the plant Direct Current (DC) system and remediation of arc flash levels.

26. Increase Generation Capacity – L'Anse Au Loup

Budget: **$736** **Actual:** **$448** **Variance:** **($288)**

This project has been carried over into 2011. The mobile transformer has been ordered but due to a longer than expected delivery time is not expected on site in L'Anse Au Loup until mid January of 2011. The new protection and control installations can not take place until after the 2011 winter generation season and will be complete by early fall.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

27. Replace Diesel Unit 2001 and Engine 566 – Francois

Budget: $168 **Actual:** $11 **Variance:** ($157)

Due to a high engineering work load and priorities on other projects already in progress in 2010, this project began later than originally planned. During the design phase it became apparent that arc flash mitigation requirements[1], which were implemented after the project budget was prepared in 2009, would require replacement of the switchgear for unit 566. When replacement of the switchgear was taken into consideration, replacement of the entire genset is the least cost alternative when compared to replacing switchgear and engine only.

As a result of the expanded equipment replacement scope, additional engineering is now required along with longer lead times on equipment delivery. The lead time on a replacement engine was expected to be approximately 12 weeks, whereas, the lead time for a complete genset is 20 to 26 weeks. In addition, with a direct engine replacement, very little engineering time was required, however, a genset and switchgear replacement requires additional engineering effort. The overall impact on the project was to delay replacement of unit 566 from late fall 2010 to late summer of 2011.

28. Replace Main Bus Splitter – Postville *(Project Cancelled)*

Budget: $149 **Actual:** $0 **Variance:** ($149)

The scope of this project was to upgrade the main plant splitter from a 400 amp rating to meet load growth in the community. During the initial development stage of this project, it was determined that the main plant splitter is actually rated at 800 amp which is adequate to meet the load requirements for Postville for the foreseeable future. Therefore this project has been cancelled.

[1] Arc flash hazards are given a Hazard Risk Category (HRC) rating. The target for diesel plants is HRC 2 or below. HRC 3 or above has to be reduced to HRC 2 or below and it has been made a requirement to address arc flash issues whenever performing work on or around equipment classified as an arc flash hazard. Stantec report 133530034-R09, Rev. 0 *Arc Flash Hazard analysis Report Francois Diesel Generating Plant*, classifies the Francois diesel plant as HRC 4.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

29. <u>Construct New Office/Warehouse/Line Depot Facilities – Happy Valley</u>

Budget: **$528** **Actual:** **$334** **Variance:** **($194)**

This project has been carried over into 2011. Delays in receiving operating information from the Contractor have delayed the consultant's submission for "LEED" certification which is expected to take 3 to 4 months after acceptable information is received. In addition, there is a secondary coat of asphalt required for the parking lot that cannot be done until summer. This project is expected to be completed within budget.

30. <u>Replace Accommodations, Septic System and Upgrade Plant Communications System – Cat Arm</u>

Budget: **$521** **Actual:** **$1,108** **Variance:** **$587**

The budget of $521,000 was carried over from 2009. The foundation, placement of units, electrical, and mechanical pricing for the installation contract for Cat Arm accommodation units was greater than the original budget. It was decided in 2009 to retender the installation contract in 2010 to provide more competition in the tender process; however, only one bid was received. In order to complete the work in time to use the facility in 2010, there was no option but to proceed with the project based on the tendered price. This added approximately $550,000 to the project cost. The cost benefit analysis was recalculated using updated budgeted cost of $1.8 million and the installation option remained the least cost alternative as the table below shows:

Cat Arm Accommodations
Alternative Comparison
Cumulative Net Present Value
To The Year
2030

Alternatives	Cumulative Net Present Value (CPW)	CPW Difference between Alternative and the Least Cost Alternative
Construct Accomodations	1,887,752	0
Stay Off-Site	2,533,795	646,043

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

31. Upgrade Accommodations – Norman Bay and Ebbegunbaeg

Budget: **$196** **Actual:** **$302** **Variance:** **$106**

The increase in costs is due primarily to the contract price for the building construction at Norman Bay with a number of factors contributing to the increased cost. First, due to the relocation of the new building to the opposite side of the site, additional water line trenching, installation of a new septic system, and cleaning and removal of the old system were required. Secondly, the completion date for the project was advanced making it necessary for the contractor to use additional workers to complete the project within the time allowed. The advance in the completion date was due to additional projects in Norman Bay that required use of the new accommodation building.

32. Install Automatic Meter Reading – Various Sites

Budget: **$490** **Actual:** **$390** **Variance:** **($100)**

This project was under budget due to the fact that deployment of a second collector on Fogo Island was not required. All meter readings from both Fogo Island and Change Islands were accessible through the submarine cable from the collector installed at the Farewell Head terminal station. Prior to installation, it was unknown if there would be issues with reception of the signals through the submarine cable therefore two collectors were budgeted.

33. Replace Off-Road Track Vehicles – Various Sites

Budget: **$685** **Actual:** **$1** **Variance:** **($684)**

The project has been carried over into 2011. The purchase of the two track units is delayed as a result of component shortages due to the down turn in the economy. The supplier estimates the units will be delivered by the end of March 2011. This project is expected to be completed within budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

34. <u>Corporate Application Environment – Upgrade Microsoft Products</u>

Budget: $751 **Actual:** $562 **Variance:** ($189)

This is a three-year project started in 2010. Due to a lack of resources, one component of the upgrade, Sharepoint, that was originally scheduled to be implemented in 2010, will now be done in 2011. This project is expected to be completed on time and within budget.

35. <u>Customer Service Application – Hydro Place</u>

Budget: $780 **Actual:** $1,210 **Variance:** $430

This project was over budget due to the following reasons. Firstly, there was a change in scope in order to address perceived security issues with the web application, as identified by a third party security assessment. This led to additional contract work as well as additional internal labour to implement and test the resulting modified system. Secondly, there was a another scope change in order to purchase hardware spares for the upgraded PBX. This was an unexpected expense in that the original intention was that support for the system, both hardware and software, would be completely outsourced to the vendor with costs to be covered by operating budgets. However, this support model was determined to be prohibitively expensive. As a result, the decision was made to bring support in house for major components of this system, requiring Hydro to purchase its own set of capital spares.

36. <u>Public Address System – Holyrood</u>

Budget: $1,156 **Actual:** $540 **Variance:** ($616)

This project has been carried over into 2011. Initially, this project was tendered in 2008/2009 and the tender responses received exceeded the planned budget so it was re-tendered and divided into two parts, design/ supply and installation/commissioning. Project costs have risen for the following reasons:

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

36. Public Address System – Holyrood (cont'd.)

- The requirement for On-Site Representatives during construction, arising out of the corporation's Contractor Safety Management program, were not included in the original budget as this requirement did not exist when the budget was prepared;
- Site specific requirements (rigid conduit, additional devices for infill, higher than estimated cable quantities) have increased material costs; and,
- Labour costs for installation are higher than originally estimated.

As a result, the overall cost of this project is $660,000 greater than originally budgeted.

37. Install Fibre Optic Cable – Hinds Lake

Budget: $683 **Actual: $459** **Variance: ($224)**

This project has been carried over into 2011. The completion date has been extended to 2011 due to the delayed delivery of the Alcatel Multiplexers and the training, installation and commissioning of the OC3 Multiplexing equipment. This project is expected to be completed within budget.

38. Replace Radomes – Various Sites

Budget: $212 **Actual: $110** **Variance: ($102)**

Costs for the project were lower than budgeted for two reasons. First, several of the radomes originally planned to be replaced were located at Four Mile Hill microwave site and were damaged in the March ice storm and subsequently replaced as part of the emergency capital project for that site. Second, the contract for supply and installation of radomes was much lower than budgeted, the budget being based on previous years' experience.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

39. Upgrade Remote Terminal Units (RTUs) – Various Sites

Budget: **$190** **Actual:** **$398** **Variance:** **$208**

This project has been carried over into 2011. The outage associated with the Bay d'Espoir portion of this project for the Bay d'Espoir Unit 7 RTU installation was originally scheduled for October 2010. However, the overall outage planning schedule resulted in the outage being scheduled in June 2010. As a result of this change, engineering and operational overtime was required in order to meet the revised outage dates. Also, during commissioning of the new RTU, an issue with the GE Energy Systems RTU hardware and firmware integration caused equipment failure, which resulted in unanticipated labour and travel being required to develop and implement a temporary fix. GE Energy Services were requested to replicate the failure and provide a permanent solution. However, during this time, GE Energy Services moved their facilities from Calgary, Alberta to Markham, Ontario which resulted in a number of the key players on GE's side changing which caused a delay in the investigation and the development of a permanent solution. A solution was finally proposed by GE in December, 2010 which will require additional labour, material and travel in 2011 to implement. This project is estimated to be $275,000 greater than budgeted.

40. Replace Stationary Battery Banks and Chargers – Various Sites

Budget: **$717** **Actual:** **$559** **Variance:** **($158)**

The total actual cost for this project was less than budget for the following reasons. Internal labour was less than anticipated due to increased efficiencies realized from lessons learned during last year's project. The same internal personnel were leveraged for this year's project. The original budget assumed two distinct installation and commission phases but we were able to complete both activities concurrently. This decreased the labour portion of the installation and commission activities by approximately $106,000. This resulted in less interest and overhead costs as well as no contingency being required.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

41. Replace Radio Link with Fiber – Bay d'Espoir

Budget: $489 **Actual:** $375 **Variance:** ($114)

Both the engineering design and installation of the equipment required less time than budgeted reducing the cost of these activities by approximately $70,000. This resulted in less interest and overhead costs as well as no contingency being required.

42. Replace Vehicles and Aerial Devices 2010 – Various Sites

Budget: $2,156 **Actual:** $1,997 **Variance:** ($159)

This project has been carried over into 2011. The project was intended to be submitted as two year project due to the difficulty in ordering and receiving all the equipment in one calendar year. Inadvertently, only the first year of this project was submitted and approved. The equipment delivery is expected in mid March 2011.

43. Upgrade System Security 2009 – Various Sites

Budget: $981 **Actual:** $1,295 **Variance:** $314

This is a multiyear project started in 2009 to be completed in 2010. It has now been carried over into 2011. There were three major components to this project during 2010; fencing upgrades, card access installation and security camera installation, all at various locations throughout the Hydro system. The fencing upgrades and card access installations have been completed. Security camera installations were scheduled to be completed by late December however, due to complications with the installations at several sites in November and December, and equipment delivery delays from the supplier, the work had to be rescheduled for the first quarter of 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

44. Microwave Radio Site Ice Storm Remediation – Four Mile Hill

Budget: $445 **Actual:** $320 **Variance:** ($125)

This project was initiated on an emergency basis to repair ice damage sustained at Hydro's Four Mile Hill site in March, 2010. The storm destroyed two microwave antennas and damaged ice shields, fire protection and the building's roof. At the time the budgetary proposal was developed, it was difficult to assess the extent of the damage without removing the roof membrane and external siding. In order to restore service as soon as possible, a budget proposal was generated to investigate the extent of the damage and effect repairs. Detailed aerial and structural assessments of the tower were required in order to provide an accurate budget for the project. The contract for the tower repairs included the material costs. Fortunately the costs were lower than anticipated.

45. Install Neutral Grounding Resistors – Come by Chance *(Project Cancelled)*

Budget: $227 **Actual:** $0 **Variance:** ($227)

This project was to be fully contributed by Hydro's customer North Atlantic Refining Limited (NARL) and was approved by Board Order No. P.U. 26 (2008). Hydro was waiting for NARL to approve the cost recovery expenditure for this project; however, this has been ongoing for 3 years and has still not been approved. Therefore Hydro will cancel this project and will resubmit when NARL makes the decision to proceed.

46. Nain Diesel Plant Rehabilitation

Budget: $1,041 **Actual:** $117 **Variance:** ($924)

Protection and control labour resources were not available to start the Nain automation work until November 2010 due to previous commitments in Ramea and Cartwright. This work is currently on-going. It has been subsequently determined that insurance proceeds estimated at $884,000 will reduce this years estimated expenditure of $1,041,000.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

47. Gas Turbine Refurbishment – Stephenville

Budget: $2,086 **Actual:** $1,269 **Variance:** ($817)

The actual cost of the overhaul work performed by Rolls Wood Group was approximately $709,000 less than budgeted. Due to the nature of gas turbine engine overhaul work, it is impossible to fully understand the scope of refurbishment required until the engine is disassembled and inspected. The required refurbishment work was less than originally anticipated resulting in an overall cost savings to this project.

48. Voisey's Bay Nickel – Long Harbour Power Supply

Budget: $3,605 **Actual:** $1,332 **Variance:** ($2,273)

This is a multiyear project started in 2010 with completion due in 2012. The delayed signing until May 2010 of the Contribution in Aid of Construction agreement with Vale resulted in no deliveryof terminal station electrical equipment in 2010. Additional delays occurred when a tender award for transmission line towers had to be cancelled due to supplier issues. Project activity has restarted with a new tender award and a review of the project indicates it will be completed within budget and on time.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE YEAR ENDING DECEMBER 31, 2010
(Greater than $100,000)

49. Replace Fuel Tank – Bay d'Espoir Campsite

Budget: $120 **Actual:** $10 **Variance:** ($110)

There are two main contributing factors that caused this project to carry over into 2011. The project was an unbudgeted capital project that was initially submitted to the PUB in early August, with approval received the last week of September. Once the tenders for fabrication and supply of the tank and fuelling cabinet were received in October, there was an 8 to 10 week delivery on most of the major components of the fuelling cabinet. This delivery schedule coupled with the planned holiday shut down of the fabrication plant meant it was impossible to meet the original delivery of mid December. All components were received by the end of December, and fabrication of the cabinet and tank is expected to be completed by the end of the first quarter, 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2001 – 2011
AS AT DECEMBER 31
($000)

Table 1: CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2001 – 2010

Year	Budget	Actual Expenditures	Variance	Percentage Variance
2001	55,897	47,501	8,396	15.0%
2002	44,660	40,217	4,443	9.9%
2003	36,122	32,506	3,616	10.0%
2004	31,435	27,984	3,451	11.0%
2005	47,760	33,952	13,808	28.9%
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%
2009	61,544	54,152	7,392	12.0%
2010	63,297	55,553	7,744	12.2%

The variances shown in Table 1 above include amounts related to the carryover of projects from year to year. Total variances actual to budget for completed projects are 1% for 2009 and 2010. These are well within acceptable ranges; however, the number of individual projects with variances greater than $100,000 in 2009 and 2010 tend to be greater than in previous years, due to continued high volatility in commodity prices and a trend of increasing costs associated with the strong labour market currently being experienced in the province.

The variances presented in Table 1 are almost entirely due to under-spending as a result of not completing all projects approved each year. It is anticipated that some carryover of projects will occur in most years as there may be unavoidable reasons for delays in project completion, for example, system constraints which are precipitated by changes in hydrology, equipment failures, etc.

In spite of strong continued effort by Hydro’s project execution team, and largely due to an imbalance between project workload and resource allocation in support of project execution, capital budget versus actual expenditure percentage variance continues to be greater than 10%. Recently there have been organizational structure changes within both Hydro and Nalcor with the establishment of a Project Execution and Technical Services division that should lead to improved delivery and compliance of capital projects in future.

NEWFOUNDLAND AND LABRADOR HYDRO
2010 CARRYOVER REPORT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000)

Project Name	PUB Approved Budget 2010	Revised Budget 2010	Total Actual Expend. 2010	Carryover Amount	Variance Explanation Ref. No.	Original Completion Year
Purchase Spare Stator Windings Units 2 - Bay d'Espoir	4,687	4,192	3,143	1,049	2	2010
Replace A/C Units in Control and Communications Room - Upper Salmon	197	156	67	89	3	2010
Replace 21 Inch Metal Cutting Lathe	80	80	0	80		2010
Condition Assessment and Life Extension Study - Holyrood	1,846	1,846	1,278	568	5	2010
Install Warm Air Make-up Access - Holyrood	170	306	219	87		2010
Replace Disconnects - Various Sites	199	199	97	102	13	2010
Replace 230 kV Breaker Controls - Massey Drive and Buchans	73	73	51	22		2010
Replace Recloser Control Panels - Various Sites	603	385	370	15	23	2010
Increase Generation Capacity - L'Ance Au Loup	736	736	448	288	26	2010
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	528	528	334	194	29	2010
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls	88	94	21	73		2010
Replace Off Road Track Vehicles - Various Sites	685	685	1	684	33	2010
Tools and Equipment Less than $ 50,000	232	44	29	15		2010
Public Address System - Holyrood	1,156	1,548	540	1,008	36	2010
Install Fibre Optic Cable - Hinds Lake	683	683	459	224	37	2010
Upgrade Remote Terminal Units - Various Sites	190	468	398	70	39	2010
Replace Vehicles and Aerial Devices 2010 - Various Sites	2,156	2,830	1,997	833	42	2010
Upgrade System Security 2009 - Various Sites	981	1,436	1,295	141	43	2010
Replace Humidifiers in Air Handling Units - Hydro Place	75	75	14	61		2010
Replace Fuel Tank - Bay D'Espoir Campsite	120	120	10	110	49	2010
Replace Switch - Oxen Pond Terminal Station	38	38	0	38		2010

NEWFOUNDLAND AND LABRADOR HYDRO
2010 CARRYOVER REPORT
FOR THE YEAR ENDING DECEMBER 31, 2010
($000)

Project Name	**PUB Approved Budget 2010**	**Revised Budget 2010**	**Total Actual Expend. 2010**	**Carryover Amount**	**Variance Explanation Ref. No.**	**Original Completion Year**
Replace Pumphouse Motor Control Centres - Holyrood	50	50	99	(49)		2011
Replace Steam Seal Regulator Unit 1 - Holyrood	335	335	16	319	7	2011
Replace Diesel Fire Pump - Holyrood	112	112	28	84		2011
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,305	1,305	705	600	9	2011
Upgrade Glycol Systems - Stephenville	261	261	3	258	10	2011
Replace Compressed Air Piping and Install						
Dew Point Monitoring - Holyrood	79	79	19	60		
New 25 kV Terminal Station - Labrador City	2,882	2,882	1,693	1,189	11	2011
Upgrade Trailer and Mobile Substation - Bishop's Falls	30	517	151	366	14	2011
Upgrade Line TL-244 - Plum Point to Bear Cove	141	141	0	141	16	2011
Upgrade Line 2 Distribution Feeder - Glenburnie	267	267	110	157	20	
Upgrade Distribution Lines - Various Sites	218	218	84	134	21	2011
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois	82	82	40	42		2011
Replace Diesel Unit 2001 and Engine 566 - Francois	168	168	11	157	27	2011
Replace Diesel Unit 2018 - McCallum	19	19	10	9		2011
Corporate Application Environment - Upgrade Microsoft Products	751	751	562	189	34	2011
Cost Recoveries	(225)	(225)	(191)	(34)		
Nain Diesel Plant Rehabilitation	1,041	1,041	118	923		2011
Confined Space Isolation (Blanks & Blinds) - Holyrood	202	202	139	63		2011
Replace Unit 565 - Little Bay Islands	18	18	0	18		2011
Replace Programmable Logic Controllers - Holyrood	1,208	1,543	1,358	185	6	2012
Voltage Conversion - Labrador City	1,089	1,089	1,525	(436)	22	2012
Voisey's Bay Nickel - Long Harbour Power Supply	3,605	3,605	1,332	2,273	48	2012
Cost Recovery - Vale Inco	(3,605)	(3,605)	(1,332)	(2,273)		
	25,556	**27,377**	**17,251**	**10,126**		

Exhibit 10 (2011 Report)

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CAPITAL EXPENDITURES AND CARRYOVER REPORT

For Year Ending December 31, 2011

March 2012

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Year Ending December 31, 2011

TABLE OF CONTENTS

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
OVERVIEW
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011
GENERATION	15,560	3,912	11,500	(4,060)
TRANSMISSION	14,889	4,804	15,516	628
RURAL SYSTEMS	23,729	9,381	23,245	(484)
GENERAL PROPERTIES	9,911	2,923	8,734	(1,176)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	579	2,001	1,001
PROJECTS APPROVED BY PU BOARD	2,267	915	2,054	(213)
PROJECTS UNDER $50,000 APPROVED BY HYDRO	99	57	66	(33)
TOTAL CAPITAL BUDGET	67,454	22,571	63,116	(4,338)

2011 Capital Budget Approved by Board Order No. P.U. 38 (2010)[1]	55,043
Carryover Projects 2010 to 2011	10,126
New Project Approved by Board Order No. 29 (2010)	450
New Project Approved by Board Order No. 34 (2010)	1,602
New Project Approved by Board Order No. 20 (2011)	134
2011 New Projects under $50,000 Approved by Hydro	99
TOTAL APPROVED CAPITAL BUDGET	67,454

[1] Due to rounding, there was a slight difference in the amount approved by the PU Board for the 2011 Capital Budget. The amount approved was $55,046.

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011
GENERATION				
HYDRO PLANTS	5,371	629	4,139	(1,232)
THERMAL PLANT	7,637	2,083	5,555	(2,082)
GAS TURBINES	2,552	1,200	1,806	(746)
TOTAL GENERATION	15,560	3,912	11,500	(4,060)
TRANSMISSION				
TERMINAL STATIONS	11,384	4,401	11,205	(179)
TRANSMISSION LINES	3,504	403	4,311	807
TOTAL TRANSMISSION	14,889	4,804	15,516	628
RURAL SYSTEMS				
DISTRIBUTION	14,633	5,850	15,994	1,361
GENERATION	5,218	1,732	4,001	(1,217)
PROPERTIES	623	96	512	(111)
METERING	637	116	417	(220)
TOOLS AND EQUIPMENT	2,618	1,587	2,321	(297)
TOTAL RURAL SYSTEMS	23,729	9,381	23,245	(484)

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
SUMMARY BY CATEGORY
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011
GENERAL PROPERTIES				
INFORMATION SYSTEMS	2,189	586	2,184	(5)
TELECONTROL	3,930	1,601	3,600	(330)
TRANSPORTATION	3,184	460	2,072	(1,112)
ADMINISTRATIVE	609	276	878	269
TOTAL GENERAL PROPERTIES	9,911	2,923	8,734	(1,176)
ALLOWANCE FOR UNFORESEEN EVENTS	1,000	579	2,001	1,001
PROJECTS APPROVED BY PU BOARD	2,267	915	2,054	(213)
PROJECTS UNDER $50,000 APPROVED BY HYDRO	99	57	66	(33)
TOTAL CAPITAL BUDGET	67,454	22,571	63,116	(4,338)

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
GENERATION
FOR THE YEAR QUARTER AND ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
HYDRO PLANT						
Replace Static Excitation System - Upper Salmon,						
Holyrood and Hinds Lake	1,214	17	18	(1,196)	-99%	1
Upgrade Burnt Dam Access Road Phase 2 - Bay d'Espoir	998	148	1,095	97	10%	
Upgrade Generating Station Service Water System - Cat Arm	360	218	349	(11)	-3%	
Upgrade Intake Gate Controls - Bay d'Espoir	352	27	507	155	44%	2
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir	258	44	161	(97)	-38%	
Purchase Spare Disconnect - Bay d'Espoir	176	40	73	(103)	-58%	3
Replace Automatic Transfer Switches - Bay d'Espoir and						
Hinds Lake	156	5	54	(102)	-65%	4
Purchase Hydro Meteorological Stations - Various Sites	113	0	0	(113)	-100%	5
Replace Fire Alarm System - Hinds Lake	109	14	21	(88)	-81%	
Install Compressor for Frazil Ice Removal - Upper Salmon		0				
Changed to Granite Canal	69	28	60	(9)	-13%	
Upgrade Public Safety Around Dams and Waterways -		0				
Bay d'Espoir	49	31	48	(1)	-3%	
Purchase Spare Stator Windings Units 2 - Bay d'Espoir	1,049	7	1,344	295	28%	6
Replacement of Fuel Tank - Bay d'Espoir Campsite	110	2	103	(7)	-6%	
Replace A/C Units in Control and Communications Room - Upper Salmon	89	(5)	74	(15)	-17%	
Replace 21 Inch Metal Cutting Lathe	80	0	77	(3)	-4%	
Purchase Tools and Equipment Less than $50,000	186	53	155	(31)	-17%	
TOTAL HYDRO PLANT	**5,371**	**629**	**4,139**	**(1,232)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
GENERATION
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
THERMAL PLANT						
Replace Programmable Logic Controllers - Holyrood	932	212	877	(55)	-6%	
Upgrade Hydrogen System - Holyrood	1192	206	281	(911)	-76%	7
Replace Pumphouse Motor Control Centres - Holyrood	950	236	1,091	141	15%	8
Upgrade Synchronous Condenser Unit 3 - Holyrood	484	142	147	(337)	-70%	9
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood	843	62	416	(427)	-51%	10
Replace Relay Panels Unit 3 - Holyrood	277	69	139	(138)	-50%	11
Replace Boiler Blowdown Tanks - Holyrood	750	202	743	(7)	-1%	
Upgrade Electrical Equipment - Holyrood	188	76	187	(1)	-1%	
Replace Steam Seal Regulator Unit 2 - Holyrood	175	32	54	(121)	-69%	12
Replace Steam Seal Regulator Unit 1 - Holyrood	533	78	318	(215)	-40%	13
Replace Diesel Fire Pump - Holyrood	279	(26)	156	(123)	-44%	14
Install Weatherhoods for Vent Fans - Holyrood	208	542	549	341	164%	15
Purchase Laser Alignment Equipment - Holyrood	79	31	31	(48)	-61%	
Condition Assessment and Life Extension Study - Holyrood	568	104	416	(152)	-27%	16
Install Warm Air Make-up Access - Holyrood	87	48	81	(6)	-7%	
Purchase Tools and Equipment Less than $50,000	94	69	69	(25)	-26%	
TOTAL THERMAL PLANT	**7,637**	**2,083**	**5,555**	**(2,082)**		
GAS TURBINES						
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,924	1,052	1,215	(709)	-37%	17
Upgrade Glycol Systems - Stephenville	557	97	539	(18)	-3%	
Upgrade Gas Turbine Operator Console - Stephenville	72	51	52	(20)	-27%	
TOTAL GAS TURBINE PLANTS	**2,552**	**1,200**	**1,806**	**(746)**		
TOTAL GENERATION	**15,560**	**3,912**	**11,500**	**(4,060)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
TRANSMISSION
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
TERMINAL STATIONS						
Upgrade Terminal Stations to 25 kV - Labrador City	4689	2,817	6,262	1,573	34%	18
Perform Grounding Upgrades - Various Sites	321	120	288	(33)	-10%	
Upgrade Substation - Wabush	459	4	14	(445)	-97%	19
Upgrade Power Transformers - Various Sites	866	217	329	(537)	-62%	20
Upgrade Station Reliability and Safety - Rocky Harbour	435	(1)	5	(430)	-99%	21
Replace 69 kV SF6 Breakers - St. Anthony Airport	490	25	499	9	2%	
Replace Breaker, Structures and Disconnects - Hawke's Bay	687	267	340	(347)	-51%	22
Replace Compressed Air System - Bay d'Espoir	84	56	87	3	4%	
Replace 230 kV Circuit Breaker - Sunnyside	41	5	8	(33)	-81%	
Upgrade Trailer and Mobile Substation - Bishop's Falls	834	36	895	61	7%	
Replace Compressed Air Piping and Install Dew Point Monitoring - Holyrood	477	200	552	75	16%	
Replace Insulators - Various Sites	401	247	512	111	28%	23
Upgrade Air Blast Circuit Breakers - Various Sites	334	(37)	297	(37)	-11%	
Replace Disconnects - Various Sites	295	316	408	113	38%	24
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station	280	28	147	(133)	-48%	25
Replace Instrument Transformers - Various Sites	199	15	149	(50)	-25%	
Install Alternate Station Services - Stony Brook and Massey Drive	86	6	6	(80)	-93%	
Replace Digital Fault Recorder - Bay d'Espoir	169	28	72	(97)	-57%	
Replace Surge Arresters - Various Sites	75	7	67	(8)	-10%	
Voisey's Bay Nickel - Long Harbour Power Supply	10,600	4,137	10,338	(262)	-2%	
Cost Recovery - Vale Inco	(10,600)	(4,137)	(10,338)	262		
Replace Disconnects - Various Sites	102	44	205	103	101%	26
Replacement of Switch B5B2-2, Oxen Pond Terminal Station	38	0	50	12	32%	
Replace 230 kV Breaker Controls - Massey Drive and Buchans	22	1	13	(9)	-41%	
TOTAL TERMINAL STATIONS	**11,384**	**4,401**	**11,205**	**(179)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
TRANSMISSION
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
TRANSMISSION LINES						
Perform Wood Pole Line Management Program - Various Sites	2,019	125	2,219	200	10%	
Replace Guy Wires TL-215 - Doyles to Grand Bay	289	9	465	176	61%	27
Upgrade Line TL-244 - Plum Point to Bear Cove	1,196	269	1,627	431	36%	28
TOTAL TRANSMISSION LINES	**3,504**	**403**	**4,311**	**807**		
TOTAL TRANSMISSION	**14,889**	**4,804**	**15,516**	**628**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
DISTRIBUTION						
Voltage Conversion - Labrador City	3,065	1,327	2,932	(133)	-4%	
Upgrade L2 Distribution Feeder - Glenburnie	735	201	418	(317)	-43%	29
Provide Service Extensions - All Service Areas	3,385	1,998	5,591	2,206	65%	30
Upgrade Distribution Systems - All Service Areas	2,499	1,238	3,401	902	36%	31
Upgrade Distribution Lines - Roddickton and Makkovik	1,779	162	1,160	(619)	-35%	32
Upgrade Distribution Systems - Rigolet, Happy Valley and Francois	1,068	398	614	(454)	-42%	33
Replace Poles - Various Sites	882	357	985	103	12%	34
Upgrade Line 2 Voltage Conversion to 25 kV - Gaultois	553	(1)	590	37	7%	
Replace Substation Infrastructure - Burgeo	128	3	7	(121)	-95%	35
Install Voltage Regulators - Conne River and L'Anse au loup	293	81	118	(175)	-60%	36
Replace Recloser Control Panels (2011) - Various Sites	232	168	178	(54)	-23%	
Replace Recloser Control Panels (2010) - Various Sites	15	(82)	0	(15)	-100%	
TOTAL DISTRIBUTION	**14,633**	**5,850**	**15,994**	**1,361**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE YEAR QUARTER AND ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
GENERATION						
Perform Arc Flash Remediation - Various Sites	430	81	108	(322)	-75%	37
Replace Fuel Storage Facility - Postville	2,007	988	1,835	(172)	-9%	
Replace Diesel Unit 2001 and Engine 566 - Francois	607	187	466	(141)	-23%	38
Replace Diesel Unit 2018 - McCallum	430	243	371	(59)	-14%	
Replace Mini Hydro Turbine - Roddicton	87	11	11	(76)	-87%	
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson	155	7	7	(148)	-95%	39
Replace Fuel Storage Tank - Francois	131	107	139	8	6%	
Upgrade Fuel Storage - Norman Bay	114	8	95	(19)	-17%	
Upgrade Plant Overhead Crane Lifting System - Mary's Harbour	47	25	31	(16)	-33%	
Nain Diesel Plant Rehabilitation	923	333	1,237	(526)	-57%	40
Cost Recovery - Insurance Claim	0	(344)	(840)	0		
Increase Generation Capacity - L'Anse Au Loup	288	86	541	253	88%	41
TOTAL GENERATION	5,218	1,732	4,001	(1,217)		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
RURAL SYSTEMS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
PROPERTIES						
Install Fall Protection Equipment - Various Sites	198	67	213	15	7%	
Legal Survey of Primary Distribution Line Right of Way - Various Sites	79	1	5	(74)	-94%	
Install Waste Oil Storage Tank - St. Lewis	79	(2)	78	(1)	-1%	
Construct New Office/Warehouse/Line Depot Facilities - Happy Valley	194	30	130	(64)	-33%	
Replace Aviation Fuel Tank and Dispensing Unit - Bishop's Falls	73	0	86	13	18%	
TOTAL PROPERTIES	**623**	**96**	**512**	**(111)**		
METERING						
Install Automatic Meter Reading - Labrador City and Port au Choix	451	69	237	(214)	-47%	42
Purchase Meters, Equipment and Tanks - Various Sites	186	47	180	(6)	-3%	
TOTAL METERING	**637**	**116**	**417**	**(220)**		
TOOLS AND EQUIPMENT						
Replace Off Road Track Vehicles - Bishop's Falls and Fogo	494	377	404	(90)	-18%	
Replace Light Duty Mobile Equipment - Various Sites	757	466	582	(175)	-23%	43
Purchase Excavators - Bishop's Falls	361	339	339	(22)	-6%	
Purchase Tools and Equipment Less than $50,000 (2011)	183	59	174	(9)	-5%	
Purchase Tools and Equipment Less than $50,000 (2010)	87	50	83	(4)	-5%	
Purchase Portable Dissolved Gas Analysis Unit - Bishop's Falls	52	44	44	(8)	-15%	
Replace Off Road Track Vehicles - Bishop's Falls and Whitbourne	684	252	695	11	2%	
TOTAL TOOLS AND EQUIPMENT	**2,618**	**1,587**	**2,321**	**(297)**		
TOTAL RURAL SYSTEMS	**23,729**	**9,381**	**23,245**	**(484)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
INFORMATION SYSTEMS						
SOFTWARE APPLICATIONS						
NEW INFRASTRUCTURE						
Perform Minor Application Enhancements - Hydro Place	121	38	121	0	0%	
Cost Recoveries	(39)	(12)	(39)	0		
UPGRADE OF TECHNOLOGY						
Corporate Application Environment - Upgrade Microsoft Products	864	253	860	(43)	-5%	
Cost Recoveries	(237)	(81)	(275)	0		
Replace iSeries Computer and Upgrade Operating System - Hydro Place	643	103	641	(2)	0%	
Cost Recoveries	(206)	(33)	(206)	0		
TOTAL SOFTWARE APPLICATIONS	**1,147**	**268**	**1,102**	**(45)**		
COMPUTER OPERATIONS						
INFRASTRUCTURE REPLACEMENT						
PC Replacement Program - Hydro Place	404	76	422	19	5%	
Replace Peripheral Infrastructure - Various Sites	258	85	276	18	7%	
Upgrade Enterprise Storage Capacity - Hydro Place	227	78	226	0	0%	
Cost Recoveries	(73)	(25)	(72)	0		
NEW INFRASTRUCTURE						
Develop Learning Management System Courses - Hydro Place	123	112	124	0	0%	
Cost Recoveries	(40)	(36)	(40)	0		
UPGRADE OF TECHNOLOGY						
Upgrade Server Technology Program - Hydro Place	209	41	214	4	2%	
Cost Recoveries	(67)	(13)	(68)	0		
TOTAL COMPUTER OPERATIONS	**1,042**	**318**	**1,082**	**40**		
TOTAL INFORMATION SYSTEMS	**2,189**	**586**	**2,184**	**(5)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
TELECONTROL						
NETWORK SERVICES						
INFRASTRUCTURE REPLACEMENT						
Replace MDR 6000 Microwave Radio (West) - Various Sites	72	24	28	(44)	-61%	
Refurbish Microwave Site - Deer Lake	207	90	114	(93)	-45%	
Replace Radomes - Various Sites	196	54	102	(94)	-48%	
Purchase Tools and Equipment less than $50,000	86	36	36	(50)	-58%	
Public Address System - Holyrood	1,008	356	1,206	198	20%	44
Install Fibre Optic Cable - Hinds Lake	224	10	117	(107)	-48%	45
Upgrade Remote Terminal Units - Various Sites	70	(18)	95	25	36%	
NETWORK INFRASTRUCTURE						
Replace Battery Banks and Chargers - Various Sites	978	558	872	(106)	-11%	46
Replace Network Communications Equipment - Various Sites	667	265	669	2	0%	
UPGRADE OF TECHNOLOGY						
Install Tower Ice Protection - Chapel Hill Microwave Site	294	199	231	(63)	-21%	
Replace Telephone Keyset - Wabush	80	12	84	5	6%	
Upgrade Site Facilities - Various Sites	48	15	46	(2)	-4%	
TOTAL TELECONTROL	**3,930**	**1,601**	**3,600**	**(330)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
GENERAL PROPERTIES
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
TRANSPORATION						
Replace Vehicles and Aerial Devices 2011 - Various Sites	2,351	457	1,254	(1,097)	-47%	47
Replace Vehicles and Aerial Devices 2010 - Various Sites	833	3	818	(15)	-2%	
TOTAL TRANSPORATION	**3,184**	**460**	**2,072**	**(1,112)**		
ADMINISTRATION						
Remove Safety Hazards - Various Sites	252	142	240	(12)	-5%	
Replace Humidifiers in Air Handling Units - Hydro Place	76	16	18	(58)	-76%	
Purchase Tools and Equipment less than $50,000	79	7	44	(35)	-44%	
Upgrade System Security 2009 - Various Sites	141	110	527	386	274%	48
Replace Humidifiers in Air Handling Units - Hydro Place	61	1	49	(12)	-20%	
TOTAL ADMINISTRATION	**609**	**276**	**878**	**269**		
TOTAL GENERAL PROPERTIES	**9,911**	**2,923**	**8,734**	**(1,176)**		

NEWFOUNDLAND and LABRADOR HYDRO
2011 CAPITAL EXPENDITURES
OTHER APPROVED FUNDS
FOR THE QUARTER AND YEAR ENDING DECEMBER 31, 2011
($000)

	PUB Approved Budget 2011	4th Quarter Actuals 2011	Total Actual Expend. 2011	Variance From Budget 2011	Percentage Variance From Budget 2011	Variance Explanation Ref. No.
ALLOCATION FOR UNFORESEEN EVENTS						
Increase Generation Capacity - Charlottetown	1,000	60	1,482	482	48%	49
Ice Storm - Baie Verte Peninsula	0	519	519	519	100%	50
Allocation for Unforeseen Events	0	0	0	0		
TOTAL ALLOCATION FOR UNFORESEEN EVENTS	**1,000**	**579**	**2,001**	**1,001**		
PROJECTS APPROVED BY PU BOARD						
CARRYOVER						
Confined Space Isolation (Blanks and Blinds) - Holyrood	1,665	415	1,330	(335)	-20%	51
Replace Unit 565 - Little Bay Islands	468	228	452	(16)	-3%	
NEW						
Upgrade Stack Breeching Unit 1 - Holyrood	134	272	272	138	103%	52
TOTAL PROJECTS APPROVED BY PU BOARD	**2,267**	**915**	**2,054**	**(213)**		
NEW PROJECTS LESS THAN $50,000 APPROVED BY HYDRO						
Replace Domestic Service Water Pump in Powerhouse Upper Salmon	28	10	10	(18)	-64%	
Replace Generator Unit 2073 - Port Hope Simpson	26	28	32	6	25%	
Purchase Crown Land - Mary's Harbour	5	0	5	(0)	-6%	
Replace Gas/Diesel Fuel Storage Tank - Cat Arm	17	19	19	2	12%	
Replace Engine 2062 - Grey River	23	0	0	(23)	-100%	
TOTAL PROJECTS LESS THAN $50,000 APPROVED BY HYDRO	**99**	**57**	**66**	**(33)**		

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

Although this is a 2011 Capital Variance Report, Hydro has explained the variances in context of the full project since many of the variances pertain to multi-year projects. Any differences in the approved annual cash flows compared to the amounts shown in the tables below are due to carry over amounts from the previous year.

1. Replace Static Excitation System – Upper Salmon, Holyrood and Hinds Lake

Budget: **$1,214** **Actual:** **$18** **Variance:** **($1,196)**

This is a three year project from 2011 to 2013 to replace static excitation systems at Upper Salmon, Holyrood and Hinds Lake. The initial project schedule and estimated cost are listed in the table below.

Year	Activity	Cost ($000)
2011	Design and Installation of the Static Excitation System – Upper Salmon	1,214.3
2012	Design and Installation of the Static Excitation System – Holyrood Unit 3	1,528.0
2013	Design and Installation of the Static Excitation System – Hinds Lake	1,366.8
	Total	$4,109.1

The overall project scope, budget and completion date are unchanged.

In the first quarter of 2011, a thorough analysis of the project execution plan was undertaken. A review of updated vendor delivery times and outage schedules, and consideration of a failure event for the Hinds Lake excitation system, led to an adjustment to the project execution plan. Installation of the Hinds Lake excitation system was advanced from 2013 to 2012; installation of the Upper Salmon excitation system was deferred from 2011 to 2013; and installation of the Holyrood excitation system was unchanged. The updated cash flow is shown in the table below.

Year	Activity	Cost ($000)
2011A	Design and tender for all three excitation systems.	17.5
2012	Install Excitation Systems – Hinds Lake and Holyrood Unit 3	2,872.3
2013	Install Excitation System – Upper Salmon	1,219.3
	Total	$4,109.1

2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

1. Replace Static Excitation System – Upper Salmon, Holyrood and Hinds Lake (cont'd.)

Progress is on pace with the new schedule. The equipment supply contracts for the three excitation systems are in the tendering stage and are expected to be awarded in the first quarter of 2012. Installation has been incorporated into the 2012 and 2013 work plans.

2. Upgrade Intake Gate Controls – Bay d'Espoir

Budget: **$352** **Actual:** **$507** **Variance:** **$155**

This is a two year project from 2011 to 2012 to upgrade the electrical controls at the Bay d'Espoir Intake Gates 1, 2 and 3, including the establishment of the supporting communications network between Intakes 1, 2, 3 and 4 and Powerhouse 1. The original budgeted project cost by year is shown in the table below.

Year	Activity	Cost ($000)
2011	Upgrade gate controls at one Intake Structure and establish communications network	352.3
2012	Upgrade gate controls at two Intake Structures	468.0
	Total	$820.3

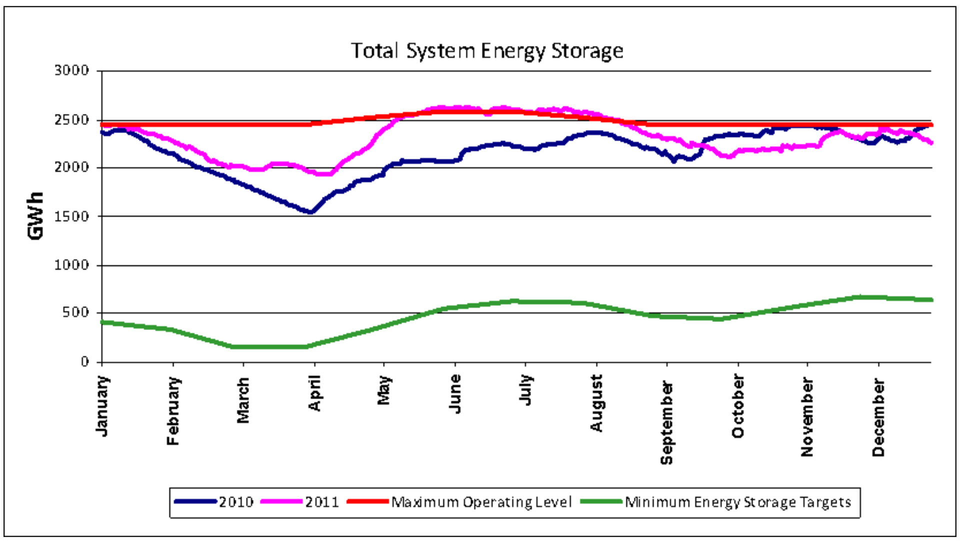
The overall project scope and completion date are unchanged and the scope of work for 2011 is complete.

In 2011, design and procurement were completed on schedule and on budget, and construction commenced during the planned summer outage. Part way through construction, however, Hydro had to change the outage schedule due to exceptionally high inflows into the Bay d'Espoir Reservoir System. The inflows during July 2011 were the highest in Hydro's sixty-year record and surpassed the previous July maximum set in 1996 by four percent as shown in the graph below. With the high reservoir levels, the required outage would have increased the risk of spilling water. To protect rate payer interests, Hydro decided to defer the balance

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

2. **Upgrade Intake Gate Controls – Bay d'Espoir (cont'd.)**

of the planned work until reservoir levels subsided (to reduce spill potential). The project team shifted focus to designing, installing and commissioning temporary gate controls, which was accomplished, and the units were released for service in July 2011. The required unit outages were secured in September 2011, at which time the project team remobilized, removed the temporary controls, and completed the original planned work.



The requirement for temporary controls and remobilization led to an increase in the project budget. The table below shows the actual expenditures for 2011 and the updated cash flow for 2012, resulting in a new project total budget:

Year	Cost ($000)
2011A	507.0
2012	495.4
Total	$1,002.4

Hydro conducted a lessons learned exercise on the 2011 portion of this project. Through this exercise, Hydro has identified an opportunity to enhance aspects of its project risk management processes. Enhancements are being implemented early in 2012 and will be applied to the 2012 work for this project.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

3. Purchase Spare Disconnect – Bay d'Espoir

Budget: $176 **Actual: $73** **Variance: ($103)**

This is a single year project to engage a vendor to design, construct and supply a spare unit disconnect switch for Bay d'Espoir. The project scope has not changed but the project schedule will carry over into 2012. The work was initially tendered without response. Hydro retendered after an effort to identify qualified bidders and was successful in engaging a vendor at a price that was within the budget. The retendering, combined with the vendor's failure to meet their promised delivery schedule, led to this project being carried into 2012. The switch design is complete and fabrication is in progress. Delivery is anticipated in 2012 with a revised project cost of $132,734 which is approximately 25 percent under budget.

4. Replace Automatic Transfer Switches – Bay d'Espoir and Hinds Lake

Budget: $156 **Actual: $54** **Variance: ($102)**

This was a single year project to replace automatic transfer switches at Hinds Lake and Bay d'Espoir Powerhouse 2 in 2011. The planned scope of work was completed on budget and on schedule for Bay d'Espoir Powerhouse 2. Regarding Hinds Lake, it was discovered in the project planning phase that the available off-the-shelf automatic transfer switches could not provide the functionality required at Hinds Lake. A technical solution that is substantially different has since been identified, a new scope of work developed, and a preliminary estimate prepared. The approved budget was insufficient to execute the work for Hinds Lake. Accordingly, Hydro has cancelled the Hinds Lake portion of this project. A separate project proposal with the new scope of work will be prepared for consideration by the Board as part of Hydro's 2013 Capital Budget Application.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

5. Purchase Hydro Meteorological Stations – Various Sites

Budget: $113 **Actual: $0** **Variance: ($113)**

This project has been cancelled. The project was to take over management responsibility of three existing hydro meteorological stations that are presently managed by Environment Canada, through a partnership with the provincial Department of Environment and Conservation (DEC). In the second quarter of 2011, DEC asserted its authority under the Water Resources Act to require Hydro to continue with the existing arrangement in cooperation with DEC and Environment Canada.

6. Purchase Spare Stator Windings Unit 2 – Bay d'Espoir

Budget: $1,049 **Actual: $1,344** **Variance: $295**

This was a one year project in 2010 to install spare windings on Bay d'Espoir Unit 2 and procure one set of spare windings for future installation on Bay d'Espoir Units 1, 3 or 4. The project is complete and there was no change to the scope. The original budget of $4,687,100 was revised in 2010 to $4,191,900. The project carried over into 2011 due to late delivery of the spare windings. The forecast final cost is $4,487,687, which is seven percent over the revised budget, but four percent below the original estimate.

7. Upgrade Hydrogen System - Holyrood

Budget: $1,192 **Actual: $281** **Variance: ($911)**

This is a two year project to upgrade the hydrogen gas system at Holyrood. The original proposed project cost and activity by year is shown in the table below.

Year	Activity	Cost ($000)
2011	Design, procure and start construction of a hydrogen electrolyzer, low pressure hydrogen bulk storage tanks, and three hydrogen gas control panels	1,191.9
2012	Complete construction; procure and install automatic hydrogen venting systems on generating Units 2 and 3, and replace the manual gas control valves and piping	800.4
	Total	$1,992.3

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

7. <u>Upgrade Hydrogen System – Holyrood</u> (cont'd.)

The overall project scope, budget and completion date are unchanged.

As a part of Hydro's overall efforts to improve project execution during the planning phase of this project in early 2011, the project execution plan was reviewed and adjusted to reduce the risk of impacting plant reliability. The focus in 2011 was changed to achieving a more complete engineering design of the new system and ordering all long lead items. These objectives were achieved in 2011. The focus in 2012 will be developing a detailed construction plan and completing the construction and commissioning. The revised cash flow is as follows:

Year	Activity	Cost ($000)
2011A	Design and order long lead items	281.2
2012	Construction and commissioning	1,711.1
	Total	$1,992.3

8. <u>Replace Pumphouse Motor Control Centres - Holyrood</u>

Budget: $950 **Actual: $1,091** **Variance: $141**

This is a two year project scheduled to be completed in 2011, but which will carry over into 2012 with an 11 percent increase in the total budget. The carry over and budget increase are a result of the original design and associated technical specification not including replacement of the relay controls required for operation of the pump house equipment. The new MCC panels, which had already been procured, did not include space for relay controls. As a result, separate relay control panels had to be designed, procured and installed. This design was conducted during construction and the relay panels were successfully incorporated into the system for one of the three generating units. The delays, however, prevented Hydro from completing the work for the other two generating units in 2011, causing the carry-over into 2012. Remaining work is integrated into the 2012 work plan.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

8. Replace Pumphouse Motor Control Centres – Holyrood (cont'd.)

Both Hydro and the engineering consultant engaged for this project reviewed their respective quality control processes as to the design omission and met to share lessons learned. One of the outcomes of that review was to obtain agreement by the consultant to cover a significant portion of the cost for the incremental scope of work.

The original and revised budget estimate by year is shown in the table below. The credit from the engineering consultant is included in the revised figures.

Year	Original Cost ($000)	Revised Cost ($000)
2010	50.0	99.5
2011	998.6	561.3
2012	-	508.0
Total	$1,048.6	$1,168.8

9. Upgrade Synchronous Condenser Unit 3 – Holyrood

Budget: **$484** **Actual:** **$147** **Variance:** **($337)**

This is a two year project to perform modifications to the Holyrood Generating Unit 3 synchronous condenser to reduce vibration levels during operation. The original cash flow by year is shown in the table below.

Year	Cost ($000)
2011	483.6
2012	405.5
Total	$889.0

The overall project scope, budget and completion date are unchanged.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

9. Upgrade Synchronous Condenser Unit 3 – Holyrood (cont'd.)

There has been a revision to the project execution plan affecting the cash flow. Hydro engaged a specialist vendor in 2011 to design and supply the equipment for this project. The sole source engagement took longer than anticipated to reach an agreement that allows for performance guarantees. Some of the progress payments that were forecast to occur in 2011 have moved into 2012, but there is no impact on delivery of the overall project. The updated cash flow is shown in the table below.

Year	Cost ($000)
2011A	147.0
2012	742.0
Total	$889.0

10. Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood

Budget: $843 **Actual: $416** **Variance: ($427)**

This was a one year project to upgrade the forced draft fan ductwork on Unit 1, which was carried over into 2012 with a budget increase from $843,000 to $1,497,941 due to exceptionally higher than estimated construction contract cost. The schedule delay was a result of Hydro taking the additional time needed to reduce contract cost and to confirm that the higher cost was warranted.

The design and procurement phases of this project were delivered on budget and on schedule; however, initial tendering of the installation work produced an evaluated low bid that was 212 percent higher than the budgeted cost. The work was not awarded at this stage. To improve pricing through the benefits of scale, Hydro packaged this work with other approved work for Holyrood and retendered. This tender included optional pricing for construction in 2011 and separate optional pricing for construction in 2012.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

10. <u>Upgrade Forced Draft Fan Ductwork Unit 1 – Holyrood</u> (cont'd.)

Hydro conducted a critical review of the project before proceeding. A cost benefit analysis of three alternatives was studied: (1) complete the project in 2011 with construction during an exceptional unit outage in the shoulder season prior to the winter availability period; (2) complete the project in 2012 with construction during the planned unit outage; and (3) terminate the project. The analysis was conducted in the same manner as that used in the submission under the 2011 Capital Budget Application, with the exceptions that updated project costs were used and a more conservative assumption was made regarding the probability of failure. In the original analysis, it was assumed that failure of the ductwork would occur in 2018 for the status quo alternative. In this updated analysis, a more conservative assumption was made that the probability of failure for the remainder of the study period is 50%. The results are summarized in the table below. The analysis clearly demonstrates that it is prudent to complete the project at the higher total project cost in 2012, on the basis of mitigation of the risk of failure and energy savings from a reduced load on the forced draft fans.

Holyrood - Upgrade Unit 1 Forced Draft Fan (FDF) Ductwork		
Alternative Comparison ***Cumulative Net Present Value*** ***To The Year 2020***		
Alternatives	**Cumulative Net Present Value (CPW)**	**CPW Difference between Alternative and the Least Cost Alternative**
(1) Modify FDF Ductwork In 2011	1,787,683	937,666
(2) Modify FDF Ductwork In 2012	850,017	0
(3) Status Quo (Terminate Project)	1,572,911	722,894

Hydro awarded the construction contact in 2011 and has incorporated the project into the 2012 work plan, for project completion in November 2012.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

11. <u>Replace Relay Panels Unit 3 - Holyrood</u>

Budget: $277 **Actual: $139** **Variance: ($138)**

This is a two year project to replace the existing hardwired relay logic infrastructure contained in the three relay panels on Unit 3 with a distributed control system (DCS). The original cash flow by year is shown in the table below.

Year	Activity	Cost ($000)
2011	Design and DCS programming	277.1
2012	Installation and commissioning	553.6
	Total	$830.7

The overall project scope and budget are unchanged. There has been a revision to the design phase of the project execution plan affecting the cash flow. The execution plan for the construction phase is being reviewed and project completion may be delayed.

This project includes an extensive engineering planning phase to compile and field verify the termination schedules and to develop control logic diagrams, from which a vendor will design and program new controls equipment. The field verification step is crucial; proceeding without accurate termination schedules would introduce high risk of project re-work and may lead to technical issues affecting unit reliability. In 2011, the termination schedules were assembled from existing drawings and field verification commenced during planned outages. The discrepancies between the drawings and actual field conditions resulted in additional termination schedule field checks and revisions are required in 2012. Hydro was therefore not in a position in 2011 to engage a vendor for design and programming. Hydro is reviewing the impact of this delay on the construction phase of the project and some of the construction may carry over into 2013. When field verification is complete, Hydro will provide the Board with a revised project schedule, budget and cash flow with the 2013 Capital Budget Application.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

11. Replace Relay Panels Unit 3 – Holyrood (cont'd.)

The revised cash flow by year, subject to further revision in 2012, is shown in the table below.

Year	Cost ($000)
2011A	139.4
2012	691.3
Total	$830.7

12. Replace Steam Seal Regulator Unit 2 - Holyrood

Budget: $175 **Actual: $54** **Variance: ($121)**

This is a two year project to replace the existing hydraulic steam seal regulator on Unit 2 with two pneumatically operated steam pressure control valves. The original budgeted cash flow by year is shown in the table below.

Year	Activity	Cost ($000)
2011	Design and DCS programming	175.0
2012	Installation and commissioning	438.4
	Total	$613.4

The project completion date is unchanged.

The original project execution plan included ordering of the control valves in 2011. As a measure to mitigate project risk, there was a deliberate delay in ordering the valves until experience was gained for identical valves on the similar steam seal regulator project for Holyrood Unit 1 that were scheduled to be installed and commissioned in 2011. The valve procurement delay will not impact overall project completion.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

12. Replace Steam Seal Regulator Unit 2 – Holyrood (cont'd.)

The overall cost of this project will increase to $794,600. During detailed design in 2011, it was determined that the replacement of the pressure safety valve, associated discharge piping and pipe supports would be required in order to provide adequate steam venting for the new steam seal regulator system.

The revised budget estimate by year is shown in the table below.

Year	Cost ($000)
2011A	53.7
2012	740.9
Total	$794.6

13. Replace Steam Seal Regulator Unit 1 – Holyrood

Budget: $533 **Actual: $318** **Variance: ($215)**

This is a two year project that was scheduled to be completed in 2011. The original budget is shown below.

Year	Cost ($000)
2010	335.0
2011	213.7
Total	$548.7

The project is carried into 2012 and the total cost of this project has increased to $658,900 with the breakdown by year as shown below.

Year	Cost ($000)
2010A	16.1
2011A	315.5
2012	327.3
Total	$658.9

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

13. Replace Steam Seal Regulator Unit 1 – Holyrood (cont'd.)

The construction contract was awarded in 2011 in time for the planned outage. Shortly after the award, the contractor submitted a revised schedule that extended the work beyond the planned outage window. The contractor was unable to revise their schedule to meet the outage requirements. The contract was terminated and retendered for execution in 2012. The work has been incorporated into the 2012 work plan.

The overall cost of this project will increase to $658,900. As outlined in Item 12 – Replace Steam Seal Regulator Unit 2, during detailed design, it was determined that the replacement of the pressure safety valve, associated discharge piping and pipe supports would be required in order to provide adequate steam venting for the new steam seal regulator system.

14. Replace Diesel Fire Pump – Holyrood

Budget: $279 **Actual: $156** **Variance: ($123)**

This is a two year project to replace the diesel fire pump. The original budget is shown below.

Year	Cost ($000)
2010	111.9
2011	195.4
Total	$307.3

The project scope is unchanged.

The design and procurement phases of this project were delivered on budget. Initial tendering of the installation work resulted in an evaluated low bid that was 182 percent higher than the budgeted cost. The work was not awarded at this stage. To improve pricing through the benefits of scale, Hydro packaged this work with other approved work for Holyrood and retendered to attract additional competitive bidders. This was successful in that the evaluated low bid on the second tender was $93,700 less than the evaluated low bid for the first tender call. The decision to retender meant that the 2011 outage window would be missed.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

14. Replace Diesel Fire Pump – Holyrood (cont'd.)

Hydro awarded the contract for construction in 2012 and the work has been incorporated into 2012 work plan.

The revised budget is shown below.

Year	Cost ($000)
2010A	27.9
2011A	155.8
2012	191.5
Total	$375.2

15. Install Weatherhoods for Vent Fans - Holyrood

Budget: $208 **Actual: $549** **Variance: $341**

This was a one year project to replace weatherhoods on the powerhouse ventilation fans.

The project was completed in 2011 and the scope was unchanged.

The design and procurement phases of this project were delivered on budget. Initial tendering of the installation work resulted in an evaluated low bid that was 420 percent higher than the budgeted cost. The work was not awarded at this stage. To improve pricing through the benefits of scale, Hydro packaged this work with other approved work for Holyrood and retendered to attract additional competitive bidders. Hydro conducted a review of the project justification at this stage, and confirmed that the project was justified on the basis of documented air quality concerns in the powerhouse, and the associated health risk to workers. Hydro awarded the construction contract and adjusted the 2011 work plan to complete the work in the fourth quarter of 2011. The work was successfully completed.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERATION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

16. Condition Assessment and Life Extension Study - Holyrood

Budget: $568 **Actual: $416** **Variance: ($152)**

This was a two year project to conduct a condition assessment for Holyrood, scheduled to be completed in 2010; however, it was carried into 2011 to complete more detailed condition assessment of the marine terminal, gas turbine plant and the stack breeching on Units 1 and 2. The project is complete and the total cost at completion was eight percent under budget.

17. Upgrade Gas Turbine Plant Life Extension - Hardwoods

Budget: $1,924 **Actual: $1,215** **Variance: ($709)**

This is a three year project to upgrade the Gas Turbine at Hardwoods. The original budget is as follows.

Year	Activity	Cost ($000)
2010	Refurbish end B gas turbine equipment. Site retrofits and upgrades.	1,304.5
2011	Refurbish end A gas turbine equipment. Site retrofits and upgrades.	1,323.6
2012	Refurbish generator and exciter. Site retrofits and upgrades.	3,366.6
	Total	$5,994.7

The scope of this project remains unchanged and the project is expected to be completed within budget.

The original project execution plan allowed for the overhaul of one gas turbine engine in each of the first two years of the project. As a result of the first engine not being completed in 2010, the plan was revised to complete one engine in 2011 and the second engine in 2012. The revised cash flow for this project is shown in the table below.

Year	Cost ($000)
2010A	704.5
2011A	1,214.6
2012	4,075.6
Total	$5,994.7

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

18. Upgrade Terminal Stations to 25 kV – Labrador City

Budget: $4,689 **Actual: $6,262** **Variance: $1,573**

The original budget was submitted as a three year project to construct two new 46/25 kV terminal stations. Each station will have two new 46/25 kV, 15/20/25 MVA power transformers, new 46 kV and 25 kV electrical equipment, and new control buildings The budget estimate by year is shown in the table below.

Year	Cost ($000)
2009	283.2
2010	3,894.8
2011	5,812.6
Total	$9,990.6

The budget for this project was previously increased to $12,650,000 and the 2012 expenditure has been adjusted to incorporate the change in the overall budget. Also, see PUB-NLH-36 (Appendix A) in the Newfoundland and Labrador Hydro 2012 Capital Budget Application.

Year	Cost ($000)
2009A	100.8
2010A	1,693.5
2011A	6,262.4
2012	4,593.3
Total	$12,650.0

This project was estimated in 2008 based on market conditions at the time and using standard escalation indices for future year expenditures. The market conditions realized in Labrador West in the past 24 months have been atypical, driven by strong economic activity in the area. The outcome is an escalation beyond Hydro's standards in contracts, materials and labour.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

19. <u>Upgrade Substation - Wabush</u>

Budget: $459 Actual: 14 Variance: ($445)

This is a two year project to upgrade the Wabush substation. Detailed engineering design, outside substation civil works and equipment delivery were to be completed in 2011 with the substation electrical equipment installation and upgrades completed in 2012. The budget estimate by year is shown in the table below.

Year	Cost ($000)
2011	459.3
2012	626.4
Total	$1,085.7

The scope of this project remains unchanged; however the final cost of this project budget is subject to tender pricing. Demand for labour resources in Labrador West has significantly increased since original submission, thus it is expected that project cost will rise.

The work completed in 2011 included the line inspections and identification of material requirements to allow for preparation of the contract for completion of the work in 2012. Contract preparation is ongoing and will be tendered in the first quarter of 2012. The revised project cash flow is shown in the table below.

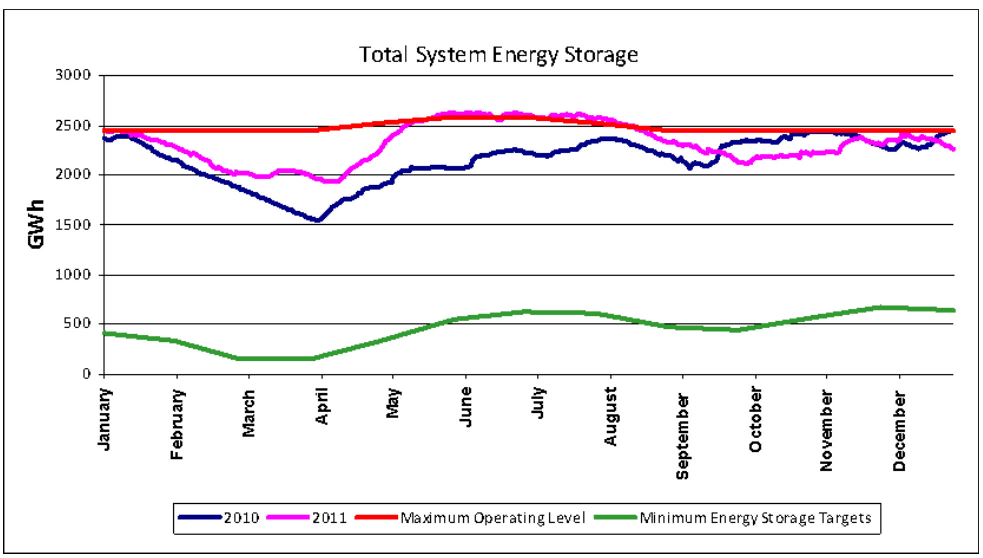
Year	Cost ($000)
2011A	14.3
2012	1,071.4
Total	$1,085.7

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

20. <u>Upgrade Power Transformers – Various Sites</u>

Budget: $866 Actual: $329 Variance: ($537)

This is a single year repeating project that Hydro applies for on an annual basis. The primary reasons for reduced spending on this project in 2011 were a reduced outage window for planned work in Bay d'Espoir and technical difficulties with bushing replacements. Exceptionally high inflows into the Bay d'Espoir reservoir system prompted increased hydraulic production from Bay d'Espoir Generating Station, resulting in a decreased outage window and thus a necessary reduction in planned work scope as illustrated in the graph below. Due to the unavailability of direct replacements for bushings, there was a need to resolve technical issues related to installation of bushings procured in 2010, and in procurement and installation of bushings in 2011. This resulted in less work being completed than planned. Additionally, this reduced work scope resulted in less overhead costs being applied and no contingency being required.



NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

21. Upgrade Station Reliability and Safety – Rocky Harbour

Budget: $435 Actual: $5 Variance: ($430)

This is a two year project to perform a general upgrade to the Rocky Harbour Terminal Station. The detailed design engineering and equipment delivery was to be completed in 2011 with the outside civil work and electrical equipment installation completed in 2012. The budget estimate for this project is shown in the table below.

Year	Cost ($000)
2011	434.8
2012	360.1
Total	$794.9

During the project detail design phase, it was discovered that the original approach to executing the work was not correct, requiring reevaluation of the execution plan, which will likely have budget and schedule implications. The revised budget and schedule will be included in the Status Report on the 2012 Capital Expenditures to June 30 as part of the 2013 Capital Budget Application.

22. Replace Breaker, Structures and Disconnects – Hawke's Bay

Budget: $687 Actual: $340 Variance: ($347)

This was a single year project to replace the 69 kV circuit breaker B7 L21 and its auxiliary equipment at the Hawke's Bay Terminal Station. This project has been carried over into 2012. This project was originally budgeted assuming that the stand-by diesels in the Hawke's Bay Terminal Station would be used extensively during the replacement of the breaker, disconnects, and structure. In order to decrease costs (particularly fuel costs) it was decided to utilize Hydro's portable substation which allowed the structure to be bypassed. The savings are approximately $187,000. The work has now been substantially completed but there are some deficiencies which need to be addressed by the contractor. The commissioning of the new equipment will be completed in 2012.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

23. Replace Insulators – Various Sites

Budget: $401 Actual: $512 Variance: $111

There was significantly more overtime required to complete the necessary insulator replacements at Sunnyside due to a fixed outage window and lost time due to weather, resulting in an extra $40,000 labour costs to complete this work. Material costs were also greater than budgeted due to more materials being required to complete the work than originally estimated resulting in an increased cost of $50,000.

24. Replace Disconnects – Various Sites (2011)

Budget: $295 Actual: $408 Variance: $113

The original plan for replacement of disconnects switches at Conne River and English Harbour West was to utilize Hydro's mobile substation in sequential outages. Due to the number of forced outages previously experienced on the Connaigre Peninsula, it was decided to avail of Newfoundland Power's mobile substation and install both mobile substations on a common outage. This minimized the frequency of outages to customers, but required extra Hydro resources to be utilized from other parts of the Province to complete the work.

25. Replace Compressor, Dryer and Air Piping Header System – Corner Brook Frequency Converter Station

Budget: $280 Actual: $147 Variance: ($133)

This is a single year project that has been carried over into 2012 and is scheduled to begin in mid March. The project was tendered in 2011 and no bids were received. To improve pricing through the benefit of scale, Hydro packaged this work with other approved work and retendered to attract additional competitive bidders. The tender has been awarded and the work is planned to be completed in the first half of 2012.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

26. Replace Disconnects – Various Sites (2010)

Budget: $102 Actual: $205 Variance: $103

This project was a single year project carried over from 2010. The total budget was $198,800 with a total expenditure of $301,000. Material costs were approximately $100,000 greater than budgeted.

27. Replace Guy Wires TL-215 – Doyles to Grand Bay

Budget: $289 Actual: $465 Variance: $176

This is a four year project to replace the existing guy wire arrangement on TL-215 with an assembly that helps reduce the fatigue problem on the existing pre-form grips. A single year project was completed in 2010 which replaced guy wires on approximately 20 percent of the line. This project will replace the guy wires on the remainder of the line with approximately 20 percent being replaced each year. The cash flow estimate by year is shown in the table below.

Year	Cost ($000)
2011	288.8
2012	318.0
2013	350.1
2014	530.0
Total	$1,486.9

The scope for this project remains unchanged and the project is expected to be completed within budget. Extra costs were incurred in 2011 due to future work and material procurement being advanced from future years into 2011, to take advantage of savings related to bulk minimum quantity orders, and to complete full sections of line in some areas.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
TRANSMISSION
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

27. Replace Guy Wires TL-215 – Doyles to Grand Bay (cont'd.)

The revised cash flow estimate by year is shown in the table below.

Year	Cost ($000)
2011A	465.1
2012	141.7
2013	350.1
2014	530.0
Total	$1,486.9

28. Upgrade Line TL-244 – Plum Point to Bear Cove

Budget: $1,196 **Actual: $1,627** **Variance: $431**

This was a two year project to upgrade transmission line TL-244, however, all the expenditures were incurred in 2011. The original budget was:

Year	Cost ($000)
2010	141.3
2011	1,055.2
Total	1,196.5

The increase in the cost is due mainly to the use of alternate generation requirements. The budget estimate was for three generating diesel units however five units were required.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

29. <u>Upgrade L2 Distribution Feeder - Glenburnie</u>

Budget: $735 Actual: $418 Variance: ($317)

This is a four year project for the design, supply and construction of an 18.5 kilometer (km) three phase distribution line from the Tablelands area to Trout River. It will also include the replacement of approximately 20 deteriorated poles located within the first 5.5 km from the Glenburnie Terminal Station.

The original project schedule and budget estimate are listed in the table below.

Year	Activity	Cost ($000)
2010	Line/Environmental Assessment	267.3
2011	Field Assessment / Line Design	578.2
2012	Material Order/ Procurement/Installation	2,114.6
2013	Environmental	596.6
	Total	$3,556.7

The overall budget and schedule are expected to remain the same.

The original project scope allowed for the completion of a technical and environmental assessment as well as the purchase of a limited amount of material in 2010 and 2011. The assessments are completed, but material will be ordered early in 2012.

The revised cash flow showing actuals for 2010 and 2011 is shown in the table below.

Year	Cost ($000)
2010A	109.9
2011A	417.9
2012	2,432.3
2013	596.6
Total	$3,556.7

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

30. <u>Provide Service Extensions – All Service Areas</u>
Budget: $3,385 Actual: $5,591 Variance: $2,206

This is an annual allotment based on past expenditures to provide service connections to new customers. The budget and actual expenditures by area is shown in the table below.

	2011 Cost ($000)	
Region	Budget	Actual
Central	1,045	1,886
Northern	1,092	1,040
Labrador	1,248	2,665
Total	$3,385	$5,591

The Central Region incurred approximately $800,000 in additional service extension work. This was primarily due to new installations in the mining industry, the sawmill/logging industry, the aquaculture industry on the Connaigre Peninsula and the electrification of a cabin area on the Baie Verte Peninsula. In addition, many new service extensions involved upgrading of the existing supporting infrastructure due to larger customer loads. Customers are also converting to electric heat which requires a switch to 200 amp or in some cases 400 amp service.

The Labrador Interconnected system has several new subdivisions under development that are driving cost increases. Examples are the New Hamel, Sheshatshui, Hudson West and Snow's Lane subdivisions. There are new homes being built in Edmunds Crescent and McGregor Avenues. There are also camp developments at Harrie Lake and Labrador City Industrial Park as well as new 3 phase services required in Wabush Industrial Park.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

31. Upgrade Distribution System – All Service Areas

Budget: $2,499 Actual: $3,401 Variance: $902

The Upgrade Distribution Systems budget is based on a five year average rather than specifically identified projects. The budget and expenditure by area is shown in the table below.

	2011 Cost ($000)	
Region	Budget	Actual
Central	998	1,365
Northern	1,051	1,488
Labrador	450	548
Total	$2,499	$3,401

The increased cost in the Central Region is due in large part to the removal of and replacement of defective distribution insulators ($125,000), the removal and replacement of rusty voltage regulators located near coastal regions ($165,000) and the removal of several rusty transformer banks located near environmentally sensitive areas ($65,000).

The increased cost in the Northern Region is due in large part to the replacement of voltage regulators ($250,000), reclosers ($80,000) and distribution line damage and equipment failures ($40,000) and due to an ice storm in Hawkes Bay.

32. Upgrade Distribution Lines – Roddickton and Makkovik

Budget: $1,779 Actual: $1,160 Variance: ($619)

This was a two year pooled project started in 2010 to upgrade distribution lines in Roddickton and Makkovik. The Roddickton portion of the project is complete. The total project for Roddickton was budgeted for $1,063,200 and the total expenditure for this work was $1,106,200.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

32. <u>Upgrade Distribution Lines – Roddickton and Makkovik</u> (cont'd.)

The Makkovik portion of the upgrade will be carried over into 2012. This project was tendered twice in 2011. The first tender received no bidders and the second was 42 percent ($337,000) over the budgeted cost. In 2012, there are distribution upgrades planned for Rigolet. These two projects will be pooled together in an effort to receive more competitive pricing. The total budget for the Makkovik upgrade is $799,500 of which $137,300 has been spent to the end of 2011.

33. <u>Upgrade Distribution Systems – Rigolet, Happy Valley and Francois</u>

Budget: $1,068 Actual: $614 Variance: ($454)

This is a two year pooled project to upgrade the distribution systems in Rigolet, Happy Valley and Francois. The Happy Valley and Francois portions of this project were budgeted to be completed in 2011 while the Rigolet upgrade will be completed in 2012. The budget for this project is shown below.

	Cost ($000)	
	2011	2012
Francois	440.9	-
Happy Valley	553.5	-
Rigolet	73.3	652.4
Total	$1,067.7	$652.4

The Francois upgrade will be carried over into 2012. This project was tendered twice in 2011 for the summer and fall construction period and there were no bidders each time. It is anticipated that contractors will be available to complete this work in May/June before the peak summer construction season.

The Happy Valley portion of this project was completed in 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

33. Upgrade Distribution Systems – Rigolet, Happy Valley and Francois (cont'd.)

The total expenditures for 2011 and the expected expenditures for 2012 are shown below.

	Cost ($000)	
	2011A	2012
Francois	116.0	324.9
Happy Valley	488.2	-
Rigolet	10.5	715.2
Total	$614.7	$1,040.1

34. Replace Poles – Various Sites

Budget: $882 **Actual: $985** **Variance: $103**

This is a one year pooled project to replace poles in Farewell Head, Grandy Brook and Westpoint. The budgeted cost and actual expenditures are shown below.

	2011 Cost ($000)	
	Budget	Actual
Farewell Head	339.6	394.0
Grandy Brook	286.4	312.4
Westpoint	256.4	279.4
Total	$882.4	$985.8

The largest variance occurred in Farewell Head and this was due to the increased labour cost compared to budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

35. <u>Replace Substation Infrastructure - Burgeo</u>

Budget: $128 Actual: $7 Variance: ($121)

This is a two year project to replace the poles, cross arms, insulation and switches. The budget estimate by year is shown in the table below.

Year	Cost ($000)
2011	127.5
2012	368.3
Total	$495.8

The scope for this project remains unchanged and the project is expected to be completed within budget.

The original project scope allowed for the completion of a technical and environmental assessment as well as the purchase of a limited amount of material in 2011. The assessments were completed, but all material will be ordered in 2012. The overall project budget will remain the same. The new project cash flow showing 2011 actual and 2012 estimate is shown in the table below.

Year	Cost ($000)
2011A	7.2
2012	488.6
Total	$495.8

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

36. Install Voltage Regulators – Conne River and L'Anse au Loup

Budget: $293 Actual: $118 Variance: ($175)

This was a single year project to install voltage regulators at Conne River and L'Anse au Loup. The breakdown of costs between the two portions of the project is shown below.

	2011 Cost ($000)	
	Budget	Actual
Conne River	147.8	81.7
L'Anse au Loup	144.8	35.9
Total	$292.6	$117.6

The Conne River installation was completed however the voltage regulators for L'Anse au Loup were delayed at the manufacturer. The expected delivery date was October 31, 2011 but the regulators left the factory mid December, and therefore there was not enough time to install them before year end. The installation is expected to be completed by the end of the first quarter 2012, resulting in a carry over of $108,900 for the L'Anse au Loup portion of the project.

37. Perform Arc Flash Remediation – Various Sites

Budget: $430 Actual: $108 Variance: ($322)

This project is a five year program to upgrade facilities to reduce the arc flash levels on electrical equipment throughout the Hydro system. The budget estimate by year is shown in the table below.

Year	Cost ($000)
2011	429.5
2012	380.3
2013	391.0
2014	401.8
2015	413.1
Total	$2,015.7

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

37. Perform Arc Flash Remediation – Various Sites (cont'd.)

The overall scope for this project remains unchanged and the project is expected to be completed within budget.

Three sites were completed in 2011. The primary reasons for the variance are related to less work being completed and savings realized on the work that was completed by coordinating arc flash upgrades with other planned work. The revised cash flow including the 2011 actuals is shown in the table below.

Year	Cost ($000)
2011A	107.6
2012	702.2
2013	391.0
2014	401.8
2015	413.1
Total	$2,015.7

38. Replace Diesel Unit 2001 and Engine 566 - Francois

Budget: $607 **Actual: $466** **Variance: ($141)**

This was a two year project started in 2010 and is to be carried over into 2012. The replacement genset for Unit 566 has been installed and commissioned, but the delivery of the replacement genset for Unit 2001 has been delayed. During factory acceptance testing, it became evident the unit was not meeting the specified vibration limits and therefore Hydro could not accept the engine. Troubleshooting of this issue by the manufacturer is currently on-going, but has not yet been resolved.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

39. Install Sequence of Events Monitor in Diesel Plant – Port Hope Simpson

Budget: $155 Actual: $7 Variance: ($148)

This project is a one year project that will be carried over into 2012. Due to the unexpected departure of three engineers in 2011, the project planning and engineering could not be started as planned. Material specifications and ordering has begun and the project is currently scheduled to be completed by mid July 2012.

40. Nain Diesel Plant Rehabilitation

Budget: $923 Actual: $397 Variance: ($526)

In the fall of 2008 there was a fire at the Nain Diesel Plant. Hydro used the Allowance for Unforeseen Events in order to do the necessary work in 2008 for a total of $304,000. In 2009, Hydro filed a multi-year unbudgeted proposal for $2,804,700 to complete the rehabilitation work which was approved by Board Order P.U. 31(2009). The total budget for this project is shown in the table below. Because there were no protection and control resources available to complete this project until late into 2010, this project was carried over into 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

40. <u>Nain Diesel Plant Rehabilitation</u> (cont'd.)

The total costs including insurance proceeds are also shown in the table below.

Cost ($000)				
Year	Budget	Actual before Proceeds	Insurance Proceeds	Net Costs
2008	304.0	304.0	-	304.0
2009	2,415.7	2,146.2	382.0	1,764.2
2010	389.0	1,001.5	883.5	118.0
2011	-	1,236.5	839.7	396.8
Total	$3,108.7	$4,688.2	$2,105.2[1]	$2,583.0

Excluding insurance proceeds, this project was approximately $1.5 million over budget.

Three main drivers were identified for the variance – protection and control work, addition of a septic system, and addition of a hydronic plant heating system. The bulk of cost overruns were due to protection and control work that accounted for over $600,000 in cost increases. The total cost of the scope additions accounted for $400,000. Additional interest and overhead costs associated with the extended schedule added another $300,000.

41. <u>Increase Generation Capacity – L'Anse Au Loup</u>

Budget: $288 **Actual: $541** **Variance: $253**

This was a two year project to replace a 600 kW diesel unit with a 1,100 kW rated diesel unit. The original budget was approved as part of the 2009 Capital Budget and is shown in the table below.

[1] The difference between the insurance proceeds quoted above and the insurance proceeds of $2,119.7 in IC-NLH-1 International Financial Reporting Standards (IFRS) is approximately $15,000 that was incorrectly classified as a capital recovery in 2009. This difference has now been recorded as an operating cost recovery for the Nain fire.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

41. Increase Generation Capacity – L'Anse Au Loup (cont'd.)

Year	Cost ($000)
2009	22.9
2010	820.8
Total	$843.7

Due to the requirement for additional capacity, it was decided to not replace a diesel unit but to add a mobile unit with a capacity of 1,825 kW. The revised budget as well as the actual amount spent is shown in the table below.

	Cost ($000)	
	Budget	Actual
2009	1,002.3	783.2
2010	516.9	447.7
2011	-	540.7
Total	$1,519.2	$1,771.6

The cost increase is due to extra costs incurred on labour and materials. The main reason for the extra labour associated with the project is that the project was carried over for an additional year therefore additional engineering and project management was required in order to finish the job. Additionally there was an overrun on the material cost. This was primarily due to the cost of the mobile transformer coming in higher than originally budgeted.

42. Install Automatic Meter Reading – Labrador City and Port au Choix

Budget: $451 Actual: $237 Variance: ($214)

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

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

42. <u>Install Automatic Meter Reading – Labrador City and Port au Choix</u> (cont'd.)

In 2011, the meters and the terminal station equipment were purchased for Labrador City and the terminal station equipment and a portion of the meters were installed. The remaining meters will be installed early in 2012. The budget estimate by service area and year are shown in the table below.

Year	Labrador City Cost ($000)	Port au Choix Cost ($000)	Total
2011	292.2	159.0	451.2
2012	58.3	29.4	87.7
Total	$350.5	$188.4	$538.9

The implementation of AMR for Port au Choix has been cancelled. The project was originally proposed based on a meter reader position becoming vacant, however, due to a change in circumstances, this did not occur and the benefit anticipated from the implementation of this project would not be realized. The budget for this work will, therefore, not be spent. The revised budget is shown in the table below

Year	Labrador City Budget ($000)
2011A	237.0
2012	113.5
Total	$350.5

43. <u>Replace Light Duty Mobile Equipment – Various Sites</u>

Budget: $757 **Actual: $582** **Variance: ($175)**

This project will be carried over into 2012 due to the delay in delivering two new prototype trailers. In addition, the overall cost is reduced by $160,000 due to changes in the types of heavy duty trailers being purchased resulting in lower cost per unit.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
RURAL SYSTEMS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

44. Public Address System - Holyrood

Budget: $1,008 **Actual: $1,206** **Variance: $198**

This project is carried over into 2012 due to a small amount of contract work left to be completed. The project is substantially complete and will be completed in 2012. The budget variance is primarily a result of the extended project schedule which has resulted in additional project management, supervision, and overhead costs.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

45. <u>Install Fibre Optic Cable – Hinds Lake</u>

Budget: $224 Actual: $117 Variance: ($107)

This is a two year project to replace microwave radio link between Blue Grass Hill Microwave site and Hinds Lake Generating Station with fibre optic cable. It was approved as part of the 2009 Capital Plan with the budget shown in the following table:

	Cost ($000)	
	Budget	Actual
2009	209.2	9.0
2010	482.9	459.1
2011	-	116.9
Total	$692.1	$585.0

The actual amount spent by year is also shown in the table above. The budget savings are due to lower project management and contract costs and no contingency being required.

46. <u>Replace Battery Banks and Chargers – Various Sites</u>

Budget: $978 Actual: $872 Variance: ($106)

This is a single year project to replace battery banks and chargers. This project is under budget mainly due to the project contingency not being required.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

47. **Replace Vehicles and Aerial Devices 2011 – Various Sites**

Budget: **$2,351** **Actual:** **$1,254** **Variance:** **($1,097)**

This is a two year project to replace 25 light-duty vehicles and five heavy-duty work vehicles. The budgeted cost by year is shown in the table below.

Year	Cost ($000)
2011	2,350.5
2012	638.9
Total	$2,989.4

The total cost of this project has been reduced by $989,400 due to two factors. Firstly there was a saving of $289,000 as a result of a downturn in the economy, which resulted in better pricing on vehicles and reduced escalation costs. Secondly, the 2010 project was intended to be submitted as a two year project due to the difficulty in ordering and receiving all the equipment in one calendar year. Inadvertently, only the first year of this project was submitted and approved in 2010 and a change order was completed for the portion of equipment ordered in 2010 and received in 2011. The 2011 multi-year project had already included the $700,000 for the equipment being received in 2011 resulting in a second change to correct the duplication.

Year	Cost ($000)
2011A	1,254.4
2012	745.6
Total	$2,000.0

48. **Upgrade System Security 2009 – Various Sites**

Budget: **$141** **Actual:** **$527** **Variance:** **$386**

This was a two year project approved as part of the 2009 Capital Budget with a total budget of $1,469,000 as shown in the table below.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
GENERAL PROPERTIES
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

48. <u>Upgrade System Security 2009 – Various Sites</u> (cont'd.)

Year	Cost ($000)
2009	767.2
2010	701.8
Total	$1,469.0

There were three major components to this project, fencing upgrades, and access installation and security camera installation.

The budget for this project was increased by $455,300 in 2010 due to the difficulty in estimating the costs since it involved security upgrade in over 90 sites. Additionally expansions of existing fencing affected the grounding grids, requiring unplanned modifications.

The installation of the security cameras was completed in 2011. However, there were difficulties in making the sites operational which required multiple site visits to troubleshoot problems and rectify the issues. This resulted in greater than anticipated labour, materials and travel costs.

The overall cost is greater than the revised budget mainly due to an increase in labour costs by $100,000, material costs by $200,000 and overhead costs by $160,000. The revised budget and actual costs are shown in the table below.

	Cost ($000)	
	Revised Budget	Actual
2009	488.0	488.0
2010	1,436.3	1,295.0
2011	-	527.2
Total	$1,924.3	$2,310.2

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

49. Increase Generation Capacity - Charlottetown

Budget: $1,000 Actual: $1,482 Variance: $482

The project utilized the allocation for unforeseen events. Please see the report called "Unforeseen Item: Increase Generating Capacity Charlottetown" filed under a separate cover.

50. Ice Storm – Baie Verte Peninsula

Budget: $0 Actual: $519 Variance: $519

The project utilized the allocation for unforeseen events. Please see the report called "Unforeseen Item: Ice Storm Damage – Baie Verte Peninsula" filed under a separate cover.

51. Confined Space Isolation (Blanks and Blinds) - Holyrood

Budget: $1,665 Actual: $1,330 Variance: ($335)

This was a two year unbudgeted project approved by Board Order No. P.U. 34(2010). The budget and actuals amount spent for this project is shown in the table blow.

	Cost ($000)	
	Budget	Actual
2010	202.0	138.9
2011	1,602.3	1,329.6
Total	$1,804.3	$1,468.5

There was a reassessment on the installation methods and location of the blanks and blinds that lead to the lower than estimated labour costs. These labour cost were approximately $280,000 less than budgeted which also resulted in less overheads and interest being incurred.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 VARIANCE EXPLANATIONS
OTHER APPROVED FUNDS
FOR THE YEAR ENDING DECEMBER 31, 2011
(Greater than $100,000 and 10% Variance from Budget)

52. <u>Upgrade Stack Breeching Unit 1 - Holyrood</u>

Budget: $134 **Actual: $272** **Variance: $138**

This was a one year project to upgrade stack breeching and replace the stack breeching support structure. Through Board Order No. 20(2011), the Board approved only the replacement of the stack breeching support structure at a cost of $133,700. This amount was from CA-NLH-9 (Appendix B) as quoted by the contractor. It did not include additional project costs such as project management, interest and overhead costs. In Table 4 of Hydro's response to the Request for information IC-NLH-1 (Appendix C), it was stated that:

> "if approval is received in September 2011 to proceed with the refurbishment project, Hydro proposes to address the most pressing concern – the condition of the support structures in 2011."

The revised schedule and revised budget estimate (Schedules 3 and 4, respectively, of that RFI response) indicated that only stack breeching support replacement work was scheduled for 2011 and the cost of that 2011 work was $277,900. The work was completed in 2011.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2002 – 2011
AS AT DECEMBER 31
($000)

Table 1: CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2002 – 2011

Year	Budget	Actual Expenditures	Variance	Percentage Variance
2002	44,660	40,217	4,443	9.9%
2003	36,122	32,506	3,616	10.0%
2004	31,435	27,984	3,451	11.0%
2005	47,760	33,952	13,808	28.9%
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%
2009	61,544	54,152	7,392	12.0%
2010	63,297	55,553	7,744	12.2%
2011	67,454	63,116	4,338	6.4%

In 2011, Hydro delivered the highest Board approved dollar value capital program execution in recent history. During 2011, Hydro commenced execution of its plan to enhance its project delivery capability. A key step in the process included organizational structure changes within both Hydro and Nalcor with the establishment of a Project Execution and Technical Services division that have lead to improved delivery and compliance of capital projects. While the reorganization has been helpful, there is still work to be done and Hydro is achieving a balance between project workload and resource allocation in support of project execution. Hydro anticipates continued progress in 2012 and further improvement in project delivery and budget compliance.

Total variances of actual to budget costs for completed projects are 1 percent for 2009 and 2010; however, it has increased to 12 percent in 2011. This is due in large part to the trend of increasing costs associated with the strong labour market currently being experienced in the province. The variance per project increased in 2011 over previous years. In 2011 Hydro was intentional and deliberate in stepping back where and when required with an objective of reduced project risk and improved probability for successful delivery in 2012.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2002 – 2011
AS AT DECEMBER 31
($000)

The variances presented in Table 1 are partially due to under-spending as a result of not completing all projects approved each year. It is anticipated that some carryover of projects will occur in most years as there may be unavoidable reasons for delays in project completion, for example, system constraints which are precipitated by changes in hydrology, equipment failures, etc. There are also cost increases and project delays being experienced due to the strong labour market. This has manifested itself for example, in eight of the projects in 2011 for which either no bids were received or bids far exceeded estimated costs. Hydro is working to address these issues by reviewing its packaging of projects to encourage competitive bids, as well as attracting additional bidders.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 CARRYOVER REPORT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Project Name	PUB Approved Budget 2011	Revised Budget 2011	Total Actual Expend. 2011	Carryover Amount	Variance Explanation Ref. No.	Original Completion Year
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir	258	258	161	97		2011
Purchase Spare Disconnect - Bay d'Espoir	176	133	73	59	3	2011
Replace Fire Alarm System - Hinds Lake	109	109	21	88		2011
Replace Pumphouse Motor Control Centres - Holyrood	949	1,069	1,091	(22)	8	2011
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood	843	1,498	416	1,082	10	2011
Replace Steam Seal Regulator Unit 1 - Holyrood	532	643	318	325	13	2011
Replace Diesel Fire Pump - Holyrood	279	347	156	192	14	2011
Upgrade Glycol Systems - Stephenville	557	1,115	539	576		2011
Replace Breaker, Structures and Disconnects - Hawke's Bay	687	687	340	347	22	2011
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station	280	280	147	133	25	2011
Replace Digital Fault Recorder - Bay d'Espoir	169	169	72	97		2011
Upgrade Distribution Lines - Makkovik	781	781	119	662	32	2011
Upgrade Distribution System - Francois	441	441	116	325	34	2011
Install Voltage Regulator - L'Anse au loup	145	145	36	109	36	2011
Replace Diesel Unit 2001 and Engine 566 - Francois	607	607	466	141	38	2011
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson	155	155	7	148	39	2011
Legal Survey of Primary Distribution Line Right of Way - Various Sites	79	79	5	74		2011
Replace Light Duty Mobile Equipment - Various Sites	757	597	583	15	43	2011
Public Address System - Holyrood	1,008	1,245	1,206	39	45	2010

NEWFOUNDLAND AND LABRADOR HYDRO
2011 CARRYOVER REPORT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Project Name	PUB Approved Budget 2011	Revised Budget 2011	Total Actual Expend. 2011	Carryover Amount	Variance Explanation Ref. No.	Original Completion Year
Upgrade Generating Station Service Water System -Cat Arm	360	360	349	11		2012
Upgrade Intake Gate Controls - Bay d'Espoir	352	534	507	27	2	2012
Replace Programmable Logic Controllers - Holyrood	933	873	877	(5)		2012
Upgrade Hydrogen System - Holyrood	1,192	1,192	281	911	7	2012
Upgrade Synchronous Condenser Unit 3- Holyrood	484	484	147	337	9	2012
Replace Relay Panels Unit 3- Holyrood	277	277	140	138	11	2012
Replace Steam Seal Regulator Unit 2 - Holyrood	175	356	54	303	12	2012
Upgrade Gas Turbine Plant Life Extension - Hardwoods	1,924	1,010	1,215	(205)	17	2012
Upgrade Terminal Stations to 25 kV - Labrador City	4,689	6,915	6,262	652	18	2012
Upgrade Substation - Wabush	459	459	14	445	19	2012
Upgrade Station Reliability and Safety - Rocky Harbour	435	435	5	429	21	2012
Replace 69 kV SF6 Breakers - St. Anthony Airport	490	490	499	(10)		2012
Replace Compressed Air System - Bay d'Espoir	84	84	87	(3)		2012
Replace 230 kV Circuit Breaker - Sunnyside	41	41	8	34		2012
Install Alternate Station Services - Stony Brook and Massey Drive	86	86	6	80		2012
Voisey's Bay Nickel - Long Harbour Power Supply	10,600	10,600	10,338	262		2012
Cost Recovery - Vale Inco	(10,600)	(10,600)	(10,338)	(262)		
Upgrade Distribution Systems - Rigolet	73	73	11	63	33	2012
Replace Substation Infrastructure- Burgeo	128	128	7	120	35	2012

NEWFOUNDLAND AND LABRADOR HYDRO
2011 CARRYOVER REPORT
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Project Name	PUB Approved Budget 2011	Revised Budget 2011	Total Actual Expend. 2011	Carryover Amount	Variance Explanation Ref. No.	Original Completion Year
Replace Mini Hydro Turbine - Roddicton	87	87	11	76		2012
Install Automatic Meter Reading - Labrador City	292	292	237	55		2012
Replace Off Road Track Vehicles - Bishop's Falls	265	154	219	(65)		2012
Replace Off Road Track Vehicles - Fogo	230	68	185	(117)		2012
Corporate Application Environment - Upgrade Microsoft Products	864	864	860	4		2012
Cost Recoveries	(237)	(237)	(275)	39		
Replace MDR 6000 Microwave Radio (West) - Various Sites	72	72	28	45		2012
Replace Vehicles and Aerial Devices 2011 - Various Sites	2,351	1,361	1,254	107	47	2012
Replace Engine # 2062 - Grey River	23	23	0	23		2012
Replace Static Excitation System - Upper Salmon, Holyrood and Hinds Lake	1,214	487	18	470	1	2013
Upgrade Electrical Equipment - Holyrood	188	188	187	1		2013
Voltage Conversion - Labrador City	3,066	3,066	2,932	134		2013
Upgrade L2 Distribution Feeder - Glenburnie	736	736	418	318	29	2013
Replace Guy Wires TL-215 - Doyles to Grand Bay	289	289	465	(176)	27	2014
Perform Grounding Upgrades - Various Sites	321	321	288	34		2015
Perform Arc Flash Remediation - Various Sites	430	430	108	322	37	2015
		Total Carryover		9,083		

NEWFOUNDLAND AND LABRADOR HYDRO
2011 REMOVE SAFETY HAZARDS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Total Approved Budget: **$252.4**
Total Expenditure: **$239.9**
Board Order P.U. 38(2010)

As part of Board Order No. P.U. 38(2010) 2011 Capital Budget, the following was included "Because of the nature of this project the Board would expect to see an explanation in Hydro's annual report on capital expenditures as to each project that was undertaken, setting out the safety hazard that was identified, the location, the steps taken to address the issue and the amount of the expenditure." Please see the following table:

Project Title/Location	Expenditure	Safety Hazard Identified	Project Scope
Purchase Highway Signs TRO Central, Northern, and Labrador	$144.3	As a result of new traffic control legislation in the province effective January 1, 2011 Hydro was required to purchase road signs and follow guidelines in the Traffic Control Manual published by the Department of Transportation and Works. Occupational Health and Safety (OH and S) Regulations require that traffic control procedures shall at minimum meet the requirements of the Department of Transportation and Works "Traffic Control Manual for Roadway Work Operations" or procedures established by a municipality that have been approved by the minister and all relevant specifications".	Highway traffic signs were purchased to be used in daily execution of work to ensure uniform and consistent methods of traffic control when completing work occurring within the right of way of a roadway.
Upgrade Burnt Bridge Bay d'Espoir System	20.5	Safety Work Observation Program (SWOP) #2011002968 Bridge decking is deteriorated and needs to be replaced.	Replaced running boards and decking
Upgrade Venam's Trail Venam's Bight	28.3	SWOP#2011002276 Trail leading to powerhouse along side of penstock is very rough; there is a high potential/concern to flip or to wipe out on an ATV.	Installed railings, retaining walls, brook crossings, and landings to improve safety of access to Venam's Bight powerhouse and intake.

NEWFOUNDLAND AND LABRADOR HYDRO
2011 REMOVE SAFETY HAZARDS
FOR THE YEAR ENDING DECEMBER 31, 2011
($000)

Project Title/Location	Expenditure	Safety Hazard Identified	Project Scope
Powerhouse #1 Stairway Bay d'Espoir	36.9	SWOP#2010000480 Concrete steps between upper parking lot and main level are severely eroded and in need of replacement. Several concrete patches came loose and pose a significant tripping hazard.	Replaced parking lot stairway from employee parking lot to powerhouse.
Mobile Foam Carts Holyrood	10.0	Holyrood had one mobile foam cart, positioned on level 1 of the Powerhouse to control larger pool fires that cannot be contained by the fixed fire protection. There was no other mobile or fixed foam protection on either level I or level III. While our units are protected with fixed deluge, pre-action and/or wet-type sprinkler systems, there was no capability to suppress flammable vapors and provide protection from re-ignition or potential fire migration from flammable liquids fires is sparse. The acquisition of 3 additional mobile foam carts would mitigate the risk to Operators and/or ERT members who may have to combat fuel-based fires.	Purchased two mobile foam carts for Emergency Response Team

APPENDIX A
PUB-NLH-36

Q. **Page E-9, New 25 kV Terminal Station – Labrador City, $3,507,000**

Given the time that has elapsed since the original budget was prepared and the issues that have arisen in obtaining tenders, please provide a revised budget based on the most recent best available information.

A. As indicated, the budget for this multi-year project was prepared in 2008. The work was approved and began in 2009 and is scheduled to be completed in 2012. A significant amount of the work to be completed in 2011/2012 is contract work related to the construction of the terminal stations and the installation of equipment.

Hydro has recently completed the tender phase and has recognized a variance between the 2008 estimates and the 2011 tender responses.

The table below provides a summary of the approved budget, the amount spent to date, and projections of the additional expenses to the end of the project.

Approved Budget:	$9,900,000
Spent to Date (Sept 2011):	$3,400,000
Budget for the Remainder of 2011:	$5,500,000
Projection for 2012:	$3,750,000
Final Forecasted Expenses:	$12,650,000
Variance:	$2,750,000

APPENDIX B
CA-NLH-9

CA-NLH-9
Holyrood (HTGS) Stack Breeching and Fuel Tank Refurbishment

Q. Re: Holyrood: Upgrade Unit 1 Stack Breeching
With respect to the budget Estimate at Section 5.1, please break out the project costs for each element or aspect of the work which Hydro is proposing to undertake in this overall project, eg. refurbishing steel casing, work on East Support Structure, work on West Support Structure, insulation of breeching externally, ice protection shelters, etc.

A. A breakout of the project cost for the budget estimate at Section 5.1 is included in the table below.

Project Task Description	Cost ($)
Labour (Internal Hydro engineering, operations, and project management labour):	114,400
Contract (Labour & Materials):	
Remove internal insulation blocks and supply/install 6 inches of external insulation	461,328
Install an ice protection shield	112,428
Replacement of expansion joints and casing repairs	774,144
Supply and install East and West support structures. Includes additional cost to replace the breeching support structures with the existing breeching left in place. A temporary support structure will be required.	133,700
Travel	2,000

The cost estimates provided by Hatch are not broken down by East and West structure, although it is not unreasonable to expect that the relevant costs can be split evenly between the two structures. Please also refer to response to IC-NLH-1.

APPENDIX C
IC-NLH-9

Q. Provide for each project **(Unit 1 Stack Breeching; Fuel Oil Storage Facility),** updated versions of the schedules at section 5.2 of each of the respective July 11 Hydro reports filed to support these projects, based on the assumption these projects would be approved by the Board in September 2011. Identify in each updated schedule the estimated amount of proposed expenditure planned to be incurred at each milestone date.

A. **Fuel Oil Storage Facility:**

When the last report was filed with the Board in July 2011, the schedule was based on receiving approval to proceed with the refurbishment project early enough so that tender documents could be prepared and a construction contract awarded by the end of September 2011. The tank would be taken out of service in 2011 to allow refurbishment to be performed such that it could be placed back in service as early as possible (estimated to be mid March 2012). This would minimize the amount of time the tank would be out of service during the 2011/12 peak load season and also during the ice season when there is risk that pack ice may be present in Conception Bay that could disrupt fuel deliveries to Holyrood.

Based on receiving approval to proceed with the project in September 2011, the target date of mid March to have the tank back in service following refurbishment is no longer realistic. The earliest back-in-service date would need to be extended well into the 2012 ice season. Hydro believes that it is less risky during the ice season to have the tank in service in its present condition then to have it out of service undergoing refurbishment. For this reason, Hydro has revised its schedule as indicated in Table 1 below. The revised schedule has resulted in changes to the overall project budget such that it has increased marginally. A revised budget estimate has been provided in Table 2.

Table 1:

Activity	**Milestone**	**Proposed Expenditure ($X1000)**
Prepare Tender Documents	October 2011	20
Invite and Award Tenders	November 2011	35
Procurement Of Material	December 2011	128
Mobilization	April 2012	480
Complete Construction	September 2012	1,966
Closeout Project	October 2012	125
Total:		**2,754**

Table 2:

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	45.0	159.5	0.0	204.5
Consultant	38.0	170.0	0.0	208.0
Contract Work	100.0	1,776.0	0.0	1,876.0
Other Direct Costs	0.0		0.0	2.0
O/H, AFUDC & Escln.	7.8	227.0	0.0	234.8
Contingency	0.0	229.1	0.0	229.1
TOTAL	**190.8**	**2,563.6**	**0.0**	**2,754.4**

Unit 1 Stack Breeching:

When the last report was filed with the Board in July 2011, the schedule was based on receiving approval to proceed with the refurbishment project early enough so that a refurbishment contract could be awarded in August 2011 and the breeching returned to service by the end of its planned scheduled outage period (late October 2011).

Based on receiving approval to proceed with the project in September 2011, the completion date for the project coinciding with the end of the planned outage schedule (late October 2011) is no longer realistic. The breeching has to be in service for the upcoming 2011/12 peak load season. If approval is received in September 2011 to proceed with the refurbishment project, Hydro proposes to address the most pressing concern - the condition of the support structures, in 2011. The intention is to replace them and in the process minimize any extension required to the planned outage period to complete the work. For this reason, Hydro revised its milestone schedule as indicated in Table 3 below. The revised schedule has resulted in changes to the overall project budget such that it has increased marginally. A revised budget estimate has been provided in Table 4.

Table 3:

Activity	Milestone	Proposed Expenditure ($X1000)
Prepare Tender Documents	October 2011	35
Invite and Award Tenders	October 2011	20
Procurement of Material Required For Breeching Support Structure Replacement	November 2011	80
Mobilization & Replace Breeching Support Structures	November 2011	40
Procurement Of Material Required For Remaining Refurbishment Work	March 2012	420
Commence Remaining Refurbishment (In Accordance With Planned Outage)	May 2012	616
Construction Complete	September 2012	620
Project Final Documentation and Closeout	October 2011	88
Total:		**1,919**

IC-NLH-1
Holyrood (HTGS) Stack Breeching and Fuel Tank Refurbishment

Table 4:

Project Cost: *($ x1,000)*	**2011**	**2012**	**Beyond**	**Total**
Material Supply	0.0	0.0	0.0	0.0
Labour	65.0	49.4	0.0	114.4
Consultant	0.0	0.0	0.0	0.0
Contract Work	200.0	1,281.6	0.0	1,481.6
Other Direct Costs	0.5	1.5	0.0	2.0
O/H, AFUDC & Escln.	12.4	148.8	0.0	161.2
Contingency	0.0	159.8	0.0	159.8
TOTAL	**277.9**	**1,641.1**	**0.0**	**1,919.0**

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CAPITAL EXPENDITURES AND CARRYOVER REPORT

For Year Ending December 31, 2012

March 2013

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Year Ending December 31, 2012

TABLE OF CONTENTS

2012 Capital Budget Variance
Overview
($000)

	Board Approved Budget	Total Expend.	Variance
HYDRAULIC PLANT	13,205	13,906	701
THERMAL PLANT	20,578	21,723	1,145
GAS TURBINES	6,555	7,300	745
TERMINAL STATIONS	24,099	27,086	2,986
TRANSMISSION	4,053	4,095	42
DISTRIBUTION	28,878	31,144	2,266
GENERATION	3,687	3,603	(84)
PROPERTIES	644	601	(43)
METERING	1,209	1,202	(7)
RURAL SYSTEMS TOOLS AND EQUIPMENT	3,666	3,217	(449)
INFORMATION SYSTEMS	3,734	3,679	(54)
TELECONTROL	4,037	4,111	74
TRANSPORTATION	5,920	4,941	(979)
ADMINISTRATIVE	381	212	(169)
MAJOR OVERHAUL AND INSPECTIONS	6,840	7,213	373
CONTINGENCY FUND	1,000	1,374	374
PROJECTS APPROVED BY PU BOARD	10,656	8,636	(2,020)
PROJECTS APPROVED FOR LESS THAN $50,000	196	161	(35)
TOTAL CAPITAL BUDGET	139,336	144,203	4,867

2012 Capital Expenditures By Year
($000)

Summary	Capital Budget[1]							Actual Expenditure and Forecast								
	2008	2009	2010	2011	2012	2013 and Beyond	Total	2008	2009	2010	2011[2]	2012	2013 and Beyond	Carryovers to 2013	Total	Variance
2012 Projects	-	-	-	-	56,327.0	9,112.2	65,439.4	-	-	-	-	45,882.3	9,112.2	8,898.5	63,893.0	(1,546.4)
2011 Projects	-	-	-	14,469.1	12,548.7	4,601.3	31,619.0	-	-	-	7,522.6	15,129.4	5,604.7	5,241.6	33,498.3	1,879.3
2010 Projects	-	-	5,088.4	10,236.0	11,458.4	1,566.1	28,348.8	-	-	4,310.3	9,501.8	8,872.1	1,566.1	5,584.1	29,834.4	1,485.6
2009 Projects	-	100.8	1,693.5	7,105.7	3,750.0	-	12,650.0	-	291.8	1,693.5	6,022.7	7,320.1	-	(223.3)	15,104.8	2,454.8
2008 Projects	96.3	1,182.2	-	-	-	-	1,278.5	2.8	119.1	539.9	1,161.7	48.5	-	-	1,872.1	593.6
Grand Total	96.3	1,283.0	6,781.9	31,810.8	84,084.1	15,279.6	139,335.7	2.8	410.9	6,543.7	24,208.8	77,252.4	16,283.0	19,500.9	144,202.6	4,866.9

2012 Capital Budget Approved by Board Order No. P.U. 2 and 5 (2012)	76,992.3
New Project Approved by Board Order No. 24 (2012)	492.1
New Project Approved by Board Order No. 25 (2012)	2,940.5
New Project Approved by Board Order No. 26 (2012)	321.4
New Project Approved by Board Order No. 27 (2012)	3,154.9
New Project Approved by Board Order No. 35 (2012)	10.2
2012 New Projects under $50,000 Approved by Hydro	172.7
Total Approved Capital Budget Before Carryovers	84,084.1
Carryovers from 2011 to 2012	9,755.9
TOTAL APPROVED CAPITAL BUDGET (As per Table 1 p. 32)	93,840.0

[1] Annual budgets previous to 2012 pertain to projects that have expenditures in 2012.

[2] There has been a restatement of expenditures in 2011 resulting from the conversion to International Financial Reporting Standards (IFRS).

2012 Capital Expenditures By Category
($000)

Hydraulic Plant	Capital Budget 2011	Capital Budget 2012	Capital Budget 2013 and Beyond	Capital Budget Total	Actual 2011	Actual 2012	Actual 2013 and Beyond	Carryovers to 2013	Actual Total	Variance	Notes
2012 Projects											
Rewind Stators Unit 4 - Bay d'Espoir	-	4,953.8	-	4,953.8	-	2,548.7	-	2,405.1	4,953.8	-	
Replace Emergency Diesel Generator - Bay d'Espoir	-	611.4	282.7	894.1	-	80.0	282.7	531.4	894.1	-	
Replace Fuel Tank at Burnt Dam - Bay d'Espoir	-	207.5	-	207.5	-	196.3	-	-	196.3	(11.2)	
Replace Rip Rap - Bay d'Espoir	-	199.1	-	199.1	-	114.4	-	-	114.4	(84.7)	
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	523.8	-	523.8	-	168.9	-	621.2	790.1	266.3	1
Purchase Tools and Equipment Less than $50,000	-	106.4	-	106.4	-	94.8	-	-	94.8	(11.6)	
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	-	48.3	-	48.3	-	50.1	-	-	50.1	1.8	
2011 Projects											
Replace Fire Alarm System - Hinds Lake	109.1	-	-	109.1	20.2	92.9	-	-	113.1	4.0	
Replace Static Excitation Systems - Upper Salmon, Holyrood and Hinds Lake[3]	487.3	2,402.5	1,219.3	4,109.1	16.8	818.8	2,295.2	978.3	4,109.1	-	
Upgrade Generating Station Service Water System - Cat Arm	360.4	440.0	-	800.4	349.3	259.6	-	191.5	800.4	-	
Upgrade Burnt Dam Spillway Structure - Bay d'Espoir	257.9	-	-	257.9	154.8	70.2	-	228.8	453.8	195.9	2
Purchase Spare Disconnect - Bay d'Espoir	175.6	-	-	175.6	70.6	43.8	-	-	114.4	(61.2)	
Upgrade Intake Gate Controls - Bay d'Espoir	352.3	468.0	-	820.3	507.0	373.6	-	341.2	1,221.8	401.5	3
Total Hydraulic Plant	1,742.6	9,960.8	1,502.0	13,205.4	1,118.7	4,912.1	2,577.9	5,297.5	13,906.2	700.8	

[3] Original budget was $4,109.1 (2010 - $1,214.3, 2011 - $1,528.0, 2012 - $1,366.8) Approved by Order No. P.U. 38 (2010). The revised budget was approved by Order No. P.U. 2 (2012).

2012 Capital Expenditures By Category
($000)

Thermal Plant	Capital Budget 2010	Capital Budget 2011	Capital Budget 2012	Capital Budget 2013 and Beyond	Capital Budget Total	Actual Expenditure and Forecast 2010	Actual Expenditure and Forecast 2011	Actual Expenditure and Forecast 2012	Actual Expenditure and Forecast 2013 and Beyond	Carryovers to 2013	Actual Expenditure and Forecast Total	Variance	Notes
2012 Projects													
Refurbish Fuel Storage Facility - Holyrood	-	-	2,641.2	-	2,641.2	-	-	1,767.1	-	874.1	2,641.2	-	
Replace Beta Attenuation Monitoring Analyzers - Holyrood	-	-	160.9	-	160.9	-	-	133.2	-	-	133.2	(27.7)	
Upgrade Forced Draft Fan Ductwork Unit 2 - Holyrood	-	-	928.6	-	928.6	-	-	102.4	-	826.2	928.6	-	
Upgrade Stack Breaching Unit 1 - Holyrood	-	-	1,522.3	-	1,522.3	-	-	1,059.5	-	-	1,059.5	(462.8)	4
Upgrade Stack Breaching Unit 2 - Holyrood	-	-	1,505.1	-	1,505.1	-	-	1,123.2	-	-	1,123.2	(381.9)	5
Replace Fuel Oil Heat Tracing - Holyrood	-	-	1,474.3	1,413.9	2,888.2	-	-	783.4	1,413.9	690.9	2,888.2	-	
Rewind Generator Units 1 and 2 - Holyrood[4]	-	-	112.2	-	112.2	-	-	-	-	-	-	(112.2)	6
Purchase Tools and Equipment Less than $50,000	-	-	89.4	-	89.4	-	-	37.4	-		37.4	(52.0)	
2011 Projects													
Upgrade Synchronous Condenser Unit 3 - Holyrood	-	483.5	405.5	-	889.0	-	141.4	784.4	-	-	925.8	36.8	
Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood	-	843.0	-	-	843.0	-	400.4	976.3	-	-	1,376.7	533.7	7
Replace Relay Panels Unit 3 - Holyrood	-	277.1	553.6	-	830.7	-	134.2	121.5	-	1,449.4	1,705.1	874.4	8
Upgrade Electrical Equipment - Holyrood	-	188.0	206.3	284.5	678.8	-	179.6	41.9	212.1	(11.9)	421.7	(257.1)	9
Upgrade Hydrogen System - Holyrood	-	1,191.9	800.4	-	1,992.3	-	270.5	1,194.5	-	527.3	1,992.3	-	
Replace Steam Seal Regulator Unit 2 - Holyrood	-	175.0	438.4	-	613.4	-	51.6	761.6	-	-	813.2	199.8	10
2010 Projects													
Replace Diesel Fire Pump - Holyrood	111.9	195.4	-	-	307.3	27.9	149.9	208.1	-	-	385.9	78.6	
Replace Pumphouse Motor Control Centres - Holyrood	50.2	998.6	-	-	1,048.8	99.5	1,070.2	285.7	-	62.2	1,517.6	468.8	11
Replace Programmable Logic Controllers - Holyrood[5]	1,357.5	872.5	748.0	-	2,978.0	1,357.5	877.2	659.8	-	-	2,894.5	(83.5)	
Replace Steam Seal Regulator Unit 1 - Holyrood	334.7	213.7	-	-	548.4	16.1	305.2	557.5	-	-	878.8	330.4	12
Total Thermal Plant	1,854.3	5,438.7	11,586.2	1,698.4	20,577.6	1,501.0	3,580.2	10,597.5	1,626.0	4,418.2	21,722.9	1,145.3	

Total 2009
total 2008

[4] The total budget was $11,901.2. Removed future years since project is cancelled.

[5] Original budget was $2,856.7 (2010 - $1,207.9, 2011 - $747.1, 2012 - $901.7) Approved by Order No. P.U. 1 (2010). The revised Budget was approved by Order No. P.U. 2 (2012).

2012 Capital Expenditures By Category
($000)

Gas Turbines	Capital Budget				Actual Expenditure and Forecast						
	2010	2011	2012	Total	2010	2011	2012	Carryovers to 2013	Total	Variance	Notes
2010 Projects											
Upgrade Glycol Systems - Stephenville	261.3	298.9	-	560.2	3.3	517.9	113.2	543.0	1,177.4	617.2	13
Upgrade Gas Turbine Plant Life Extension - Hardwoods[6]	704.5	1,009.8	4,280.4	5,994.7	704.5	1,168.9	505.7	3,743.6	6,122.7	128.0	
Total Gas Turbines	965.8	1,308.7	4,280.4	6,554.9	707.8	1,686.8	618.9	4,286.6	7,300.1	745.2	

[6] Original budget was $5,994.7 (2010 - $1,304.5, 2011 - $1,323.6, 2012 - $3,366.6) Approved by Order No. P.U. 1 (2010). The revised Budget was approved by Order No. P.U.

2012 Capital Expenditures By Category
($000)

Terminal Stations	Capital Budget						Actual Expenditure and Forecast								
	2009	2010	2011	2012	2013 and Beyond	Total	2009	2010	2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects															
Upgrade Circuit Breakers - Various Sites	-	-	-	1,677.3	-	1,677.3	-	-	-	1,287.9	-	-	1,287.9	(389.4)	14
Replace Surge Arrestors - Various Sites	-	-	-	75.7	-	75.7	-	-	-	69.4	-	-	69.4	(6.3)	
Replace Instrument Transformers - Various Sites	-	-	-	452.4	-	452.4	-	-	-	318.6	-	-	318.6	(133.8)	15
Upgrade Power Transformers - Various Sites	-	-	-	1,246.3	-	1,246.3	-	-	-	1,406.6	-	-	1,406.6	160.3	16
Replace Disconnects - Various Sites	-	-	-	351.8	-	351.8	-	-	-	319.2	-	-	319.2	(32.6)	
Replace Compressed Air Piping and Install Dew Point Monitor - Buchans	-	-	-	28.4	278.3	306.8	-	-	-	-	278.3	28.5	306.8	-	
Replace Insulators - Various Sites	-	-	-	411.6	-	411.6	-	-	-	104.2			104.2	(307.4)	17
2011 Projects															
Perform Grounding Upgrades - Various Sites	-	-	321.2	324.0	1,011.5	1,656.7	-	-	287.6	240.7	1,011.5	116.9	1,656.7	-	
Replace Compressed Air System - Bay d'Espoir	-	-	83.9	563.6	-	647.5	-	-	83.7	1,084.2	-	136.9	1,304.8	657.3	18
Replace Digital Fault Recorder - Bay d'Espoir	-	-	168.6	-	-	168.6	-	-	69.1	74.6	-	-	143.7	(24.9)	
Replace 230 kV Circuit Breaker - Sunnyside	-	-	41.3	590.1	-	631.4	-	-	7.3	638.8	-	-	646.1	14.7	
Install Alternate Station Services - Stony Brook and Massey Drive	-	-	86.0	109.2	-	195.2	-	-	5.5	155.7	-	34.0	195.2	-	
Replace Compressor, Dryer and Air Piping Header System - Corner Brook Frequency Converter Station	-	-	280.2	-	-	280.2	-	-	141.8	139.2	-	122.1	403.1	122.9	19
Upgrade Substation - Wabush	-	-	459.3	626.4	-	1,085.7	-	-	13.8	907.6	-	362.6	1,284.0	198.3	20
Replace 69 kV SF6 Breakers - St. Anthony Airport	-	-	489.9	290.1	-	779.9	-	-	480.5	276.4	-	-	756.9	(23.0)	
Upgrade Station Reliability and Safety - Rocky Harbour	-	-	434.8	360.1	-	794.9	-	-	5.2	1,180.8	-	-	1,186.0	391.1	21
Replace Breaker, Structures and Disconnects - Hawke's Bay	-	-	687.4	-	-	687.4	-	-	331.2	260.5	-	-	591.7	(95.7)	
2010 Projects															
Voisey's Bay Nickel - Long Harbour Power Supply	-	122.9	5,505.3	9,169.8	-	14,798.0	-	1,332.0	9,854.0	2,187.4	-	-	13,373.4	(1,424.6)	
Cost Recovery - Vale Inco	-	(122.9)	(5,505.3)	(9,169.8)	-	(14,798.0)	-	(1,332.0)	(9,854.0)	(2,187.4)	-	-	(13,373.4)	1,424.6	
2009 Projects															
Upgrade Terminal Stations to 25 kV - Labrador City[7]	100.8	1,693.5	7,105.7	3,750.0	-	12,650.0	291.8	1,693.5	6,022.7	7,320.1	-	(223.3)	15,104.8	2,454.8	22
Total Terminal Stations	100.8	1,693.5	10,158.3	10,857.0	1,289.8	24,099.4	291.8	1,693.5	7,448.4	15,784.5	1,289.8	577.7	27,085.7	2,986.3	

[7] Original budget was $9,990.6 (2009 - $283.2, 2010 - $3,894.8, 2011 - $5,812.6) Approved by Order No. P.U. 36 (2008). The revised Budget was approved by Order No. P.U. 2 (2012).

2012 Capital Expenditures By Category
($000)

Transmission	Capital Budget 2011	Capital Budget 2012	Capital Budget 2013 and Beyond	Capital Budget Total	Actual Expenditure and Forecast 2011	Actual Expenditure and Forecast 2012	Actual Expenditure and Forecast 2013 and Beyond	Actual Expenditure and Forecast Carryovers to 2013	Actual Expenditure and Forecast Total	Variance	Notes
2012 Projects											
Install Ice Monitoring Equipment - Various Sites	-	47.0	-	47.0	-	45.4	-	-	45.4	(1.6)	
Perform Wood Pole Line Management Program - Various Sites	-	2,519.3	-	2,519.3	-	2,562.8	-	-	2,562.8	43.5	
2011 Projects											
Replace Guy Wires TL-215 - Doyles to Grand Bay	288.8	318.0	880.1	1,486.9	447.6	256.0	880.0	(96.7)	1,486.9	-	
Total Transmission	288.8	2,884.3	880.1	4,053.2	447.6	2,864.2	880.0	(96.7)	4,095.1	41.9	

2012 Capital Expenditures By Category
($000)

Distribution	Capital Budget 2010	Capital Budget 2011	Capital Budget 2012	Capital Budget 2013 and Beyond	Capital Budget Total	Actual 2010	Actual 2011	Actual 2012	Actual 2013 and Beyond	Carryovers to 2013	Actual Total	Variance	Notes
2012 Projects													
Replace Recloser Control Panels - Various Sites	-	-	202.3	-	202.3	-	-	113.9	-	-	113.9	(88.4)	
Provide Service Extensions - All Service Areas	-	-	4,172.0	-	4,172.0	-	-	6,031.8	-	-	6,031.8	1,859.8	23
Upgrade Distribution Systems - All Service Areas	-	-	2,508.0	-	2,508.0	-	-	3,134.1	-	-	3,134.1	626.1	24
Upgrade Distribution Lines - Bay d'Espoir, Parsons Pond and Plum Point	-	-	1,385.2	1,110.5	2,495.7	-	-	1,189.1	1,110.5	17.2	2,316.8	(178.9)	
Distribution Systems Additions - Various Sites	-	-	2,172.1	-	2,172.1	-	-	2,115.9	-	-	2,115.9	(56.2)	
2011 Projects													
Replace Substation Infrastructure- Burgeo	-	127.5	368.3	-	495.8	-	6.9	739.0	-	-	745.9	250.1	25
Upgrade Distribution Systems Francois, Rigolet and Happy Valley	-	1,067.7	652.4	-	1,720.1	-	609.8	1,187.3	-	-	1,797.1	77.0	
Install Voltage Regulators - Conne River and L'Anse au loup	-	292.6	-	-	292.6	-	116.1	96.7	-	-	212.8	(79.8)	
2010 Projects													
Voltage Conversion - Labrador City	1,088.9	3,501.2	3,840.7	969.5	9,400.3	1,524.6	2,825.0	4,120.6	969.5	(39.4)	9,400.3	-	
Upgrade L2 Distribution Feeder - Glenburnie	267.3	578.2	2,114.6	596.6	3,556.7	109.9	402.4	1,382.7	596.6	1,065.1	3,556.7	-	
Upgrade Distribution Lines - Roddickton and Makkovik	217.7	1,645.0	-	-	1,862.7	83.4	1,155.5	479.9	-	-	1,718.8	(143.9)	
Total Distribution	1,573.9	7,212.2	17,415.6	2,676.6	28,878.3	1,717.9	5,115.7	20,591.0	2,676.6	1,042.9	31,144.1	2,265.8	

2012 Capital Expenditures By Category
($000)

Generation	Capital Budget					Actual Expenditure and Forecast							
	2010	2011	2012	2013 and Beyond	Total	2010	2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects													
Perform FEED for Diesel Plant Remediation - Various Sites	-	-	110.4	-	110.4	-	-	43.6	-	66.8	110.4	-	
Replace Fuel Storage Tanks - St. Lewis	-	-	465.1	-	465.1	-	-	249.3	-	-	249.3	(215.8)	26
2011 Projects													
Perform Arc Flash Remediation - Various Sites	-	429.5	380.3	1,205.9	2,015.7	-	103.5	91.7	1,205.9	614.6	2,015.7	-	
Replace Mini Hydro Turbine - Roddickton	-	86.8	235.4	-	322.2	-	10.7	221.0	-	246.6	478.3	156.1	27
Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson	-	154.8	-	-	154.8	-	6.6	(6.6)	-	-	-	(154.8)	28
2010 Projects													
Replace Diesel Unit 2001 and Engine 566 - Francois	168.4	450.1	-	-	618.5	11.2	446.9	81.3	-	209.6	749.0	130.5	29
Total Generation	168.4	1,121.2	1,191.2	1,205.9	3,686.7	11.2	567.7	680.3	1,205.9	1,137.6	3,602.7	(84.0)	

2012 Capital Expenditures By Category
($000)

Properties	Capital Budget			Actual Expenditure and Forecast					
	2011	2012	Total	2011	2012	Carryovers to 2013	Total	Variance	Notes
2012 Projects									
Install Fall Protection Equipment - Various Sites	-	199.2	199.2	-	186.5	-	186.5	(12.7)	
Upgrade Mechanical Workshop - St. Anthony	-	87.0	87.0	-	75.3	-	75.3	(11.7)	
Install Waste Oil Storage Tank - L'Anse au Loup	-	81.5	81.5	-	82.7	-	82.7	1.2	
Legal Survey of Primary Distribution Line Right of Ways - Various Sites - 2012	-	197.9	197.9	-	190.4	-	190.4	(7.5)	
2011 Projects									
Legal Survey of Primary Distribution Line Right of Ways - Various Sites - 2011	78.7	-	78.7	4.5	61.5	-	66.0	(12.7)	
Total Properties	78.7	565.6	644.3	4.5	596.4	-	600.9	(43.4)	

2012 Capital Expenditures By Category
($000)

Metering	Capital Budget				Actual Expenditure and Forecast						
	2011	2012	2013 and Beyond	Total	2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Purchase Meters, Equipment and Metering Tanks - Various Sites	-	190.4	-	190.4	-	193.3	-	-	193.3	2.9	
Install Automatic Meter Reading - Plum Point and Bear Cove	-	379.6	288.0	667.6	-	390.8	288.0	(19.3)	659.5	(8.1)	
2011 Projects											
Install Automatic Meter Reading - Labrador City[8]	292.2	58.3	-	350.5	228.0	120.8	-	-	348.8	(1.7)	
Total Metering	292.2	628.3	288.0	1,208.5	228.0	704.9	288.0	(19.3)	1,201.6	(6.9)	

[8] Original budget was $538.9 (2011 - $451.2, 2012 - $87.7) Approved by Order No. P.U. 38 (2010) to install automatic meter reading for Labrador City and Port aux Chois. The Port aux Choix portion of the project was cancelled. The revised Budget was approved by Order No. P.U. 2 (2012).

2012 Capital Expenditures By Category
($000)

Tools and Equipment	Capital Budget				Actual Expenditure and Forecast						
	2011	2012	2013 and Beyond	Total	2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
<u>2012 Projects</u>											
Replace Off Road Track Vehicles - Flowers Cove and Cow Head	-	482.5	395.6	878.1	-	-	395.6	482.5	878.1	-	
Replace Light Duty Mobile Equipment - Various Sites	-	400.6	-	400.6	-	413.1	-	-	413.1	12.5	
Replace Excavator - L'Anse au Loup	-	120.0	-	120.0	-	79.2	-	-	79.2	(40.8)	
Tools and Equipment Less than $50,000	-	406.3	-	406.3	-	360.1	-	18.3	378.4	(27.9)	
<u>2011 Projects</u>											
Replace Off Road Track Vehicles - Bishop's Falls and Fogo	494.3	609.4	-	1,103.7	403.5	426.5	-	-	830.0	(273.7)	30
Replace Light Duty Mobile Equipment - Various Sites	757.0	-	-	757.0	582.5	55.6	-	-	638.1	(118.9)	31
Total Tools and Equipment	1,251.3	2,018.8	395.6	3,665.7	986.0	1,334.5	395.6	500.8	3,216.9	(448.8)	

2012 Capital Expenditures By Category
($000)

Information Systems	Capital Budget					Actual Expenditure and Forecast							
	2010	2011	2012	2013 and Beyond	Total	2010	2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
<u>2012 Projects</u>													
Perform Minor Application Enhancements - Hydro Place	-	-	123.4	-	123.4	-	-	113.3	-	-	113.3	(10.1)	
Cost Recoveries	-	-	(41.9)	-	(41.9)	-	-	(38.5)	-	-	(38.5)	3.4	
Implement Work Protection Safety Code Application - Hydro Place	-	-	115.6	-	115.6	-	-	114.2	-	-	114.2	(1.4)	
Upgrade JD Edwards - Hydro Place	-	-	284.0	587.6	871.6	-	-	518.3	587.6	(234.3)	871.6	-	
Cost Recoveries	-	-	(96.6)	(199.8)	(296.3)	-	-	(176.2)	(199.8)	79.7	(296.3)	-	
Upgrade Energy Management System - Hydro Place	-	-	117.8	-	117.8	-	-	107.0	-	-	107.0	(10.8)	
Upgrade Microsoft Project - Hydro Place	-	-	91.3	-	91.3	-	-	91.3	-	-	91.3	-	
Cost Recoveries	-	-	(31.0)	-	(31.0)	-	-	(31.0)	-	-	(31.0)	-	
Upgrade Creditron System - Hydro Place	-	-	37.5	-	37.5	-	-	39.0	-	-	39.0	1.5	
Replace Personal Computers - Various Sites	-	-	490.6	-	490.6	-	-	499.0	-	-	499.0	8.4	
Replace Peripheral Infrastructure - Various Sites	-	-	327.5	-	327.5	-	-	328.5	-	-	328.5	1.0	
Upgrade Enterprise Storage Capacity - Hydro Place	-	-	306.3	-	306.3	-	-	298.1	-	-	298.1	(8.2)	
Cost Recoveries	-	-	(104.1)	-	(104.1)	-	-	(101.3)	-	-	(101.3)	2.8	
Upgrade Server Technology Program - Hydro Place	-	-	202.6	-	202.6	-	-	201.7	-	-	201.7	(0.9)	
Cost Recoveries	-	-	(30.9)	-	(30.9)	-	-	(30.4)	-	-	(30.4)	0.5	
Upgrade Computer Room - Hydro Place	-	-	122.0	-	122.0	-	-	9.3	-	112.7	122.0	-	
Cost Recoveries	-	-	(41.5)	-	(41.5)	-	-	(3.2)	-	(38.3)	(41.5)	-	
<u>2010 Projects</u>													
Corporate Application Environment - Upgrade Microsoft Products	751.4	675.1	678.1	-	2,104.6	563.4	858.1	682.3	-	-	2,103.8	(0.8)	
Cost Recoveries	(225.4)	(202.5)	(203.4)	-	(631.4)	(191.0)	(275.4)	(204.7)	-	-	(671.1)	(39.7)	
Total Information Systems	526.0	472.6	2,347.3	387.8	3,733.7	372.4	582.7	2,416.7	387.8	(80.2)	3,679.4	(54.3)	

2012 Capital Expenditures By Category
($000)

Telecontrol	Capital Budget 2008	2009	2010	2011	2012	Total	Actual Expenditure and Forecast 2008	2009	2010	2011	2012	Carryovers to 2013	Total	Variance	Notes
2012 Projects															
Upgrade Communication Services - Paradise River	-	-	-	-	97.5	97.5	-	-	-	-	80.2	-	80.2	(17.3)	
Replace Radomes - Various Sites	-	-	-	-	172.0	172.0	-	-	-	-	157.4	-	157.4	(14.6)	
Replace Battery Banks and Chargers - Various Sites	-	-	-	-	880.8	880.8	-	-	-	-	662.1	-	662.1	(218.7)	32
Replace Network Communications Equipment - Various Sites	-	-	-	-	521.6	521.6	-	-	-	-	448.8	-	448.8	(72.8)	
Replace Telephone Systems - Port Saunders and Whitbourne	-	-	-	-	199.3	199.3	-	-	-	-	173.1		173.1	(26.2)	
Upgrade Site Facilities - Various Sites	-	-	-	-	46.5	46.5	-	-	-	-	41.4	-	41.4	(5.1)	
Purchase Tools and Equipment Less than $50,000	-	-	-	-	85.3	85.3	-	-	-	-	45.2		45.2	(40.1)	
2011 Projects															
Replace MDR 6000 Microwave Radio (West) - Various Sites	-	-	-	72.0	683.3	755.3	-	-	-	26.4	603.8	-	630.2	(125.1)	33
2008 Projects															
Public Address System - Holyrood	96.3	1,182.2	-	-	-	1,278.5	2.8	119.1	539.9	1,161.7	48.5	-	1,872.1	593.6	34
Total Telecontrol	96.3	1,182.2	-	72.0	2,686.3	4,036.8	2.8	119.1	539.9	1,188.1	2,260.5	-	4,110.5	73.7	

2012 Capital Expenditures By Category
($000)

Transportation	Capital Budget 2011	2012	2013 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Replace Vehicles and Aerial Devices (2012-2013) - Various Sites	-	1,711.4	1,218.8	2,930.2	-	1,594.1	1,218.8	117.3	2,930.2	-	
2011 Projects											
Replace Vehicles and Aerial Devices (2011-2012) - Various Sites	2,350.5	638.9	-	2,989.4	1,254.4	756.2	-	-	2,010.6	(978.8)	35
Total Transportation	2,350.5	2,350.3	1,218.8	5,919.6	1,254.4	2,350.3	1,218.8	117.3	4,940.8	(978.8)	

Administration	Capital Budget 2011	2012	2013 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Remove Safety Hazards - Various Sites	-	249.1	-	249.1	-	141.4	-	-	141.4	(107.7)	36
Purchase Tools and Equipment Less than $50,000	-	131.6	-	131.6	-	70.7	-	-	70.7	(60.9)	
Total Administation	-	380.7	-	380.7	-	212.1	-	-	212.1	(168.6)	

Major Overhauls and Inspections	Capital Budget 2011	2012	2013 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Condition Assessment and Life Extension Phase 2 - Holyrood	-	1,215.7	-	1,215.7	-	565.2	-	650.5	1,215.7	-	
Overhaul Turbine Unit 1 - Holyrood	-	4,193.1	-	4,193.1	-	4,007.5	-	-	4,007.5	(185.6)	
Overhaul Diesel Units - Various Sites	-	974.1	-	974.1	-	1,605.2	-	-	1,605.2	631.1	37
Overhaul Turbine/Generator Units - Granite Canal and Upper Salmon	-	456.6	-	456.6	-	384.1	-	-	384.1	(72.5)	
Total Major Overhauls and Inspections	-	6,839.5	-	6,839.5	-	6,562.0	-	650.5	7,212.5	373.0	

2012 Capital Expenditures By Category
($000)

Contingency Fund	Capital Budget 2011	2012	2013 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Black Tickle Plant Rehabiliation	-	1,000.0	-	1,000.0		1,374.4	-	-	1,374.4	374.4	38
Total Contingency Fund	-	1,000.0	-	1,000.0		1,374.4	-	-	1,374.4	374.4	

Unbudgeted Projects Approved by PUB	Capital Budget 2011	2012	2013 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Upgrade Access Road - Cat Arm	-	492.1	-	492.1	-	233.6	-	-	233.6	(258.5)	39
Upgrade Dam - Cat Arm	-	3,154.9	-	3,154.9	-	1,188.5	-	-	1,188.5	(1,966.4)	40
Increase Generation - Mary's Harbour	-	321.4	1,295.0	1,616.4	-	51.0	1,295.0	270.4	1,616.4	-	
Gas Turbine Alternator Rewind - Stephenville	-	2,940.5	2,252.1	5,192.6	-	1,758.0	2,252.1	1,387.4	5,397.5	204.9	
Hydro Place Penthouse Roof Replacement	-	10.2	189.5	199.7	-	-	189.5	10.2	199.7	-	
Total Unbudgeted Projects Approved by PUB	-	6,919.1	3,736.6	10,655.7		3,231.1	3,736.6	1,668.0	8,635.7	(2,020.0)	

Projects Less than $50,000 Approved by Hydro	Capital Budget 2011	2012	2013 and Beyond	Total	Actual Expenditure and Forecast 2011	2012	2013 and Beyond	Carryovers to 2013	Total	Variance	Notes
2012 Projects											
Purchase Diesel Plant Property - English Harbour West	-	50.0	-	50.0	-	49.7	-	-	49.7	(0.3)	
Replace Wavetrap - Sunnyside	-	14.6	-	14.6	-	10.8	-	-	10.8	(3.8)	
Gate Hoist Rehabilitation - Burnt Dam	-	35.7	-	35.7	-	32.0	-	-	32.0	(3.7)	
Land Purchase - Happy Valley-Goose Bay	-	46.2	-	46.2	-	46.2	-	-	46.2	-	
2011 Projects											
Replace Engine 2062 - Grey River	23.0	26.2	-	49.2	-	22.3	-	-	22.3	(26.9)	
Total Projects Less than $50,000 Approved by Hydro	23.0	172.7	-	195.7	-	161.0	-	-	161.0	(34.7)	

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

1. Upgrade Burnt Dam Spillway - Bay d'Espoir

Budget: $523.8 Total: $790.1 Variance: $266.3

This is a one-year project which has been carried over into 2013. There is a budget increase due to the difference between the budgeted and actual tendered costs for the disassembly and inspection contract and the consultant design cost. The project has been carried over into 2013 as a result of having to reapply for a project to refurbish the stop logs to allow for the approved inspections to be completed safely.

2. Upgrade Burnt Dam Spillway Structure- Bay d'Espoir

Budget: $257.9 Total: $453.8 Variance: $195.9

This is a one-year project initiated in 2011 that was carried over into 2012. The budget increase is due to the use of external resources to design and oversee project execution. In addition, contract pricing obtained through competitive bid process was higher than estimated. The internal review and approval of the budget variances resulted in delayed tender award for the execution of the work. This project will be completed in 2013.

3. Upgrade Intake Gate Controls - Bay d'Espoir

Budget: $820.3 Total: $1,221.8 Variance: $401.5

This is a two-year project initiated in 2011. The scope of this project remains unchanged however due to the timing and the complexity of the work resulted in increased labour costs. The work planned for 2011 was completed; however the work to be completed in 2012 has been delayed until at least 2013 due to system constraints which prevented a suitable outage window to complete the work.

4. Upgrade Stack Breaching Unit 1 - Holyrood

Budget: $1,522.3 Total: $1,059.5 Variance: ($462.8)

This is a one-year project completed in 2012. As a result of tendering the contract work for both Unit 1 and Unit 2 Stack Breaching projects together, a savings was realized. In addition, no project contingency funds were used.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

5. **Upgrade Stack Breaching Unit 2 - Holyrood**

Budget: $1,505.1 Total: $1,123.2 Variance: ($381.9)

This is a one-year project completed in 2012. As a result of tendering the contract work for both Unit 1 and Unit 2 Stack Breaching projects together, a savings was realized. In addition, no project contingency funds were used.

6. **Rewind Generator Units 1 and 2 - Holyrood**

Budget: $112.2 Total: $0 Variance: ($112.2)

This project has been cancelled. With the updated long-term plan for Holyrood, Units 1 and 2 will no longer be required to operate as synchronous condensers to 2041. A 2012 review of the Unit 1 and 2 generator stator windings concluded that the windings are expected to operate reliably up to 2017 and do not require replacement.

7. **Upgrade Forced Draft Fan Ductwork Unit 1 - Holyrood**

Budget: $843.0 Total: $1,376.7 Variance: $533.7

This was a one-year project to be completed in 2011 which was carried over into 2012. The increased project cost is a result of higher than estimated pricing for the installation contract.

A risk-based cost benefit analysis completed in September 2011 clearly demonstrated that it was prudent to complete the project at the higher cost, based upon energy savings from a reduced load on the forced draft fans and mitigation of the risk of failure which could result in an unplanned outage of Unit 1.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

8. <u>Replace Relay Panels Unit 3 - Holyrood</u>

Budget: $830.7 Total: $1,705.1 Variance: $874.4

This is a two-year project initiated in 2011. Additional engineering and plant resource time was required in 2012 in order to complete the field investigations to bring the existing Unit 3 relay panel control schematics and termination schedules up to 'as-built' status. As these 'as-built' drawings form the basis of the control panel design, the contract for the design and supply of the new control panel will now be executed in 2013. As a result, the project will be carried over into 2013.

The installation time for the control panel will be longer than anticipated due to the greater than originally estimated number of cables and conductors entering the Unit 3 relay panel. Cables must be properly labeled and organized for successful commissioning. Also, the commissioning period will be longer in 2013 because in addition to the new control processor being added to the project, the existing Unit 3 control processors will have to be partially re-commissioned. These factors have increased the outage from eight to 12 weeks and have increased both labour and construction costs.

9. <u>Upgrade Electrical Equipment - Holyrood</u>

Budget: $678.8 Total: $421.7 Variance: ($257.1)

This is a three-year project initiated in 2011 to replace the circuit protection equipment in six motor control centers (MCCs) located in the Holyrood plant powerhouse and to replace one MCC and items of the electrical switchgear in the Holyrood Gas Turbine building.

The MCC refurbishments planned for 2011 were completed. A portion of this project was to perform electric upgrades to the Holyrood Gas Turbine however, that work has been cancelled as the Gas Turbine is currently not in service. The remaining MCC refurbishments will be completed in 2013.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

10. <u>Replace Steam Seal Regulator Unit 2 - Holyrood</u>

Budget: $613.4 Total: $813.2 Variance: $199.8

This project was a two-year project initiated in 2011 to replace the existing hydraulic steam seal regulator on Unit 2 with two pneumatically operated steam pressure control valves.

During the detailed design phase in 2011, it was determined that the replacement of the pressure safety valve, associated discharge piping and pipe supports would be required in order to provide adequate steam venting for the new steam seal regulator system. This work scope was not included in the original project scope and thus increased the project above the original estimated cost.

11. <u>Replace Pumphouse Motor Control Centres - Holyrood</u>

Budget: $1,048.8 Total: $1,517.6 Variance: $468.8

This is a two-year project initiated in 2010 which was carried over into 2012. The engineering design and construction specification prepared for this budget did not cover all the aspects of work required to complete this project. This resulted in increased costs for labour and for the installation contract. The installation and commissioning of the Units 1 and 2 pumphouse motor control centers (MCCs) will now be completed during the scheduled 2013 unit outages.

12. <u>Replace Steam Seal Regulator Unit 1 - Holyrood</u>

Budget: $548.4 Total: $878.8 Variance: $330.4

This is a two-year project initiated in 2010 and then carried over into 2012 due to the inability of the contractor to complete the work within the planned outage window. The total cost of this project has increased due to an increase in contract and labour costs over the budgeted amounts, as the contract was retendered which extended the project schedule.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

13. <u>Upgrade Glycol Systems - Stephenville</u>

Budget: $560.1 Total: $1,177.4 Variance: $617.3

This is a two-year project initiated in 2010 which was carried over into 2012 due to multiple tenders being required to secure suitable bids. While the construction work was planned to be completed in the spring of 2012, it was postponed as a result of the alternator failure at the Stephenville Gas Turbine. The glycol system upgrade project cannot be commissioned and placed in service until the alternator refurbishment work is completed. The cost of this project has increased due to an increase in engineering, labour and material costs and also as a result of project delays.

14. <u>Upgrade Circuit Breakers - Various Sites</u>

Budget: $1,677.3 Total: $1,287.9 Variance: ($389.4)

This 2012 project was to replace four breakers at the Bottom Brook, Doyles, Hardwoods and Massey Drive Terminal Stations. Due to the unavailability of a suitable outage window, the breaker replacement in Hardwoods could not be completed. The replacement of the Hardwoods breaker will now be completed under a future circuit breaker project.

15. <u>Replace Instrument Transformers - Various Sites</u>

Budget: $452.4 Total: $318.6 Variance: ($133.8)

This is a one-year project completed in 2012. The final project cost was lower than budgeted as a result of delayed delivery of instrument transformers and the unavailability of suitable outage windows for some installations. The replacement of these instrument transformers will be completed under a future instrument transformer project.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

16. Upgrade Power Transformers - Various Sites

Budget: $1,246.3 Total: $1,406.6 Variance: $160.3

In addition to the planned 2012 power transformer upgrades, there was an additional transformer upgrade required to ensure the winter load in Happy Valley/Goose Bay resulting in increased project costs.

17. Replace Insulators - Various Sites

Budget: $411.6 Total: $104.2 Variance: ($307.4)

The insulators ordered for 2012 were not received due to issues experienced at the manufacturing plant in Japan. These insulators are committed for delivery in 2013 and will be installed as part of the 2013 capital program.

18. Replace Compressed Air System - Bay d'Espoir

Budget: $647.5 Total: $1,304.8 Variance: $657.3

This is a two-year project initiated in 2011 which has been carried into 2013. The project is approximately 90% complete; however it was not completed on time due to limited breaker outage availability. The increase in project cost is primarily due to tendered bids for construction that were higher than estimated.

19. Replace Compressor, Dryer, and Air Piping Header System - Corner Brook Frequency Converter Station

Budget: $280.2 Total: $403.1 Variance: $122.9

This project was originally planned to be completed in 2011 and was carried into 2012 due to difficulties in obtaining bids for the work in 2011. The contract work for this project was combined with other project work and tendered a second time which resulted in contract pricing which was higher than estimated.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

19. Replace Compressor, Dryer, and Air Piping Header System - Corner Brook Frequency Converter Station (cont'd.)

In addition to increased contract pricing, design changes were required in the course of the project which resulted in increased engineering and material costs. The material required to complete the design changes could not be delivered in 2012, and as a result, this project has been carried into 2013. The project is 90% complete.

20. Upgrade Substation - Wabush

Budget: $1,085.7 **Total: $1,284.0** **Variance: $198.3**

This is a two-year project initiated in 2011 which has been carried into 2013. During the detail design phase, additional required design work was identified related to the grounding and yard upgrade work which affected both the project budget and schedule. The project scope includes grounding upgrades within the substation that, for safety reasons, could not be completed late in the year. These upgrades will now be completed during the construction season in the summer of 2013. The overall budget for this project has increased due to higher than anticipated contract pricing.

21. Upgrade Station Reliability and Safety - Rocky Harbour

Budget: $794.9 **Total: $1,186.0** **Variance: $391.1**

This is a two-year project completed in 2012. During the detail design phase, it was realized that some work necessary to complete the project had not been identified at the budget stage which resulted in higher than budgeted contract costs.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

22. <u>Upgrade Terminal Stations to 25 kV - Labrador City</u>

Budget: $12,650 **Total: $15,104.8** **Variance: $2,454.8**

The original budget was submitted as a three-year project to construct two new 46/25 kV terminal stations. Each station will have two new 46/25 kV, 15/20/25 MVA power transformers, new 46 kV and 25 kV electrical equipment and new control buildings. The budget for this project was previously increased to $12,650,000 and the 2012 budget has been adjusted to incorporate the change in the overall budget.

This project was estimated in 2008 based on market conditions at the time and using standard escalation indices for future year expenditures. The market conditions realized in Labrador West during the project execution phase have been a-typical, driven by strong economic activity in the area. The outcome is an escalation beyond Hydro’s anticipation in construction contracts, materials and labour.

An additional $2.4 million is required to complete this project as a result of contract pricing increases above estimated amounts for contracts to project completion, use of consultants for design review, commissioning cost estimates which were low compared to the actual cost to commission the specific type and size of stations involved, and additional material costs. All contracts have now been awarded and construction is complete. One of the two terminal stations is in service as of December 2012, and commissioning of the remaining station is ongoing.

This project has been carried over into 2013 as a result of delays in building delivery which have resulted in a delay in completion of the station commissioning work.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

23. <u>Provide Service Extensions - All Service Areas</u>
Budget: $4,172.0 Total: $6,031.8 Variance: $1,859.8

This is an annual allotment based on past expenditures to provide service connections to new customers. The budget and actual expenditures by area is shown in the table below.

	Budget ($000)	Actual ($000)
Central	1,200.0	1,231.3
Northern	1,267.0	1,727.7
Labrador	1,705.0	3,072.8
Total	4,172.0	6,031.8

The Labrador Interconnected system has new subdivisions and line extensions under development that are driving cost increases. Examples are the construction of two new subdivisions Tibett & Brett and Osprey; the extension and rerouting of poles on Hamilton River Road; and as well, the line extensions on Northwest River and Sheshatshiu. In addition, there are developments such as an apartment building, office building, sewer treatment plant and other business developments.

The northern region has also had greater than normal expenditures for service extensions driven by new subdivisions in St. Anthony and Port Saunders, as well as other commercial developments such as a stadium, school, cabin development and health center.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

24. **Upgrade Distribution System - All Service Areas**

Budget: $2,508.0 **Total: $3,134.1** **Variance: $626.1**

The budget for distribution upgrades is based on a five-year average. The budget and expenditure by area is shown in the table below.

	Budget ($000)	Actual ($000)
Central	993.0	1,854.2
Northern	1,089.0	1,010.2
Labrador	426.0	269.7
Total	2,508.0	3,134.1

The increase in costs compared to budget is due to a transformer failure in Paradise River, a larger than normal replacement of voltage regulators, porcelain cut-outs and transformers as well as the replacement of Hendrix Insulators on Fogo Island.

25. **Replace Substation Infrastructure - Burgeo**

Budget: $495.8 **Total: $745.9** **Variance: $250.1**

This is a two-year project completed in 2012. The increase in project cost is due to tendered contract pricing which was higher than budgeted.

26. **Replace Fuel Storage Tanks - St. Lewis**

Budget: $465.1 **Total: $249.3** **Variance: ($215.8)**

This is a one-year project completed in 2012. The decrease in project cost is mainly due to contract costs which were lower than budgeted.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

27. Replace Mini Hydro Turbine - Roddickton

Budget: $322.2 Total: $478.3 Variance: $156.1

This is a two-year project initiated in 2011. The increase in project cost compared to budget is due to a scope change to include a generator replacement. The generator rotor shaft failed in 2010. This failure occurred after the project proposal was submitted for approval. A cost-benefit analysis was performed to compare the feasibility of replacing the generator at additional cost under the same project, postponing the work, or cancelling the current project and shutting down the plant. The results of the cost-benefit analysis favoured proceeding with the turbine overhaul and replacement of the generator.

This project has been carried over into 2013 as a result of longer than anticipated lead time for procurement of a replacement generator.

28. Install Sequence of Events Monitor in Diesel Plant - Port Hope Simpson

Budget: $154.8 Total: 0 Variance: ($154.8)

This is a one-year project that was carried over from 2011. Hydro has decided to cancel this project at this time given studies on-going regarding power generation for the area that could affect the requirement for this functionality.

29. Replace Diesel Unit 2001 and Engine 566 - Francois

Budget: $618.5 Total: $749.0 Variance: $130.5

This project is a two-year project initiated in 2010. The replacement genset for Unit 566 was installed and commissioned in 2011, but delivery of the replacement genset for Unit 2001 was delayed. During factory acceptance testing, the unit did not meet the specified vibration limits. Factory troubleshooting of this issue has been on-going with resolution in December 2012. The replacement genset will now be delivered in 2013.

The project cost has increased as a result of increased genset installation costs for Unit 566 and additional engineering costs associated with troubleshooting of engine issues and extension of the project schedule.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

30. Replace Off-Road Track Vehicles - Bishop's Falls and Fogo

Budget: $1,103.7 Total: $830.0 Variance: ($273.7)

Due to new products available in the utility track industry subsequent to the budget approval, Hydro was able to obtain more versatile units and achieve savings on the original budget.

31. Replace Light Duty Mobile Equipment - Various Sites

Budget: $757.0 Total: $638.1 Variance: ($118.9)

The project cost is less than budgeted due to changes in the types of heavy duty trailers being purchased resulting in lower cost per unit.

32. Replace Battery Banks and Chargers - Various Sites

Budget: $880.8 Total: $662.1 Variance: ($218.7)

The project cost was lower than budgeted as a result of lower than budgeted labour and material costs. In addition, no project contingency funds were used.

33. Replace MDR 6000 Microwave Radio (West) - Various Sites

Budget: $755.3 Total: $630.2 Variance: ($125.1)

This is a two-year project initiated in 2011. The project cost is lower than budgeted as a result of there being no requirement to use contingency funds.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

34. Public Address System - Holyrood

Budget: $1,278.5 Total: $1,872.1 Variance: $593.6

This project was a two-year project planned to be completed in 2009. Initially, the project was tendered in 2008/2009 and the tender responses received exceeded the budget. As a result, the work was divided into two parts, design/ supply and installation/commissioning and re-tendered. This resulted in an extended project schedule which had the design and supply work completed in 2010 and installation and commissioning work substantially completed in 2011.

Project costs have risen primarily for the following reasons:

- the requirement for On-Site Representatives during construction, arising out of Hydro's Contractor Safety Management program, were not included in the original budget as this requirement did not exist when the budget was prepared;
- site specific requirements (rigid conduit, additional devices for infill, higher than estimated cable quantities) have resulted in increased material costs;
- contract costs for installation were higher than originally estimated; and,
- extension of the project schedule which resulted in additional project management, supervision and overhead costs.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

35. <u>Replace Vehicles and Aerial Devices 2011 - Various Sites</u>

Budget: $2,989.4 Total: $2,010.6 Variance: ($978.8)

This is a two-year project to replace 25 light-duty vehicles and five heavy-duty work vehicles.

There are two factors contributing to the favourable variance. Firstly, there was a saving of $289,000 as a result of a downturn in the national economy, which resulted in better pricing on vehicles and reduced escalation costs. Secondly, the 2010 project was intended to be submitted as a two-year project due to the difficulty in ordering and receiving all the equipment in one calendar year. Inadvertently, only the first year of this project was submitted and approved in 2010 and a change order was completed for the portion of equipment ordered in 2010 and received in 2011. The 2011 multi-year project had already included the $700,000 for the equipment being received in 2011 resulting in a second change to correct the duplication.

36. <u>Remove Safety Hazards - Various Sites</u>

Budget: $249.1 Total: $141.4 Variance: ($107.7)

This is a one-year project completed in 2012. This project is based on the requirement to ensure adequate capital funding is available to quickly address capital related safety hazards as they are identified. Therefore, it is only utilized to the extent that specific hazards are identified. The hazards identified in 2012 are itemized in the 2012 Remove Safety Hazards table, p. 34-35.

37. <u>Overhaul Diesel Units - Various Sites</u>

Budget: $974.1 Total: $1,605.2 Variance: $631.1

The project planned for completion of 12 overhauls in 2012. Hydro also completed eight unplanned overhauls in 2012 due to engine failures, resulting in additional costs. Hydro is reviewing its work processes on diesel units to make recommendations to potentially minimize future diesel failures.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2012
(Greater than $100,000 and 10% Variance from Budget)
($000)

38. Black Tickle Plant Rehabilitation

Contingency Fund: $1,000.0 Total: $1,374.4 Variance: $374.4

The variance between the budgeted cost of $2.6 million and actual expenditures for this project is due primarily to lower than anticipated engineering and internal labour costs. There was less engineering input required to carry out the work and the operations crew's performance and productivity was higher than anticipated, thus reducing the associated labour costs. Rental costs, including temporary generation and chopper usage, were also less than estimated. In addition, no project contingency funds were used.

39. Upgrade Access Road - Cat Arm

Budget: $492.1 Total: $233.6 Variance: ($258.5)

This is a one-year project completed in 2012. The original budget estimate was based on the construction material having to be trucked from a distant quarry. During project execution, an acceptable source of suitable material was found within a short distance of the work site which resulted in a reduction in transportation and processing costs for construction material.

40. Upgrade Dam - Cat Arm

Budget: $3,154.9 Total: $1,188.5 Variance: ($1,966.4)

This is a one-year project completed in 2012. The project cost is lower than budgeted primarily as a result of tendered contract costs which were lower than estimated. The savings on the contract cost also resulted in lower costs for internal labour, equipment rentals and travel costs. In addition, no project contingency funds were used.

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2003 - 2012
AS AT DECEMBER 31
($000)

Table 1: CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2003 – 2012

Capital Budgets/Expenditures 2003 - 2012

Year	Budget	Actual Expenditures	Variance	Percentage Variance
2003	36,122	32,506	3,616	10.0%
2004	31,435	27,984	3,451	11.0%
2005	47,760	33,952	13,808	28.9%
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%
2009	61,544	54,152	7,392	12.0%
2010	63,297	55,553	7,744	12.2%
2011	67,454	63,116	4,338	6.4%
2012	93,840	77,252	16,588	17.7%

In 2012, Hydro delivered the highest Board approved dollar value capital program execution in recent history. During 2011, Hydro commenced execution of its plan to enhance its project delivery capability. A key step in the process included organizational structure changes within both Hydro and Nalcor with the establishment of a Project Execution and Technical Services division that has lead to improved delivery of and compliance on capital projects. While the reorganization has been helpful, there is still work to be done and Hydro is achieving a balance between project workload and resource allocation in support of project execution. Hydro anticipates continued progress in 2013 and further improvement in project delivery and budget compliance.

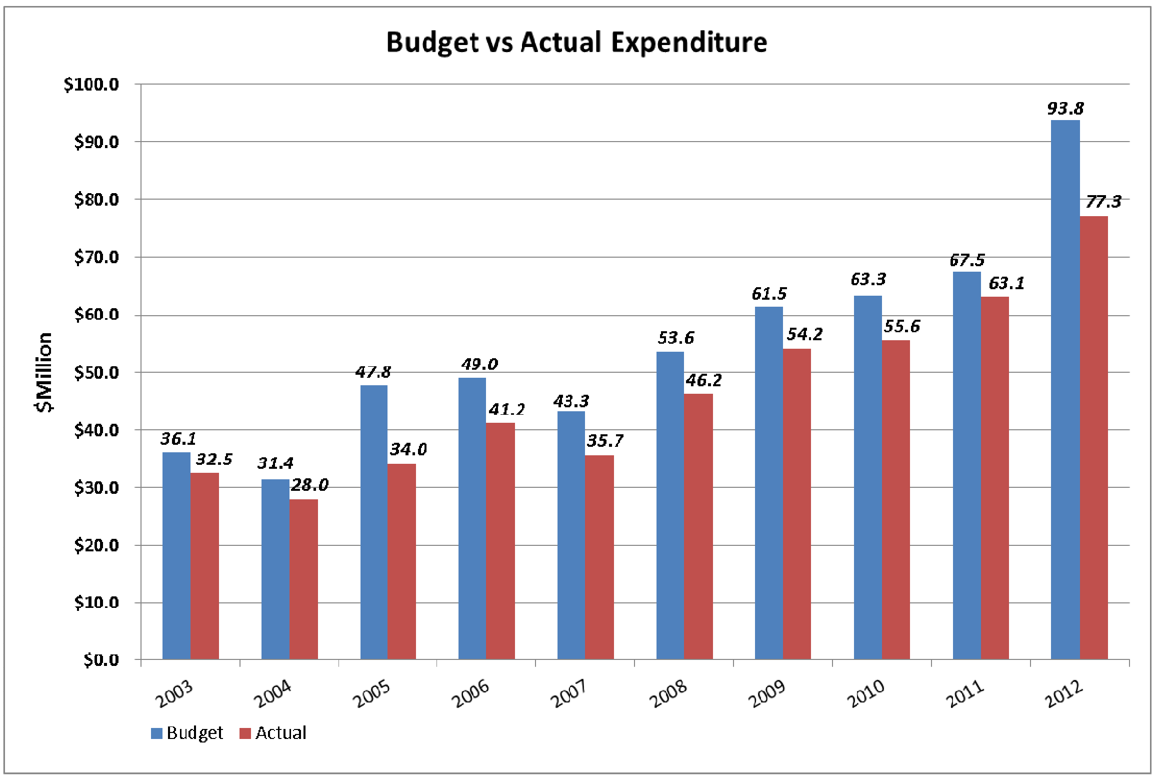
The variances presented in Table 1 are partially due to under-spending as a result of not completing all projects approved each year. It is anticipated that some carryover of projects will occur in most years as there may be unavoidable reasons for delays in project completion, for example, system constraints which are precipitated by changes in hydrology, equipment failures, etc. There are also cost increases and project

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2003 – 2012
AS AT DECEMBER 31
($000)

delays being experienced due to the strong labour market. Hydro is working to address these issues by reviewing its packaging of projects to encourage competitive bids, as well as attracting additional bidders.

The chart below is a graphical representation of the data presented in Table 1. This chart clearly illustrates the upward trend in both budgeted and actual expenditures over the ten year period.

Chart 1: CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2003 – 2012



NEWFOUNDLAND AND LABRADOR HYDRO
2012 REMOVE SAFETY HAZARDS
FOR THE YEAR ENDING DECEMBER 31, 2012
($000)

Total Approved Budget: **$249.1**
Total Expenditure: **$141.4**

Board Order P.U. 38(2010)
As part of Board Order No. P.U. 38(2010) 2011 Capital Budget, the following was included: "Because of the nature of this project the Board would expect to see an explanation in Hydro's annual report on capital expenditures as to each project that was undertaken, setting out the safety hazard that was identified, the location, the steps taken to address the issue and the amount of the expenditure." Please see the following table for projects undertaken in 2012:

Safety Hazards

Project Title/Location	Expenditure	Safety Hazard Identified	Project Scope
Replacement of GP plugs in Bay d'Espoir turbine pits	$19.0	SWOP#2007002794, #2007002795, #2007002797, and #2010003509 In the turbine pit areas of Bay d'Espoir powerhouse 1 there are 60A, 600V plugs installed for use by maintenance personnel. These plugs are undersized (require minimum 100A capacity) and several have grounding issues and have been tagged out. The current practice is to power maintenance equipment in this area from 600V plugs located at the floor above the turbine pit and run cables along the floor to the area where work is being performed. By replacing these plugs with higher capacity, grounded plugs, the maintenance crews will be able to perform work in a safer manner as tripping hazards will be eliminated and the distance to run cables and to de-energize equipment will be greatly reduced.	Replacement of 60A, 600V plugs with 100A, 600V plugs and correction of grounding deficiencies.
Purchase new master log for Bay d'Espoir powerhouse 1	35.7	SWOP #2008001675 The master log is a critical piece of equipment used to safely isolate the draft tubes of the turbines so that work can be completed in this area. In addition to this, Occupational Health and Safety Regulations of Newfoundland (Part XV, section 371) require that "Below-the-Hook Lifting Devices" be designed, constructed, inspected, tested, and maintained in accordance with ASME B30.20-1993.	Purchase of new master log which meets the requirements of Occupational Health and Safety regulations.

NEWFOUNDLAND AND LABRADOR HYDRO
2012 REMOVE SAFETY HAZARDS
FOR THE YEAR ENDING DECEMBER 31, 2012
($000)

Safety Hazards (cont'd.)			
Repair Victoria Control Structure access road Bridges – Bay d'Espoir	19.7	SWOP #2011006545 and #2012000034 On the road to Victoria Control Structure there are three wooden bridges. The bridges were constructed in early 90's. Bridge 1 is about 5.5 km and 2 and 3 are about 6 km from Burnt Dam Spillway accommodations, respectively. There are several areas on the bridges where the decking is cracked or missing. All three bridges require decking and/or runners to be replaced.	Decking and runners were replaced on Bridge 1 and runners were replaced on bridges 2 and 3.
Installation of disconnect switches at Salmon River spillway gates	12.0	SWOP #2011006262 The switch type and rotary type breakers installed in gatehouses 1, 2 and 3 do not provide sufficient worker protection. To operate the breakers, the operator must open the panel cover and directly switch or engage the breakers; a hazardous exposure of personnel to arc flash and other hazards.	Three 100A, 600V disconnect switches were installed at the Salmon River spillway gate houses.
Holyrood overhead door safety enhancements	25.0	SWOP #2011003212, and #2011003235 A high-potential incident involving an overhead door initiated an investigation into the condition and the operational safety of all overhead doors at HTGS. Two separate condition assessments revealed a number of recommended replacements and modifications that should be made in order to improve on the overall safety and reliability of all overhead doors	Installed retractable barricades, erected signage, and replaced mechanical safety edge on two overhead doors.
Stephenville parking lot upgrade	30.0	SWOP #2009003239, #2011001195, and #2011007408 The safety issue identified was that there was not enough room for larger vehicles (especially when towing a trailer) to enter the existing yard and be able to maneuver in the yard safely.	Relocated the fence to increase space in the existing yard and re-positioned the main gate.

Exhibit 11

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REVIEW OF DEMAND BILLING TO NEWFOUNDLAND POWER

NEWFOUNDLAND AND LABRADOR HYDRO

APRIL 2008

Table of Contents

1 EXECUTIVE SUMMARY

A review of Newfoundland and Labrador Hydro's (Hydro) rate structure for the sale of power and energy to Newfoundland Power (NP) has been completed, in accordance with an agreement filed during Hydro's 2006 General Rate Application (GRA). NP, the Consumer Advocate (CA) and Hydro (the Parties) have reached agreement as follows:

- The Parties recommend continuing with the current demand billing approach. While alternate rate designs are available, the current methodology used to calculate billing demand from Hydro to NP reasonably balances Hydro's operating and planning demand requirements with revenue stability and rate practicality considerations. It is judged that at this point in time the costs of implementation and ongoing administration of alternative approaches would exceed potential benefits.

- Significant changes in marginal costs, system configuration, or other considerations may warrant a further review of the rate structure for the sale of power and energy from Hydro to NP. In addition, the CA recommends that the wholesale rate design be revisited if deemed a deterrent to the province's demand management and energy conservation initiatives.

The one outstanding issue to be resolved at a technical conference or through some other regulatory proceeding is:

- Whether NP's curtailable load should be treated in a manner similar to NP's existing generation credits. The CA recommends that this issue be addressed prior to the next winter period (December 1, 2008) because the CA's perspective is that service interruptions are causing undue hardship to Curtailable Service customers with limited system benefit. Hydro and NP recommend that this be reviewed at Hydro's next GRA, as there are Cost of Service implications which may be of interest and subject to intervention by other affected parties, such as the Industrial Customers.

2 INTRODUCTION

This report on the review of demand billing to NP was prepared as a result of the October 20, 2006 Agreement on Cost of Service, Rate Design and Rate Stabilization Plan, filed as part of Hydro's 2006 GRA.

Subparagraph 5c of the October 20, 2006 Agreement states:

> "Following the current GRA, Hydro and Newfoundland Power will enter into discussions towards development of a demand billing approach to reflect the marginal cost of capacity during the winter months. A report documenting the agreement and justifications (or if agreement is not reached, the reasons why agreement was not reached) will be prepared by Hydro and submitted to the Board on or before June 30, 2007."

Reflecting marginal costs in rate designs is consistent with generally accepted rate design principles. The review of the demand billing approach in NP's rate design considers the generally accepted rate design principles agreed to by all Parties in the 2006 Hydro GRA.[1]

This report sets forth the demand billing approaches that were considered in assessing the benefits in changing the existing demand billing approach for the sale of power and energy from Hydro to NP. This review reflects current system attributes. However, rate design is an ongoing process. Changes to the Island Interconnected System resulting in significant changes in system costs may warrant further consideration of the NP wholesale rate design.

[1] The generally accepted principles were provided in Schedule A to the Cost of Service Agreement at Hydro's 2006 GRA.

3 BACKGROUND

3.1 Rate Structure for Sales of Power and Energy from Hydro to NP

Prior to 2005, the wholesale rate from Hydro to NP was on an energy-only basis. In Order No. P.U. 44 (2004), the Board of Commissioners of Public Utilities (the Board) approved changes to the rate structure to include, among other things:

- A two-block energy rate structure, with the tail block priced at the test year marginal cost of production at Holyrood;
- A monthly demand charge, which would be phased in to reflect the test year embedded demand costs; and
- A billing demand, for which the demand charge will apply, to be based on the greater of the highest peak during the winter season or the minimum billing demand.[2] The minimum billing demand is set at 99% of the test year billing demand.

The principal objectives for introducing a demand component in Hydro's rate to NP were:

- To provide an appropriate cost-based price signal;
- To maintain revenue stability; and
- To provide an incentive to control peak on the Island Interconnected System.

[2] Billing demand is calculated based on the highest weather adjusted native load in the months of December, January, February and March, minus the generation credit.

The Board recognized that the results of the marginal cost study, when completed, would provide further information to evaluate the wholesale rate design.[3]

NP has responded to the demand price signal in the following manner:

- Increased participation in its curtailable service option. The number of participants has increased from eight customers during the 2004-2005 winter season to 20 in 2007-2008. This option provides approximately 8 MW of peak load reduction.

- Enabled load curtailments at its own buildings and facilities during peak load. This added approximately 2 MW of peak load reduction.

- Developed procedures and voltage monitoring capabilities to enable expanded voltage control management during peak load periods. The potential load reduction through enabling voltage control is difficult to determine as it is dependant on a number of factors including system voltage conditions at peak and the timing of the peak.

- Reviewed its maintenance and operating practices for its generation plants to improve availability of its generation during winter high load periods.

- Continued and enhanced its customer and company facilities energy efficiency efforts. Energy efficiency programming has generally targeted end uses that would also have an impact on peak demand.

Since the release of Hydro's marginal cost study (see Section 3.2), NP has tempered further development of direct peak management options. The marginal cost study

[3] Board Order No. P.U. 14 (2004), page 136.

found that the marginal cost of capacity is very low suggesting a limited amount of expenditures can be justified solely to reduce system peak at this time.

Since the demand and energy rate came into place, NP's peak billing demand has been below the minimum billing demand, contributing to savings being provided to customers through the purchased power unit variance reserve for the years 2006 and 2007.

3.2 Marginal Costs

In June 2006, Hydro filed a report entitled "Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission" (Marginal Cost Study). Hydro filed a follow-up report in July 2006 entitled "Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design" (Marginal Cost Implications Report).[4] These reports provided the basis for reviewing the efficiency of customer rates on the Island Interconnected System.

The Marginal Cost Implications Report describes the implications of the marginal cost results for Hydro's class revenue allocation and rate structures, and summarizes NERA's recommendations. In the Executive Summary of that report, NERA concluded that:

- There is no marginal cost basis for seasonal or Time of Day (TOD) energy charges;

- The marginal generation and transmission capacity costs would support only small time-differentiated winter demand charges (and no demand charges in non-winter months); and

[4] Both reports were prepared by NERA Economic Consulting (NERA). Copies of the reports were included as Attachments 2 and 3 to the Request for Information PUB 1 NLH, filed at Hydro's 2006 GRA.

- If fuel prices fall significantly below current (2007) forecast levels, net marginal generation capacity costs will be higher, and marginal energy costs will be comparably lower. These situations would call for larger winter demand charges with greater TOD differentiation.

NERA's conclusion for the rate charged by Hydro to NP was that the two-block energy charge, with the tail block set near marginal (Holyrood fuel) cost, is nearly optimal, but the demand charge is above marginal capacity cost and should ideally be time-differentiated and applied only in winter months.[5]

The embedded cost-based (2007 Approved Cost of Service) demand rate to NP by Hydro is significantly above the marginal cost of generation and transmission capacity on the Island Interconnected System. NP's demand charge was reduced from the embedded cost-based $5.64 per kW per month to $4.00 per kW per month, to acknowledge that marginal demand costs are lower than embedded cost-based demand costs as a result of the negotiated settlements at Hydro's 2006 GRA (Negotiated Settlements) and approved in Board Order No. P.U. 8 (2007).

3.3 Wholesale Structures used elsewhere in Canada

It is also important when evaluating demand billing approaches to consider experience elsewhere as the approaches have received significant regulatory scrutiny prior to approval and implementation.

[5] NERA stated: "An alternative would be to keep the energy tail-block price at marginal cost, introduce a time differentiated demand charge at full marginal cost and, again, reconcile to the class revenue requirement by adjusting the price of the first energy block. The resulting demand charges are quite small, but their presence in the rate structure would preserve this element for future years when marginal capacity costs may be higher. The implementation of the time-differentiated demand charges would require only minor changes to the billing system. An appropriate definition of billing demand in this rate structure would be the highest 15-minute demand in the winter season (November – March), with separate calculations for peak and off-peak billing demand. There would be no demand charges applicable in the non-winter months." Source: Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design, July 2006, prepared by NERA for Newfoundland and Labrador Hydro.

Wholesale rate structures in use elsewhere in Canada are presented in Table 1. Of the six utilities reviewed, rate structures include:

- One with an energy-only rate (Yukon Energy Corp.);
- Two with a single highest peak demand billing component (Northwest Territories and Nova Scotia Power);
- One with a monthly peak demand billing component, with no tie in to highest peak (NB Power); and
- Two with a monthly peak demand billing component, with a ratchet tied in to highest peak (Sask Power with a 65% ratchet and BC Hydro with a 75% ratchet).

Table 1

Wholesale Rate Structures in Canada

Utility	Rate Structure
Yukon Energy Corp.	Wholesale primary rate to The Yukon Electrical Company is an energy-only rate.
Northwest Territories Power Corp.	**Rate Schedule 101 Wholesale Primary Service** NUL-Yellowknife is subject to a 100% demand ratchet beginning April 1, 2002. Therefore, billing demand for NUL-Yellowknife shall be the greater of the current month's maximum Demand or the maximum Demand experienced during the 12-month period ending with the current billing month.
Sask Power	**Reseller Rates E31: 25 kV and E32 138 kV incl. service to the Cities of Swift Current and Saskatoon** Billing Demand - The monthly billing demand shall be the monthly Recorded Demand but the billing demand shall not be less than 65% of the maximum billing demand in the preceding 11 months.
NB Power	**Service to Saint John Energy & City of Edmundston: Rate Schedule N-17:** (http://www.nbpower.com/en/customers/policies/RSP_June2007.pdf (page 62 of 77)) The rate is subject to the Wholesale customer signing a contract with NB Power for a period up to at least March 31, 2006. Demand Charge: $12.31 per kW per month Energy Charge: 5.73¢ per kWh for all kWh in the month
BC Hydro	**Wholesale transmission Rate 3808 – Fortis BC** (http://www.bchydro.com/rx_files/policies/policies1459.pdf) Demand for billing purposes is the greatest of: 1. the Total Purchase Capacity for that billing month, plus 1.2 times the Total Excess Capacity for that billing month; or 2. 75% times the sum of the highest Total Purchase Capacity registered in any of the preceding eleven months, plus 1.2 times the highest Total Excess Capacity in any of the preceding 11 months; or 3. 50% of the Total Nominated Capacity, plus 1.2 times the Total Excess Capacity for that billing month.
Nova Scotia Power Inc.	**Municipal Tariff** **http://www.nspower.ca/documents/definitions/External%20Web%20NSPI%20Tariffs%20April%201%202007.pdf** Demand Charge: $9.38/kVA per month, or the actual maximum demand in the previous December, January and February occurring in the previous 11 months. Energy Charge: 5.63 cents/kWh

There does not appear to be any significant regulatory preference for use of billing demand based on the highest annual peak versus highest monthly peaks, or vice versa. The experience of the Parties to this report is that both billing methodologies are in common practice.

None of the jurisdictions included in Table 1 use a time-differentiated billing demand based on periods shorter than a month; i.e., hourly peaks. Hourly billing demands are more common in competitive markets where hourly market prices are based on the bid price of the highest cost generator dispatched (ignoring transmission constraints). When supply is tight, owing to high demands and/or shortage of generation capacity, market prices rise as higher cost generation is dispatched. The difference between the market price and a generator's marginal production cost represents the contribution to the generator's fixed costs. Market prices are established hourly and applied to consumption in the corresponding hour, so capacity is effectively billed on an hourly basis.

3.4 Framework for Current Review

The negotiations during Hydro's 2006 GRA resulted in agreement to consider a demand billing approach to reflect the marginal cost of capacity during the winter months. The Parties that have participated in this review are NP; the CA; and Hydro.

Meetings to discuss demand billing alternatives were held throughout 2007, and the Parties participated in the preparation of this report, which provides the results of this review.

The framework for this review as agreed to by the Parties is as follows:

1. The wholesale rate will recover NP's share of the revenue requirement as determined by the final Cost of Service study.

2. The energy rate structure will continue to be a two-block structure with the second block charge set at a level reflecting the test year production cost at Holyrood.

3. The size of the first-block and the applicable energy charge will collect the remainder of the revenue requirement not forecast to be collected through the demand charge and second block energy charge. The goal will be to ensure that marginal energy is priced at Holyrood production costs.

4. The magnitude of the demand rate is reduced to $4.00/kW per month, as agreed upon during Hydro's 2006 GRA, to reflect the lower marginal cost of capacity relative to that determined in the Cost of Service study.

5. The demand billing approach (i.e., the determination of the monthly peak demand) will reflect the higher marginal cost of capacity in the winter months, meaning the current application of the demand charge to the single highest weather adjusted native load for the winter season will be reconsidered, as necessary.

3.5 Hydro's Planning and Operating Approach

Hydro is responsible for ensuring that there is an adequate amount of electricity production to meet the hourly electricity demand on the Island Interconnected System. Ensuring adequate generation involves long-term planning so there is sufficient capacity available to supply forecasted loads. In the operating timeframe, Hydro dispatches generation to ensure the amount of generation being produced matches the instantaneous demand for electricity on the system.

The long-term planning and operations dispatch is determined on a least-cost basis. To minimize the cost of generation requires cooperation between all the companies that operate generation on the Island Interconnected System. These include Non-Utility Generators, Industrial Customers and NP.

Ensuring least-cost operation is also a major element in the pricing of electricity. An understanding of Hydro's operating and planning approaches provide a basis for conducting an evaluation of the demand billing approach used in Hydro's wholesale rate to NP.

3.5.1 Hydro's Operating Approach

Hydro maintains contractual and operational relationships with NP, the Industrial Customers and Non-Utility Generators to ensure effective overall management of all generation on the Island Interconnected System.

NP owns and operates approximately 95 MW of hydroelectric generation and 51 MW of standby gas turbine and diesel generation. Through cooperation with Hydro in meeting its responsibilities for the provision of least-cost service, the following operating practices exist:

- Upon request by Hydro, NP will maximize its hydroelectric and thermal generation and will exercise load curtailments.
- During the winter season, NP will attempt to maximize its hydroelectric generation during system peak hours.
- NP operates its thermal generation when needed by the system when either NP's or Hydro's transmission is out of service for repairs or maintenance.
- NP dispatches its hydroelectric generation to maximize energy production and minimize more expensive thermal energy production.

It is appropriate that Hydro's wholesale rate to NP reflect this operational relationship.

3.5.2 Hydro's Planning Approach

Hydro has established criteria to ensure a reliable supply of electricity to the total Island Interconnected System. The criteria for generation on the Island Interconnected System are that there should be sufficient generating capacity to:

- supply all of its firm load requirements with firm system capability; and

- satisfy a Loss of Load Hours (LOLH) target of not more than 2.8 hours per year.

The firm load criterion is assessed on the basis of system capability for energy production during an extended period of low precipitation. The analysis of LOLH considers the likelihood that each generating plant may not be available due to events such as planned maintenance or unplanned equipment failures. This criterion is calculated giving appropriate consideration of load, which through agreement with customers, is considered non-firm and can be interrupted when adequate generation is not available.[6] Meeting a certain LOLH criteria effectively determines the amount of reserve capacity that is required to ensure sufficient generation capacity exists to meet customer demand.

The probability that generation plants will not provide sufficient production to supply customer demand is higher during periods of high customer demand. A study completed by Hydro in April 2001 showed that in the months when the load is the highest (i.e., January and February), the likelihood of insufficient capacity is also the highest.[7] Further, the Marginal Cost Study identifies a winter on-peak period when the

[6] Load curtailments through options such as interruptible or curtailable load options for customers can provide a means to avoid the need for new generation by reducing the likelihood of insufficient generation to meet firm load. These options tend to be only available for short periods of time impacting LOLH but not materially impacting firm energy requirements.

[7] In April 2001, Hydro filed *An Analysis to Determine the Relationship Between Load Factor and System Reserve Requirement* with the Board.

load on average is the greatest based on the hours when LOLH is the greatest during the year.[8]

There are effectively two primary means to meet the generation criteria. These are the addition of generation and reduction or changes in load requirements.

Depending on the nature of the generation addition, the impact on the firm system capability will vary. For example, wind generation can be counted on to provide a certain amount of energy in a year; however it cannot be depended upon to produce energy at all times when the system requires it (i.e., when there is no wind). As a result, wind generation can have a greater impact on providing energy to meet the firm load requirement than it may have on providing capacity to meet the LOLH criterion.

Depending on the nature of the load change, the impact on firm load requirements will vary. For example, reducing customer peak demand and energy usage during the summer will help meet the firm load criterion but will have little or no impact on the LOLH.[9]

It is appropriate that Hydro's wholesale rate to NP provide an incentive to manage load and develop customer pricing options that ultimately result in the meeting of the generation planning criteria in an overall economically efficient manner.[10] Through efficient pricing and the promotion of energy conservation, customers can be incented to modify electricity use to reduce the need for costly generation additions to the power

[8] According to the Marginal Cost Study, 83% of the value of capacity is associated with the winter peak period, defined as the months of December through March, weekdays from 7:00 to 12:00 and from 16:00 to 20:00. About 16% of the value of capacity should be assigned to the winter off-peak period, and the remaining 1% should be assigned to the non-winter period. These assignments are based on the relative loss of load hours in each month. Within a month, capacity costs are assigned to hours based on each hour type's relative probability of being the peak hour of the month.
[9] Given most generation is available year round and the relatively low customer demand during the summer months, there is a low probability of there being insufficient capacity during the summer. As a result, load reductions during the summer have very little impact on LOLH.
[10] NP is required through legislation to provide least cost reliable power to its customers. This requires NP to do its part in ensuring the overall system develops and operates in a least cost manner.

system. Since, at this time, Hydro is unable to model LOLH contributions down to the hourly level, the Parties are unable to assess which of the three billing approaches considered in this report would lead to optimal reductions in LOLH.

3.5.3 System Load Characteristics

The overall load on the Island Interconnected System includes a broad mixture of industrial, commercial and residential load. An important characteristic of the load on the Island Interconnected System is the significant amount of electric heat that exists in the residential and commercial sectors and the lack of cooling load required. As a result, the consumption of electricity is highest in the winter and the maximum demand requirements occur during cold snaps when windchill conditions are below -20º C. The maximum demand requirements typically occur during the period between 4:30 pm and 6:30 pm triggered by people returning home from work and the sun setting requiring an increase in lighting load.

NP customers consume approximately 79% of Hydro's annual energy production to supply the Island Interconnected System. During system peak, NP's customers consume about 85% of Hydro's system peak.[11] Due to the effect that extreme winter cold snaps have on customer usage and the limited number of extreme cold snaps that occur, the number of hours where the customer demand is near peak conditions is limited. This is illustrated in Table 2.

Table 2

Newfoundland Power's Frequency of Peak Load Conditions[12]

Demand as % of Peak	# Hours/yr exceeded	# Days/yr exceeded
95%	12	3
90%	42	12
85%	167	35
80%	430	65

[11] Source: Demand and energy allocators from Hydro's 2007 Test Year Cost of Service Study.
[12] Load Shape based on load data from December 2003 to March 2007.

NP requires a large portion of the total electricity requirements on the Island Interconnected System. The nature of the load required by NP is such that peak conditions exist for relatively few times during the year. However, history has shown that peak conditions may occur during any of the months of December through March.

When NP's load peaks, typically the entire system is at maximum load. When peak load conditions exist, the risk of power shortages is relatively high. As a result, the peak demand required by NP has both short and long-term implications for operating and planning the Island Interconnected System. Therefore, providing NP a long-term price signal to manage its peak demand is appropriate given Hydro's generation planning approach.

4 DEMAND BILLING REVIEW

Three billing demand approaches were considered:

- The current demand billing approach based on NP's single highest peak demand in the winter period;
- A demand billing approach based on NP's single highest peak demand in each winter month; and
- A billing demand approach based on NP's demand in each hour of the winter peak period. In effect, the demand charge would be an adder applied to the energy charge in hours corresponding to the winter peak period.

The approaches are evaluated on the basis of their effectiveness in meeting rate design objectives. The primary rate design objectives include fairness, efficiency and the effectiveness in yielding the revenue allocated to NP in the Cost of Service study. There are also a number of secondary design objectives such as simplicity, ease of understanding, and administrative effectiveness.

4.1 Current Demand Billing Approach: Single Highest Annual Peak

4.1.1 Description

Under the current rate structure, NP's annual demand charges are billed based on its highest demand (metered in 15-minute intervals) in the months of December through March (Native Peak). The billing demand equals the Native Peak, adjusted to reflect normal peak day weather, less the credit for NP's generation (Generation Credit).[13] This credit avoids the need for NP to operate its generation at time of system peak in

[13] The generation credit reduces NP's demand at time of system peak by a predetermined amount based on the amount of NP's installed generation. NP's generation is tested each winter season to confirm its availability and justify the provision of the Generation Credit.

order to reduce its billing demand. This demand pricing feature eliminates the financial incentive for NP to operate its thermal generation at a time when there may be other less costly sources of generation available to supply customers.

The billing demand cannot be less than the minimum billing demand that is set at 99% of test year billing demand.

The demand charge to NP is the same level for all months of the year, such that the annual demand charges is computed as:

Annual Demand Charge = Monthly Demand Charge x Billing Demand x 12

4.1.2 Discussion

The current billing demand approach was introduced by Hydro and adopted by the Board after considerable evidence. The advantages and disadvantages of the current billing approach are presented below.
Advantages:

- Inclusion of a separate demand and energy charge in the wholesale rate provides a more clear distinction between the cost causation effects of demand and energy, when compared to recovering demand costs on an hourly basis.

- NP is provided with a price signal that encourages the deferral of new generation and transmission capital resources on the Island Interconnected System based on reducing system peak demand requirements. Deferral of new generation costs will act to reduce the overall costs of generating electricity on the Island Interconnected System.

- Generally, during the single peak period the probability of power system shortages is relatively high. NP's peak normally occurs at the same time as the system peak occurs. Therefore, NP responding to the price signal and reducing its peak will over the long term reduce system peak and reduce the probability of power system shortages.

- The demand charge can be easily modified to better reflect marginal costs as it changes over time.

- It has been in effect for several years and as a result there are no additional implementation costs. With the experience gained, the utilities have managed their operations and developed mechanisms to ensure manageable impacts on utility revenue and costs. NP has responded to the price signal by implementing load management measures, such as expanding NP's ability to curtail load during peak.

- The current billing approach requires NP to demonstrate the available capacity of its generation each winter season to receive its billing demand reduction in lieu of operating its generation to reduce it peak demand.

- Use of a single peak billing demand is an accepted billing approach in similar Canadian jurisdictions.

Disadvantages:

- The single CP method puts limited emphasis on reducing demand during the remaining on-peak hours identified in the NERA Marginal Cost Study.[14] This demand billing approach provides less of an incentive to design retail rates to

[14] Pricing on a single annual peak basis has a different impact depending on the nature of the customers' load. For instance, an industrial customer operates near peak load for many hours during the year. Therefore, in order for an industrial customer to control their peak they would need to institute changes that effects the load in a great number of hours during the year. This would have a greater impact on LOLH than a change in the annual peak demand of a customer that operates near peak load for very few hours during the year.

reflect higher costs for consumption during the full on-peak period than if capacity costs were recovered through higher on-peak energy charges. The option of a peak period hourly capacity charge is discussed in Section 4.3.

- The current form of peak demand billing results in NP requesting customer load curtailments to reduce its demand costs. Some of these requests occur during periods when the system has adequate generation available and may impose unnecessary hardship on customers. For example, during the 2006-07 winter season customers were requested to curtail four times. These four curtailments occurred to reduce purchased power demand costs and were not initiated due to system requirements. This disadvantage can be eliminated by treating NP's curtailable load as discussed in Section 4.4.

- The current rate has resulted in administrative complexities to ensure reasonable recovery of costs for both Hydro and NP. These include weather normalization of peak demand, true-up of monthly demand charges and the existence of a minimum billing demand. NP has also implemented a reserve to limit the potential volatility of purchased power demand costs based on billing using a single peak while maintaining the demand management incentive.

4.2 Monthly Winter Peaks

4.2.1 Description

This option would be similar to the current rate structure, except that for each winter month the billing demand would be computed as the highest Weather-Adjusted Native Load in each winter month. Similar to the current rate, the minimum billing demand would be 99% of the test year forecast of Native Load less Generation for each winter month.

The procedure for calculating a demand rate to be applied to each of the four billing demands would be to divide the target annual demand revenues to be recovered, by the sum of the test year forecast Native Loads in each of the four months, net of the Generation Credit in each month. Under this alternative, NP would pay demand charges in each of the four winter months and nothing in the eight remaining months.

By way of example,

- if the relative test year forecasts of Native Load less Generation Credits are 1.00 for December and January and 0.95 for February and March; and

- assuming the current $4.00/kW per month x 12 months, or $48.00/kW per year as the per unit cost recovery target,

the $/kW rate would be:

$48.00 / (1.00+1.00+0.95+0.95) = $48.00 / 3.90, or ~$12.31/kW.

4.2.2 Discussion

The advantages and disadvantages of the billing approach using monthly winter peaks are presented below.

Advantages:

- Inclusion of a separate demand and energy charge in the wholesale rate provides a more clear distinction between the cost causation effects of demand and energy, when compared to recovering demand costs on an hourly basis.

- NP would be provided with a price signal that encourages the deferral of new generation and transmission capital resources on the Island Interconnected System based on reducing system peak demand requirements. Deferral of new generation costs will act to reduce the overall costs of generating electricity on the Island Interconnected System.

- This approach would also require NP to demonstrate the available capacity of its generation each winter season to receive its billing demand reduction in lieu of operating its generation to reduce peak demand.

- It is capable of simply being modified upwards or downwards to recognize directional movements in the marginal cost of capacity.

- Use of all winter month peaks in determining billing demand would recognize that it is beneficial to reduce demand in periods other than at the time of system peak. This recognition provides a stronger signal to NP to charge customers for demand for the entire winter on-peak period than the single peak method currently used.

- Determining billing demand based on monthly peaks is an accepted methodology used in other Canadian jurisdictions, although heavily weighting the demand charge for the peak period is not a common practice.

Disadvantages:

- Customer bill impacts would be significant, shifting cash flow from the current monthly billing of annual demand to billing demand in only the winter months, with NP unable to pass the cash flow implications along to its customers. This cash-flow issue could be addressed by spreading the actual billing over 12 months. Recovering annual demand charges over only a portion of the year (e.g., winter months) is not common practice in similar Canadian jurisdictions.

- Basing billing demands in some months on a relatively low peak could provide an incentive for NP to incur costs to undertake load management at times when the probability of system shortages is relatively low compared to the probability of system shortages occurring during times of system peak. Peak reduction activities usually occur three to five times per year. Under a monthly winter peak approach, peak reduction activities would be required to be initiated more frequently, thus increasing the associated costs.

- This form of peak demand billing would result in increased frequency of NP requesting customer load curtailments to reduce its demand costs. Some of these requests occur during periods when the system has adequate generation available and may impose unnecessary hardship on customers. This disadvantage can be eliminated by treating NP's curtailable load as discussed in Section 4.4.

- Current administrative mechanisms, including weather normalization of peak demand, true-up of monthly demand charges, minimum billing demand and NP's purchased power reserve would remain a requirement and would include greater complexity under this demand billing approach.

- There would be costs associated with implementation of this demand billing approach. For example, a review of the monthly peak forecast methodology would be necessary.

4.3 Hourly Winter Peaks

4.3.1 Description

Hourly winter peak billing would result in the demand charge effectively being restated as an energy charge and applied to consumption during on-peak periods in the winter months. The rate would be designed to recover the same revenue previously recovered through the demand charges in the previous approaches.

For example, based on a capacity revenue allocation of $4.00/kW per month ($48.00/kW per year) and 774 winter peak hours, the adder would be determined as:

$48.00/kW per year / 774 hours per year = $0.062/kWh or 6.2 cents/kWh

Every kWh delivered to NP in the winter peak period (i.e., weekdays from 7:00 to 12:00 and from 16:00 to 20:00 during the months of December, January, February and March) would be subject to a demand charge of 6.2 cents/kWh. This charge would be in addition to the energy charge component of the existing demand and energy rate to NP.

4.3.2 Discussion

This method recovers capacity costs through an on-peak energy charge and has many features similar to a time-of-use (seasonal/daily) energy-only rate. The advantages and disadvantage of the billing approach using monthly winter peaks are presented below.

Advantages:

- NP would be provided with a price signal that encourages the deferral of new generation and transmission capital resources on the Island Interconnected System based on reducing system peak demand requirements. Deferral of new generation costs will act to reduce the overall costs of generating electricity on the Island Interconnected System.

- This billing approach would provide an additional incentive to conserve energy by shifting load from on-peak periods to off-peak periods.

- This billing approach will provide NP with the incentive to implement passive load control alternatives, such as time-of-use rates, for its retail customers. Such controls give control of demand to the consumer rather than the utility.

- This billing approach will result in NP curtailing customers based solely upon a generation/load imbalance and not for the purpose of reducing demand costs. See Section 4.4.

- The price can be easily modified to better reflect marginal costs of capacity as they change over time.

Disadvantages:

- Customer bill impacts would be significant, shifting cash flow from the current monthly billing of annual demand to on-peak energy charges that apply only in the winter months, with NP unable to pass the cash flow implications along to its customers. This cash-flow issue could be addressed by spreading the actual billing over 12 months. Recovering annual capacity charges over only a portion of the year (e.g., winter months) is not common practice in similar Canadian jurisdictions.

- This billing method would reduce the incentive through the wholesale rate to expand load curtailment options that typically only affect load at times of system peak. Maintaining this incentive would require other mechanisms where Hydro pays separately for load curtailment.

- Inclusion of a separate demand and energy charge in the wholesale rate provides a more clear distinction between the cost causation effects of demand and energy, when compared to recovering demand costs on an hourly basis.

- Recovery of capacity costs through an on-peak energy charge is not a common wholesale rate design methodology used in other similar Canadian jurisdictions.

- Current administrative mechanisms, including weather normalization of hourly peak demands, true-up of monthly demand charges, and NP's purchased power reserve would remain a requirement and would include greater complexity under this demand billing approach.

- There would be costs associated with implementation of this demand billing approach including development of a methodology to ensure that Hydro recovers its correct revenue requirement, and a review of monthly peak forecast methodology.

4.4 NP's Curtailable Load

The use of a billing demand based on the highest peak during the winter season or based on the monthly peaks during the winter season provides NP with a direct incentive to reduce its peaks through the use of its curtailable load. However, NP's responding to this incentive may not result in the most effective use of curtailable load to the system.

On most peak days, the system has adequate generation available and customer curtailments are not required. It may be more efficient to have Hydro reflect a curtailable load credit in determining NP's billing demand and have Hydro request NP to curtail customer load when the system requires it. This approach would be similar to the approach used by Hydro and NP to provide for the most efficient use of NP's generation during peak periods. Providing Hydro the responsibility to dispatch curtailable load when required would also result in less inconvenience to customers that has resulted from increased frequency in requests to curtail. Over the longer term, an increased number of curtailment requests may result in reduced participation and reduced curtailable load available.

Hydro and NP agree in principle with adjusting the billing demand to reflect available curtailable load. However, details on how the curtailable load amount is determined, tested, and modified on an ongoing basis require review. Hydro and NP agree to propose changes to the wholesale demand and energy rate to accommodate a change in the treatment of NP's curtailable load at Hydro's next GRA, due to the impact on other customers. That is, implementing such a mechanism for the curtailable load has Cost of Service implications and should be tested during a GRA process where all customer groups have an opportunity to offer evidence or argument on the matter.

The CA's perspective is that service interruptions to Curtailable Service customers cause undue hardship and cannot be justified when the interruptions do not coincide with system emergencies. The CA's view is that this issue should be addressed prior to the start of the next winter period on December 1, 2008 regardless of whether Hydro files a rate application.

5 SUMMARY

Rate design requires a balancing of objectives. All the demand billing options considered in reviewing NP's wholesale rate had some desirable attributes.

Fairness is an important element in evaluating rate designs. Wholesale rates under all three of the approaches under consideration can be designed to be fair (as NP is the only customer in its class) and generate the necessary revenues. Since total revenue requirements are apportioned to the Industrial Customers and NP directly from the Cost of Service study, there is no issue of inter-class fairness in their rate design. However, perceived fairness in rate design approaches between NP and the Industrial Customers has been an issue before the Board. Inclusion of a separate demand and energy charge in the wholesale rate provides a clear distinction between the cost causation effects of demand and energy and is consistent with wholesale rates in similar Canadian jurisdictions.

Customer understandability is also a consideration in rate design. However, NP is a large and sophisticated customer, and the differences in rate complexity are not a major issue among the rate designs reviewed.

The wholesale rate should encourage efficient use of society's resources and discourage inefficient use. While the Parties agree that NP's peak demand normally occurs at the same time as the system peak, and that during the system peak the probability of power shortages is high, the Parties are unable to make a clear determination of which demand billing approach provides the most efficient price signal in terms of deferring new generation capacity.

All three rate options present administrative complexities. However, both Hydro and NP have gained experience with the existing rate and there are no additional implementation costs. With the experience gained, the utilities have managed their operations and developed mechanisms to ensure manageable impacts on utilities revenues and costs. Continuation with the existing rate is also expected to have lower ongoing administration costs.

Overall the current demand billing approach to NP reasonably reflects the importance of system peak in Hydro's generation planning criteria; provides a strong incentive for NP to minimize the requirements of its customers during the winter season at the time of system peak; provides a strong seasonal price signal to NP to reflect in retail rates; and is practical for both Hydro and NP from an administrative perspective.

All Parties to the review have agreed that change in the demand billing approach is not justified at this time. The rate to NP will be a subject of ongoing supervision by the Board. Future changes to the Island Interconnected System configuration, or substantial changes in marginal costs, may warrant further consideration of revisions to the NP rate design.

The CA has two concerns relating to the price signal resulting from the current demand billing approach:

- It provides incentive for NP to run its generation and interrupt its Curtailable Service customers to reduce its peak demand even when there may be no benefit to the system; and

- It provides a stronger incentive for NP to favour utility-controlled load management over customer-controlled load management.

An hourly billing demand approach avoids these incentives because the costs for NP to run its generation would far exceed the benefits, and because curtailable customers would never sign on to a rate knowing they would be interrupted for the entire winter peak period. With regard to the second point, under the hourly billing demand approach there remains incentive for NP to pursue utility-controlled load management programs while increasing the incentive over the current approach for customer-controlled load management programs (i.e., water heater load management in response to Time-of-Use rates). The CA believes that customer-controlled load management programs are generally more acceptable to customers.

The CA recognizes that the shortcomings relating to the price signal under any of the three approaches can be “fixed”. For example, under the current approach, regulatory intervention ensures NP gains no additional economic benefit from operating its generation to reduce its winter peak demand. Further, the issue of interrupting Curtailable Service customers when there is no benefit to the system can be addressed as outlined in Section 4.4. Therefore, the CA agrees that there is not a strong argument for changing the billing approach at this time.

However, the CA’s agreement with continuation of the existing approach is contingent on results. The CA has not seen the type of commitment to demand management and energy conservation in the province that it believes is needed. While the CA is encouraged with undertakings such as the Conservation and Demand Management Potential Study and the Retail Rate Design Study, at this point, they remain only studies with no tangible results. Energy prices have soared in recent years and the CA feels strongly that consumers want the utilities to pursue every avenue possible to reduce costs. Therefore, while in agreement with extending the current demand billing approach, the CA believes the door should be left open in the event results from these studies (or other studies such as those relating to the system expansion program) suggest the demand billing approach should be revisited. The CA states this giving particular attention to the Retail Rate Design Study – the CA does not want the wholesale rate billing approach to be a deterrent to implementation of retail rate options for customers.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

REVIEW OF INDUSTRIAL CUSTOMER RATE DESIGN

NEWFOUNDLAND AND LABRADOR HYDRO
FEBRUARY 5, 2008

TABLE OF CONTENTS

Appendices

1 Executive Summary

A review of Newfoundland and Labrador Hydro's (Hydro) rate structure for the sale of power and energy to Industrial Customers (IC) has been completed, in accordance with the agreement reached during Hydro's 2006 General Rate Application (GRA). The IC and Hydro have reached agreement as follows:

- A two-block rate structure for IC with a marginal cost based second block can improve price signals and economic efficiency.
- The tail block or second block should be priced at Hydro's Test Year marginal cost of supply.
- An IC will be able to apply to Hydro to have their first block energy adjusted to take account of significant changes to their business or output. The difference between the marginal cost of fuel and the energy revenue received should be recoverable by Hydro through an automatic rate adjustment.
- Industrial Customers entering the Island Interconnected System between rate hearings will be charged a Test Year average energy charge, in addition to regular IC demand charges, for all kilowatt-hours (kWh). The difference between the cost of fuel and the energy revenue received should be recoverable by Hydro through an automatic rate adjustment.
- Hydro will continue to bill IC embedded cost-based demand charges for their full Power on Order.
- Industrial Customer generation does not affect the two-block rate structure, and vice versa.

Outstanding issues to be resolved at a Technical Conference or through some other regulatory proceeding are:

- Two methods[1] of calculating first blocks as presented herein:

  - One method of computing a first block for each customer, without shifting costs between customers, is to calculate the block sizes based on the Test Year percentage of system energy supplied from generation sources other than Holyrood, applied to each customer's Test Year energy forecast. In principle then, each customer's first block energy represents a proportionate share of Hydro's hydraulic resources and the second block represents energy to be supplied by Holyrood.

  - To mitigate possible manipulation of block sizing, a second block sizing method is to set the blocks monthly as a percentage of total energy consumed. For instance, the first block would be 75% of monthly energy consumption. While this approach offers ease of administration and understandability, it mutes the price signal provided to the IC in that every kWh would be partially priced at first block rates.

- Monthly block sizing for the IC raises issues when unusual operating circumstances, such as strikes or temporary plant shutdowns, result in the customer not using all of the first block energy in a given month. The IC perspective is that the unused first block kWh should be available in future periods. Hydro's position is that the first block energy is a monthly allotment, and should not be carried from period to period.

- The format, timing and details of automatic fuel-related rate adjustments, considered where a new customer enters the Island Interconnected System between Test Years, or where an existing IC is given an increased first block.

Issues which the IC and Hydro have discussed in detail, but deferred final decision to other ongoing studies and reports, are:

- DSM and conservation initiatives should be viewed outside the rate structure, and will be considered as part of Conservation and Demand Management initiatives.

---

[1] See Appendix B for illustration of how both methods would maintain 2007 Test Year Revenue Requirement by customer.

- Depending upon the method used to calculate block sizes, the load variation provision of the Rate Stabilization Plan may no longer be required. This will be considered as part of the ongoing Rate Stabilization Plan review.

2 Introduction

This report on rate design alternatives for IC was prepared as a result of the October 20, 2006 Agreement on Cost of Service, Rate Design and Rate Stabilization Plan, filed as part of Hydro's 2006 GRA.

Paragraph nine of the October 20, 2006 agreement states that the "Framework for Industrial Customers' Rate Design Review", attachment B to the October 20, 2006 agreement, (the Framework) will apply to the review process on the rate design for the Industrial Customers. The framework document is attached hereto as Appendix A.

The Framework outlines the agreement to implement marginal price signals on the discretionary or marginal components of the IC load. This review of the IC rate structure also considers the generally accepted rate design principles agreed to by all Parties in the 2006 Hydro GRA[2].

This report contains a summary of the rate design principles and methods considered for altering the IC rate structure, and recommends changes where appropriate.

[2] The generally accepted principles were provided in Schedule A to the October 20, 2006 Cost of Service Agreement.

3 Background

3.1 Industrial Customer Rate Structure

The existing rate structure for Hydro's Industrial Customers includes:

- Monthly demand charges based on Test Year embedded costs, applied to the customers' annual declaration of Power on Order;
- An average-embedded-cost energy rate, based on Test Year costs, applied to all firm energy; and
- Specifically assigned charges based on Test Year embedded costs.

3.2 Marginal Costs

In June 2006, Hydro filed a report entitled "Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission" (Marginal Cost Study). Hydro filed a follow-up report in July 2006 entitled "Implications of Marginal Cost Results for Class Revenue Allocation and Rate Design" (Marginal Cost Implications Report)[3]. These reports provided the basis for reviewing the efficiency of customer rates on the Island Interconnected System.

The Marginal Cost Studies concluded that:
"Looking just at the marginal cost relationships … Firm industrial rates should have much higher energy charges and much lower demand charges." NERA also stated [4] "We recognize that rate setting requires balancing many objectives, one of which is economic efficiency, but we have not studied all of the objectives and issues related to Hydro's rates."

The Parties to this review agreed that a two-block rate structure for Industrial Customers with a marginal cost based second block can improve price signals and economic efficiency while maintaining a consideration of the other rate design principles agreed to in the October 20, 2006 agreement.

[3] Both reports were prepared by NERA Economic Consulting (NERA). Copies of the reports were included as Attachments 2 and 3 to the Request for Information PUB 1 NLH, filed at Hydro's 2006 GRA.
[4] Reference: Request for Information NP-89 NLH, filed during Hydro's 2006 GRA.

3.2.1 Current Review

The negotiated settlements resulted in agreement to incorporate a marginal price signal into the IC rate structure.

The Parties that have participated in the IC Rate Design Review are Industrial Customers and Hydro. The broad goal of the rate design review was to develop a rate proposal that could be applied to all Industrial Customers. To that end, the Parties have approached the review in a manner that attempts to satisfy the concerns of Hydro and the IC. Newfoundland Power and the Consumer Advocate were provided with draft reports, and their comments are considered in this final report.

Meetings to discuss the rate design alternatives were held during 2007. This report provides the results of the IC Rate Design review.

4 IC Rate Design Review

The proposals for discussion as specified in the Framework are reviewed in this report. Characteristics considered during this review include:

- Energy Blocks;
- Demand Charges;
- Customer Generation;
- Other Contract Provisions; and
- Demand Side Management (DSM) and Conservation Implementation.

The load variation provision of the Rate Stabilization Plan (RSP), as it relates to Industrial Customers was also considered during this review.

4.1 Impacts on Load and Customer Decisions

Marginal price signals should neither detract from economic growth in the province nor encourage reduction in IC operations. The proposed rate design's anticipated impacts on the economics of customer choice are:

- Providing a mechanism for real load growth by permitting each customer access to additional lower-priced, first block energy;
- Providing an automatic mechanism for new customers to have first and second blocks of energy;
- Providing a marginal price signal to encourage customers to conserve and obtain the immediate benefits of the fuel savings; and
- If actual consumption mirrors forecast consumption, retaining each IC's anticipated 2007 Test Year total billing with the revised rate design.

Further, the two-block rate design has been developed with the goal of preserving the following possible range of outcomes as a result of changes to Industrial load characteristics:

- **Industrial Customer load decreases slightly affecting only the second block energy consumption.** In this scenario, the customer saves at the marginal cost rate. The change is largely revenue neutral to Hydro as there are fuel expense savings to offset the lost revenues.

- **Industrial Customer loads decrease substantially affecting both first and second block energy consumption**. In this scenario, the customer would save a certain amount at the marginal cost rate and the remainder at the lower rate. Hydro would likely experience savings to fuel expense that more than offset the lost revenue. However, customers are protected from an excessive "windfall" potential to Hydro by the over-earning provision.

- **Industrial Customer load grows slightly with no material change in customer's output.** In this scenario, all incremental consumption is priced at the marginal cost rate. Hydro is held largely revenue neutral as the incremental revenue is set to offset the incremental fuel expense.

- **Industrial Customer load grows due to a material change in process or output.** In this case, it may be reasonable for Hydro to increase the first block size and access to the lower priced energy. This could have negative impacts on Hydro's revenues, as the incremental revenues would not be sufficient to offset the incremental fuel expense. Potential methods for addressing this situation are discussed further in this report.

4.2 Energy Blocks

The energy blocks for IC were to be considered during this review, specifically:

- Pricing that would apply to each energy block;

- The means to set an initial annual division between the first block for each customer versus the run-out or second block;

- The basis and timing under which the size of the first block might be adjusted for each customer (both short-term and long-term);
- Approaches used to set the first block energy allocation to new Industrial Customers coming on the system; and
- Means to apply the annual first block energy concept to monthly billing.

4.2.1 Energy Block Pricing

As an initial step, there was agreement between the Parties on the following general characteristics of the rate design:

- The tail block or second block should be priced at Hydro's Test Year marginal cost of supply. Under the present system characteristics, it was agreed that the second block should be priced consistent with the cost of fuel at Holyrood. It was also agreed that the basis for the price of the second block could change in the future if system conditions change (for example, in the case of a Labrador Interconnection) and that the second block price should be reviewed at each General Rate Application.
- If customer loads remain at Test Year levels, the overall effect of the rate design should be revenue neutral compared to a single block embedded cost-based rate.
- Ideally, the rate design should ensure Industrial Customers have some portion of their load exposed to the marginal cost price signal in each month.

4.2.2 Means to Set Block

As there are IC of varying sizes, with varying load factors, block sizes are required for each customer. Several methods were explored, some of which result in shifting costs between customers. One method of computing a first block for each customer, without shifting costs between customers is to calculate the block sizes based on the Test Year percentage of system energy supplied from generation sources other than Holyrood, applied to each customer's Test Year energy forecast. In principle then, each customer's first block energy represents a proportionate share of Hydro's hydraulic resources and the second block represents energy to be supplied by Holyrood. Based on the 2007 Forecast Cost of Service, the blocks would be calculated as illustrated in Table 1 below.

Table 1: Calculation of Industrial Customer Blocks

Line No.	Description	Amount						Source
	Industrial Customers							
	Calculation of Industrial Customer Total Second Block							
1	Total Cost of No. 6 Fuel	$ 137,356,005						Schedule 2.1A, Page 1 of 2 Ln 2, Col 4
2	Industrial Customer Firm Energy Allocation Ratio	0.1438						Schedule 3.1A, Page 1 of 2, Ln 15, Col 4
3	Industrial Customer Firm Energy No. 6 Fuel Cost	$ 19,758,319						Ln 1 * Ln 2
4	Average No. 6 Fuel Cost per Barrel	$ 55.47						
5	No 6 Fuel Barrels Allocated to Industrial Customer Firm Energy	356,196						Ln 3 / Ln 4
6	Efficiency Factor (kWh per Barrel)	630						
	Holyrood kWh Allocated to Industrial Customer Firm Energy							
7	- Industrial Customer Total Second Block	224,403,466						Ln 5 * Ln 6
8	Industrial Customer Total Firm KWh at Generator	922,411,479						Schedule 3.1A, Page 1 of 2, Ln 2, Col 4 *1000
9	First Block Ratio	75.67%						1 - (Ln 7 / Ln 8)
	Calculation of Individual Industrial Customer Blocks	Total	ACI - SV	ACI - GF	CBPP	NARL	AUR	Source
10	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	Load Forecast
11	First Block Ratio		75.7%	75.7%	75.7%	75.7%	75.7%	Ln 9
12	Annual First Block kWh	676,735,471	4,313,309	99,433,122	338,708,260	185,623,628	48,657,152	Ln 10 * Ln 11
13	Annual Second Block kWh	217,564,529	1,386,691	31,966,878	108,891,740	59,676,372	15,642,848	Ln 10 - Ln 12
14	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	Ln 12 + Ln 13
	Energy (First Block):	Amount						Source
15	Total Energy Revenue Requirement	$32,877,667						Schedule 1.3.1, Page 1 of 3, Ln 2. Col 8
16	Less: Second Block Energy Revenue	19,156,163						Ln 13 * Ln 22 / 1000
17	First Block Energy Revenue	$13,721,504						((Sch 1.3.2, pg 1, Ln 1, Col 3) - Ln 8) * Ln 12
18	First Block Energy Consumed (MWh)	676,735						Ln 12 /1000
19	**Rate (Mills/kWh)**	**20.28**						Ln 17/ Ln 18
	Energy (Second Block):							
20	Average No. 6 Fuel Cost per Barrel	$55.47						
21	Efficiency Factor (kWh per Barrel)	630						
22	**Rate (Mills/kWh)**	**88.05**						

4.2.3 Basis and Timing of Block Changes

When an existing customer changes its production process or otherwise materially increases output and therefore requires additional load, it may not be practical to price all energy sales at the tail block, or Holyrood rate. Such a rate structure may inhibit overall provincial economic growth. At the same time, the purpose of a marginal price signal is to encourage efficient use of the Island Interconnected System resources, and load growth attributable to reasons other than production or revenue growth of the customer's should be priced at the marginal cost of supply.

The Parties discussed whether there might be rate design solutions to this problem, including alternatives for block sizes, block pricing or demand charges. However, there did not seem to be a mechanism that would accomplish the objective of distinguishing between load growth due to changes in the industrial process compared to simple load creep. As such, the Parties discussed other administrative mechanisms.

In order to minimize administrative complexities, the Parties discussed an adjustment mechanism whereby an Industrial Customer could apply to Hydro to have their first block energy adjusted to take account of significant changes to their business or output. In order to qualify for such an adjustment, it was agreed that the following criteria must be met:

- There must be a material change in the customer's electricity requirements resulting in an increased Power on Order of at least 1 MW.
- The increased electricity requirements must be driven by growth or change in the customer's business including:
    - legislated or regulatory requirements;
    - an increase in production or output;
    - improvements in product quality; or
    - change in or addition of a new type of product.

The onus would be on the customer making the application to demonstrate that the additional electricity requirements meet the tests necessary for an energy block adjustment. Application would be made to the Public Utilities Board (the Board) to alter blocks, on a case-by-case basis.

4.2.4 New Customer Block Sizing

When a new customer enters the system, it may not be practical to price all energy sales at the tail block, or Holyrood rate since this could result in barriers for new industry to develop in the province. As well, it is not reasonable to assume that a GRA would immediately result from the entrance of a new customer. It is likely that new customers may take an extended period to reach a 'normal' operating load. Additionally, new customers often require a ramp up, or construction period before production related operations are on line, and forecasting of power and energy requirements for this period may not be realistic. Therefore, it is proposed that customers entering the Island Interconnected System between rate hearings will be charged a Test Year average energy charge, in addition to regular IC demand charges, for all kilowatt-hours.

Since the incremental costs to serve the new customer would likely be incurred entirely at the marginal fuel cost while the incremental revenues would be an average cost based rate, this treatment would likely result in a negative impact to Hydro's net income. It would not take a very large new Industrial Customer to have a material impact on Hydro's net income.

In order to mitigate Hydro's exposure to this risk, the Parties agreed that it would be reasonable to have an adjustment mechanism that adjusts rates for all customers on the Island Interconnected System. The rate adjustment would be based on the most recently approved Cost of Service study, and would require Hydro to apply to the Board for a rate adjustment. The incremental system generation would be adjusted to account for the new fuel expense and the additional electricity sales. This treatment has the following advantages:

- It allows new Industrial Customers to share in the benefits of the low-cost hydroelectric system;
- It protects Hydro from excessive earnings risk between rate applications and prevents the need for a full General Rate Application in the event that a new Industrial Customer joins the system. This protects all Parties from unnecessary administrative and regulatory costs related to a GRA.
- It produces rates that are consistent with the most recently reviewed Cost of Service study.

This proposal has been discussed with, and agreed to by, Newfoundland Power and the Consumer Advocate.

4.2.5 Block Sizing where a Customer Load Materially Decreases

When a customer load materially decreases on a permanent or semi-permanent basis, block sizes should be reset to reflect the decreased requirements. While Industrial Customers are contractually obliged to declare Power on Order on an annual basis, there is no contractual requirement to declare energy requirements. Depending on the load change, having a fixed first block may provide an incentive to the Industrial Customer to declare a higher than necessary Power on Order.

Table 2 illustrates the comparative cost to the customer when a Test Year load is substantially reduced.

Table 2: Customer Load Reduction

		Test Year			
	Units		**Rate**		**Cost to Customer $**
Demand:	54,000	kW	6.68	$/kW/mo.	4,328,640
Energy:					
First Block	338,708,260	kWh	20.28	mills/kWh	6,867,657
Second Block	108,891,740	kWh	88.05	mills/kWh	9,587,721
	447,600,000				16,455,377
Total Cost					20,784,017
		Power on Order Reduced by 22 MW			
	Units		**Rate**		**Cost to Customer**
Demand:	32,000	kW	6.68	$/kW/mo.	2,565,120
Energy:					
Revised Requirement	241,600,000	kWh			
First Block Ratio	75.67%				
First Block	182,823,761	kWh	20.28	mills/kWh	3,706,939
Second Block	58,776,239	kWh	88.05	mills/kWh	5,175,141
	241,600,000				8,882,080
Total Cost					11,447,200
		Power on Order Not Reduced			
	Units		**Rate**		**Cost to Customer**
Demand:	54,000	kW	6.68	$/kW/mo.	4,328,640
Energy:					
First Block	241,600,000	kWh	20.28	mills/kWh	4,898,687
Second Block	-	kWh	88.05	mills/kWh	-
	241,600,000				4,898,687
Total Cost					9,227,327

While it is possible to include in the customer contract a provision requiring the customer to advise Hydro when a substantial permanent or long-term load decrease is to occur, there does not appear to be a practical means of ensuring that provision has received compliance. It should be noted that potential gains to Hydro because of such fuel savings would, of course, be subject to existing over-earnings mechanisms.

4.2.5.1 Rate Design Alternative

To mitigate possible manipulation of block sizing, the Parties considered the option of simplifying the two-block energy structure to set the blocks monthly as a percentage of total energy consumed. For instance, the first block would be 75% of monthly energy consumption. While this approach offers ease of administration and understandability, it mutes the price signal provided to the IC in that every kWh would be priced partially at first block prices.

4.2.6 Means to Apply the Annual First Block to Monthly Billing

The proposed block sizing is based on Test Year percentage of energy supplied from sources other than Holyrood. Since the IC load factor tends to be stable, the first block can be divided by 12 to determine monthly block size, and some portion of the energy sales would be priced at the tail block rate. This is illustrated in Table 3 following.

Table 3: Monthly Blocks 2007 Test Year

	ACI - SV	ACI - GF	CBPP	NARL	AUR
Annual First Block (MWh)	4,313	99,433	338,708	185,624	48,657
divided by	12	12	12	12	12
Monthly First Block (MWh)	359	8,286	28,226	15,469	4,055
2007 Test Year					
Minimum Monthly MWh forecast	-	9,900	32,500	19,100	4,800
Maximum Monthly MWh forecast	1,300	11,600	39,400	21,800	5,500
Average Monthly MWh forecast	475	10,950	37,300	20,442	5,358

The Parties discussed the possibility of a customer not using all of its first block energy in a given month due to an emergency shutdown, strike or lockout. The IC propose that if such an event occurred, energy sales for the year would be reviewed. If the load factor for the year is higher than the customer's historic load factor, indicating that the IC may have made up the unused energy, then the rate for the number of kWh above the calculated load factor will be adjusted from the second block rate to first block. The Parties could not come to an agreement on a proposal to resolve this rate issue and have agreed to include a summary of both perspectives in this report. The Parties will look to make their respective cases on this matter to the Board and request that the Board determine their preferred treatment with respect to this issue.

Hydro and the IC note that the first block energy has been sized so that under normal operating conditions each IC will use their full allocation of first block energy in each month with some energy being purchased in the second block at marginal cost based rates. Hydro and the IC reviewed historic load patterns of the IC to confirm the appropriateness of the block sizing for this purpose. This is consistent with the rate objectives for the IC rate design in that the rates and revenues track the costs on the system (i.e. that they are consistent with overall Cost of Service) with a marginal cost price signal on the more discretionary or incremental portion of the IC load.

Hydro and the IC also recognize that in the case of certain extreme operating events, such as a fire or other emergency or a strike, it is possible that an IC's load could drop below the second block level. In such a case, the IC would not receive the maximum monthly amount of first block energy for which they would otherwise be eligible.

4.2.6.1 Customer Perspective

Under other than normal operating conditions, an IC may not use all of the first block energy. The IC position is that the customer should have access to an annual first block of energy, broken down by month for billing purposes, and that the customer should be entitled to make up for a temporary shutdown by producing more in a subsequent month, and continuing to receive the benefit of the first block rate.

4.2.6.2 Hydro Perspective

However, from Hydro's perspective, the first block of lower cost energy represents an opportunity for the IC to have access to benefits from the low cost hydro-electric generation resources. It is not, in Hydro's view, an entitlement to that amount of low cost energy. Therefore, it is not necessary to have a mechanism in place to allow an IC to "carry over" unused first block energy from month to month.

4.3 Demand Charges

Demand charges for Industrial Customers are calculated based on Test Year embedded costs that are classified as demand and have been allocated to the Industrial Customer rate class. Although the Marginal Cost Study identifies the marginal cost of demand as negligible, it is recognized that demand does in fact have a value from a planning and winter capacity perspective. Each IC is billed for firm Power on Order for each month of the year.

This review was undertaken with the objective of having new rate designs continue to be based on the embedded Cost of Service study, but with a marginal price signal applied to the discretionary or marginal components of load. In the case of the IC, there is little discretionary demand. No benefits have been identified to warrant changes to the existing embedded cost-based method of designing the demand charge to IC. Since Hydro commits to provide firm Power on Order to the IC based on the individual customer requirements, it is reasonable, and has been agreed that Hydro will continue to bill IC embedded cost based demand charges for their full Power on Order.

Non-firm energy is identified as that in excess of 100% load factor energy. Non-firm supply means that Hydro is not obligated to supply the power, but does if sufficient capacity is available on the system. Any change in this identification of the supply as non-firm may result in capacity constraints on the system, and no changes to non-firm provisions are proposed at this time.

The review of the IC rate design considered whether implementing the marginal cost energy block would require changes to the existing demand charges, Power on Order and provisions for firm and non-firm supply. It was determined by the Parties that no such changes were required.

4.4 Customer Generation

Some of Hydro's IC have their own generation facilities. Therefore, rate design which includes tail block pricing at the marginal energy price will result in higher or lower costs for those customers with their own generation, based on fuel prices. Hydro and Corner Brook Pulp and Paper Limited (CBPP) are currently in separate discussions to permit the optimization of CBPP's hydraulic generation in other circumstances and both Parties believe that any resulting agreement is independent of this review of Industrial Customers' rate design.

The Parties discussed the possible interactions of the generation credits and the marginal cost rate design and consider that the implementation of a marginal energy price remains an appropriate signal.

Abitibi Consolidated Incorporated, Grand Falls (ACI-GF), also has available generation, as well as available compensation. The current contract provisions do not offer ACI-GF an opportunity to alter their generation patterns based upon the rate design considered in this report, and the implementation of a marginal energy price remains an appropriate signal.

4.5 DSM and Conservation

There is an existing joint study being conducted by Newfoundland Power and Hydro on Conservation and Demand Management (CDM). That study will address potential CDM opportunities for the utilities' customers including IC, and this topic will therefore not be addressed in this report.

4.6 Load Variation Provision of the Rate Stabilization Plan

The introduction of a two-block energy rate structure for Industrial Customers requires consideration of the load variation provision of the RSP. The existing load variation provision of the RSP provides for load changes to be recovered from or refunded to the customer group based on the difference between energy revenue and Test Year fuel costs or savings. With tail block pricing based on the Test Year fuel price, load variations at the tail block result in a small change to the existing RSP. Table 4 illustrates a 10 GWh load variation at the existing IC energy rate and at the 2007 Test Year tail block energy rate.

Table 4: Load Variation Comparison

	Sales Variance (kWh)	Cost of Service No. 6 Fuel Cost ($)	Firm Energy Rate ($/kWh)	Holyrood Conversion Factor	Load Variation ($)
Existing Rates	10,000,000	55.46	0.03676	630	512,717
2007 Test Year Tail Block Rate	10,000,000	55.46	0.08805	630	(183)

If all IC load variations were to occur at the tail block, it would appear that there is no need for a load variation component of the RSP. There are, however, instances when an IC load variation may occur within first block sales. During a labour disruption, a prolonged maintenance outage or under other possible circumstances, monthly sales to an individual IC may be less than the first block threshold. In that case, Hydro would save fuel at Holyrood, and lose revenue at a much smaller rate, resulting in savings to Hydro. Potential windfall profits to Hydro are mitigated by Hydro's excess earnings cap however, and the potential for Hydro to make such windfall profits in this manner is very limited.

There may also be instances where there are additional sales to an IC at first block energy prices, and the related Holyrood fuel would cost substantially more than the additional revenue earned. This would occur, for example, if a new customer enters the system, or an existing customer experiences production growth that qualifies for additional energy at first block prices. Table 5 shows the potential impacts on Hydro under various IC load growth scenarios.

Table 5: Revenue and Fuel Comparison – Additional IC load at First Block

Customer Forecast	**Case 1**	**Case 2**	**Case 3**	**Case 4**
Monthly Billing Demand (kW)	**10,000**	**15,000**	**20,000**	**25,000**
Average Annual Energy (kWh Sales)	**50,000,000**	**80,000,000**	**150,000,000**	**165,000,000**
Load Factor	57.1%	60.9%	85.6%	75.3%
Customer kWh/kW	417	444	625	550
Test Year First Block Ratio	**75.67%**	**75.67%**	**75.67%**	**75.67%**
First Block kWh/kW	315	336	473	416
Monthly First Block kWh	3,153,004	5,044,806	9,459,011	10,404,912
Annual First Block kWh	37,836,043	60,537,669	113,508,130	124,858,943
Annual Second Block kWh	12,163,957	19,462,331	36,491,870	40,141,057
Average Annual Energy (kWh Sales)	50,000,000	80,000,000	150,000,000	165,000,000
Revenue				
Demand	765,600	1,148,400	1,531,200	1,914,000
Energy First Block	767,164	1,227,463	2,301,493	2,531,643
Energy Second Block	1,071,014	1,713,623	3,213,043	3,534,347
Total Revenue	2,603,779	4,089,486	7,045,737	7,979,990
Fuel Impacts				
kWh Increase (Decrease) * 1.03 (losses)	51,500,000	82,400,000	154,500,000	169,950,000
Equivalent bbls No. 6 Fuel (630 kWh/bbl)	81,746	130,794	245,238	269,762
Cost ($55/bbl)	4,496,032	7,193,651	13,488,095	14,836,905
Variance between Fuel Savings and Hydro Revenue	(1,892,253)	(3,104,165)	(6,442,359)	(6,856,915)

As illustrated in Table 5, there would be a negative impact on utility revenues as Hydro's incremental revenues would not be sufficient to offset the incremental fuel expense. It may be reasonable for the utility to absorb this revenue impact, subject to a maximum threshold. If the revenue impact exceeded the threshold, Hydro would have recourse to make rate adjustments based on a limited scope re-run of its Cost of Service. Hydro would adjust only loads and fuel expense; other variables would remain the same as at the most recently approved General Rate Application. The Cost of Service rebalancing would adjust rates for all customers, not only Industrials. This will be further discussed in the ongoing RSP review, after consideration by Newfoundland Power and the Consumer Advocate.

APPENDIX A

Framework for Industrial Customers' Rate Design Review

1.0 Current Rate Design Methodology

The current Industrial Customer (IC) firm rate design entails a single demand charge applied to all Power on Order each month and a single energy charge applied to all firm kWh consumed. Non-firm kWh are priced largely at the cost of fuel at Holyrood.

2.0 Rate Design Review

In light of the principles identified in Attachment A, Hydro and the ICs will enter into discussions following the 2006 GRA directed toward development of a suitable revised Island Industrial rate design focused on the following points:

1) New rate designs will continue to be based on recovering the full IC revenue requirement measured by the embedded Cost of Service study, but with a marginal price signal on the discretionary or marginal components of the load.

2) The discussions will focus on development of a suitable and practical industrial rate design for future implementation subject to review by stakeholders and the Board.

3) A variety of issues related to practical implementation and fairness require careful consideration. Guidance on these matters will be sought through discussions at times with each of the Industrial Customers regarding the unique characteristics of their operations and specific facility plans, and through review of similar rate structures in other jurisdictions. Practical issues include, but are not limited to:

a. **Energy Blocks:** Determination of a reasonable approach for sizing first block energy versus run-out (marginal) blocks, including:

- The means to set an initial annual division between the first block for each customer versus the run-out or second block.
- The basis and timing under which the size of the first block might be adjusted for each customer (both short-term and long-term).

- Approaches used to set the first block energy allocation to new Industrial Customers coming on the system.
- Means to apply the annual first block energy concept to monthly billing.

b. **Demand Charges:** Interaction between demand changes, actual metered peak loads, Power on Order and delimitation between firm and non-firm supplies.

c. **Customer Generation:** Interaction with customer generation including impacts on dispatch and expansion of generation capability.

d. **Other Contract Provisions:** Interactions with other provisions in the existing Industrial Customer contracts such as Force Majeure events, and interaction with non-firm rate provisions.

e. **Impacts on Loads and Customer Decisions:** Impacts on the economics of customer choices with respect to expansions of operations, or reductions. This matter should include an understanding of any likely impact of the rate design on the future growth and development of the level of industrial activity of Newfoundland.

f. **DSM and Conservation:** Implications for IC to implement DSM or conservation activities to reduce net loads on Hydro's system and capture long-term system savings.

APPENDIX B

Industrial Customer Energy Revenue

Energy Sales at Existing Rates

		Total	ACI - SV	ACI - GF	CBPP	NARL	AUR	Source
1	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	2007Test Year Load Forecast
2	Rate (mills/kWh)		36.76	36.76	36.76	36.76	36.76	
3	Energy Sales ($)	32,874,468	209,532	4,830,264	16,453,776	9,017,228	2,363,668	Ln 1 * Ln 2 /1000

Energy Sales where Second Block represents Test Year Holyrood Energy

		Total	ACI - SV	ACI - GF	CBPP	NARL	AUR	Source
3	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	2007Test Year Load Forecast
4	First Block Ratio		75.67%	75.67%	75.67%	75.67%	75.67%	Table 1
5	Annual First Block kWh	676,716,810	4,313,190	99,430,380	338,698,920	185,618,510	48,655,810	Ln 3 * Ln 4
6	Annual Second Block kWh	217,583,190	1,386,810	31,969,620	108,901,080	59,681,490	15,644,190	Ln 3 - Ln 5
7	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	Ln 5 + Ln 6
8	First Block Rate (mills/kWh)	20.28						
9	Second Block Rate (mills/kWh)	88.05						
10	First Block Revenue ($)		87,471	2,016,448	6,868,814	3,764,343	986,740	Ln 5 * Ln 8 /1000
11	Second Block Revenue ($)		122,109	2,814,925	9,588,740	5,254,955	1,377,471	Ln 6 * Ln 9 /1000
12	Energy Sales ($)	32,882,017	209,580	4,831,373	16,457,554	9,019,299	2,364,211	Ln 10 + Ln 11
13	Difference	7,549	48	1,109	3,778	2,071	543	Ln 12 - Ln 3

Energy Sales where Second Block 25% of monthly total

		Total	ACI - SV	ACI - GF	CBPP	NARL	AUR	Source
14	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	2007Test Year Load Forecast
15	First Block Ratio		75.00%	75.00%	75.00%	75.00%	75.00%	Table 1
16	Annual First Block kWh	670,725,000	4,275,000	98,550,000	335,700,000	183,975,000	48,225,000	Ln 14 * Ln 15
17	Annual Second Block kWh	223,575,000	1,425,000	32,850,000	111,900,000	61,325,000	16,075,000	Ln 14 - Ln 16
18	Average Annual Energy (kWh Sales)	894,300,000	5,700,000	131,400,000	447,600,000	245,300,000	64,300,000	Ln 16 + Ln 17
19	First Block Rate (mills/kWh)	19.67						
20	Second Block Rate (mills/kWh)	88.05						
21	First Block Revenue ($)		84,089	1,938,479	6,603,219	3,618,788	948,586	Ln 16 * Ln 19 /1000
22	Second Block Revenue ($)		125,471	2,892,443	9,852,795	5,399,666	1,415,404	Ln 17 * Ln 20 /1000
23	Energy Sales ($)	32,878,940	209,561	4,830,921	16,456,014	9,018,455	2,363,990	Ln 21 + Ln 22
24	Difference	4,472	29	657	2,238	1,227	322	Ln 23 - Ln 3

First Block Energy Rate variable based on how blocks are fixed. The formula is:
Test Year Industrial Customer Energy Related Revenue Requirement
less
Second Block Energy Revenue
equals
Revenue Requirement to be recovered through first block sales
divided by
Energy Sales kwh
equals
First Block Rate

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Total System
Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Island Interconnected ($)	4 Island Isolated ($)	5 Labrador Isolated ($)	6 L'Anse au Loup ($)	7 Labrador Interconnected ($)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	115,928,303	89,425,968	5,339,758	13,492,944	1,321,586	6,348,048	Detailed Analysis
2	Fuels - No. 6 Fuel	200,692,615	200,692,615	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	17,978,931	111,816	2,558,555	14,697,487	533,749	77,323	Detailed Analysis
4	Fuels - Gas Turbine	802,435	606,127	-	-	-	196,308	
5	Power Purchases -CF(L)Co	2,363,382	-	-	-	-	2,363,382	Detailed Analysis
6	Power Purchases - Other	56,310,580	52,417,542	244,656	-	3,353,241	295,141	Detailed Analysis
7	Depreciation	52,366,908	46,731,192	479,097	1,981,176	335,840	2,839,603	Detailed Analysis
	Expense Credits:							
8	Sundry	(632,669)	(488,035)	(29,141)	(73,637)	(7,212)	(34,644)	Total O&M Expenses
9	Building Rental Income	(15,744)	(15,744)	-	-	-	0	Detailed Analysis
10	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
11	Suppliers' Discounts	(100,257)	(77,337)	(4,618)	(11,669)	(1,143)	(5,490)	Total O&M Expenses
12	Pole Attachments	(1,594,680)	(1,149,732)	(23,664)	(102,972)	(68,280)	(250,032)	Detailed Analysis
13	Secondary Energy Revenues	-	-	-	-	-	-	Island Interconnected
14	Wheeling Revenues	-	0	-	-	-	-	Island Interconnected
15	Application Fees	(26,868)	(11,624)	(228)	(1,668)	(368)	(12,980)	Detailed Analysis
16	Meter Test Revenues	(6,720)	(3,907)	(132)	(486)	(197)	(1,997)	Weighted Customers
17	**Total Expense Credits**	**(2,376,938)**	**(1,746,380)**	**(57,783)**	**(190,432)**	**(77,200)**	**(305,143)**	
18	**Subtotal Expenses**	**444,066,215**	**388,238,880**	**8,564,283**	**29,981,175**	**5,467,216**	**11,814,662**	
19	Disposal Gain/Loss	1,303,697	1,005,645	141,781	137,281	(179)	19,169	Detailed Analysis
20	**Subtotal Rev Reqt Excl Return**	**445,369,912**	**389,244,525**	**8,706,064**	**30,118,456**	**5,467,037**	**11,833,830**	
21	Return on Debt	87,868,604	80,235,295	581,432	2,440,180	476,336	4,135,361	Rate Base
22	Return on Equity	34,579,153	31,575,197	228,812	960,290	187,454	1,627,399	Rate Base
23	**Total Revenue Requirement**	**567,817,669**	**501,055,017**	**9,516,308**	**33,518,926**	**6,130,827**	**17,596,591**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Total System
Return on Rate Base

Line No	1	2 Total $	3 Island Interconnected $	4 Island Isolated $	5 Labrador Isolated $	6 L'Anse au Loup $	7 Labrador Interconnected $	8 Basis of Proration
	Rate Base:							
1	Average Net Book Value	1,417,712,234	1,294,247,390	9,479,378	37,575,082	7,854,180	68,556,204	Schedule 2.3
2	Cash Working Capital	5,335,790	4,871,110	35,677	141,420	29,560	258,022	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	45,130,957	45,130,957	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	3,520,945	94,498	168,823	3,158,525	47,228	51,871	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	2,233,160	2,121,588	-	-	-	111,572	Detailed Fuel Analysis
6	Inventory/Supplies	24,700,787	21,993,318	228,133	826,119	185,345	1,467,872	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Holyrood	-	-					Detailed Analysis
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	65,450,500	59,750,587	437,628	1,734,702	362,598	3,164,985	Prorated on Average Net Book Value - L. 1
9	Total Rate Base	**1,564,084,373**	**1,428,209,448**	**10,349,639**	**43,435,848**	**8,478,912**	**73,610,526**	
10	Less: Rural Portion	-	-	-	-	-	-	Schedule 2.6, L. 9
11	Rate Base Available for Equity Return	**1,564,084,373**	**1,428,209,448**	**10,349,639**	**43,435,848**	**8,478,912**	**73,610,526**	
	Corporate Targets:							
12	Capital Structure: Percent of Debt	70.101% (1)						
13	Return	8.014%						
14	Weighted Average Return: Debt	**5.618%**						
15	Capital Structure: Percent of Equity	25.123% (1)						
16	Return	8.800%						
17	Weighted Average Return: Equity	**2.211%**						
18	Weighted Average Cost of Capital	**7.829%**						
	Return on Rate Base by System (%):							
19	Return on Rate Base - Debt Component	-	5.618%	5.618%	5.618%	5.618%	5.618%	
20	Return on Rate Base - Equity Component	-	2.211%	2.211%	2.211%	2.211%	2.211%	
	Return on Rate Base ($):							
21	Return on Debt	87,868,604	80,235,295	581,432	2,440,180	476,336	4,135,361	Schedule 2.6, L.12
22	Return on Equity	34,579,153	31,575,197	228,812	960,290	187,454	1,627,399	Schedule 2.6, L.13
23	Return on Rate Base ($)	**122,447,757**	**111,810,492**	**810,244**	**3,400,470**	**663,790**	**5,762,761**	Schedule 2.6, L.14
	Return on Total Rate Base (%):							
24	Return on Rate Base - Debt Component	5.618%	5.618%	5.618%	5.618%	5.618%	5.618%	L. 21 divided by L.9
25	Return on Rate Base - Equity Component	2.211%	2.211%	2.211%	2.211%	2.211%	2.211%	L. 22 divided by L.9
26	Return on Rate Base (%)	**7.829%**	**7.829%**	**7.829%**	**7.829%**	**7.829%**	**7.829%**	L. 23 divided by L.9

(1) Debt and equity weightings reflect a 0.417% funded ARO and 4.359% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Total System
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credits ($)	Deficit ($)	RSP Activity ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	Revenue to Cost Coverage (Col.2/3)
	Total System							
1	Newfoundland Power	453,009,608	399,122,877	-	53,882,421	-	453,005,298	
2	RSP Activity	-	-	-	-	-	-	
3	Subtotal Newfoundland Power	**453,009,608**	**399,122,877**	**-**	**53,882,421**	**-**	**453,005,298**	**1.14**
4	Island Industrial	28,952,325	28,955,711	-	-		28,955,711	1.00
5	Unallocated RSP Hydraulic Variation	-	-	-	-		-	-
6	Labrador Industrial	2,108,486	2,108,486	-	-		2,108,486	1.00
7	CFB - Goose Bay Secondary	877,416	13,982	863,434	-		877,416	62.76
8	Rural Labrador Interconnected	22,316,579	15,474,123	-	6,842,261		22,316,384	1.44
	Rural Deficit Areas							
9	Island Interconnected	48,364,264	72,976,430	-	(24,612,166)		48,364,264	0.66
10	Island Isolated	1,606,057	9,516,308	-	(7,910,251)		1,606,057	0.17
11	Labrador Isolated	7,855,459	33,518,926	-	(25,663,467)		7,855,459	0.23
12	L'Anse au Loup	2,728,595	6,130,827	-	(3,402,233)		2,728,595	0.45
13	Revenue Credit Applied to Deficit (100.0%)	-	-	(863,434)	863,434		-	-
14	**Subtotal**	**60,554,374**	**122,142,491**	**(863,434)**	**(60,724,682)**	**-**	**60,554,374**	**0.50**
15	**Total**	**567,818,789**	**567,817,669**	**-**	**-**	**-**	**567,817,669**	**1.00**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit Allocation ($)	RSP Activity ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	Revenue to Cost Coverage (Col.2/3)
	Island Interconnected							
1	Newfoundland Power	453,009,608	399,122,877	-	53,882,421	-	453,005,298	
2	NLP RSP Activity	-					-	
3	**Subtotal Newfoundland Power**	**453,009,608**	**399,122,877**	**-**	**53,882,421**	**-**	**453,005,298**	**1.14**
4	Industrial - Firm	28,952,325	28,955,711	-			28,955,711	
5	Industrial - Non-Firm	-	-	-			-	
6	Industrial RSP Activity	-					-	
7	**Subtotal Industrial**	**28,952,325**	**28,955,711**	**-**	**-**		**28,955,711**	**1.00**
8	**Unallocated RSP Hydraulic Variation**	**-**						
	Rural							
9	1.1 Domestic	13,573,252	22,001,654	-	(8,428,402)		13,573,252	0.62
10	1.12 Domestic All Electric	16,174,390	26,410,568	-	(10,236,178)		16,174,390	0.61
11	1.3 Special	18,372	61,924	-	(43,553)		18,372	0.30
12	2.1 General Service 0-10 kW	2,088,235	2,888,414	-	(800,179)		2,088,235	0.72
13	2.2 General Service 10-100 kW	7,289,243	9,919,304	-	(2,630,061)		7,289,243	0.73
14	2.3 General Service 110-1,000 kVa	5,307,611	6,710,671	-	(1,403,060)		5,307,611	0.79
15	2.4 General Service Over 1,000 kVa	2,970,787	3,726,191	-	(755,404)		2,970,787	0.80
16	4.1 Street and Area Lighting	942,374	1,257,704	-	(315,330)		942,374	0.75
17	**Subtotal Rural**	**48,364,264**	**72,976,430**	**-**	**(24,612,166)**		**48,364,264**	**0.66**
18	**Total Island Interconnected**	**530,326,197**	**501,055,017**	**-**	**29,270,255**		**530,325,273**	**1.06**

Note1:
Calculation of Island Industrial Non-Firm Revenue Credit

Island Industrial Non-Firm Revenues, Ln 5, Col 2	-
Island Industrial Non-Firm Allocated Cost of Service, Ln 5, Col 3	-
Credit to be allocated to Island Interconnected Firm Customers	-

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit ($)	RSP Activity ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	Revenue to Cost Coverage (Col.2/3)
	Island Isolated							
1	1.2 Domestic Diesel	829,278	7,222,927		(6,393,649)		829,278	0.11
2	1.2G Government Domestic Diesel	0	0		0		0	0.00
3	1.23 Churches, Schools & Com Halls	0	0		0		0	0.00
4	2.1 General Service 0-10 kW	208,946	901,802		(692,856)		208,946	0.23
5	2.2 GS 10-100 kW	530,250	1,231,172		(700,922)		530,250	0.43
6	2.3 GS 110-1,000 kVa	0	0		0		0	0.00
7	2.4 General Service Over 1,000 kVa	0	0		0		0	0.00
8	2.5 GS Diesel	0	0		0		0	0.00
9	2.5G Gov't General Service Diesel	0	0		0		0	0.00
10	4.1 Street and Area Lighting	37,583	160,407		(122,823)		37,583	0.23
11	4.1G Gov't Street and Area Lighting	0	0		0		0	0.00
12	**Total**	**1,606,057**	**9,516,308**		**(7,910,251)**		**1,606,057**	**0.17**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit ($)	RSP Activity ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	Revenue to Cost Coverage (Col.2/3)
	Labrador Isolated							
1	1.2 Domestic Diesel	3,392,239	18,714,106		(15,321,867)		3,392,239	0.18
2	1.2G Government Domestic Diesel	0	0		0		0	0.00
3	1.23 Churches, Schools & Com Halls	0	0		0		0	0.00
4	2.1 General Service 0-10 kW	1,206,641	3,519,793		(2,313,152)		1,206,641	0.34
5	2.2 GS 10-100 kW	2,634,666	7,396,165		(4,761,499)		2,634,666	0.36
6	2.3 GS 110-1,000 kVa	294,502	1,955,225		(1,660,722)		294,502	0.15
7	2.4 General Service Over 1,000 kVa	222,612	1,576,011		(1,353,399)		222,612	0.14
8	2.5 GS Diesel	0	0		0		0	0.00
9	2.5G Gov't General Service Diesel	0	0		0		0	0.00
10	4.1 Street and Area Lighting	104,800	357,626		(252,826)		104,800	0.29
11	4.1G Gov't Street and Area Lighting	0	0		0		0	0.00
12	**Total**	**7,855,459**	**33,518,926**		**(25,663,467)**		**7,855,459**	**0.23**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit ($)	RSP Activity ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	Revenue to Cost Coverage (Col.2/3)
	L'Anse au Loup							
1	1.1 Domestic	516,950	1,220,082		(703,132)		516,950	0.42
2	1.12 Domestic All Electric	1,180,721	2,860,900		(1,680,179)		1,180,721	0.41
3	2.1 General Service 0-10 kW	168,308	331,960		(163,652)		168,308	0.51
4	2.2 General Service 10-100 kW	602,843	1,235,980		(633,137)		602,843	0.49
5	2.3 General Service 110-1,000 kVa	216,712	421,548		(204,837)		216,712	0.51
6	4.1 Street and Area Lighting	43,062	60,357		(17,296)		43,062	0.71
7	**Total L'Anse Au Loup**	**2,728,595**	**6,130,827**		**(3,402,233)**		**2,728,595**	**0.45**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

	1	2	3	4	5	6	7	8
Line No.	Rate Class	Revenues ($)	Cost of Service Before Deficit and Revenue Credit Allocation ($)	Revenue Credit ($)	Deficit Allocation ($)	RSP Activity ($)	Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected							
1	Industrial IOCC Firm	2,099,261	2,099,261		-		2,099,261	1.00
2	Industrial IOCC Non-Firm	9,225	9,225		-		9,225	1.00
3	**Subtotal Industrial**	**2,108,486**	**2,108,486**	**-**	**-**		**2,108,486**	**1.00**
4	**CFB - Goose Bay Secondary**	877,416	13,982	863,434	-		877,416	62.76
	Rural							
5	1.1 Domestic	134,181	210,451	-	93,056		303,507	0.64
6	1.1A Domestic All Electric	13,141,457	9,479,157	-	4,191,440		13,670,597	1.39
7	2.1 General Service 0-10 kW	444,040	293,249	-	129,667		422,917	1.51
8	2.2 General Service 10-100 kW	2,440,610	1,495,529	-	661,285		2,156,814	1.63
9	2.3 General Service 110-1,000 kVa	3,446,780	2,192,754	-	969,580		3,162,333	1.57
10	2.4 General Service Over 1,000 kVa	2,293,616	1,514,647	-	669,738		2,184,386	1.51
11	4.1 Street and Area Lighting	415,895	288,336	-	127,495		415,830	1.44
12	**Subtotal Rural**	**22,316,579**	**15,474,123**	**-**	**6,842,261**		**22,316,384**	**1.44**
13	**Total Labrador Interconnected**	**25,302,481**	**17,596,591**	**863,434**	**6,842,261**		**25,302,286**	**1.44**

Note1:
Calculation of CFB - Goose Bay Secondary Revenue Credit

CFB - Goose Bay Secondary Revenues, Ln 4, Col 2		877,416
CFB - Goose Bay Secondary Allocated Cost of Service, Ln 4, Col 3		(13,982)
CFB - Goose Bay Secondary Allocated Deficit, Ln 4, Col 5		-
Revenue Credit		863,434
Revenue Credit Applied to Deficit	**100.0%**	863,434
Revenue Credit Applied to Firm Regulated Labrador Interconnected Customers		-
		863,434

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Total System
Rural Deficit Allocation

	1	2	3	4	5	6
		Before Deficit and Revenue Credit Allocation				
Line No.	Rate Class	Allocated Revenue Reqt ($)	Demand ($)	Energy ($)	Customer ($)	Source
	CLASSIFICATION TO DEMAND, ENERGY, CUSTOMERS:					
1	Newfoundland Power	399,122,877	127,044,995	267,676,715	4,401,167	Schedule 1.3.1, p. 1
2	Rural Labrador Interconnected	15,474,123	9,869,114	879,460	4,725,549	Schedule 1.3.1, p. 3
3	**Total**	**414,597,000**	**136,914,109**	**268,556,175**	**9,126,716**	
4	Deficit Classified	60,724,682	20,053,367	39,334,555	1,336,761	Prorated on Line 3
	UNIT COSTS OF DEFICIT:		CP kW	MWH	Customers *	
	Island Interconnected:					
5	Newfoundland Power		1,175,961	5,794,481	9,096	
6	**Subtotal Island Interconnected**		**1,175,961**	**5,794,481**	**9,096**	
	Labrador Interconnected:					
7	Rural Labrador Interconnected		137,599	658,575	10,854	
8	**Subtotal Labrador Interconnected**		**137,599**	**658,575**	**10,854**	
9	**Total**		**1,313,560**	**6,453,055**	**19,950**	
10	Deficit Unit Costs		$15.27 $/KW	$6.10 $/MWH	$67.01 $/Customer	Line 4 / Line 9

* Specifically assigned costs are converted to equivalent unweighted customers by dividing the assigned cost by the allocated customer cost per unweighted customer.

Rural Customer Costs per Rural Customer:	
Island Interconnected:	$483.85
Labrador Interconnected:	$435.37

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Total System
Rural Deficit Allocation

Line No.	1	2	3	4	5	6
		Deficit Allocation				
	Rate Class	Allocated Revenue Reqt ($)	Demand ($)	Energy ($)	Customer ($)	Source
	ALLOCATION OF DEFICIT:					
11	Island Interconnected	53,882,421	17,952,720	35,320,217	609,484	Line 6 x Line 10
12	Labrador Interconnected	6,842,261	2,100,647	4,014,338	727,276	Line 8 x Line 10
13	**Allocated Totals**	**60,724,682**	**20,053,367**	**39,334,555**	**1,336,761**	

	CUSTOMER DEFICIT ALLOCATION:	Amount	Percent
	Island Interconnected:		
14	Newfoundland Power	53,882,421	88.7%
15	Sub-Total Island Interconnected	53,882,421	
	Labrador Interconnected:		
16	Rural Labrador Interconnected	6,842,261	11.3%
17	Subtotal Labrador Interconnected	6,842,261	
18	**Total**	**60,724,682**	100.0%

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Unit Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand			Non-Demand		Demand			Non-Demand	
Line No.		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Island Interconnected										
1	Newfoundland Power	9.12	-	0.04785	-	366,763.89	10.35	-	0.05431	-	416,277.78
2	Industrial - Firm	9.13	-	0.04782	-	29,923.93	9.13	-	0.04782	-	29,923.93
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-
	Rural							-	-		
4	1.1 Domestic	-	0.10043	0.05298	0.15342	37.94	-	-	-	-	-
5	1.12 Domestic All Electric	-	0.11050	0.05301	0.16351	37.96	-	-	-	-	-
6	1.3 Special	-	0.12560	0.05258	0.17818	37.65	-	-	-	-	-
7	2.1 General Service 0-10 kW	-	0.08379	0.05328	0.13707	42.17	-	-	-	-	-
8	2.2 General Service 10-100 kW	30.56	-	0.05312	-	55.28	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	22.82	-	0.05316	-	72.35	-	-	-	-	-
10	2.4 General Service Over 1,000 kVa	22.89	-	0.05322	-	72.09	-	-	-	-	-
11	4.1 Street and Area Lighting	-	0.11896	0.05326	0.17222	69.44	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Unit Demand, Energy & Customer Amounts

Line No.	1 Rate Class	2 Before Deficit and Revenue Credit Allocation Demand Demand ($/kW)	3 Demand Non-Demand ($/kWh)	4 Energy ($/kWh)	5 Non-Demand Demand & Energy ($/kWh)	6 Customer ($/Bill)	7 After Deficit and Revenue Credit Allocation Demand Demand ($/kW)	8 Demand Non-Demand ($/kWh)	9 Energy ($/kWh)	10 Non-Demand Demand & Energy ($/kWh)	11 Customer ($/Bill)
	Isolated Systems:										
1	1.2 Domestic Diesel	-	0.26295	0.65326	0.91621	53.50					
2	2.1 General Service 0-10 kW	-	0.19862	0.64811	0.84673	58.56					
3	2.2 GS 10-100 kW	66.59	-	0.64071	-	75.06					
4	2.3 GS 110-1,000 kVa	26.23	-	0.62328	-	91.68					
5	2.4 General Service Over 1,000 kVa	10.80	-	0.62436	-	91.83					
6	**Subtotal Metered Demand Classes**	51.23	-	0.63496	-	75.90					
7	4.1 Street and Area Lighting	-	0.32553	0.65965	0.98518	106.35					
	Island Isolated										
8	1.2 Domestic Diesel	-	0.42205	0.76051	1.18255	70.46	-	-	-	-	-
9	2.1 General Service 0-10 kW	-	0.30155	0.76272	1.06427	81.60	-	-	-	-	-
10	2.2 GS 10-100 kW	173.81	-	0.76497	-	117.98	-	-	-	-	-
11	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-
12	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-
13	4.1 Street and Area Lighting	-	0.49278	0.76332	1.25610	125.27	-	-	-	-	-
	Labrador Isolated										
14	1.2 Domestic Diesel	-	0.22004	0.62433	0.84437	47.66	-	-	-	-	-
15	2.1 General Service 0-10 kW	-	0.17935	0.62664	0.80599	53.08	-	-	-	-	-
16	2.2 GS 10-100 kW	57.65	-	0.62617	-	70.31	-	-	-	-	-
17	2.3 GS 110-1,000 kVa	26.23	-	0.62328	-	91.68	-	-	-	-	-
18	2.4 General Service Over 1,000 kVa	10.80	-	0.62436	-	91.83	-	-	-	-	-
19	4.1 Street and Area Lighting	-	0.27240	0.62671	0.89910	99.43	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Unit Demand, Energy & Customer Amounts

Line No.	1	2	3	4	5	6	7	8	9	10	11
	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand			Non-Demand		Demand			Non-Demand	
		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	L'Anse au Loup										
1	1.1 Domestic	-	0.07286	0.17075	0.24361	39.77	-	-	-	-	-
2	1.12 Domestic All Electric	-	0.08460	0.17042	0.25502	39.69	-	-	-	-	-
3	2.1 General Service 0-10 kW	-	0.05825	0.17096	0.22921	43.06	-	-	-	-	-
4	2.2 General Service 10-100 kW	17.69	-	0.17080	-	53.68	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	12.30	-	0.17100	-	67.21	-	-	-	-	-
6	4.1 Street and Area Lighting	-	0.08100	0.17216	0.25316	71.48	-	-	-	-	-
	Labrador Interconnected										
7	Industrial - IOCC Firm	2.33	-	0.00144	-	5.00	2.33	-	0.00144	-	5.00
8	Industrial - IOCC Non-Firm	-	-	0.00144	0.00144	0.00	-	-	0.00144	0.00144	0.00
9	CFB - Goose Bay Secondary	-	-	0.00144	0.00144	0.00	-	-	0.00144	0.00144	0.00
	Rural							-	-		
10	1.1 Domestic	-	0.01791	0.00154	0.01945	33.52	-	0.02583	0.00222	0.02805	48.35
11	1.1A Domestic All Electric	-	0.01825	0.00156	0.01981	33.99	-	0.02632	0.00225	0.02856	49.02
12	**Subtotal Domestic**	-	0.01825	0.00156	0.01980	33.97	-	0.02631	0.00225	0.02856	48.99
								-	-		
13	2.1 General Service 0-10 kW	-	0.01277	0.00157	0.01434	37.72	-	0.01842	0.00226	0.02068	54.40
14	2.2 General Service 10-100 kW	4.69	-	0.00157	-	49.42	6.76	-	0.00227	-	71.27
15	2.3 General Service 110-1,000 kVa	5.60	-	0.00157	-	63.93	8.08	-	0.00227	-	92.20
16	2.4 General Service Over 1,000 kVa	8.70	-	0.00152	-	61.79	12.54	-	0.00219	-	89.11
17	4.1 Street and Area Lighting	-	0.02092	0.00156	0.02247	56.35	0.00	0.03016	0.00224	0.03241	81.26

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Island Interconnected								
1	Newfoundland Power	399,122,877	127,044,995	267,676,715	4,401,167	453,005,298	144,196,335	303,813,630	4,995,333
2	Industrial - Firm	28,955,711	7,631,172	19,529,103	1,795,436	28,955,711	7,631,172	19,529,103	1,795,436
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-
	Rural								
4	1.1 Domestic	22,001,654	10,920,135	5,760,973	5,320,545	-	-	-	-
5	1.12 Domestic All Electric	26,410,568	15,385,753	7,380,394	3,644,421	-	-	-	-
6	1.3 Special	61,924	43,331	18,141	452	-	-	-	-
7	2.1 General Service 0-10 kW	2,888,414	1,147,867	729,868	1,010,679	-	-	-	-
8	2.2 General Service 10-100 kW	9,919,304	5,899,887	3,419,784	599,632	-	-	-	-
9	2.3 General Service 110-1,000 kVa	6,710,671	4,021,401	2,616,342	72,929	-	-	-	-
10	2.4 General Service Over 1,000 kVa	3,726,191	2,052,374	1,665,166	8,651	-	-	-	-
11	4.1 Street and Area Lighting	1,257,704	344,997	154,440	758,267	-	-	-	-
12	**Subtotal Rural**	72,976,430	39,815,746	21,745,108	11,415,576				
13	**Total Island Interconnected**	501,055,017	174,491,913	308,950,927	17,612,178				

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Isolated Systems:								
1	1.2 Domestic Diesel	25,937,033	6,934,566	17,228,005	1,774,462				
2	2.1 General Service 0-10 kW	4,421,596	952,315	3,107,392	361,888				
3	2.2 GS 10-100 kW	8,627,337	1,949,494	6,541,837	136,006				
4	2.3 GS 110-1,000 kVa	1,955,225	172,433	1,775,091	7,701				
5	2.4 General Service Over 1,000 kVa	1,576,011	76,138	1,498,770	1,102				
6	**Subtotal Metered Demand Classes**	12,158,572	2,198,066	9,815,698	144,808				
7	4.1 Street and Area Lighting	518,033	123,944	251,154	142,936				
8	**Total Isolated Systems**	**43,035,234**	**10,208,891**	**30,402,249**	**2,424,094**				
	Island Isolated								
9	1.2 Domestic Diesel	7,222,927	2,364,158	4,260,100	598,669	-	-	-	-
10	2.1 General Service 0-10 kW	901,802	228,062	576,838	96,903	-	-	-	-
11	2.2 GS 10-100 kW	1,231,172	391,530	818,348	21,294	-	-	-	-
12	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-
14	4.1 Street and Area Lighting	160,407	45,237	70,073	45,097	-	-	-	-
15	**Total Island Isolated**	**9,516,308**	**3,028,987**	**5,725,358**	**761,962**				
	Labrador Isolated								
16	1.2 Domestic Diesel	18,714,106	4,570,408	12,967,905	1,175,793	-	-	-	-
17	2.1 General Service 0-10 kW	3,519,793	724,253	2,530,555	264,986	-	-	-	-
18	2.2 GS 10-100 kW	7,396,165	1,557,965	5,723,489	114,712	-	-	-	-
19	2.3 GS 110-1,000 kVa	1,955,225	172,433	1,775,091	7,701	-	-	-	-
20	2.4 General Service Over 1,000 kVa	1,576,011	76,138	1,498,770	1,102	-	-	-	-
21	4.1 Street and Area Lighting	357,626	78,706	181,081	97,839	-	-	-	-
22	**Total Labrador Isolated**	**33,518,926**	**7,179,904**	**24,676,890**	**1,662,132**				

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	L'Anse au Loup								
1	1.1 Domestic	1,220,082	306,665	718,702	194,715	-	-	-	-
2	1.12 Domestic All Electric	2,860,900	888,728	1,790,226	181,947	-	-	-	-
3	2.1 General Service 0-10 kW	331,960	67,689	198,654	65,617	-	-	-	-
4	2.2 General Service 10-100 kW	1,235,980	310,858	875,522	49,600	-	-	-	-
5	2.3 General Service 110-1,000 kVa	421,548	90,899	326,616	4,033	-	-	-	-
6	4.1 Street and Area Lighting	60,357	10,530	22,381	27,447	-	-	-	-
7	**Total L'Anse au Loup**	**6,130,827**	**1,675,369**	**3,932,101**	**523,358**				
	Labrador Interconnected								
8	Industrial - IOCC Firm	2,099,261	1,734,241	364,961	60	2,099,261	1,734,241	364,961	60
9	Industrial - IOCC Non-Firm	9,225	-	9,225	-	9,225	-	9,225	-
10	CFB - Goose Bay Secondary	13,982	-	13,982	-	13,982	-	13,982	-
	Rural								
11	1.1 Domestic	210,451	40,444	3,469	166,539	303,507	58,327	5,002	240,178
12	1.1A Domestic All Electric	9,479,157	5,435,351	463,976	3,579,830	13,670,597	7,838,724	669,134	5,162,739
13	**Subtotal Domestic**	**9,689,608**	**5,475,794**	**467,445**	**3,746,369**	**13,974,105**	**7,897,050**	**674,137**	**5,402,917**
14	2.1 General Service 0-10 kW	293,249	70,901	8,705	213,643	422,917	102,252	12,554	308,110
15	2.2 General Service 10-100 kW	1,495,529	997,119	106,431	391,979	2,156,814	1,438,020	153,492	565,301
16	2.3 General Service 110-1,000 kVa	2,192,754	1,899,982	173,098	119,674	3,162,333	2,740,106	249,637	172,590
17	2.4 General Service Over 1,000 kVa	1,514,647	1,389,801	121,139	3,707	2,184,386	2,004,336	174,703	5,347
18	4.1 Street and Area Lighting	288,336	35,515	2,643	250,177	415,830	51,219	3,811	360,800
19	**Subtotal Rural**	**15,474,123**	**9,869,114**	**879,460**	**4,725,549**	**22,316,384**	**14,232,983**	**1,268,335**	**6,815,066**
20	**Total Labrador Interconnected**	**17,596,591**	**11,603,355**	**1,267,627**	**4,725,609**	**24,438,852**	**15,967,224**	**1,656,502**	**6,815,126**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Island Interconnected				
1	Newfoundland Power	13,929,036	5,594,300	1	12
2	Industrial - Firm	835,400	408,400	5	60
3	Industrial - Non-Firm	-	-	-	-
	Rural				
4	1.1 Domestic	-	108,732	11,686	140,232
5	1.12 Domestic All Electric	-	139,234	8,001	96,012
6	1.3 Special	-	345	1	12
7	2.1 General Service 0-10 kW	-	13,699	1,997	23,964
8	2.2 General Service 10-100 kW	193,058	64,373	904	10,848
9	2.3 General Service 110-1,000 kVa	176,185	49,217	84	1,008
10	2.4 General Service Over 1,000 kVa	89,662	31,287	10	120
11	4.1 Street and Area Lighting	-	2,900	910	10,920
12	**Subtotal Rural**	**458,905**	**409,787**	**23,593**	**283,116**
13	**Total Island Interconnected**	**15,223,341**	**6,412,487**	**23,599**	**283,188**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Isolated Systems:				
1	1.2 Domestic Diesel	-	26,372	2,764	33,168
2	2.1 General Service 0-10 kW	-	4,795	515	6,180
3	2.2 GS 10-100 kW	29,278	10,210	151	1,812
4	2.3 GS 110-1,000 kVa	6,574	2,848	7	84
5	2.4 General Service Over 1,000 kVa	7,053	2,401	1	12
6	**Subtotal Metered Demand Classes**	42,905	15,459	159	1,908
7	4.1 Street and Area Lighting	-	381	112	1,344
8	**Total Isolated Systems**	**42,905**	**47,006**	**3,550**	**42,600**
	Island Isolated				
9	1.2 Domestic Diesel	-	5,602	708	8,496
10	2.1 General Service 0-10 kW	-	756	99	1,188
11	2.2 GS 10-100 kW	2,253	1,070	15	180
12	2.3 GS 110-1,000 kVa	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-
14	4.1 Street and Area Lighting	-	92	30	360
15	**Total Island Isolated**	**2,253**	**7,520**	**852**	**10,224**
	Labrador Isolated				
16	1.2 Domestic Diesel	-	20,771	2,056	24,672
17	2.1 General Service 0-10 kW	-	4,038	416	4,992
18	2.2 GS 10-100 kW	27,025	9,140	136	1,632
19	2.3 GS 110-1,000 kVa	6,574	2,848	7	84
20	2.4 General Service Over 1,000 kVa	7,053	2,401	1	12
21	4.1 Street and Area Lighting	-	289	82	984
22	**Total Labrador Isolated**	**40,652**	**39,487**	**2,698**	**32,376**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Demands, Sales, & Number of Bills

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	L'Anse au Loup				
1	1.1 Domestic	-	4,209	408	4,896
2	1.12 Domestic All Electric	-	10,505	382	4,584
3	2.1 General Service 0-10 kW	-	1,162	127	1,524
4	2.2 General Service 10-100 kW	17,568	5,126	77	924
5	2.3 General Service 110-1,000 kVa	7,392	1,910	5	60
6	4.1 Street and Area Lighting	-	130	32	384
7	**Total L'Anse au Loup**	**24,960**	**23,042**	**1,031**	**12,372**
	Labrador Interconnected				
8	Industrial - IOCC Firm	744,000	253,200	1	12
9	Industrial - IOCC Non-Firm	-	6,400		
10	CFB - Goose Bay Secondary	-	9,700	-	-
	Rural				
11	1.1 Domestic	-	2,258	414	4,968
12	1.1A Domestic All Electric	-	297,866	8,776	105,312
13	**Subtotal Domestic**	-	**300,124**	**9,190**	**110,280**
14	2.1 General Service 0-10 kW	-	5,551	472	5,664
15	2.2 General Service 10-100 kW	212,721	67,636	661	7,932
16	2.3 General Service 110-1,000 kVa	339,153	110,145	156	1,872
17	2.4 General Service Over 1,000 kVa	159,808	79,753	5	60
18	4.1 Street and Area Lighting	-	1,698	370	4,440
19	**Subtotal Rural**	**711,681**	**564,907**	**10,854**	**130,248**
20	**Total Labrador Interconnected**	**1,455,681**	**834,207**	**10,855**	**130,260**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Rate Calculations for Newfoundland Power

	1	2	3
Line No.	Description	Amount	Source
	Newfoundland Power:		
	Demand:		
1	Demand Revenue Requirement	127,044,995	Sch 1.3.1, pg 1, Ln 1, Col 3
2	Billing Units (kW)	13,929,036	Sch 1.3.2, pg 1, Ln 1, Col 2
3	**Rate ($/kW/mo.)**	**9.12**	Ln 1 / Ln 2
	Energy (First Block):		
4	Total Revenue Requirement	$453,005,298	Sch 1.2, pg 1, Ln 1, Col 7
5	Less: Demand Revenue	127,032,808	Ln 2 * Ln 3
6	Revenue Requirement to be Recovered Through Energy Rates	$ 325,972,490	Ln 4 - Ln 5
	Non-Fuel Energy Costs:		
7	Energy Revenue Requirement	267,676,715	Sch 1.3.1, pg 1, Ln 1, Col 4
	Less Allocated Holyrood Fuel Costs		
8	Total Holyrood Fuel Costs	200,692,615	Sch 1.1, pg 1, Ln 2, Col 3
9	Newfoundland Power Trans. Energy Allocation Ratio	0.8673	Sch 3.1A, pg 1, Ln 14, Col 4
10	Allocated Holyrood Fuel Costs	174,067,395	Ln 8 * Ln 9
11	**Non-Fuel Energy Costs:**	$ 93,609,320	Ln 7 - Ln 10
12	First Block Energy Consumed (MWh)	3,360,000	
13	**Rate (Mills/kWh)**	**27.86**	Ln 11 / Ln 12
	Energy (Second Block):		
14	Total Revenue Requirement	$453,005,298	Sch 1.2, pg 1, Ln 1, Col 7
15	Less: Demand Revenue	127,032,808	Ln 2 * Ln 3
16	Less: First Block Revenue	93,609,600	Ln 12 * Ln 13
17	Second Block Energy Revenue	$232,362,890	
18	Second Block Energy Consumed (MWh)	2,234,300	
19	**Rate (Mills/kWh)**	**104.00**	Ln 17 / Ln 18
20	Average No. 6 Fuel Cost per Barrel	$108.74	
21	Efficiency Factor (kWh per Barrel)	612	
22	**Rate (Mills/kWh)**	**177.68**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Value of Newfoundland Power Thermal Generation Credit

	1	2	3
Line No.	Description	Amount	Source
1	Island Interconnected System:		
2	Generation demand costs ($)	117,697,000	Sch 2.1A, C. 3, Ln 23
3	Coincident peak (kW)	1,341,001	Sch 3.1A, C. 3, Ln 13
4	Generation demand costs ($/kW)	87.77	Ln 2 / Ln 3
5	NP thermal generation capacity credit (kW)	35,993	[1]
6	Gross value of credit to NP ($)	3,159,106	Ln 4 x Ln 5
7	Less NP's cost share:		
8	Percentage	88.01%	Sch 3.1A, C. 5, Ln 14
9	Amount ($)	(2,780,470)	Ln 6 x Ln 8
10	Net value of credit to NP ($)	378,635	Ln 6 - Ln 9

[1] NP gas turbine and diesel generation capacity (kW)	41,500
÷ System reserve	1.15
NP thermal generation capacity credit (kW)	35,993

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Calculation of Firming Up Charge

	1	2	3	4
Line No.	Description	Total	Gas Turbine	Transmission & Terminals
1	Operating & Maintenance	5,931,934	1,123,552	4,808,382
2	O&M Overhead	5,849,984	1,598,356	4,251,628
3	Depreciation	5,950,454	570,837	5,379,617
4	Return	13,446,027	1,055,804	12,390,222
5	**Total**	**31,178,398**	**4,348,549**	**26,829,849**
6	Capacity (kW)		100,000	1,686,300
7	Cost ($/kW)	$59.40	$43.49	$15.91
8	Rate ($/kWh)	$0.01248		

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Calculation of Transmission Wheeling Charge

	1	2
Line No.	Description	
1	Island Interconnected Transmission Revenue Requirement	26,885,705
2	Transmission Energy Output (MWh)	6,450,000
3	Rate ($/kWh)	$0.00417

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural Prod &		Primary Lines		Line Transformers		Secondary Lines						Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations							Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Expenses																	
1	Operating & Maintenance	89,425,968	36,190,554	21,009,520	9,060,010	3,984,329	1,275,897	5,637,899	1,479,032	382,086	676,324	899,871	970,187	418,945	383,690	137,350	2,626,994	2,503,294
2	Fuels-No. 6 Fuel	200,692,615	-	200,692,615	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	111,816	111,816	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	606,127	606,127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	52,417,542	23,090,823	28,664,957	-	661,762	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	46,731,192	19,239,600	13,904,180	5,379,617	2,653,528	550,962	1,658,832	450,325	204,992	362,852	259,909	286,003	76,879	212,599	129,093	229,286	1,132,536
	Expense Credits																	
8	Sundry	(488,035)	(197,507)	(114,658)	(49,444)	(21,744)	(6,963)	(30,768)	(8,072)	(2,085)	(3,691)	(4,911)	(5,295)	(2,286)	(2,094)	(750)	(14,337)	(13,662)
9	Building Rental Income	(15,744)	(5,686)	(5,095)	(1,988)	(946)	(176)	(691)	(181)	(47)	(83)	(110)	(119)	(51)	(33)	(17)	-	(522)
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(77,337)	(31,298)	(18,169)	(7,835)	(3,446)	(1,103)	(4,876)	(1,279)	(330)	(585)	(778)	(839)	(362)	(332)	(119)	(2,272)	(2,165)
12	Pole Attachments	(1,149,732)	-	-	-	-	-	(664,945)	(227,247)	-	-	(117,696)	(139,844)	-	-	-	-	-
13	Secondary Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(11,624)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11,624)	-
16	Meter Test Revenues	(3,907)	-	-	-	-	-	-	-	-	-	-	-	-	(3,907)	-	-	-
17	**Total Expense Credits**	**(1,746,380)**	**(234,491)**	**(137,922)**	**(59,267)**	**(26,136)**	**(8,242)**	**(701,280)**	**(236,779)**	**(2,462)**	**(4,359)**	**(123,495)**	**(146,097)**	**(2,700)**	**(6,366)**	**(885)**	**(28,232)**	**(16,349)**
18	**Subtotal Expenses**	**388,238,880**	**79,004,428**	**264,133,350**	**14,380,359**	**7,273,483**	**1,818,616**	**6,595,450**	**1,692,578**	**584,615**	**1,034,818**	**1,036,285**	**1,110,092**	**493,124**	**589,923**	**265,558**	**2,828,047**	**3,619,481**
19	Disposal Gain / Loss	1,005,645	354,786	374,559	115,124	52,510	9,792	36,264	10,115	3,139	5,556	6,374	6,814	2,210	1,959	1,091	1,811	23,543
20	**Subtotal Revenue Requirement Ex. Return**	**389,244,525**	**79,359,215**	**264,507,910**	**14,495,483**	**7,325,993**	**1,828,408**	**6,631,714**	**1,702,693**	**587,754**	**1,040,374**	**1,042,659**	**1,116,906**	**495,334**	**591,882**	**266,649**	**2,829,857**	**3,643,024**
21	Return on Debt	80,235,295	27,511,224	31,358,934	8,891,233	4,057,886	757,407	2,809,065	782,566	242,079	428,500	492,831	526,904	171,933	151,547	84,223	141,665	1,827,298
22	Return on Equity	31,575,197	10,826,561	12,340,760	3,498,989	1,596,910	298,064	1,105,458	307,965	95,266	168,629	193,945	207,354	67,661	59,639	33,144	55,750	719,101
23	**Total Revenue Reqmt**	**501,055,017**	**117,697,000**	**308,207,603**	**26,885,705**	**12,980,790**	**2,883,879**	**10,546,237**	**2,793,224**	**925,099**	**1,637,502**	**1,729,435**	**1,851,163**	**734,928**	**803,068**	**384,016**	**3,027,273**	**6,189,423**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

	1	19	20	21
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	1,173,331	616,657	Carryforward from Sch.2.4 L.30
2	Fuels-No. 6 Fuel	-	-	Production - Demand, Energy ratios Sch.4.1 L.10
3	Fuels-Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L.12
4	Fuels-Gas Turbine	-	-	Production - Demand, Energy ratios Sch.4.1 L.11
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.7
7	Depreciation	-	-	Carryforward from Sch.2.5 L.40
	Expense Credits			
8	Sundry	(6,403)	(3,365)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.34
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
11	Suppliers' Discounts	(1,015)	(533)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(7,418)**	**(3,899)**	
18	**Subtotal Expenses**	**1,165,913**	**612,758**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.40
20	**Subtotal Revenue Requirement Ex. Return**	**1,165,913**	**612,758**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.9
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.11
23	**Total Revenue Reqmt**	**1,165,913**	**612,758**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural Prod &	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount	Production Demand	Transmission Energy	Transmission Demand	Transmission Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Production	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Hydraulic																	
1	Bay D'Espoir	205,287,321	91,588,866	113,698,455	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	173,700,320	77,496,337	96,203,983	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	83,007,896	37,033,943	45,973,952	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	270,355,729	120,619,114	149,736,616	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	22,088,673	9,854,854	12,233,819	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	112,042,966	49,987,930	62,055,036	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Hydraulic	4,882,132	2,178,161	2,703,971	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**871,365,037**	**388,759,205**	**482,605,832**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	233,407,565	181,264,315	52,143,250	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	27,677,497	27,677,497	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	8,787,244	8,787,244	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**1,141,237,342**	**606,488,260**	**534,749,082**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	276,091,346	-	-	154,130,048	86,411,569	-	-	-	-	-	-	-	-	-	-	-	35,549,729
15	Lines - Hydraulic	55,229,656	24,640,691	30,588,964	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	121,395,187	-	-	74,516,025	22,357,282	-	-	-	-	-	-	-	-	-	-	-	24,521,880
17	Term Stns - Hydraulic	33,784,335	15,072,869	18,711,466	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	8,580,157	6,663,350	1,916,807	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	700,310	700,310	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	11,364,538	-	-	-	-	11,364,538	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**175,824,526**	**22,436,529**	**20,628,273**	**74,516,025**	**22,357,282**	**11,364,538**	-	-	-	-	-	-	-	-	-	-	**24,521,880**
22	**Subtotal Transmission**	**507,145,527**	**47,077,220**	**51,217,237**	**228,646,073**	**108,768,851**	**11,364,538**	-	-	-	-	-	-	-	-	-	-	**60,071,608**
	Distribution																	
23	Substations	9,260,896	414,826	-	-	-	8,846,070	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	3,977,843	-	-	-	-	-	2,999,094	382,072	-	-	347,862	248,814	-	-	-	-	-
25	Poles	95,088,529	-	-	-	-	-	54,994,261	18,794,438	-	-	9,734,023	11,565,808	-	-	-	-	-
26	Primary Conductor & Eqpt	14,815,388	-	-	-	-	-	13,141,249	1,674,139	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	8,345,650	-	-	-	-	-	8,345,650	-	-	-	-	-	-	-	-	-	-
28	Transformers	14,920,941	-	-	-	-	-	-	-	5,386,460	9,534,481	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	4,466,619	-	-	-	-	-	-	-	-	-	2,604,039	1,862,580	-	-	-	-	-
30	Services	5,906,069	-	-	-	-	-	-	-	-	-	-	-	5,906,069	-	-	-	-
31	Meters	3,767,515	-	-	-	-	-	-	-	-	-	-	-	-	3,767,515	-	-	-
32	Street Lighting	1,936,292	-	-	-	-	-	-	-	-	-	-	-	-	-	1,936,292	-	-
33	**Subtotal Distribution**	**162,485,741**	**414,826**	-	-	-	**8,846,070**	**79,480,254**	**20,850,649**	**5,386,460**	**9,534,481**	**12,685,924**	**13,677,202**	**5,906,069**	**3,767,515**	**1,936,292**	-	-
34	**Subttl Prod, Trans, & Dist**	**1,810,868,610**	**653,980,306**	**585,966,319**	**228,646,073**	**108,768,851**	**20,210,608**	**79,480,254**	**20,850,649**	**5,386,460**	**9,534,481**	**12,685,924**	**13,677,202**	**5,906,069**	**3,767,515**	**1,936,292**	-	**60,071,608**
35	General	181,051,933	77,692,186	43,635,390	16,590,227	7,095,667	2,545,291	11,272,397	2,957,172	763,942	1,352,241	1,799,199	1,939,788	837,636	829,285	274,617	6,807,361	4,659,534
36	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	1,515,071	1,515,071	-	0	-	0	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	200,794	72,515	64,973	25,353	12,061	2,241	8,813	2,312	597	1,057	1,407	1,517	655	418	215	-	6,661
39	Software - General	3,755,096	1,356,122	1,215,085	474,130	225,548	41,910	164,814	43,237	11,170	19,771	26,306	28,362	12,247	7,812	4,015	-	124,567
40	**Total Plant**	**1,997,391,503**	**734,616,199**	**630,881,767**	**245,735,783**	**116,102,126**	**22,800,049**	**90,926,278**	**23,853,369**	**6,162,169**	**10,907,551**	**14,512,835**	**15,646,869**	**6,756,607**	**4,605,030**	**2,215,139**	**6,807,361**	**64,862,370**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	19
Line No.	Description	Basis of Functional Classification
	Production	
	Hydraulic	
1	Bay D'Espoir	Production - Demand, Energy ratios Sch.4.1 L.1
2	Upper Salmon	Production - Demand, Energy ratios Sch.4.1 L.1
3	Hinds Lake	Production - Demand, Energy ratios Sch.4.1 L.1
4	Cat Arm	Production - Demand, Energy ratios Sch.4.1 L.1
5	Paradise River	Production - Demand, Energy ratios Sch.4.1 L.1
6	Granite Canal	Production - Demand, Energy ratios Sch.4.1 L.1
7	Other Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.1, 2
8	**Subtotal Hydraulic**	
9	Holyrood	Production - Demand, Energy ratios Sch.4.1 L.3
10	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.4
11	Roddickton	Production - Demand, Energy ratios Sch.4.1 L.3
12	Diesel	Production - Demand, Energy ratios Sch.4.1 L.5
13	**Subtotal Production**	
	Transmission	
14	Lines	Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
15	Lines - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.17
16	Terminal Stations	Production - Demand, Energy subtotals, L. 13; Transmission - Demand; Spec Assigned - Custmr
17	Term Stns - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.20
18	Term Stns - Holyrood	Production - Demand, Energy ratios Sch.4.1 L.21
19	Term Stns - Gas Tur/Dsl	Production - Demand, Energy ratios Sch.4.1 L.22, 23
20	Term Stns - Distribution	Distribution - Substations Demand
21	**Subtotal Term Stns**	
22	**Subtotal Transmission**	
	Distribution	
23	Substations	Production - Demand; Dist Substns - Demand
24	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
25	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
26	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
27	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
28	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
29	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
30	Services	Services Customer
31	Meters	Meters - Customer
32	Street Lighting	Street Lighting - Customer
33	**Subtotal Distribution**	
34	**Subttl Prod, Trans, & Dist**	
35	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.15, 16
36	Telecontrol - Custmr & Spec	Specifically Assigned - Customer
37	Feasibility Studies	Production, Transmission - Demand
38	Feasibility Studies - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.34
39	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.34
40	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Distribution Primary Lines Customer ($)	10 Distribution Line Transformers Demand ($)	11 Distribution Line Transformers Customer ($)	12 Distribution Secondary Lines Demand ($)	13 Distribution Secondary Lines Customer ($)	14 Distribution Services Customer ($)	15 Distribution Meters Customer ($)	16 Distribution Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	146,667,150	65,435,497	81,231,652	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	155,736,648	69,481,851	86,254,797	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	71,597,675	31,943,278	39,654,398	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	245,540,111	109,547,634	135,992,477	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	19,348,707	8,632,419	10,716,288	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	104,354,922	46,557,912	57,797,011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Small Hydraulic	3,094,994	1,380,831	1,714,164	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**746,340,207**	**332,979,421**	**413,360,786**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
9	Holyrood	63,362,456	49,207,283	14,155,173	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	10,743,412	10,743,412	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	2,081,952	2,081,952	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**822,528,027**	**395,012,069**	**427,515,959**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
14	Lines	168,923,532	-	-	101,782,144	49,155,730	-	-	-	-	-	-	-	-	-	-	-	17,985,658
15	Lines - Hydraulic	47,282,890	21,095,245	26,187,645	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	66,668,364	-	-	40,251,794	15,788,536	-	-	-	-	-	-	-	-	-	-	-	10,628,033
17	Term Stns - Hydraulic	20,980,251	9,360,332	11,619,919	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	1,415,356	1,099,166	316,191	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	429,626	429,626	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	7,925,373	-	-	-	-	7,925,373	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**97,418,970**	**10,889,123**	**11,936,110**	**40,251,794**	**15,788,536**	**7,925,373**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**10,628,033**
22	**Subtotal Transmission**	**313,625,391**	**31,984,367**	**38,123,755**	**142,033,938**	**64,944,266**	**7,925,373**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**28,613,691**
	Distribution																	
23	Substations	3,912,384	144,305	-	-	-	3,768,079	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	2,988,107	-	-	-	-	-	2,252,884	287,008	-	-	261,310	186,906	-	-	-	-	-
25	Poles	55,142,293	-	-	-	-	-	31,891,435	10,898,984	-	-	5,644,806	6,707,067	-	-	-	-	-
26	Primary Conductor & Eqpt	6,912,321	-	-	-	-	-	6,131,228	781,092	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	2,401,161	-	-	-	-	-	2,401,161	-	-	-	-	-	-	-	-	-	-
28	Transformers	10,432,369	-	-	-	-	-	-	-	3,766,085	6,666,284	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	2,842,486	-	-	-	-	-	-	-	-	-	1,657,170	1,185,317	-	-	-	-	-
30	Services	2,549,244	-	-	-	-	-	-	-	-	-	-	-	2,549,244	-	-	-	-
31	Meters	2,230,055	-	-	-	-	-	-	-	-	-	-	-	-	2,230,055	-	-	-
32	Street Lighting	1,306,514	-	-	-	-	-	-	-	-	-	-	-	-	-	1,306,514	-	-
33	**Subtotal Distribution**	**90,716,935**	**144,305**	**-**	**-**	**-**	**3,768,079**	**42,676,708**	**11,967,084**	**3,766,085**	**6,666,284**	**7,563,286**	**8,079,290**	**2,549,244**	**2,230,055**	**1,306,514**	**-**	**-**
34	**Subttl Prod, Trans, & Dist**	**1,226,870,354**	**427,140,742**	**465,639,714**	**142,033,938**	**64,944,266**	**11,693,452**	**42,676,708**	**11,967,084**	**3,766,085**	**6,666,284**	**7,563,286**	**8,079,290**	**2,549,244**	**2,230,055**	**1,306,514**	**-**	**28,613,691**
35	General	61,979,648	26,596,426	14,937,737	5,679,345	2,429,065	871,331	3,858,888	1,012,331	261,521	462,914	615,921	664,049	286,749	283,890	94,010	2,330,369	1,595,102
36	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	1,515,071	1,515,071	-	0	-	0	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	21,957	7,644	8,333	2,542	1,162	209	764	214	67	119	135	145	46	40	23	-	512
39	Software - General	3,860,360	1,344,003	1,465,140	446,911	204,348	36,794	134,283	37,655	11,850	20,976	23,798	25,422	8,021	7,017	4,111	-	90,033
40	**Total Net Book Value**	**1,294,247,390**	**456,603,886**	**482,050,924**	**148,162,736**	**67,578,841**	**12,601,786**	**46,670,643**	**13,017,284**	**4,039,524**	**7,150,292**	**8,203,140**	**8,768,906**	**2,844,059**	**2,521,001**	**1,404,659**	**2,330,369**	**30,299,338**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural Prod &		Primary Lines		Line Transformers		Secondary Lines						Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations							Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Production	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Hydraulic	11,574,317	5,163,877	6,410,439	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Holyrood / Thermal	17,548,304	13,628,013	3,920,291	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Gas Turbine	1,040,944	1,040,944	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Diesel	226,064	226,064	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	2,496,334	1,326,628	1,169,706	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Production**	**32,885,963**	**21,385,526**	**11,500,437**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
8	Transmission Lines	3,744,074	278,451	345,669	1,741,738	976,489	-	-	-	-	-	-	-	-	-	-	-	401,728
9	Terminal Stations	5,087,316	649,180	596,860	2,156,051	646,887	328,822	-	-	-	-	-	-	-	-	-	-	709,517
10	Other	2,019,730	187,487	203,975	910,593	433,177	45,260	-	-	-	-	-	-	-	-	-	-	239,238
11	**Subtotal Transmission**	**10,851,120**	**1,115,118**	**1,146,503**	**4,808,382**	**2,056,553**	**374,082**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,350,483**
	Distribution																	
12	Other	6,524,248	17,052	-	-	-	363,625	3,267,103	857,084	221,415	391,923	521,466	562,213	242,774	-	79,593	-	-
13	Meters	240,353	-	-	-	-	-	-	-	-	-	-	-	-	240,353	-	-	-
14	**Subtotal Distribution**	**6,764,601**	**17,052**	**-**	**-**	**-**	**363,625**	**3,267,103**	**857,084**	**221,415**	**391,923**	**521,466**	**562,213**	**242,774**	**240,353**	**79,593**	**-**	**-**
15	**Subttl Prod, Trans, & Dist**	**50,501,684**	**22,517,695**	**12,646,940**	**4,808,382**	**2,056,553**	**737,707**	**3,267,103**	**857,084**	**221,415**	**391,923**	**521,466**	**562,213**	**242,774**	**240,353**	**79,593**	**-**	**1,350,483**
16	Customer Accounting	1,972,992	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,972,992	-
	Administrative & General:																	
	Plant-Related:																	
17	Production	5,659,715	3,007,745	2,651,970	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Prod - Gas Turb & Diesel	1,275,556	1,275,556	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Transmission	4,424,868	410,751	446,873	1,994,947	949,013	99,156	-	-	-	-	-	-	-	-	-	-	524,128
20	Distribution	2,106,974	5,379	-	-	-	114,708	1,030,631	270,373	69,847	123,635	164,500	177,354	76,585	48,854	25,108	-	-
21	Prod, Trans, Distn	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Prod, Trans, Distn and General Plant	406,146	149,375	128,282	49,967	23,608	4,636	18,489	4,850	1,253	2,218	2,951	3,182	1,374	936	450	1,384	13,189
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	1,251,650	148,825	90,789	405,306	192,807	35,826	140,889	36,961	9,548	16,901	22,488	24,245	10,469	6,678	3,432	-	106,485
24	Property Insurance	1,286,094	603,240	511,078	77,732	25,129	19,415	9,618	2,523	652	1,154	1,535	1,655	715	708	234	5,808	24,898
	Revenue-Related:																	
25	Municipal Tax	1,173,331	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	PUB Assessment	616,657	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	All Expense-Related	17,202,851	7,382,010	4,146,065	1,576,339	674,203	241,844	1,071,059	280,979	72,587	128,485	170,953	184,311	79,589	78,795	26,093	646,809	442,731
28	Prod, Trans, and Distn Expense-Related	1,547,450	689,977	387,522	147,336	63,016	22,604	100,109	26,262	6,785	12,009	15,979	17,227	7,439	7,365	2,439	-	41,381
29	**Subtotal Admin & General**	**36,951,292**	**13,672,858**	**8,362,580**	**4,251,628**	**1,927,777**	**538,190**	**2,370,795**	**621,948**	**160,671**	**284,402**	**378,405**	**407,974**	**176,171**	**143,336**	**57,757**	**654,001**	**1,152,811**
30	**Total Operating & Maintenance Expenses**	**89,425,968**	**36,190,554**	**21,009,520**	**9,060,010**	**3,984,329**	**1,275,897**	**5,637,899**	**1,479,032**	**382,086**	**676,324**	**899,871**	**970,187**	**418,945**	**383,690**	**137,350**	**2,626,994**	**2,503,294**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	19	20	21
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Hydraulic	-	-	Prorated on Hydraulic Plant in Service - Sch.2.2 L.8
2	Holyrood / Thermal	-	-	Prorated on Holyrood Plant in Service - Sch.2.2 L.9
3	Roddickton	-	-	Prorated on Roddickton Plant in Service - Sch.2.2 L.11
4	Gas Turbine	-	-	Prorated on Gas Turbines Plant in Service - Sch.2.2 L.10
5	Diesel	-	-	Prorated on Diesel Plant in Service - Sch.2.2 L.12
6	Other	-	-	Prorated on Production Plant in Service - Sch.2.2 L.13
7	**Subtotal Production**	**-**	**-**	
	Transmission			
8	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.14, 15
9	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.21
10	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.22
11	**Subtotal Transmission**	**-**	**-**	
	Distribution			
12	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 33, less L. 31
13	Meters	-	-	Meters - Customer
14	**Subtotal Distribution**	**-**	**-**	
15	**Subttl Prod, Trans, & Dist**	**-**	**-**	
16	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
17	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.13
18	Prod - Gas Turb & Diesel		-	Prorated on Gas Turbine & Diesel Production Plant in Service - Sch.2.2 L.10, 12
19	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.22
20	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.33
21	Prod, Trans, Distn	-	-	Prorated on Prod, Trans & Distribution Plant in Service - Sch.2.2 L.34
22	Prod, Trans, Distn and General Plant	-	-	Prorated on Total Plant in Service, Sch. 2.2, L. 40
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	-	-	Prorated on Total Plant in Service, Sch. 2.2, L. 34 Less L. 8 and L. 9
24	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.13, 21, 23, 35 - 36
	Revenue-Related:			
25	Municipal Tax	1,173,331	-	Revenue-related
26	PUB Assessment	-	616,657	Revenue-related
27	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 15, 16
28	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L 15
29	**Subtotal Admin & General**	**1,173,331**	**616,657**	
30	**Total Operating & Maintenance Expenses**	**1,173,331**	**616,657**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production and		Rural Prod &	Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Production	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Hydraulic																	
1	Bay D'Espoir	3,519,191	1,570,086	1,949,105	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	3,001,997	1,339,340	1,662,657	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	1,348,883	601,804	747,080	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	5,488,067	2,448,499	3,039,568	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	448,265	199,993	248,271	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	2,413,843	1,076,935	1,336,908	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Small Hydraulic	66,890	29,843	37,047	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**16,287,136**	**7,266,500**	**9,020,636**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	9,145,639	7,102,503	2,043,136	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	420,168	420,168	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	73,383	73,383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**25,926,325**	**14,862,554**	**11,063,771**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	5,527,830	-	-	3,226,595	1,701,150	-	-	-	-	-	-	-	-	-	-	-	600,084
15	Lines - Hydraulic	1,381,675	616,434	765,241	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	2,560,560	-	-	1,522,272	677,341	-	-	-	-	-	-	-	-	-	-	-	360,947
17	Term Stns - Hydraulic	736,188	328,450	407,738	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	54,165	42,065	12,101	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	14,370	14,370	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	316,612	-	-	-	-	316,612	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**3,681,896**	**384,885**	**419,838**	**1,522,272**	**677,341**	**316,612**	-	-	-	-	-	-	-	-	-	-	**360,947**
22	**Subtotal Transmission**	**10,591,402**	**1,001,319**	**1,185,080**	**4,748,867**	**2,378,492**	**316,612**	-	-	-	-	-	-	-	-	-	-	**961,032**
	Distribution																	
23	Substations	146,190	4,515	-	-	-	141,675	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	63,361	-	-	-	-	-	47,771	6,086	-	-	5,541	3,963	-	-	-	-	-
25	Poles	1,589,329	-	-	-	-	-	919,185	314,134	-	-	162,696	193,313	-	-	-	-	-
26	Primary Conductor & Eqpt	223,599	-	-	-	-	-	198,332	25,267	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	94,774	-	-	-	-	-	94,774	-	-	-	-	-	-	-	-	-	-
28	Transformers	489,154	-	-	-	-	-	-	-	176,585	312,570	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	48,193	-	-	-	-	-	-	-	-	-	28,097	20,097	-	-	-	-	-
30	Services	47,940	-	-	-	-	-	-	-	-	-	-	-	47,940	-	-	-	-
31	Meters	181,911	-	-	-	-	-	-	-	-	-	-	-	-	181,911	-	-	-
32	Street Lighting	118,055	-	-	-	-	-	-	-	-	-	-	-	-	-	118,055	-	-
33	**Subtotal Distribution**	**3,002,504**	**4,515**	-	-	-	**141,675**	**1,260,062**	**345,486**	**176,585**	**312,570**	**196,334**	**217,373**	**47,940**	**181,911**	**118,055**	-	-
34	**Subttl Prod, Trans, & Dist**	**39,520,231**	**15,868,388**	**12,248,851**	**4,748,867**	**2,378,492**	**458,287**	**1,260,062**	**345,486**	**176,585**	**312,570**	**196,334**	**217,373**	**47,940**	**181,911**	**118,055**	-	**961,032**
35	General	6,098,194	2,616,829	1,469,728	558,792	238,996	85,731	379,677	99,604	25,731	45,546	60,601	65,336	28,213	27,932	9,250	229,286	156,942
36	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	513,937	513,937	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	18,820	7,557	5,833	2,261	1,133	218	600	165	84	149	93	104	23	87	56	-	458
39	Software - General	580,010	232,889	179,768	69,696	34,907	6,726	18,493	5,070	2,592	4,587	2,881	3,190	704	2,670	1,733	-	14,104
40	**Total Deprecn Expense**	**46,731,192**	**19,239,600**	**13,904,180**	**5,379,617**	**2,653,528**	**550,962**	**1,658,832**	**450,325**	**204,992**	**362,852**	**259,909**	**286,003**	**76,879**	**212,599**	**129,093**	**229,286**	**1,132,536**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural Prod &												Specifically
Line		Total	Production	Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	1,294,247,390	456,603,886	482,050,924	148,162,736	67,578,841	12,601,786	46,670,643	13,017,284	4,039,524	7,150,292	8,203,140	8,768,906	2,844,059	2,521,001	1,404,659	2,330,369	30,299,338
2	Cash Working Capital	4,871,110	1,718,503	1,814,277	557,634	254,344	47,429	175,653	48,993	15,203	26,911	30,874	33,003	10,704	9,488	5,287	8,771	114,036
3	Fuel Inventory - No. 6 Fuel	45,130,957	-	45,130,957	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	94,498	94,498	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	2,121,588	2,121,588	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	21,993,318	8,088,874	6,946,652	2,705,802	1,278,403	251,052	1,001,191	262,650	67,852	120,103	159,801	172,288	74,397	50,706	24,391	74,956	714,201
7	Deferred Charges: Holyrood	-	-	-														
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	59,750,587	21,079,703	22,254,498	6,840,122	3,119,864	581,778	2,154,610	600,960	186,490	330,102	378,708	404,828	131,300	116,385	64,848	107,584	1,398,808
9	Total Rate Base	**1,428,209,448**	**489,707,051**	**558,197,308**	**158,266,295**	**72,231,452**	**13,482,044**	**50,002,096**	**13,929,886**	**4,309,069**	**7,627,409**	**8,772,524**	**9,379,025**	**3,060,460**	**2,697,581**	**1,499,184**	**2,521,680**	**32,526,384**
10	Less: Rural Asset Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Rate Base Available for Equity Return	**1,428,209,448**	**489,707,051**	**558,197,308**	**158,266,295**	**72,231,452**	**13,482,044**	**50,002,096**	**13,929,886**	**4,309,069**	**7,627,409**	**8,772,524**	**9,379,025**	**3,060,460**	**2,697,581**	**1,499,184**	**2,521,680**	**32,526,384**
12	Return on Debt	80,235,295	27,511,224	31,358,934	8,891,233	4,057,886	757,407	2,809,065	782,566	242,079	428,500	492,831	526,904	171,933	151,547	84,223	141,665	1,827,298
13	Return on Equity	31,575,197	10,826,561	12,340,760	3,498,989	1,596,910	298,064	1,105,458	307,965	95,266	168,629	193,945	207,354	67,661	59,639	33,144	55,750	719,101
14	Return on Rate Base	**111,810,492**	**38,337,785**	**43,699,694**	**12,390,222**	**5,654,797**	**1,055,471**	**3,914,523**	**1,090,532**	**337,345**	**597,128**	**686,776**	**734,257**	**239,595**	**211,186**	**117,367**	**197,415**	**2,546,399**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	19
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 40
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Demand, Energy ratios Sch.4.1 L.10
4	Fuel Inventory - Diesel	Production - Demand, Energy ratios Sch.4.1 L.12
5	Fuel Inventory - Gas Turbine	Production - Demand, Energy ratios Sch.4.1 L.11
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 40
7	Deferred Charges: Holyrood	Production - Demand, Energy ratios Sch.4.1 L.3
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Asset Portion	N/A
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch.1.1,p2,L.14
13	Return on Equity	L.11 x Sch.1.1,p2,L.17
14	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Basis of Allocation to Classes of Service

Line	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							Distribution											
				Production and		Rural Prod &		Primary Lines		Line Transformers		Secondary Lines						Specifically
No.	Description	Total Amount	Production Demand	Transmission Energy	Transmission Demand	Transmission Demand	Substations Demand	Demand	Customer	Demand	Customer	Demand	Customer	Services Customer	Meters Customer	Street Lighting Customer	Accounting Customer	Assigned Customer
			(1 CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
	Amounts																	
1	Newfoundland Power	-	1,175,961	5,794,481	1,175,507	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Industrial - Firm	-	71,073	423,014	68,936	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	-	25,803	123,003	25,027	25,027	23,790	23,790	11,686	21,952	11,686	21,952	11,686	11,686	11,686	-	11,686	-
5	1.12 Domestic All Electric	-	36,339	157,509	35,246	35,246	33,504	33,504	8,001	30,916	8,001	30,916	8,001	8,001	8,001	-	8,001	-
6	1.3 Special	-	103	390	100	100	95	95	1	88	1	88	1	1	1	-	1	-
7	2.1 GS 0-10 kW	-	2,697	15,497	2,616	2,616	2,487	2,487	1,997	2,295	1,997	2,295	1,997	3,749	3,749	-	1,997	-
8	2.2 GS 10-100 kW	-	13,904	72,822	13,486	13,486	12,819	12,819	904	11,828	904	11,828	904	4,312	4,312	-	904	-
9	2.3 GS 110-1,000 kVa	-	9,480	55,411	9,195	9,195	8,741	8,741	84	7,383	84	7,383	84	707	707	-	84	-
10	2.4 GS Over 1,000 kVa	-	4,828	35,393	4,683	4,683	4,451	4,451	10	4,107	10	4,107	10	84	84	-	10	-
11	4.1 Street and Area Lighting	-	811	3,281	787	787	748	748	910	690	910	690	910	-	-	1	910	-
12	**Subtotal Rural**	**-**	**93,966**	**463,306**	**91,141**	**91,141**	**86,635**	**86,635**	**23,593**	**79,259**	**23,593**	**79,259**	**23,593**	**28,541**	**28,541**	**1**	**23,593**	**-**
13	**Total**	**-**	**1,341,001**	**6,680,800**	**1,335,583**	**91,141**	**86,635**	**86,635**	**23,593**	**79,259**	**23,593**	**79,259**	**23,593**	**28,541**	**28,541**	**1**	**23,593**	**-**
	Ratios Excluding Return on Equity																	
14	Newfoundland Power	-	0.8769	0.8673	0.8801	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial - Firm	-	0.0530	0.0633	0.0516	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	-	0.0192	0.0184	0.0187	0.2746	0.2746	0.2746	0.4953	0.2770	0.4953	0.2770	0.4953	0.4094	0.4094	-	0.4953	-
18	1.12 Domestic All Electric	-	0.0271	0.0236	0.0264	0.3867	0.3867	0.3867	0.3391	0.3901	0.3391	0.3901	0.3391	0.2803	0.2803	-	0.3391	-
19	1.3 Special	-	0.0001	0.0001	0.0001	0.0011	0.0011	0.0011	0.0000	0.0011	0.0000	0.0011	0.0000	0.0000	0.0000	-	0.0000	-
20	2.1 GS 0-10 kW	-	0.0020	0.0023	0.0020	0.0287	0.0287	0.0287	0.0846	0.0290	0.0846	0.0290	0.0846	0.1314	0.1314	-	0.0846	-
21	2.2 GS 10-100 kW	-	0.0104	0.0109	0.0101	0.1480	0.1480	0.1480	0.0383	0.1492	0.0383	0.1492	0.0383	0.1511	0.1511	-	0.0383	-
22	2.3 GS 110-1,000 kVa	-	0.0071	0.0083	0.0069	0.1009	0.1009	0.1009	0.0036	0.0932	0.0036	0.0932	0.0036	0.0248	0.0248	-	0.0036	-
23	2.4 GS Over 1,000 kVa	-	0.0036	0.0053	0.0035	0.0514	0.0514	0.0514	0.0004	0.0518	0.0004	0.0518	0.0004	0.0029	0.0029	-	0.0004	-
24	4.1 Street and Area Lighting	-	0.0006	0.0005	0.0006	0.0086	0.0086	0.0086	0.0386	0.0087	0.0386	0.0087	0.0386	-	-	1.0000	0.0386	-
25	**Subtotal Rural**	**-**	**0.0701**	**0.0693**	**0.0682**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
26	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

	1	19	20
		Revenue Related	
Line No.	Description	Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	Newfoundland Power	-	443,269,708
2	Industrial - Firm	-	17,320,404
3	Industrial - Non-Firm	-	-
	Rural		
4	1.1 Domestic	13,017,786	13,017,786
5	1.12 Domestic All Electric	16,084,681	16,084,681
6	1.3 Special	18,312	18,312
7	2.1 GS 0-10 kW	2,329,848	2,329,848
8	2.2 GS 10-100 kW	6,891,578	6,891,578
9	2.3 GS 110-1,000 kVa	6,074,116	6,074,116
10	2.4 GS Over 1,000 kVa	2,854,933	2,854,933
11	4.1 Street and Area Lighting	993,375	993,375
12	**Subtotal Rural**	**48,264,628**	**48,264,628**
13	**Total**	**48,264,628**	**508,854,740**
	Ratios Excluding Return on Equity		
14	Newfoundland Power	-	0.8711
15	Industrial - Firm	-	0.0340
16	Industrial - Non-Firm	-	-
	Rural		
17	1.1 Domestic	0.2697	0.0256
18	1.12 Domestic All Electric	0.3333	0.0316
19	1.3 Special	0.0004	0.0000
20	2.1 GS 0-10 kW	0.0483	0.0046
21	2.2 GS 10-100 kW	0.1428	0.0135
22	2.3 GS 110-1,000 kVa	0.1259	0.0119
23	2.4 GS Over 1,000 kVa	0.0592	0.0056
24	4.1 Street and Area Lighting	0.0206	0.0020
25	**Subtotal Rural**	**1.0000**	**0.0948**
26	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service

Line No.	Description	Total Amount	Production Demand	Production and Transmission Energy	Transmission Demand	Rural Prod & Transmission Demand	Distribution: Substations Demand	Distribution: Primary Lines Demand	Distribution: Primary Lines Customer	Distribution: Line Transformers Demand	Distribution: Line Transformers Customer	Distribution: Secondary Lines Demand	Distribution: Secondary Lines Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: Street Lighting Customer	Accounting Customer	Specifically Assigned Customer
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
	Allocated Rev Reqmt Excl Return	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Newfoundland Power	314,627,389	69,592,303	229,416,527	12,758,124	-	-	-	-	-	-	-	-	-	-	-	-	2,326,654
2	Industrial - Firm	23,039,537	4,206,059	16,748,067	748,183	-	-	-	-	-	-	-	-	-	-	-	-	1,316,371
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	15,543,987	1,527,027	4,869,956	271,631	2,011,740	502,086	1,821,089	843,372	162,791	515,314	288,786	553,222	202,813	242,344	-	1,401,675	-
5	1.12 Domestic All Electric	18,491,420	2,150,519	6,236,123	382,539	2,833,143	707,091	2,564,648	577,427	229,259	352,818	406,698	378,772	138,859	165,925	-	959,678	-
6	1.3 Special	42,567	6,105	15,452	1,086	8,043	2,007	7,281	72	651	44	1,155	47	17	21	-	120	-
7	2.1 GS 0-10 kW	2,070,097	159,625	613,569	28,394	210,293	52,485	190,364	144,122	17,017	88,061	30,188	94,539	65,070	77,753	-	239,530	-
8	2.2 GS 10-100 kW	7,026,919	822,832	2,883,192	146,367	1,084,018	270,547	981,286	65,241	87,710	39,863	155,595	42,796	74,839	89,426	-	108,430	-
9	2.3 GS 110-1,000 kVa	4,804,041	561,041	2,193,836	99,799	739,128	184,470	669,081	6,062	54,752	3,704	97,129	3,977	12,274	14,667	-	10,075	-
10	2.4 GS Over 1,000 kVa	2,711,824	285,706	1,401,300	50,822	376,396	93,940	340,725	722	30,458	441	54,032	473	1,461	1,746	-	1,199	-
11	4.1 Street and Area Lighting	886,743	47,997	129,887	8,538	63,232	15,781	57,240	65,674	5,117	40,128	9,077	43,080	-	-	266,649	109,150	-
12	**Subtotal Rural**	**51,577,599**	**5,560,852**	**18,343,316**	**989,176**	**7,325,993**	**1,828,408**	**6,631,714**	**1,702,693**	**587,754**	**1,040,374**	**1,042,659**	**1,116,906**	**495,334**	**591,882**	**266,649**	**2,829,857**	**-**
13	**Total**	**389,244,525**	**79,359,215**	**264,507,910**	**14,495,483**	**7,325,993**	**1,828,408**	**6,631,714**	**1,702,693**	**587,754**	**1,040,374**	**1,042,659**	**1,116,906**	**495,334**	**591,882**	**266,649**	**2,829,857**	**3,643,024**
	Allocated Return on Debt																	
14	Newfoundland Power	60,634,027	24,125,357	27,198,649	7,825,572	-	-	-	-	-	-	-	-	-	-	-	-	1,484,448
15	Industrial - Firm	4,245,451	1,458,102	1,985,580	458,920	-	-	-	-	-	-	-	-	-	-	-	-	342,849
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	4,634,027	529,370	577,361	166,613	1,114,308	207,986	771,378	387,618	67,049	212,243	136,500	260,984	70,398	62,051	-	70,169	-
18	1.12 Domestic All Electric	5,682,786	745,514	739,328	234,642	1,569,285	292,908	1,086,335	265,389	94,425	145,315	192,233	178,687	48,199	42,484	-	48,042	-
19	1.3 Special	13,891	2,117	1,832	666	4,455	832	3,084	33	268	18	546	22	6	5	-	6	-
20	2.1 GS 0-10 kW	587,224	55,337	72,742	17,417	116,482	21,741	80,634	66,239	7,009	36,270	14,269	44,599	22,586	19,908	-	11,991	-
21	2.2 GS 10-100 kW	2,075,577	285,249	341,819	89,779	600,440	112,073	415,654	29,985	36,125	16,419	73,545	20,189	25,977	22,897	-	5,428	-
22	2.3 GS 110-1,000 kVa	1,368,200	194,494	260,092	61,215	409,405	76,416	283,410	2,786	22,551	1,526	45,910	1,876	4,260	3,755	-	504	-
23	2.4 GS Over 1,000 kVa	727,910	99,045	166,132	31,173	208,487	38,914	144,324	332	12,545	182	25,539	223	507	447	-	60	-
24	4.1 Street and Area Lighting	266,202	16,639	15,399	5,237	35,024	6,537	24,246	30,184	2,107	16,528	4,290	20,323	-	-	84,223	5,464	-
25	**Subtotal Rural**	**15,355,817**	**1,927,764**	**2,174,706**	**606,741**	**4,057,886**	**757,407**	**2,809,065**	**782,566**	**242,079**	**428,500**	**492,831**	**526,904**	**171,933**	**151,547**	**84,223**	**141,665**	**-**
26	**Total**	**80,235,295**	**27,511,224**	**31,358,934**	**8,891,233**	**4,057,886**	**757,407**	**2,809,065**	**782,566**	**242,079**	**428,500**	**492,831**	**526,904**	**171,933**	**151,547**	**84,223**	**141,665**	**1,827,298**
	Allocated Return on Equity																	
27	Newfoundland Power	23,861,461	9,494,113	10,703,553	3,079,617	-	-	-	-	-	-	-	-	-	-	-	-	584,179
28	Industrial - Firm	1,670,723	573,811	781,390	180,600	-	-	-	-	-	-	-	-	-	-	-	-	134,922
29	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
30	1.1 Domestic	1,823,640	208,324	227,210	65,568	438,516	81,849	303,562	152,540	26,386	83,525	53,717	102,706	27,704	24,419	-	27,614	-
31	1.12 Domestic All Electric	2,236,361	293,384	290,950	92,339	617,565	115,269	427,508	104,439	37,159	57,186	75,650	70,319	18,968	16,719	-	18,906	-
32	1.3 Special	5,466	833	721	262	1,753	327	1,214	13	105	7	215	9	2	2	-	2	-
33	2.1 GS 0-10 kW	231,092	21,777	28,626	6,854	45,839	8,556	31,732	26,067	2,758	14,273	5,615	17,551	8,888	7,835	-	4,719	-
34	2.2 GS 10-100 kW	816,807	112,255	134,517	35,331	236,293	44,104	163,573	11,800	14,216	6,461	28,942	7,945	10,223	9,011	-	2,136	-
35	2.3 GS 110-1,000 kVa	538,431	76,540	102,355	24,090	161,114	30,072	111,531	1,096	8,875	600	18,067	738	1,677	1,478	-	198	-
36	2.4 GS Over 1,000 kVa	286,456	38,977	65,378	12,268	82,046	15,314	56,796	131	4,937	71	10,050	88	200	176	-	24	-
37	4.1 Street and Area Lighting	104,759	6,548	6,060	2,061	13,783	2,573	9,541	11,878	829	6,504	1,688	7,998	-	-	33,144	2,150	-
38	**Subtotal Rural**	**6,043,013**	**758,638**	**855,817**	**238,772**	**1,596,910**	**298,064**	**1,105,458**	**307,965**	**95,266**	**168,629**	**193,945**	**207,354**	**67,661**	**59,639**	**33,144**	**55,750**	**-**
39	**Total**	**31,575,197**	**10,826,561**	**12,340,760**	**3,498,989**	**1,596,910**	**298,064**	**1,105,458**	**307,965**	**95,266**	**168,629**	**193,945**	**207,354**	**67,661**	**59,639**	**33,144**	**55,750**	**719,101**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	19	20
		Revenue Related	
Line No.	Description	Municipal Tax	PUB Assessment
	Allocated Rev Reqmt Excl Return		($)
1	Newfoundland Power	-	533,781
2	Industrial - Firm	-	20,857
3	Industrial - Non-Firm	-	-
	Rural		
4	1.1 Domestic	314,466	15,676
5	1.12 Domestic All Electric	388,552	19,369
6	1.3 Special	442	22
7	2.1 GS 0-10 kW	56,281	2,806
8	2.2 GS 10-100 kW	166,478	8,299
9	2.3 GS 110-1,000 kVa	146,730	7,314
10	2.4 GS Over 1,000 kVa	68,966	3,438
11	4.1 Street and Area Lighting	23,997	1,196
12	**Subtotal Rural**	**1,165,913**	**58,120**
13	**Total**	**1,165,913**	**612,758**
	Allocated Return on Debt		
14	Newfoundland Power	-	-
15	Industrial - Firm	-	-
16	Industrial - Non-Firm	-	-
	Rural		
17	1.1 Domestic	-	-
18	1.12 Domestic All Electric	-	-
19	1.3 Special	-	-
20	2.1 GS 0-10 kW	-	-
21	2.2 GS 10-100 kW	-	-
22	2.3 GS 110-1,000 kVa	-	-
23	2.4 GS Over 1,000 kVa	-	-
24	4.1 Street and Area Lighting	-	-
25	**Subtotal Rural**	**-**	**-**
26	**Total**	**-**	**-**
	Allocated Return on Equity		
27	Newfoundland Power	-	-
28	Industrial - Firm	-	-
29	Industrial - Non-Firm	-	-
	Rural		
30	1.1 Domestic	-	-
31	1.12 Domestic All Electric	-	-
32	1.3 Special	-	-
33	2.1 GS 0-10 kW	-	-
34	2.2 GS 10-100 kW	-	-
35	2.3 GS 110-1,000 kVa	-	-
36	2.4 GS Over 1,000 kVa	-	-
37	4.1 Street and Area Lighting	-	-
38	**Subtotal Rural**	**-**	**-**
39	**Total**	**-**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution: Substations Demand ($)	8 Distribution: Primary Lines Demand ($)	9 Distribution: Primary Lines Customer ($)	10 Distribution: Line Transformers Demand ($)	11 Distribution: Line Transformers Customer ($)	12 Distribution: Secondary Lines Demand ($)	13 Distribution: Secondary Lines Customer ($)	14 Distribution: Services Customer ($)	15 Distribution: Meters Customer ($)	16 Distribution: Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Total Revenue Requiremt																	
40	Newfoundland Power	399,122,877	103,211,773	267,318,728	23,663,313	-	-	-	-	-	-	-	-	-	-	-	-	4,395,281
41	Industrial - Firm	28,955,711	6,237,972	19,515,036	1,387,703	-	-	-	-	-	-	-	-	-	-	-	-	1,794,142
42	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
43	1.1 Domestic	22,001,654	2,264,721	5,674,528	503,811	3,564,564	791,922	2,896,029	1,383,530	256,225	811,082	479,002	916,912	300,914	328,813	-	1,499,458	-
44	1.12 Domestic All Electric	26,410,568	3,189,418	7,266,401	709,520	5,019,993	1,115,268	4,078,491	947,255	360,843	555,320	674,581	627,778	206,025	225,127	-	1,026,627	-
45	1.3 Special	61,924	9,055	18,005	2,014	14,252	3,166	11,579	118	1,024	69	1,915	78	26	28	-	128	-
46	2.1 GS 0-10 kW	2,888,414	236,738	714,938	52,665	372,615	82,782	302,731	236,429	26,784	138,604	50,072	156,689	96,545	105,496	-	256,240	-
47	2.2 GS 10-100 kW	9,919,304	1,220,336	3,359,528	271,477	1,920,751	426,724	1,560,513	107,026	138,051	62,743	258,081	70,930	111,039	121,334	-	115,994	-
48	2.3 GS 110-1,000 kVa	6,710,671	832,075	2,556,283	185,104	1,309,646	290,958	1,064,022	9,945	86,178	5,830	161,106	6,591	18,211	19,900	-	10,778	-
49	2.4 GS Over 1,000 kVa	3,726,191	423,728	1,632,810	94,263	666,928	148,168	541,846	1,184	47,940	694	89,621	785	2,168	2,369	-	1,283	-
50	4.1 Street and Area Lighting	1,257,704	71,184	151,346	15,836	112,040	24,891	91,027	107,737	8,054	63,160	15,056	71,401	-	-	384,016	116,764	-
51	**Subtotal Rural**	**72,976,430**	**8,247,254**	**21,373,839**	**1,834,689**	**12,980,790**	**2,883,879**	**10,546,237**	**2,793,224**	**925,099**	**1,637,502**	**1,729,435**	**1,851,163**	**734,928**	**803,068**	**384,016**	**3,027,273**	**-**
52	**Total**	**501,055,017**	**117,697,000**	**308,207,603**	**26,885,705**	**12,980,790**	**2,883,879**	**10,546,237**	**2,793,224**	**925,099**	**1,637,502**	**1,729,435**	**1,851,163**	**734,928**	**803,068**	**384,016**	**3,027,273**	**6,189,423**
	Re-classification of Revenue-Related																	
53	Newfoundland Power	-	138,219	357,987	31,689	-	-	-	-	-	-	-	-	-	-	-	-	5,886
54	Industrial - Firm	-	4,497	14,067	1,000	-	-	-	-	-	-	-	-	-	-	-	-	1,293
55	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
56	1.1 Domestic	0	34,501	86,445	7,675	54,302	12,064	44,118	21,077	3,903	12,356	7,297	13,968	4,584	5,009	-	22,843	-
57	1.12 Domestic All Electric	0	50,035	113,993	11,131	78,752	17,496	63,982	14,860	5,661	8,712	10,583	9,848	3,232	3,532	-	16,105	-
58	1.3 Special	(0)	68	136	15	108	24	87	1	8	1	14	1	0	0	-	1	-
59	2.1 GS 0-10 kW	(0)	4,944	14,931	1,100	7,782	1,729	6,322	4,938	559	2,895	1,046	3,272	2,016	2,203	-	5,351	-
60	2.2 GS 10-100 kW	0	21,888	60,256	4,869	34,450	7,654	27,989	1,920	2,476	1,125	4,629	1,272	1,992	2,176	-	2,080	-
61	2.3 GS 110-1,000 kVa	(0)	19,549	60,059	4,349	30,770	6,836	24,999	234	2,025	137	3,785	155	428	468	-	253	-
62	2.4 GS Over 1,000 kVa	0	8,397	32,356	1,868	13,216	2,936	10,737	23	950	14	1,776	16	43	47	-	25	-
63	4.1 Street and Area Lighting	0	1,455	3,094	324	2,290	509	1,861	2,202	165	1,291	308	1,459	-	-	7,849	2,387	-
64	**Subtotal Rural**	**0**	**140,836**	**371,269**	**31,330**	**221,669**	**49,247**	**180,095**	**45,254**	**15,747**	**26,530**	**29,438**	**29,991**	**12,295**	**13,435**	**7,849**	**49,046**	**-**
65	**Total**	**0**	**283,551**	**743,323**	**64,020**	**221,669**	**49,247**	**180,095**	**45,254**	**15,747**	**26,530**	**29,438**	**29,991**	**12,295**	**13,435**	**7,849**	**49,046**	**7,179**
	Total Allocated Revenue Requirement																	
66	Newfoundland Power	399,122,877	103,349,992	267,676,715	23,695,003	-	-	-	-	-	-	-	-	-	-	-	-	4,401,167
67	Industrial - Firm	28,955,711	6,242,469	19,529,103	1,388,703	-	-	-	-	-	-	-	-	-	-	-	-	1,795,436
68	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
69	1.1 Domestic	22,001,654	2,299,222	5,760,973	511,486	3,618,867	803,986	2,940,147	1,404,606	260,128	823,438	486,300	930,880	305,498	333,823	-	1,522,300	-
70	1.12 Domestic All Electric	26,410,568	3,239,452	7,380,394	720,650	5,098,745	1,132,764	4,142,473	962,115	366,504	564,031	685,164	637,626	209,258	228,659	-	1,042,732	-
71	1.3 Special	61,924	9,123	18,141	2,030	14,360	3,190	11,667	119	1,032	70	1,930	79	26	28	-	129	-
72	2.1 GS 0-10 kW	2,888,414	241,682	729,868	53,765	380,396	84,511	309,053	241,366	27,343	141,499	51,117	159,962	98,561	107,699	-	261,591	-
73	2.2 GS 10-100 kW	9,919,304	1,242,223	3,419,784	276,346	1,955,201	434,378	1,588,502	108,946	140,527	63,869	262,710	72,202	113,030	123,510	-	118,075	-
74	2.3 GS 110-1,000 kVa	6,710,671	851,624	2,616,342	189,453	1,340,416	297,794	1,089,020	10,179	88,203	5,967	164,891	6,746	18,639	20,367	-	11,031	-
75	2.4 GS Over 1,000 kVa	3,726,191	432,125	1,665,166	96,131	680,144	151,104	552,583	1,207	48,890	708	91,397	800	2,211	2,416	-	1,309	-
76	4.1 Street and Area Lighting	1,257,704	72,639	154,440	16,159	114,330	25,400	92,887	109,939	8,218	64,451	15,364	72,860	-	-	391,866	119,151	-
77	**Subtotal Rural**	**72,976,430**	**8,388,090**	**21,745,108**	**1,866,019**	**13,202,459**	**2,933,127**	**10,726,332**	**2,838,478**	**940,846**	**1,664,032**	**1,758,873**	**1,881,155**	**747,223**	**816,503**	**391,866**	**3,076,319**	**-**
78	**Total**	**501,055,017**	**117,980,551**	**308,950,927**	**26,949,726**	**13,202,459**	**2,933,127**	**10,726,332**	**2,838,478**	**940,846**	**1,664,032**	**1,758,873**	**1,881,155**	**747,223**	**816,503**	**391,866**	**3,076,319**	**6,196,602**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	19 Revenue Related Municipal Tax ($)	20 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requiremt			
40	Newfoundland Power	-	533,781	
41	Industrial - Firm	-	20,857	
42	Industrial - Non-Firm	-	-	
	Rural			
43	1.1 Domestic	314,466	15,676	
44	1.12 Domestic All Electric	388,552	19,369	
45	1.3 Special	442	22	
46	2.1 GS 0-10 kW	56,281	2,806	
47	2.2 GS 10-100 kW	166,478	8,299	
48	2.3 GS 110-1,000 kVa	146,730	7,314	
49	2.4 GS Over 1,000 kVa	68,966	3,438	
50	4.1 Street and Area Lighting	23,997	1,196	
51	**Subtotal Rural**	**1,165,913**	**58,120**	
52	**Total**	**1,165,913**	**612,758**	
	Re-classification of Revenue-Related			
53	Newfoundland Power	-	(533,781)	Re-classification to demand, energy and customer is based on rate class revenue
54	Industrial - Firm	-	(20,857)	requirements excluding revenue-related items.
55	Industrial - Non-Firm	-	-	
	Rural			
56	1.1 Domestic	(314,466)	(15,676)	
57	1.12 Domestic All Electric	(388,552)	(19,369)	
58	1.3 Special	(442)	(22)	
59	2.1 GS 0-10 kW	(56,281)	(2,806)	
60	2.2 GS 10-100 kW	(166,478)	(8,299)	
61	2.3 GS 110-1,000 kVa	(146,730)	(7,314)	
62	2.4 GS Over 1,000 kVa	(68,966)	(3,438)	
63	4.1 Street and Area Lighting	(23,997)	(1,196)	
64	**Subtotal Rural**	**(1,165,913)**	**(58,120)**	
65	**Total**	**(1,165,913)**	**(612,758)**	
	Total Allocated Revenue Requirement			
66	Newfoundland Power	-	-	
67	Industrial - Firm	-	-	
68	Industrial - Non-Firm	-	-	
	Rural			
69	1.1 Domestic	-	-	
70	1.12 Domestic All Electric	-	-	
71	1.3 Special	-	-	
72	2.1 GS 0-10 kW	-	-	
73	2.2 GS 10-100 kW	-	-	
74	2.3 GS 110-1,000 kVa	-	-	
75	2.4 GS Over 1,000 kVa	-	-	
76	4.1 Street and Area Lighting	-	-	
77	**Subtotal Rural**	**-**	**-**	
78	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Interconnected
Allocation of Specifically Assigned Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
			OM&A				Depreciation				Expense Credits							
Line No.	Description	Total Amount ($)	Transmission Lines ($) (Plant)	Transmission Terminals ($) (Plant)	Administrative & General ($) (C3 & C4)	Other ($) (C3 & C4)	Transmission Lines ($) (Direct)	Transmission Terminals ($) (Direct)	Telecontrol & Feasibility Study ($) (Direct)	General ($) (Exp C3,4,6)	Rental Income ($) (Plant)	Other ($) (C6)	Gains/Losses ($) (NBV)	Subtotal Excluding Return ($)	Return on Debt ($) (NBV)	Return on Equity ($) (NBV)	Subtotal Excl Rev Related ($)	Revenue Related ($)
	Basis of Allocation - Amounts																	
1	Newfoundland Power		24,461,333	11,250,747	35,712,080	35,712,080	-	-	-	744,179	35,712,080	35,712,080	23,245,006	-	23,245,006	23,245,006	-	-
	Industrial																	
2	Vale		6,554,033	4,483,533	11,037,566	11,037,566	-	-	-	247,748	11,037,566	11,037,566	346,005	-	346,005	346,005	-	-
3	Abitibi Consolidated - GF		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Corner Brook P& P - CB		-	6,734,904	6,734,904	6,734,904	-	-	-	221,690	6,734,904	6,734,904	4,700,096	-	4,700,096	4,700,096	-	-
5	Corner Brook P& P - DL		-	19,788	19,788	19,788	-	-	-	651	19,788	19,788	13,279	-	13,279	13,279	-	-
6	North Atlantic Refining Limited		-	1,122,955	1,122,955	1,122,955	-	-	-	36,964	1,122,955	1,122,955	309,305	-	309,305	309,305	-	-
7	Teck Resources		4,534,363	909,953	5,444,316	5,444,316	-	-	-	99,251	5,444,316	5,444,316	0	-	0	0	-	-
8	**Subtotal Industrial**		**11,088,396**	**13,271,133**	**24,359,528**	**24,359,528**	**-**	**-**	**-**	**606,304**	**24,359,528**	**24,359,528**	**5,368,685**	**-**	**5,368,685**	**5,368,685**	**-**	**-**
9	**Total**		**35,549,729**	**24,521,880**	**60,071,608**	**60,071,608**	**-**	**-**	**-**	**1,350,483**	**60,071,608**	**60,071,608**	**28,613,691**	**-**	**28,613,691**	**28,613,691**	**-**	**-**
10	**Basis of Allocation - Ratios**																	
11	Newfoundland Power		0.6881	0.4588	0.5945	0.5945	-	-	-	0.5510	0.5945	0.5945	0.8124	-	0.8124	0.8124	-	-
	Industrial																	
12	Vale		0.1844	0.1828	0.1837	0.1837	-	-	-	0.1835	0.1837	0.1837	0.0121	-	0.0121	0.0121	-	-
13	Abitibi Consolidated - GF		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Corner Brook P& P - CB		-	0.2746	0.1121	0.1121	-	-	-	0.1642	0.1121	0.1121	0.1643	-	0.1643	0.1643	-	-
15	Corner Brook P& P - DL		-	0.0008	0.0003	0.0003	-	-	-	0.0005	0.0003	0.0003	0.0005	-	0.0005	0.0005	-	-
16	North Atlantic Refining Ltd.		-	0.0458	0.0187	0.0187	-	-	-	0.0274	0.0187	0.0187	0.0108	-	0.0108	0.0108	-	-
17	Teck Resources		0.1275	0.0371	0.0906	0.0906	-	-	-	0.0735	0.0906	0.0906	0.0000	-	0.0000	0.0000	-	-
18	**Subtotal Industrial**		**0.3119**	**0.5412**	**0.4055**	**0.4055**	**-**	**-**	**-**	**0.4490**	**0.4055**	**0.4055**	**0.1876**	**-**	**0.1876**	**0.1876**	**-**	**-**
19	**Total**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**	**-**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**	**1.0000**	**1.0000**	**-**	**-**
	Amounts Allocated																	
20	Newfoundland Power	4,401,167	276,424	325,530	685,337	142,225	596,025	197,200	-	94,507	(310)	(9,409)	19,126	2,326,654	1,484,448	584,179	4,395,281	5,886
	Industrial																	
21	Vale	533,724	74,063	129,727	211,818	43,958	4,059	10,180	-	31,463	(96)	(2,908)	285	502,548	22,096	8,696	533,340	384
22	Abitibi Consolidated - GF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Corner Brook P& P - CB	941,708	-	194,868	129,247	26,822	-	141,633	-	28,154	(59)	(1,774)	3,867	522,757	300,153	118,120	941,030	678
24	Corner Brook P& P - DL	3,246	-	573	380	79	-	943	-	83	(0)	(5)	11	2,062	848	334	3,244	2
25	North Atlantic Refining Ltd.	101,748	-	32,492	21,550	4,472	-	10,992	-	4,694	(10)	(296)	254	74,149	19,753	7,773	101,675	73
26	Teck Resources	215,009	51,240	26,329	104,480	21,682	-	-	-	12,604	(47)	(1,434)	0	214,854	0	0	214,854	155
27	**Subtotal Industrial**	**1,795,436**	**125,304**	**383,988**	**467,474**	**97,013**	**4,059**	**163,748**	**-**	**76,998**	**(212)**	**(6,418)**	**4,417**	**1,316,371**	**342,849**	**134,922**	**1,794,142**	**1,293**
28	**Total**	**6,196,602**	**401,728**	**709,517**	**1,152,811**	**239,238**	**600,084**	**360,947**	**-**	**171,505**	**(522)**	**(15,826)**	**23,543**	**3,643,024**	**1,827,298**	**719,101**	**6,189,423**	**7,179**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Expenses																
1	Operating & Maintenance	5,339,758	1,782,833	2,285,143	-	13,740	455,607	139,662	50,421	89,249	95,206	99,970	80,783	27,632	16,109	166,932	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	2,558,555	-	2,558,555	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	244,656	-	244,656	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	479,097	168,742	216,583	-	1,707	31,376	9,787	6,891	12,198	5,768	6,386	3,699	6,601	3,838	5,521	-
	Expense Credits																
8	Sundry	(29,141)	(9,730)	(12,471)	-	(75)	(2,486)	(762)	(275)	(487)	(520)	(546)	(441)	(151)	(88)	(911)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(4,618)	(1,542)	(1,976)	-	(12)	(394)	(121)	(44)	(77)	(82)	(86)	(70)	(24)	(14)	(144)	-
12	Pole Attachments	(23,664)	-	-	-	-	(13,686)	(4,677)	-	-	(2,422)	(2,878)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(228)	-	-	-	-	-	-	-	-	-	-	-	-	-	(228)	-
16	Meter Test Revenues	(132)	-	-	-	-	-	-	-	-	-	-	-	(132)	-	-	-
17	**Total Expense Credits**	**(57,783)**	**(11,271)**	**(14,447)**	**-**	**(87)**	**(16,566)**	**(5,560)**	**(319)**	**(564)**	**(3,024)**	**(3,510)**	**(511)**	**(307)**	**(102)**	**(1,283)**	**-**
18	**Subtotal Expenses**	**8,564,283**	**1,940,304**	**5,290,491**	**-**	**15,360**	**470,417**	**143,889**	**56,994**	**100,883**	**97,949**	**102,846**	**83,971**	**33,927**	**19,844**	**171,169**	**-**
19	Disposal Gain / Loss	141,781	47,247	60,282	-	567	13,654	4,141	2,028	3,589	2,445	2,686	2,711	1,173	626	632	-
20	**Subtotal Revenue Requirement Ex. Return**	**8,706,064**	**1,987,551**	**5,350,773**	**-**	**15,927**	**484,071**	**148,029**	**59,021**	**104,473**	**100,394**	**105,532**	**86,682**	**35,099**	**20,471**	**171,802**	**-**
21	Return on Debt	581,432	190,713	252,832	-	2,269	55,011	16,686	8,125	14,383	9,884	10,849	10,898	4,709	2,511	2,562	-
22	Return on Equity	228,812	75,052	99,498	-	893	21,648	6,567	3,198	5,660	3,890	4,269	4,289	1,853	988	1,008	-
23	**Total Revenue Requirement**	**9,516,308**	**2,253,316**	**5,703,102**	**-**	**19,089**	**560,730**	**171,282**	**70,344**	**124,515**	**114,168**	**120,651**	**101,870**	**41,661**	**23,970**	**175,372**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Revenue Requirement (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	34,738	1,732	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(190)	(9)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(30)	(1)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(220)**	**(11)**	
18	**Subtotal Expenses**	**34,519**	**1,721**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**34,519**	**1,721**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**34,519**	**1,721**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	Description (1)	Total Amount ($) (2)	Production Demand ($) (3)	Production and Transmission Energy ($) (4)	Transmission Demand ($) (5)	Distribution: Substations Demand ($) (6)	Distribution: Primary Lines Demand ($) (7)	Distribution: Primary Lines Customer ($) (8)	Distribution: Line Transformers Demand ($) (9)	Distribution: Line Transformers Customer ($) (10)	Distribution: Secondary Lines Demand ($) (11)	Distribution: Secondary Lines Customer ($) (12)	Distribution: Services Customer ($) (13)	Distribution: Meters Customer ($) (14)	Distribution: Street Lighting Customer ($) (15)	Accounting Customer ($) (16)	Specifically Assigned Customer ($) (17)
	Production																
1	Diesel	13,847,770	5,965,582	7,882,188	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**13,847,770**	**5,965,582**	**7,882,188**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	253,722	201,749	-	-	51,973	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	87,909	-	-	-	-	66,279	8,444	-	-	7,688	5,499	-	-	-	-	-
8	Poles	2,497,840	-	-	-	-	1,444,621	493,703	-	-	255,699	303,817	-	-	-	-	-
9	Primary Conductor & Equipment	245,402	-	-	-	-	217,672	27,730	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	529,909	-	-	-	-	-	-	191,297	338,612	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	167,794	-	-	-	-	-	-	-	-	97,824	69,970	-	-	-	-	-
13	Services	306,489	-	-	-	-	-	-	-	-	-	-	306,489	-	-	-	-
14	Meters	127,455	-	-	-	-	-	-	-	-	-	-	-	127,455	-	-	-
15	Street Lighting	61,116	-	-	-	-	-	-	-	-	-	-	-	-	61,116	-	-
16	**Subtotal Distribution**	**4,277,634**	**201,749**	**-**	**-**	**51,973**	**1,728,571**	**529,877**	**191,297**	**338,612**	**361,210**	**379,286**	**306,489**	**127,455**	**61,116**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**18,125,404**	**6,167,330**	**7,882,188**	**-**	**51,973**	**1,728,571**	**529,877**	**191,297**	**338,612**	**361,210**	**379,286**	**306,489**	**127,455**	**61,116**	**-**	**-**
18	General	2,555,649	912,926	1,183,165	-	4,497	149,561	45,846	16,552	29,298	31,253	32,817	26,518	7,161	5,288	110,767	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	37,586	12,789	16,345	-	108	3,584	1,099	397	702	749	787	636	264	127	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**20,718,638**	**7,093,046**	**9,081,697**	**-**	**56,578**	**1,881,716**	**576,822**	**208,245**	**368,611**	**393,212**	**412,889**	**333,643**	**134,880**	**66,531**	**110,767**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.6
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and													Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	6,267,682	2,700,101	3,567,581	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**6,267,682**	**2,700,101**	**3,567,581**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	137,590	101,542	-	-	36,048	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	31,744	-	-	-	-	23,933	3,049	-	-	2,776	1,986	-	-	-	-	-
8	Poles	1,208,684	-	-	-	-	699,040	238,899	-	-	123,731	147,015	-	-	-	-	-
9	Primary Conductor & Equipment	146,739	-	-	-	-	130,157	16,581	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	356,922	-	-	-	-	-	-	128,849	228,073	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	42,085	-	-	-	-	-	-	-	-	24,535	17,549	-	-	-	-	-
13	Services	170,613	-	-	-	-	-	-	-	-	-	-	170,613	-	-	-	-
14	Meters	75,443	-	-	-	-	-	-	-	-	-	-	-	75,443	-	-	-
15	Street Lighting	39,731	-	-	-	-	-	-	-	-	-	-	-	-	39,731	-	-
16	**Subtotal Distribution**	**2,209,550**	**101,542**	-	-	**36,048**	**853,131**	**258,529**	**128,849**	**228,073**	**151,042**	**166,550**	**170,613**	**75,443**	**39,731**	-	-
17	**Subttl Prod, Trans, & Dist**	**8,477,231**	**2,801,643**	**3,567,581**	-	**36,048**	**853,131**	**258,529**	**128,849**	**228,073**	**151,042**	**166,550**	**170,613**	**75,443**	**39,731**	-	-
18	General	975,473	348,457	451,606	-	1,716	57,086	17,499	6,318	11,183	11,929	12,526	10,122	2,733	2,018	42,279	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	26,674	8,815	11,225	-	113	2,684	813	405	718	475	524	537	237	125	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**9,479,378**	**3,158,915**	**4,030,412**	-	**37,878**	**912,901**	**276,842**	**135,572**	**239,974**	**163,446**	**179,600**	**181,271**	**78,413**	**41,874**	**42,279**	-

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	2,015,352	868,208	1,147,144	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	344,827	148,551	196,277	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**2,360,179**	**1,016,759**	**1,343,420**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	407,722	19,820	-	-	5,106	169,818	52,056	18,793	33,266	35,486	37,262	30,110	-	6,004	-	-
9	Meters	8,131	-	-	-	-	-	-	-	-	-	-	-	8,131	-	-	-
10	**Subtotal Distribution**	**415,853**	**19,820**	-	-	**5,106**	**169,818**	**52,056**	**18,793**	**33,266**	**35,486**	**37,262**	**30,110**	**8,131**	**6,004**	-	-
11	**Subttl Prod, Trans, & Dist**	**2,776,032**	**1,036,579**	**1,343,420**	-	**5,106**	**169,818**	**52,056**	**18,793**	**33,266**	**35,486**	**37,262**	**30,110**	**8,131**	**6,004**	-	-
12	Customer Accounting	125,769	-	-	-	-	-	-	-	-	-	-	-	-	-	125,769	-
	Administrative & General:																
	Plant-Related:																
13	Production	556,710	239,829	316,881	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	482,097	22,737	-	-	5,857	194,813	59,718	21,560	38,162	40,709	42,746	34,542	14,364	6,888	-	-
16	Prod, Trans, Distn Plant	312,913	106,471	136,076	-	897	29,842	9,148	3,303	5,846	6,236	6,548	5,291	2,200	1,055	-	-
17	Prod, Trans, Distn and Gen Plt	4,213	1,442	1,847	-	12	383	117	42	75	80	84	68	27	14	23	-
18	Property Insurance	13,351	5,675	7,266	-	45	120	37	13	23	25	26	21	6	4	89	-
	Revenue Related:																
19	Municipal Tax	34,738	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	1,732	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	947,141	338,337	438,489	-	1,667	55,428	16,991	6,134	10,858	11,583	12,162	9,828	2,654	1,960	41,051	-
22	Prod, Trans, and Distn Expense-Related	85,062	31,762	41,164	-	156	5,203	1,595	576	1,019	1,087	1,142	923	249	184	-	-
23	**Subtotal Admin & General**	**2,437,956**	**746,254**	**941,723**	-	**8,634**	**285,789**	**87,606**	**31,628**	**55,983**	**59,720**	**62,708**	**50,673**	**19,501**	**10,104**	**41,162**	-
24	**Total Operating & Maintenance Expenses**	**5,339,758**	**1,782,833**	**2,285,143**	-	**13,740**	**455,607**	**139,662**	**50,421**	**89,249**	**95,206**	**99,970**	**80,783**	**27,632**	**16,109**	**166,932**	-

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L6
2	Other	-		Production - Demand, Energy ratios Sch.4.1 L6
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod, Trans, Distn and Gen Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	34,738	-	Revenue-related
20	PUB Assessment	-	1,732	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**34,738**	**1,732**	
24	**Total Operating & Maintenance Expenses**	**34,738**	**1,732**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	272,888	117,559	155,329	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**272,888**	**117,559**	**155,329**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substn Struct & Eqpt	5,357	3,895	-	-	1,461	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	902	-	-	-	-	680	87	-	-	79	56	-	-	-	-	-
8	Poles	35,407	-	-	-	-	20,478	6,998	-	-	3,625	4,307	-	-	-	-	-
9	Primary Conductor & Equipment	2,726	-	-	-	-	2,418	308	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	16,561	-	-	-	-	-	-	5,979	10,583	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	764	-	-	-	-	-	-	-	-	446	319	-	-	-	-	-
13	Services	2,343	-	-	-	-	-	-	-	-	-	-	2,343	-	-	-	-
14	Meters	6,154	-	-	-	-	-	-	-	-	-	-	-	6,154	-	-	-
15	Street Lighting	3,522	-	-	-	-	-	-	-	-	-	-	-	-	3,522	-	-
16	**Subtotal Distribution**	**73,736**	**3,895**	**-**	**-**	**1,461**	**23,575**	**7,393**	**5,979**	**10,583**	**4,149**	**4,682**	**2,343**	**6,154**	**3,522**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**346,624**	**121,455**	**155,329**	**-**	**1,461**	**23,575**	**7,393**	**5,979**	**10,583**	**4,149**	**4,682**	**2,343**	**6,154**	**3,522**	**-**	**-**
18	General	127,386	45,505	58,975	-	224	7,455	2,285	825	1,460	1,558	1,636	1,322	357	264	5,521	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	5,087	1,783	2,280	-	21	346	109	88	155	61	69	34	90	52	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**479,097**	**168,742**	**216,583**	**-**	**1,707**	**31,376**	**9,787**	**6,891**	**12,198**	**5,768**	**6,386**	**3,699**	**6,601**	**3,838**	**5,521**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Substations Demand ($)	Primary Lines Demand ($)	Primary Lines Customer ($)	Line Transformers Demand ($)	Line Transformers Customer ($)	Secondary Lines Demand ($)	Secondary Lines Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
1	Average Net Book Value	9,479,378	3,158,915	4,030,412	-	37,878	912,901	276,842	135,572	239,974	163,446	179,600	181,271	78,413	41,874	42,279	-
2	Cash Working Capital	35,677	11,889	15,169	-	143	3,436	1,042	510	903	615	676	682	295	158	159	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	168,823	-	168,823	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	228,133	78,102	99,999	-	623	20,720	6,351	2,293	4,059	4,330	4,546	3,674	1,485	733	1,220	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	437,628	145,835	186,069	-	1,749	42,145	12,781	6,259	11,079	7,546	8,291	8,369	3,620	1,933	1,952	-
8	Total Rate Base	**10,349,639**	**3,394,741**	**4,500,473**	**-**	**40,392**	**979,202**	**297,016**	**144,634**	**256,014**	**175,937**	**193,113**	**193,996**	**83,814**	**44,697**	**45,609**	**-**
9	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base Available for Equity Return	**10,349,639**	**3,394,741**	**4,500,473**	**-**	**40,392**	**979,202**	**297,016**	**144,634**	**256,014**	**175,937**	**193,113**	**193,996**	**83,814**	**44,697**	**45,609**	**-**
11	Return on Debt	581,432	190,713	252,832	-	2,269	55,011	16,686	8,125	14,383	9,884	10,849	10,898	4,709	2,511	2,562	-
12	Return on Equity	228,812	75,052	99,498	-	893	21,648	6,567	3,198	5,660	3,890	4,269	4,289	1,853	988	1,008	-
13	Return on Rate Base	**810,244**	**265,765**	**352,329**	**-**	**3,162**	**76,659**	**23,253**	**11,323**	**20,043**	**13,774**	**15,118**	**15,187**	**6,562**	**3,499**	**3,571**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)		(Rural Cust)	(Rural Cust)	
	Amounts																
1	1.2 Domestic Diesel	-	1,247	5,928	1,247	1,204	1,204	708	1,139	708	1,139	708	708	708	-	708	-
2	1.2G Government Domestic Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	-	120	800	120	116	116	99	110	99	110	99	186	186	-	99	-
5	2.2 GS 10-100 kW	-	205	1,132	205	198	198	15	188	15	188	15	72	72	-	15	-
6	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	-	24	97	24	23	23	30	22	30	22	30	-	-	30	30	-
11	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**-**	**1,596**	**7,958**	**1,596**	**1,541**	**1,541**	**852**	**1,458**	**852**	**1,458**	**852**	**966**	**966**	**30**	**852**	**-**
	Ratios																
13	1.2 Domestic Diesel	-	0.7813	0.7449	0.7813	0.7813	0.7813	0.8310	0.7813	0.8310	0.7813	0.8310	0.7333	0.7333	-	0.8310	-
14	1.2G Government Domestic Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	-	0.0752	0.1006	0.0752	0.0752	0.0752	0.1162	0.0752	0.1162	0.0752	0.1162	0.1924	0.1924	-	0.1162	-
17	2.2 GS 10-100 kW	-	0.1286	0.1423	0.1286	0.1286	0.1286	0.0177	0.1286	0.0177	0.1286	0.0177	0.0743	0.0743	-	0.0177	-
18	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	0.0149	0.0122	0.0149	0.0149	0.0149	0.0352	0.0149	0.0352	0.0149	0.0352	-	-	1.0000	0.0352	-
23	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Basis of Allocation to Classes of Service (CONT'D.)

	1	18	19
		Revenue Related	
Line No.	Description	Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	774,659	774,659
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	-	-
4	2.1 GS 0-10 kW	199,416	199,416
5	2.2 GS 10-100 kW	414,441	414,441
6	2.3 GS 110-1,000 kVa	-	-
7	2.4 GS Over 1,000 kVa	-	-
8	2.5 GS Diesel	-	-
9	2.5G Gov't General Service Diesel	-	-
10	4.1 Street and Area Lighting	40,434	40,434
11	4.1G Gov't Street and Area Lighting	-	-
12	**Total**	**1,428,950**	**1,428,950**
	Ratios		
13	1.2 Domestic Diesel	0.5421	0.5421
14	1.2G Government Domestic Diesel	-	-
15	1.23 Churches, Schools & Com Halls	-	-
16	2.1 GS 0-10 kW	0.1396	0.1396
17	2.2 GS 10-100 kW	0.2900	0.2900
18	2.3 GS 110-1,000 kVa	-	-
19	2.4 GS Over 1,000 kVa	-	-
20	2.5 GS Diesel	-	-
21	2.5G Gov't General Service Diesel	-	-
22	4.1 Street and Area Lighting	0.0283	0.0283
23	4.1G Gov't Street and Area Lighting	-	-
24	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	6,603,385	1,552,900	3,986,046	-	12,444	378,211	123,010	46,114	86,815	78,439	87,696	63,561	25,737	-	142,765	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	827,124	149,369	538,166	-	1,197	36,379	17,194	4,436	12,135	7,545	12,258	16,680	6,754	-	19,955	-
5	2.2 GS 10-100 kW	1,130,652	255,677	761,237	-	2,049	62,270	2,613	7,592	1,844	12,915	1,863	6,441	2,608	-	3,033	-
6	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	144,902	29,605	65,323	-	237	7,210	5,212	879	3,679	1,495	3,716	-	-	20,471	6,049	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**8,706,064**	**1,987,551**	**5,350,773**	**-**	**15,927**	**484,071**	**148,029**	**59,021**	**104,473**	**100,394**	**105,532**	**86,682**	**35,099**	**20,471**	**171,802**	**-**
	Allocated Return on Debt and Equity																
13	1.2 Domestic Diesel	619,542	207,646	262,467	-	2,471	59,895	19,323	8,847	16,655	10,761	12,563	11,136	4,811	-	2,967	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	74,679	19,973	35,436	-	238	5,761	2,701	851	2,328	1,035	1,756	2,922	1,263	-	415	-
17	2.2 GS 10-100 kW	100,519	34,188	50,125	-	407	9,861	410	1,457	354	1,772	267	1,128	488	-	63	-
18	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	15,504	3,959	4,301	-	47	1,142	819	169	706	205	532	-	-	3,499	126	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**810,244**	**265,765**	**352,329**	**-**	**3,162**	**76,659**	**23,253**	**11,323**	**20,043**	**13,774**	**15,118**	**15,187**	**6,562**	**3,499**	**3,571**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	18,713	933	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	4,817	240	
5	2.2 GS 10-100 kW	10,012	499	
6	2.3 GS 110-1,000 kVa	-	-	
7	2.4 GS Over 1,000 kVa	-	-	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	977	49	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**34,519**	**1,721**	
	Allocated Return on Debt and Equity			
13	1.2 Domestic Diesel	-	-	
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	-	-	
17	2.2 GS 10-100 kW	-	-	
18	2.3 GS 110-1,000 kVa	-	-	
19	2.4 GS Over 1,000 kVa	-	-	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	-	-	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Total Revenue Requirement																
25	1.2 Domestic Diesel	7,222,927	1,760,546	4,248,513	-	14,915	438,106	142,333	54,961	103,470	89,201	100,259	74,698	30,549	-	145,732	-
26	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	2.1 GS 0-10 kW	901,802	169,342	573,603	-	1,435	42,140	19,894	5,287	14,462	8,580	14,014	19,602	8,017	-	20,370	-
29	2.2 GS 10-100 kW	1,231,172	289,865	811,362	-	2,456	72,132	3,024	9,049	2,198	14,686	2,130	7,569	3,096	-	3,096	-
30	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	4.1 Street and Area Lighting	160,407	33,563	69,625	-	284	8,352	6,031	1,048	4,384	1,701	4,248	-	-	23,970	6,175	-
35	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	**Total**	**9,516,308**	**2,253,316**	**5,703,102**	**-**	**19,089**	**560,730**	**171,282**	**70,344**	**124,515**	**114,168**	**120,651**	**101,870**	**41,661**	**23,970**	**175,372**	**-**
	Re-classification of Revenue-Related																
37	1.2 Domestic Diesel	0	4,802	11,587	-	41	1,195	388	150	282	243	273	204	83	-	397	-
38	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	2.1 GS 0-10 kW	(0)	955	3,235	-	8	238	112	30	82	48	79	111	45	-	115	-
41	2.2 GS 10-100 kW	0	2,496	6,986	-	21	621	26	78	19	126	18	65	27	-	27	-
42	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	4.1 Street and Area Lighting	(0)	216	448	-	2	54	39	7	28	11	27	-	-	154	40	-
47	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	**Total**	**0**	**8,469**	**22,256**	**-**	**72**	**2,107**	**565**	**264**	**411**	**429**	**398**	**379**	**155**	**154**	**579**	**-**
	Total Allocated Revenue Requirement																
49	1.2 Domestic Diesel	7,222,927	1,765,348	4,260,100	-	14,955	439,301	142,721	55,111	103,753	89,444	100,532	74,902	30,632	-	146,129	-
50	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	2.1 GS 0-10 kW	901,802	170,297	576,838	-	1,443	42,378	20,007	5,316	14,544	8,628	14,093	19,713	8,062	-	20,484	-
53	2.2 GS 10-100 kW	1,231,172	292,360	818,348	-	2,477	72,753	3,050	9,127	2,217	14,813	2,148	7,634	3,122	-	3,122	-
54	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	4.1 Street and Area Lighting	160,407	33,779	70,073	-	286	8,406	6,070	1,055	4,413	1,711	4,276	-	-	24,124	6,215	-
59	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	**Total**	**9,516,308**	**2,261,784**	**5,725,358**	**-**	**19,161**	**562,837**	**171,847**	**70,609**	**124,926**	**114,597**	**121,049**	**102,249**	**41,816**	**24,124**	**175,951**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
25	1.2 Domestic Diesel	18,713	933	
26	1.2G Government Domestic Diesel	-	-	
27	1.23 Churches, Schools & Com Halls	-	-	
28	2.1 GS 0-10 kW	4,817	240	
29	2.2 GS 10-100 kW	10,012	499	
30	2.3 GS 110-1,000 kVa	-	-	
31	2.4 GS Over 1,000 kVa	-	-	
32	2.5 GS Diesel	-	-	
33	2.5G Gov't General Service Diesel	-	-	
34	4.1 Street and Area Lighting	977	49	
35	4.1G Gov't Street and Area Lighting	-	-	
36	**Total**	**34,519**	**1,721**	
	Re-classification of Revenue-Related			
37	1.2 Domestic Diesel	(18,713)	(933)	Re-classification to demand, energy and customer is based on rate class revenue
38	1.2G Government Domestic Diesel	-	-	requirements excluding revenue-related items.
39	1.23 Churches, Schools & Com Halls	-	-	
40	2.1 GS 0-10 kW	(4,817)	(240)	
41	2.2 GS 10-100 kW	(10,012)	(499)	
42	2.3 GS 110-1,000 kVa	-	-	
43	2.4 GS Over 1,000 kVa	-	-	
44	2.5 GS Diesel	-	-	
45	2.5G Gov't General Service Diesel	-	-	
46	4.1 Street and Area Lighting	(977)	(49)	
47	4.1G Gov't Street and Area Lighting	-	-	
48	**Total**	**(34,519)**	**(1,721)**	
	Total Allocated Revenue Requirement			
49	1.2 Domestic Diesel	-	-	
50	1.2G Government Domestic Diesel	-	-	
51	1.23 Churches, Schools & Com Halls	-	-	
52	2.1 GS 0-10 kW	-	-	
53	2.2 GS 10-100 kW	-	-	
54	2.3 GS 110-1,000 kVa	-	-	
55	2.4 GS Over 1,000 kVa	-	-	
56	2.5 GS Diesel	-	-	
57	2.5G Gov't General Service Diesel	-	-	
58	4.1 Street and Area Lighting	-	-	
59	4.1G Gov't Street and Area Lighting	-	-	
60	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and		Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount ($)	Production Demand ($)	Transmission Energy ($)	Transmission Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Expenses																
1	Operating & Maintenance	13,492,944	3,909,301	6,986,282	-	114,891	881,066	259,245	46,045	81,504	144,151	160,511	94,215	53,052	29,672	562,714	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	14,697,487	-	14,697,487	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	1,981,176	587,756	1,055,714	-	23,327	128,625	38,641	13,016	23,039	20,448	23,316	10,634	24,306	13,622	18,731	-
	Expense Credits																
8	Sundry	(73,637)	(21,335)	(38,127)	-	(627)	(4,808)	(1,415)	(251)	(445)	(787)	(876)	(514)	(290)	(162)	(3,071)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(11,669)	(3,381)	(6,042)	-	(99)	(762)	(224)	(40)	(70)	(125)	(139)	(81)	(46)	(26)	(487)	-
12	Pole Attachments	(102,972)	-	-	-	-	(59,554)	(20,353)	-	-	(10,541)	(12,525)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(1,668)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,668)	-
16	Meter Test Revenues	(486)	-	-	-	-	-	-	-	-	-	-	-	(486)	-	-	-
17	**Total Expense Credits**	**(190,432)**	**(24,716)**	**(44,169)**	**-**	**(726)**	**(65,124)**	**(21,992)**	**(291)**	**(515)**	**(11,452)**	**(13,539)**	**(596)**	**(822)**	**(188)**	**(5,226)**	**-**
18	**Subtotal Expenses**	**29,981,175**	**4,472,342**	**22,695,315**	**-**	**137,491**	**944,566**	**275,895**	**58,770**	**104,027**	**153,147**	**170,288**	**104,253**	**76,535**	**43,107**	**576,219**	**-**
19	Disposal Gain / Loss	137,281	38,323	67,159	-	1,907	14,039	4,189	951	1,683	2,224	2,528	1,949	1,068	548	714	-
20	**Subtotal Revenue Requirement Ex. Return**	**30,118,456**	**4,510,665**	**22,762,474**	**-**	**139,398**	**958,605**	**280,083**	**59,721**	**105,711**	**155,371**	**172,816**	**106,202**	**77,604**	**43,655**	**576,933**	**-**
21	Return on Debt	2,440,180	631,988	1,284,584	-	31,391	231,346	69,004	15,598	27,609	36,671	41,667	31,965	17,553	9,004	11,799	-
22	Return on Equity	960,290	248,708	505,526	-	12,354	91,042	27,155	6,138	10,865	14,431	16,397	12,579	6,908	3,543	4,643	-
23	**Total Revenue Requirement**	**33,518,926**	**5,391,361**	**24,552,584**	**-**	**183,143**	**1,280,994**	**376,243**	**81,456**	**144,185**	**206,473**	**230,880**	**150,747**	**102,065**	**56,202**	**593,375**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Revenue Requirement (CONT'D.)

	1	18	19	20
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	162,209	8,086	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.11
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(885)	(44)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(140)	(7)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(1,026)**	**(51)**	
18	**Subtotal Expenses**	**161,184**	**8,035**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**161,184**	**8,035**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**161,184**	**8,035**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	48,833,343	16,834,277	31,999,065	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**48,833,343**	**16,834,277**	**31,999,065**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	2,768,570	1,856,642	-	-	911,928	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	311,966	-	-	-	-	235,207	29,964	-	-	27,281	19,513	-	-	-	-	-
8	Poles	9,471,448	-	-	-	-	5,477,793	1,872,051	-	-	969,573	1,152,031	-	-	-	-	-
9	Primary Conductor & Equipment	1,493,462	-	-	-	-	1,324,701	168,761	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	1,018,826	-	-	-	-	-	-	367,796	651,030	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	265,156	-	-	-	-	-	-	-	-	154,586	110,570	-	-	-	-	-
13	Services	752,559	-	-	-	-	-	-	-	-	-	-	752,559	-	-	-	-
14	Meters	469,011	-	-	-	-	-	-	-	-	-	-	-	469,011	-	-	-
15	Street Lighting	237,014	-	-	-	-	-	-	-	-	-	-	-	-	237,014	-	-
16	**Subtotal Distribution**	**16,788,012**	**1,856,642**	-	-	**911,928**	**7,037,701**	**2,070,776**	**367,796**	**651,030**	**1,151,441**	**1,282,115**	**752,559**	**469,011**	**237,014**	-	-
17	**Subttl Prod, Trans, & Dist**	**65,621,355**	**18,690,919**	**31,999,065**	-	**911,928**	**7,037,701**	**2,070,776**	**367,796**	**651,030**	**1,151,441**	**1,282,115**	**752,559**	**469,011**	**237,014**	-	-
18	General	9,269,170	2,740,713	4,938,321	-	70,104	541,021	159,190	28,274	50,048	88,517	98,562	57,853	31,659	18,220	446,688	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	136,075	38,758	66,355	-	1,891	14,594	4,294	763	1,350	2,388	2,659	1,561	973	491	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**75,026,600**	**21,470,390**	**37,003,741**	-	**983,923**	**7,593,316**	**2,234,261**	**396,833**	**702,428**	**1,242,345**	**1,383,336**	**811,972**	**501,643**	**255,726**	**446,688**	-

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.7
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Net Book Value

Line No.	Description (1)	Total Amount ($) (2)	Production Demand ($) (3)	Production and Transmission Energy ($) (4)	Transmission Demand ($) (5)	Distribution: Substations Demand ($) (6)	Distribution: Primary Lines Demand ($) (7)	Distribution: Primary Lines Customer ($) (8)	Distribution: Line Transformers Demand ($) (9)	Distribution: Line Transformers Customer ($) (10)	Distribution: Secondary Lines Demand ($) (11)	Distribution: Secondary Lines Customer ($) (12)	Distribution: Services Customer ($) (13)	Distribution: Meters Customer ($) (14)	Distribution: Street Lighting Customer ($) (15)	Accounting Customer ($) (16)	Specifically Assigned Customer ($) (17)
	Production																
1	Diesel	24,679,237	8,507,653	16,171,584	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**24,679,237**	**8,507,653**	**16,171,584**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	1,243,706	754,022	-	-	489,684	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	101,353	-	-	-	-	76,415	9,735	-	-	8,863	6,340	-	-	-	-	-
8	Poles	4,964,860	-	-	-	-	2,871,417	981,314	-	-	508,243	603,886	-	-	-	-	-
9	Primary Conductor & Equipment	729,211	-	-	-	-	646,810	82,401	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	684,577	-	-	-	-	-	-	247,132	437,445	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	87,613	-	-	-	-	-	-	-	-	51,078	36,534	-	-	-	-	-
13	Services	506,521	-	-	-	-	-	-	-	-	-	-	506,521	-	-	-	-
14	Meters	277,615	-	-	-	-	-	-	-	-	-	-	-	277,615	-	-	-
15	Street Lighting	141,556	-	-	-	-	-	-	-	-	-	-	-	-	141,556	-	-
16	**Subtotal Distribution**	**8,737,011**	**754,022**	**-**	**-**	**489,684**	**3,594,642**	**1,073,450**	**247,132**	**437,445**	**568,184**	**646,760**	**506,521**	**277,615**	**141,556**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**33,416,248**	**9,261,675**	**16,171,584**	**-**	**489,684**	**3,594,642**	**1,073,450**	**247,132**	**437,445**	**568,184**	**646,760**	**506,521**	**277,615**	**141,556**	**-**	**-**
18	General	4,053,689	1,198,597	2,159,678	-	30,659	236,605	69,619	12,365	21,887	38,711	43,104	25,301	13,846	7,968	195,350	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	105,145	29,142	50,884	-	1,541	11,311	3,378	778	1,376	1,788	2,035	1,594	874	445	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**37,575,082**	**10,489,414**	**18,382,146**	**-**	**521,883**	**3,842,557**	**1,146,447**	**260,275**	**460,708**	**608,683**	**691,899**	**533,415**	**292,334**	**149,970**	**195,350**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	6,786,602	2,339,540	4,447,062	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	335,942	115,809	220,133	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**7,122,544**	**2,455,348**	**4,667,195**	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	1,185,642	134,893	-	-	66,255	511,318	150,450	26,722	47,300	83,657	93,151	54,676	-	17,220	-	-
9	Meters	29,921	-	-	-	-	-	-	-	-	-	-	-	29,921	-	-	-
10	**Subtotal Distribution**	**1,215,563**	**134,893**	-	-	**66,255**	**511,318**	**150,450**	**26,722**	**47,300**	**83,657**	**93,151**	**54,676**	**29,921**	**17,220**	-	-
11	**Subttl Prod, Trans, & Dist**	**8,338,107**	**2,590,241**	**4,667,195**	-	**66,255**	**511,318**	**150,450**	**26,722**	**47,300**	**83,657**	**93,151**	**54,676**	**29,921**	**17,220**	-	-
12	Customer Accounting	422,164	-	-	-	-	-	-	-	-	-	-	-	-	-	422,164	-
	Administrative & General:																
	Plant-Related:																
13	Production	653,752	225,368	428,385	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	350,191	38,729	-	-	19,022	146,803	43,195	7,672	13,580	24,019	26,744	15,698	9,783	4,944	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn and General Plt	394,109	112,782	194,378	-	5,168	39,887	11,736	2,085	3,690	6,526	7,267	4,265	2,635	1,343	2,346	-
18	Property Insurance	48,345	17,022	29,337	-	780	430	126	22	40	70	78	46	25	14	355	-
	Revenue Related:																
19	Municipal Tax	162,209	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	8,086	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	2,860,489	845,791	1,523,978	-	21,634	166,960	49,127	8,725	15,445	27,316	30,417	17,853	9,770	5,623	137,849	-
22	Prod, Trans, and Distn Expense-Related	255,493	79,369	143,010	-	2,030	15,668	4,610	819	1,449	2,563	2,854	1,675	917	528	-	-
23	**Subtotal Admin & General**	**4,732,673**	**1,319,060**	**2,319,087**	-	**48,635**	**369,748**	**108,795**	**19,323**	**34,204**	**60,495**	**67,360**	**39,538**	**23,131**	**12,452**	**140,550**	-
24	**Total Operating & Maintenance Expenses**	**13,492,944**	**3,909,301**	**6,986,282**	-	**114,891**	**881,066**	**259,245**	**46,045**	**81,504**	**144,151**	**160,511**	**94,215**	**53,052**	**29,672**	**562,714**	-

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L7
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L7
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod, Trans, Distn and General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	162,209	-	Revenue-related
20	PUB Assessment	-	8,086	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**162,209**	**8,086**	
24	**Total Operating & Maintenance Expenses**	**162,209**	**8,086**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Depreciation Expense

Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Distribution: Substations Demand ($)	Primary Lines Demand ($)	Primary Lines Customer ($)	Line Transformers Demand ($)	Line Transformers Customer ($)	Secondary Lines Demand ($)	Secondary Lines Customer ($)	Services Customer ($)	Meters Customer ($)	Street Lighting Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Production																
1	Diesel	1,276,361	439,999	836,362	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,276,361**	**439,999**	**836,362**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substn Struct & Eqpt	46,085	25,993	-	-	20,093	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	2,782	-	-	-	-	2,097	267	-	-	243	174	-	-	-	-	-
8	Poles	146,828	-	-	-	-	84,918	29,021	-	-	15,030	17,859	-	-	-	-	-
9	Primary Conductor & Equipment	19,606	-	-	-	-	17,391	2,216	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	32,296	-	-	-	-	-	-	11,659	20,637	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	2,094	-	-	-	-	-	-	-	-	1,221	873	-	-	-	-	-
13	Services	8,090	-	-	-	-	-	-	-	-	-	-	8,090	-	-	-	-
14	Meters	22,646	-	-	-	-	-	-	-	-	-	-	-	22,646	-	-	-
15	Street Lighting	12,672	-	-	-	-	-	-	-	-	-	-	-	-	12,672	-	-
16	**Subtotal Distribution**	**293,099**	**25,993**	**-**	**-**	**20,093**	**104,406**	**31,504**	**11,659**	**20,637**	**16,494**	**18,906**	**8,090**	**22,646**	**12,672**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**1,569,460**	**465,992**	**836,362**	**-**	**20,093**	**104,406**	**31,504**	**11,659**	**20,637**	**16,494**	**18,906**	**8,090**	**22,646**	**12,672**	**-**	**-**
18	General	388,682	114,926	207,077	-	2,940	22,686	6,675	1,186	2,099	3,712	4,133	2,426	1,328	764	18,731	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	23,034	6,839	12,275	-	295	1,532	462	171	303	242	277	119	332	186	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**1,981,176**	**587,756**	**1,055,714**	**-**	**23,327**	**128,625**	**38,641**	**13,016**	**23,039**	**20,448**	**23,316**	**10,634**	**24,306**	**13,622**	**18,731**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	37,575,082	10,489,414	18,382,146	-	521,883	3,842,557	1,146,447	260,275	460,708	608,683	691,899	533,415	292,334	149,970	195,350	-
2	Cash Working Capital	141,420	39,479	69,184	-	1,964	14,462	4,315	980	1,734	2,291	2,604	2,008	1,100	564	735	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	3,158,525	-	3,158,525	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	826,119	236,411	407,449	-	10,834	83,610	24,601	4,370	7,734	13,679	15,232	8,941	5,524	2,816	4,918	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	1,734,702	484,257	848,635	-	24,093	177,397	52,927	12,016	21,269	28,101	31,942	24,626	13,496	6,924	9,019	-
8	Total Rate Base	**43,435,848**	**11,249,560**	**22,865,939**	**-**	**558,775**	**4,118,026**	**1,228,290**	**277,640**	**491,446**	**652,754**	**741,678**	**568,989**	**312,454**	**160,274**	**210,022**	**-**
9	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base Available for Equity Return	**43,435,848**	**11,249,560**	**22,865,939**	**-**	**558,775**	**4,118,026**	**1,228,290**	**277,640**	**491,446**	**652,754**	**741,678**	**568,989**	**312,454**	**160,274**	**210,022**	**-**
11	Return on Debt	2,440,180	631,988	1,284,584	-	31,391	231,346	69,004	15,598	27,609	36,671	41,667	31,965	17,553	9,004	11,799	-
12	Return on Equity	960,290	248,708	505,526	-	12,354	91,042	27,155	6,138	10,865	14,431	16,397	12,579	6,908	3,543	4,643	-
13	Return on Rate Base	**3,400,470**	**880,696**	**1,790,110**	**-**	**43,745**	**322,389**	**96,159**	**21,736**	**38,474**	**51,102**	**58,064**	**44,545**	**24,461**	**12,547**	**16,442**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Functional Classification of Rate Base (CONT'D.)

Line No.	Description (1)	Basis of Functional Classification (18)
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically
Line No.	Description	Total Amount	Production Demand	Transmission Energy	Transmission Demand	Substations Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Assigned Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)		(Rural Cust)	(Rural Cust)	
	Amounts																
1	1.2 Domestic Diesel	-	4,652	22,045	4,652	4,501	4,501	2,056	4,272	2,056	4,272	2,056	2,056	2,056	-	2,056	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	-	734	4,286	734	711	711	416	674	416	674	416	781	781	-	416	-
5	2.2 GS 10-100 kW	-	1,581	9,701	1,581	1,530	1,530	136	1,452	136	1,452	136	649	649	-	136	-
6	2.3 GS 110-1,000 kVa	-	176	3,023	176	170	170	7	161	7	161	7	59	59	-	7	-
7	2.4 GS Over 1,000 kVa	-	77	2,548	77	75	75	1	71	1	71	1	8	8	-	1	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	-	80	307	80	77	77	82	73	82	73	82	-	-	82	82	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**-**	**7,301**	**41,909**	**7,301**	**7,063**	**7,063**	**2,698**	**6,704**	**2,698**	**6,704**	**2,698**	**3,553**	**3,553**	**82**	**2,698**	**-**
	Ratios																
13	1.2 Domestic Diesel	-	0.6372	0.5260	0.6372	0.6372	0.6372	0.7620	0.6372	0.7620	0.6372	0.7620	0.5787	0.5787	-	0.7620	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	-	0.1006	0.1023	0.1006	0.1006	0.1006	0.1542	0.1006	0.1542	0.1006	0.1542	0.2198	0.2198	-	0.1542	-
17	2.2 GS 10-100 kW	-	0.2166	0.2315	0.2166	0.2166	0.2166	0.0504	0.2166	0.0504	0.2166	0.0504	0.1825	0.1825	-	0.0504	-
18	2.3 GS 110-1,000 kVa	-	0.0241	0.0721	0.0241	0.0241	0.0241	0.0026	0.0241	0.0026	0.0241	0.0026	0.0166	0.0166	-	0.0026	-
19	2.4 GS Over 1,000 kVa	-	0.0106	0.0608	0.0106	0.0106	0.0106	0.0004	0.0106	0.0004	0.0106	0.0004	0.0024	0.0024	-	0.0004	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	0.0109	0.0073	0.0109	0.0109	0.0109	0.0304	0.0109	0.0304	0.0109	0.0304	-	-	1.0000	0.0304	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax (Prior Year (Rural Revenues)	19 Revenue Related PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	3,006,792	3,006,792
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	-	-
4	2.1 GS 0-10 kW	1,075,012	1,075,012
5	2.2 GS 10-100 kW	2,040,550	2,040,550
6	2.3 GS 110-1,000 kVa	183,870	183,870
7	2.4 GS Over 1,000 kVa	255,562	255,562
8	2.5 GS Diesel	-	-
9	2.5G Gov't General Service Diesel	-	-
10	4.1 Street and Area Lighting	110,648	110,648
11	4.1G Gov't Street and Area Lighting	-	-
12	**Total**	**6,672,434**	**6,672,434**
	Ratios		
13	1.2 Domestic Diesel	0.4506	0.4506
14	1.2G Government Domestic Diesel	-	-
15	1.23 Churches, Schools & Com Halls	-	-
16	2.1 GS 0-10 kW	0.1611	0.1611
17	2.2 GS 10-100 kW	0.3058	0.3058
18	2.3 GS 110-1,000 kVa	0.0276	0.0276
19	2.4 GS Over 1,000 kVa	0.0383	0.0383
20	2.5 GS Diesel	-	-
21	2.5G Gov't General Service Diesel	-	-
22	4.1 Street and Area Lighting	0.0166	0.0166
23	4.1G Gov't Street and Area Lighting	-	-
24	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and													Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightinç	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	16,732,283	2,874,191	11,973,437	-	88,824	610,822	213,436	38,054	80,556	99,002	131,694	61,455	44,906	-	439,649	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	3,156,540	453,782	2,327,882	-	14,024	96,438	43,190	6,008	16,301	15,631	26,649	23,348	17,061	-	88,965	-
5	2.2 GS 10-100 kW	6,672,852	976,882	5,269,067	-	30,190	207,607	14,114	12,934	5,327	33,649	8,709	19,386	14,165	-	29,073	-
6	2.3 GS 110-1,000 kVa	1,792,647	108,622	1,641,746	-	3,357	23,084	727	1,438	274	3,742	448	1,762	1,287	-	1,497	-
7	2.4 GS Over 1,000 kVa	1,452,937	47,879	1,383,782	-	1,480	10,175	104	634	39	1,649	64	252	184	-	214	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	311,197	49,309	166,561	-	1,524	10,479	8,513	653	3,213	1,698	5,252	-	-	43,655	17,535	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**30,118,456**	**4,510,665**	**22,762,474**	**-**	**139,398**	**958,605**	**280,083**	**59,721**	**105,711**	**155,371**	**172,816**	**106,202**	**77,604**	**43,655**	**576,933**	**-**
	Allocated Return on Debt and Equity																
13	1.2 Domestic Diesel	1,981,823	561,179	941,627	-	27,874	205,426	73,278	13,850	29,319	32,562	44,247	25,776	14,155	-	12,530	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	363,253	88,600	183,072	-	4,401	32,433	14,828	2,187	5,933	5,141	8,954	9,793	5,378	-	2,535	-
17	2.2 GS 10-100 kW	723,313	190,734	414,375	-	9,474	69,820	4,846	4,707	1,939	11,067	2,926	8,131	4,465	-	829	-
18	2.3 GS 110-1,000 kVa	162,578	21,208	129,112	-	1,053	7,763	249	523	100	1,231	151	739	406	-	43	-
19	2.4 GS Over 1,000 kVa	123,074	9,348	108,825	-	464	3,422	36	231	14	542	22	106	58	-	6	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	46,429	9,627	13,099	-	478	3,524	2,923	238	1,169	559	1,765	-	-	12,547	500	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**3,400,470**	**880,696**	**1,790,110**	**-**	**43,745**	**322,389**	**96,159**	**21,736**	**38,474**	**51,102**	**58,064**	**44,545**	**24,461**	**12,547**	**16,442**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	72,634	3,621	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	25,969	1,295	
5	2.2 GS 10-100 kW	49,293	2,457	
6	2.3 GS 110-1,000 kVa	4,442	221	
7	2.4 GS Over 1,000 kVa	6,174	308	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	2,673	133	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**161,184**	**8,035**	
	Allocated Return on Debt and Equity			
13	1.2 Domestic Diesel	-	-	
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	-	-	
17	2.2 GS 10-100 kW	-	-	
18	2.3 GS 110-1,000 kVa	-	-	
19	2.4 GS Over 1,000 kVa	-	-	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	-	-	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically
Line		Total	Production	Transmission	Transmission	Substations	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Assigned
No.	Description	Amount ($)	Demand ($)	Energy ($)	Demand ($)	Demand ($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	Customer ($)
	Total Revenue Requirement																
1	1.2 Domestic Diesel	18,714,106	3,435,370	12,915,064	-	116,699	816,248	286,714	51,904	109,875	131,565	175,941	87,232	59,061	-	452,179	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	3,519,793	542,382	2,510,954	-	18,425	128,871	58,018	8,195	22,234	20,772	35,602	33,141	22,438	-	91,500	-
5	2.2 GS 10-100 kW	7,396,165	1,167,616	5,683,442	-	39,664	277,427	18,960	17,641	7,266	44,716	11,635	27,516	18,630	-	29,902	-
6	2.3 GS 110-1,000 kVa	1,955,225	129,830	1,770,858	-	4,410	30,848	976	1,962	374	4,972	599	2,501	1,693	-	1,540	-
7	2.4 GS Over 1,000 kVa	1,576,011	57,228	1,492,607	-	1,944	13,597	139	865	53	2,192	86	357	242	-	220	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	357,626	58,936	179,660	-	2,002	14,003	11,435	890	4,382	2,257	7,017	-	-	56,202	18,034	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**33,518,926**	**5,391,361**	**24,552,584**	**-**	**183,143**	**1,280,994**	**376,243**	**81,456**	**144,185**	**206,473**	**230,880**	**150,747**	**102,065**	**56,202**	**593,375**	**-**
	Re-classification of Revenue-Related																
13	1.2 Domestic Diesel	(0)	14,055	52,841	-	477	3,340	1,173	212	450	538	720	357	242	-	1,850	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	0	4,234	19,601	-	144	1,006	453	64	174	162	278	259	175	-	714	-
17	2.2 GS 10-100 kW	(0)	8,227	40,047	-	279	1,955	134	124	51	315	82	194	131	-	211	-
18	2.3 GS 110-1,000 kVa	0	310	4,233	-	11	74	2	5	1	12	1	6	4	-	4	-
19	2.4 GS Over 1,000 kVa	-	236	6,164	-	8	56	1	4	0	9	0	1	1	-	1	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	(0)	466	1,421	-	16	111	90	7	35	18	55	-	-	444	143	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**(0)**	**27,529**	**124,306**	**-**	**935**	**6,541**	**1,853**	**416**	**710**	**1,054**	**1,137**	**817**	**553**	**444**	**2,922**	**-**
	Total Allocated Revenue Requirement																
25	1.2 Domestic Diesel	18,714,106	3,449,425	12,967,905	-	117,176	819,588	287,887	52,116	110,325	132,103	176,661	87,589	59,303	-	454,029	-
26	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	2.1 GS 0-10 kW	3,519,793	546,616	2,530,555	-	18,568	129,877	58,471	8,259	22,407	20,934	35,880	33,399	22,613	-	92,215	-
29	2.2 GS 10-100 kW	7,396,165	1,175,843	5,723,489	-	39,943	279,382	19,094	17,765	7,317	45,031	11,717	27,710	18,762	-	30,113	-
30	2.3 GS 110-1,000 kVa	1,955,225	130,140	1,775,091	-	4,421	30,922	979	1,966	375	4,984	600	2,507	1,697	-	1,543	-
31	2.4 GS Over 1,000 kVa	1,576,011	57,464	1,498,770	-	1,952	13,654	140	868	54	2,201	86	359	243	-	221	-
32	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	4.1 Street and Area Lighting	357,626	59,402	181,081	-	2,018	14,114	11,526	897	4,417	2,275	7,073	-	-	56,647	18,177	-
35	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	**Total**	**33,518,926**	**5,418,891**	**24,676,890**	**-**	**184,078**	**1,287,535**	**378,096**	**81,872**	**144,895**	**207,528**	**232,017**	**151,564**	**102,618**	**56,647**	**596,297**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
1	1.2 Domestic Diesel	72,634	3,621	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	25,969	1,295	
5	2.2 GS 10-100 kW	49,293	2,457	
6	2.3 GS 110-1,000 kVa	4,442	221	
7	2.4 GS Over 1,000 kVa	6,174	308	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	2,673	133	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**161,184**	**8,035**	
	Re-classification of Revenue-Related			
13	1.2 Domestic Diesel	(72,634)	(3,621)	Re-classification to demand, energy and customer is based on rate class revenue requirements excluding revenue-related items.
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	(25,969)	(1,295)	
17	2.2 GS 10-100 kW	(49,293)	(2,457)	
18	2.3 GS 110-1,000 kVa	(4,442)	(221)	
19	2.4 GS Over 1,000 kVa	(6,174)	(308)	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	(2,673)	(133)	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	**(161,184)**	**(8,035)**	
	Total Allocated Revenue Requirement			
25	1.2 Domestic Diesel	-	-	
26	1.2G Government Domestic Diesel	-	-	
27	1.23 Churches, Schools & Com Halls	-	-	
28	2.1 GS 0-10 kW	-	-	
29	2.2 GS 10-100 kW	-	-	
30	2.3 GS 110-1,000 kVa	-	-	
31	2.4 GS Over 1,000 kVa	-	-	
32	2.5 GS Diesel	-	-	
33	2.5G Gov't General Service Diesel	-	-	
34	4.1 Street and Area Lighting	-	-	
35	4.1G Gov't Street and Area Lighting	-	-	
36	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Revenue Requirement

Line No.	Description	Total Amount ($)	Production Demand ($)	Production and Transmission Energy ($)	Transmission Demand ($)	Distribution: Substations Demand ($)	Distribution: Primary Lines Demand ($)	Distribution: Primary Lines Customer ($)	Distribution: Line Transformers Demand ($)	Distribution: Line Transformers Customer ($)	Distribution: Secondary Lines Demand ($)	Distribution: Secondary Lines Customer ($)	Distribution: Services Customer ($)	Distribution: Meters Customer ($)	Distribution: Street Lightin Customer ($)	Accounting Customer ($)	Specifically Assigned Customer ($)
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
	Expenses																
1	Operating & Maintenance	1,321,586	612,600	-	-	7,464	268,707	81,737	13,896	24,597	46,902	52,098	12,448	18,742	4,848	112,632	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	533,749	-	533,749	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	3,353,241	-	3,353,241	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	335,840	150,729	-	-	5,250	79,411	24,706	8,270	14,639	13,224	15,156	2,966	10,282	4,374	6,832	-
	Expense Credits																
8	Sundry	(7,212)	(3,343)	-	-	(41)	(1,466)	(446)	(76)	(134)	(256)	(284)	(68)	(102)	(26)	(615)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(1,143)	(530)	-	-	(6)	(232)	(71)	(12)	(21)	(41)	(45)	(11)	(16)	(4)	(97)	-
12	Pole Attachments	(68,280)	-	-	-	-	(39,490)	(13,496)	-	-	(6,990)	(8,305)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(368)	-	-	-	-	-	-	-	-	-	-	-	-	-	(368)	-
16	Meter Test Revenues	(197)	-	-	-	-	-	-	-	-	-	-	-	(197)	-	-	-
17	**Total Expense Credits**	**(77,200)**	**(3,873)**	**-**	**-**	**(47)**	**(41,188)**	**(14,012)**	**(88)**	**(156)**	**(7,286)**	**(8,634)**	**(79)**	**(315)**	**(31)**	**(1,080)**	**-**
18	**Subtotal Expenses**	**5,467,216**	**759,456**	**3,886,990**	**-**	**12,666**	**306,930**	**92,431**	**22,078**	**39,080**	**52,840**	**58,620**	**15,335**	**28,709**	**9,191**	**118,385**	**-**
19	Disposal Gain / Loss	(179)	(66)	-	-	(3)	(55)	(17)	(4)	(7)	(9)	(11)	(2)	(3)	(1)	(1)	-
20	**Subtotal Revenue Requirement Ex. Return**	**5,467,037**	**759,390**	**3,886,990**	**-**	**12,663**	**306,875**	**92,413**	**22,074**	**39,074**	**52,831**	**58,609**	**15,333**	**28,706**	**9,190**	**118,383**	**-**
21	Return on Debt	476,336	175,168	2,653	-	7,261	144,835	45,721	9,819	17,381	24,756	28,356	6,182	7,337	2,890	3,975	-
22	Return on Equity	187,454	68,934	1,044	-	2,857	56,997	17,993	3,864	6,840	9,742	11,159	2,433	2,888	1,137	1,564	-
23	**Total Revenue Requirement**	**6,130,827**	**1,003,492**	**3,890,688**	**-**	**22,782**	**508,707**	**156,128**	**35,758**	**63,295**	**87,330**	**98,125**	**23,948**	**38,931**	**13,217**	**123,923**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Revenue Requirement (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	61,833	3,082	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.12
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(337)	(17)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(53)	(3)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(391)**	**(19)**	
18	**Subtotal Expenses**	**61,442**	**3,063**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**61,442**	**3,063**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**61,442**	**3,063**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount ($)	Demand ($)	Energy ($)	Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	5,872,273	5,872,273	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**5,872,273**	**5,872,273**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	195,594	66,298	-	-	129,296	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	99,575	-	-	-	-	75,075	9,564	-	-	8,708	6,228	-	-	-	-	-
8	Poles	6,805,435	-	-	-	-	3,935,909	1,345,108	-	-	696,659	827,759	-	-	-	-	-
9	Primary Conductor & Equipment	858,267	-	-	-	-	761,283	96,984	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	683,627	-	-	-	-	-	-	246,789	436,838	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	218,908	-	-	-	-	-	-	-	-	127,623	91,285	-	-	-	-	-
13	Services	221,083	-	-	-	-	-	-	-	-	-	-	221,083	-	-	-	-
14	Meters	189,800	-	-	-	-	-	-	-	-	-	-	-	189,800	-	-	-
15	Street Lighting	86,105	-	-	-	-	-	-	-	-	-	-	-	-	86,105	-	-
16	**Subtotal Distribution**	**9,358,393**	**66,298**	-	-	**129,296**	**4,772,267**	**1,451,656**	**246,789**	**436,838**	**832,990**	**925,272**	**221,083**	**189,800**	**86,105**	-	-
17	**Subttl Prod, Trans, & Dist**	**15,230,666**	**5,938,571**	-	-	**129,296**	**4,772,267**	**1,451,656**	**246,789**	**436,838**	**832,990**	**925,272**	**221,083**	**189,800**	**86,105**	-	-
18	General	1,570,399	771,959	-	-	8,578	316,626	96,313	16,374	28,983	55,266	61,389	14,668	24,482	5,713	170,048	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	31,583	12,314	-	-	268	9,896	3,010	512	906	1,727	1,919	458	394	179	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**16,832,649**	**6,722,844**	-	-	**138,142**	**5,098,789**	**1,550,980**	**263,675**	**466,726**	**889,984**	**988,579**	**236,210**	**214,675**	**91,996**	**170,048**	-

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.8
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Net Book Value

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount ($)	Demand ($)	Energy ($)	Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Production																
1	Diesel	2,578,956	2,578,956	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**2,578,956**	**2,578,956**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	132,258	14,286	-	-	117,972	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	16,704	-	-	-	-	12,594	1,604	-	-	1,461	1,045	-	-	-	-	-
8	Poles	3,467,893	-	-	-	-	2,005,649	685,436	-	-	355,001	421,807	-	-	-	-	-
9	Primary Conductor & Equipment	286,882	-	-	-	-	254,464	32,418	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	434,624	-	-	-	-	-	-	156,899	277,724	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	53,811	-	-	-	-	-	-	-	-	31,372	22,439	-	-	-	-	-
13	Services	96,377	-	-	-	-	-	-	-	-	-	-	96,377	-	-	-	-
14	Meters	112,346	-	-	-	-	-	-	-	-	-	-	-	112,346	-	-	-
15	Street Lighting	45,679	-	-	-	-	-	-	-	-	-	-	-	-	45,679	-	-
16	**Subtotal Distribution**	**4,646,572**	**14,286**	**-**	**-**	**117,972**	**2,272,706**	**719,458**	**156,899**	**277,724**	**387,834**	**445,291**	**96,377**	**112,346**	**45,679**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**7,225,528**	**2,593,242**	**-**	**-**	**117,972**	**2,272,706**	**719,458**	**156,899**	**277,724**	**387,834**	**445,291**	**96,377**	**112,346**	**45,679**	**-**	**-**
18	General	605,917	297,850	-	-	3,310	122,166	37,161	6,318	11,183	21,324	23,686	5,660	9,446	2,204	65,611	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	22,735	8,160	-	-	371	7,151	2,264	494	874	1,220	1,401	303	353	144	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**7,854,180**	**2,899,252**	**-**	**-**	**121,653**	**2,402,023**	**758,883**	**163,710**	**289,781**	**410,378**	**470,378**	**102,339**	**122,145**	**48,027**	**65,611**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	330,527	330,527	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	49,105	49,105	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**379,633**	**379,633**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	300,868	2,176	-	-	4,243	156,602	47,636	8,098	14,335	27,335	30,363	7,255	-	2,826	-	-
9	Meters	12,109	-	-	-	-	-	-	-	-	-	-	-	12,109	-	-	-
10	**Subtotal Distribution**	**312,976**	**2,176**	-	-	**4,243**	**156,602**	**47,636**	**8,098**	**14,335**	**27,335**	**30,363**	**7,255**	**12,109**	**2,826**	-	-
11	**Subttl Prod, Trans, & Dist**	**692,609**	**381,808**	-	-	**4,243**	**156,602**	**47,636**	**8,098**	**14,335**	**27,335**	**30,363**	**7,255**	**12,109**	**2,826**	-	-
12	Customer Accounting	84,105	-	-	-	-	-	-	-	-	-	-	-	-	-	84,105	-
	Administrative & General:																
	Plant-Related:																
13	Production	79,208	79,208	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	104,359	739	-	-	1,442	53,217	16,188	2,752	4,871	9,289	10,318	2,465	2,117	960	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod,Trans, Distn & General Plt	3,423	1,367	-	-	28	1,037	315	54	95	181	201	48	44	19	35	-
18	Property Insurance	10,847	9,529	-	-	196	450	137	23	41	78	87	21	35	8	241	-
	Revenue Related:																
19	Municipal Tax	61,833	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	3,082	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	260,898	128,249	-	-	1,425	52,603	16,001	2,720	4,815	9,182	10,199	2,437	4,067	949	28,251	-
22	Prod, Trans, and Distn Expense-Related	21,223	11,699	-	-	130	4,799	1,460	248	439	838	930	222	371	87	-	-
23	**Subtotal Admin & General**	**544,872**	**230,792**	-	-	**3,221**	**112,105**	**34,101**	**5,797**	**10,262**	**19,568**	**21,735**	**5,193**	**6,633**	**2,023**	**28,527**	-
24	**Total Operating & Maintenance Expenses**	**1,321,586**	**612,600**	-	-	**7,464**	**268,707**	**81,737**	**13,896**	**24,597**	**46,902**	**52,098**	**12,448**	**18,742**	**4,848**	**112,632**	-

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L8
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L8
3	**Subtotal Production**	**-**	**-**	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	**-**	**-**	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	**-**	**-**	
11	**Subttl Prod, Trans, & Dist**	**-**	**-**	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod,Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	61,833	-	Revenue-related
20	PUB Assessment	-	3,082	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**61,833**	**3,082**	
24	**Total Operating & Maintenance Expenses**	**61,833**	**3,082**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Diesel	117,552	117,552	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**117,552**	**117,552**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	5,263	429	-	-	4,834	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	463	-	-	-	-	349	44	-	-	40	29	-	-	-	-	-
8	Poles	98,102	-	-	-	-	56,737	19,390	-	-	10,043	11,932	-	-	-	-	-
9	Primary Conductor & Equipment	9,739	-	-	-	-	8,639	1,101	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	20,782	-	-	-	-	-	-	7,502	13,280	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	1,306	-	-	-	-	-	-	-	-	762	545	-	-	-	-	-
13	Services	2,342	-	-	-	-	-	-	-	-	-	-	2,342	-	-	-	-
14	Meters	9,164	-	-	-	-	-	-	-	-	-	-	-	9,164	-	-	-
15	Street Lighting	4,084	-	-	-	-	-	-	-	-	-	-	-	-	4,084	-	-
16	**Subtotal Distribution**	**151,246**	**429**	**-**	**-**	**4,834**	**65,725**	**20,535**	**7,502**	**13,280**	**10,845**	**12,506**	**2,342**	**9,164**	**4,084**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**268,798**	**117,980**	**-**	**-**	**4,834**	**65,725**	**20,535**	**7,502**	**13,280**	**10,845**	**12,506**	**2,342**	**9,164**	**4,084**	**-**	**-**
18	General	63,098	31,017	-	-	345	12,722	3,870	658	1,165	2,221	2,467	589	984	230	6,832	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	3,945	1,732	-	-	71	965	301	110	195	159	184	34	134	60	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**335,840**	**150,729**	**-**	**-**	**5,250**	**79,411**	**24,706**	**8,270**	**14,639**	**13,224**	**15,156**	**2,966**	**10,282**	**4,374**	**6,832**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	7,854,180	2,899,252	-	-	121,653	2,402,023	758,883	163,710	289,781	410,378	470,378	102,339	122,145	48,027	65,611	-
2	Cash Working Capital	29,560	10,912	-	-	458	9,040	2,856	616	1,091	1,545	1,770	385	460	181	247	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	47,228	-	47,228	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	185,345	74,025	-	-	1,521	56,143	17,078	2,903	5,139	9,800	10,885	2,601	2,364	1,013	1,872	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	362,598	133,848	-	-	5,616	110,892	35,035	7,558	13,378	18,946	21,716	4,725	5,639	2,217	3,029	-
8	Total Rate Base	**8,478,912**	**3,118,036**	**47,228**	**-**	**129,248**	**2,578,099**	**813,852**	**174,788**	**309,389**	**440,668**	**504,749**	**110,050**	**130,608**	**51,438**	**70,759**	**-**
9	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base Available for Equity Return	**8,478,912**	**3,118,036**	**47,228**	**-**	**129,248**	**2,578,099**	**813,852**	**174,788**	**309,389**	**440,668**	**504,749**	**110,050**	**130,608**	**51,438**	**70,759**	**-**
11	Return on Debt	476,336	175,168	2,653	-	7,261	144,835	45,721	9,819	17,381	24,756	28,356	6,182	7,337	2,890	3,975	-
12	Return on Equity	187,454	68,934	1,044	-	2,857	56,997	17,993	3,864	6,840	9,742	11,159	2,433	2,888	1,137	1,564	-
13	Return on Rate Base	**663,790**	**244,102**	**3,697**	**-**	**10,118**	**201,832**	**63,714**	**13,684**	**24,221**	**34,499**	**39,515**	**8,616**	**10,225**	**4,027**	**5,540**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
			(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
	Amounts																
1	1.1 Domestic Diesel	-	1,036	4,524	1,036	985	985	408	910	408	910	408	408	408	-	408	-
2	1.12 Domestic All Electric	-	3,008	11,291	3,008	2,861	2,861	382	2,643	382	2,643	382	382	382	-	382	-
3	2.1 GS 0-10 kW	-	228	1,249	228	217	217	127	201	127	201	127	238	238	-	127	-
4	2.2 GS 10-100 kW	-	1,050	5,510	1,050	999	999	77	922	77	922	77	367	367	-	77	-
5	2.3 GS 110-1,000 kVa	-	307	2,053	307	292	292	5	269	5	269	5	42	42	-	5	-
6	4.1 Street and Area Lighting	-	35	140	35	34	34	32	31	32	31	32	-	-	1	32	-
7	**Total**	**-**	**5,664**	**24,767**	**5,664**	**5,388**	**5,388**	**1,031**	**4,977**	**1,031**	**4,977**	**1,031**	**1,438**	**1,438**	**1**	**1,031**	**0**
	Ratios																
8	1.1 Domestic Diesel	-	0.1829	0.1827	0.1829	0.1829	0.1829	0.3957	0.1829	0.3957	0.1829	0.3957	0.2838	0.2838	-	0.3957	-
9	1.12 Domestic All Electric	-	0.5311	0.4559	0.5311	0.5311	0.5311	0.3705	0.5311	0.3705	0.5311	0.3705	0.2657	0.2657	-	0.3705	-
10	2.1 GS 0-10 kW	-	0.0403	0.0504	0.0403	0.0403	0.0403	0.1232	0.0403	0.1232	0.0403	0.1232	0.1658	0.1658	-	0.1232	-
11	2.2 GS 10-100 kW	-	0.1853	0.2225	0.1853	0.1853	0.1853	0.0747	0.1853	0.0747	0.1853	0.0747	0.2555	0.2555	-	0.0747	-
12	2.3 GS 110-1,000 kVa	-	0.0541	0.0829	0.0541	0.0541	0.0541	0.0048	0.0541	0.0048	0.0541	0.0048	0.0293	0.0293	-	0.0048	-
13	4.1 Street and Area Lighting	-	0.0062	0.0056	0.0062	0.0062	0.0062	0.0310	0.0062	0.0310	0.0062	0.0310	-	-	1.0000	0.0310	-
14	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**0.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	Description	18	19
	1	Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.1 Domestic Diesel	535,772	535,772
2	1.12 Domestic All Electric	1,035,643	1,035,643
3	2.1 GS 0-10 kW	161,308	161,308
4	2.2 GS 10-100 kW	555,908	555,908
5	2.3 GS 110-1,000 kVa	209,102	209,102
6	4.1 Street and Area Lighting	45,736	45,736
7	**Total**	**2,543,471**	**2,543,471**
	Ratios		
8	1.1 Domestic Diesel	0.2106	0.2106
9	1.12 Domestic All Electric	0.4072	0.4072
10	2.1 GS 0-10 kW	0.0634	0.0634
11	2.2 GS 10-100 kW	0.2186	0.2186
12	2.3 GS 110-1,000 kVa	0.0822	0.0822
13	4.1 Street and Area Lighting	0.0180	0.0180
14	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmsn	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	1.1 Domestic Diesel	1,069,210	138,887	710,023	-	2,316	56,125	36,571	4,037	15,463	9,662	23,194	4,351	8,146	-	46,848	-
2	1.12 Domestic All Electric	2,537,144	403,297	1,772,104	-	6,725	162,976	34,240	11,723	14,477	28,058	21,716	4,074	7,627	-	43,863	-
3	2.1 GS 0-10 kW	291,936	30,619	196,020	-	511	12,374	11,384	890	4,813	2,130	7,220	2,543	4,760	-	14,583	-
4	2.2 GS 10-100 kW	1,126,955	140,748	864,713	-	2,347	56,877	6,902	4,091	2,918	9,792	4,377	3,917	7,333	-	8,841	-
5	2.3 GS 110-1,000 kVa	392,749	41,108	322,201	-	686	16,612	448	1,195	189	2,860	284	449	840	-	574	-
6	4.1 Street and Area Lighting	49,041	4,730	21,930	-	79	1,911	2,868	137	1,213	329	1,819	-	-	9,190	3,674	-
7	**Total**	**5,467,037**	**759,390**	**3,886,990**	**-**	**12,663**	**306,875**	**92,413**	**22,074**	**39,074**	**52,831**	**58,609**	**15,333**	**28,706**	**9,190**	**118,383**	**-**
	Allocated Return on Debt and Equity																
8	1.1 Domestic Diesel	150,871	44,645	675	-	1,851	36,914	25,214	2,503	9,585	6,310	15,638	2,445	2,901	-	2,192	-
9	1.12 Domestic All Electric	323,755	129,638	1,686	-	5,374	107,189	23,607	7,267	8,974	18,322	14,641	2,289	2,717	-	2,052	-
10	2.1 GS 0-10 kW	40,024	9,842	186	-	408	8,138	7,848	552	2,984	1,391	4,868	1,429	1,696	-	682	-
11	2.2 GS 10-100 kW	109,024	45,243	823	-	1,875	37,408	4,758	2,536	1,809	6,394	2,951	2,201	2,612	-	414	-
12	2.3 GS 110-1,000 kVa	28,799	13,214	306	-	548	10,926	309	741	117	1,868	192	252	299	-	27	-
13	4.1 Street and Area Lighting	11,316	1,520	21	-	63	1,257	1,978	85	752	215	1,226	-	-	4,027	172	-
14	**Total**	**663,790**	**244,102**	**3,697**	**-**	**10,118**	**201,832**	**63,714**	**13,684**	**24,221**	**34,499**	**39,515**	**8,616**	**10,225**	**4,027**	**5,540**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line No.	Description	Municipal Tax ($)	PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.1 Domestic Diesel	12,942	645	
2	1.12 Domestic All Electric	25,018	1,247	
3	2.1 GS 0-10 kW	3,897	194	
4	2.2 GS 10-100 kW	13,429	669	
5	2.3 GS 110-1,000 kVa	5,051	252	
6	4.1 Street and Area Lighting	1,105	55	
7	**Total**	**61,442**	**3,063**	
	Allocated Return on Debt and Equity			
8	1.1 Domestic Diesel	-	-	
9	1.12 Domestic All Electric	-	-	
10	2.1 GS 0-10 kW	-	-	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	-	-	
13	4.1 Street and Area Lighting	-	-	
14	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmsn	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Total Revenue Requirement																
1	1.1 Domestic Diesel	1,220,082	183,532	710,698	-	4,167	93,039	61,785	6,540	25,048	15,972	38,831	6,796	11,047	-	49,040	-
2	1.12 Domestic All Electric	2,860,900	532,935	1,773,790	-	12,099	270,165	57,847	18,990	23,452	46,379	36,357	6,363	10,343	-	45,915	-
3	2.1 GS 0-10 kW	331,960	40,462	196,206	-	919	20,512	19,232	1,442	7,797	3,521	12,087	3,971	6,456	-	15,265	-
4	2.2 GS 10-100 kW	1,235,980	185,991	865,535	-	4,222	94,286	11,660	6,628	4,727	16,186	7,328	6,118	9,945	-	9,255	-
5	2.3 GS 110-1,000 kVa	421,548	54,322	322,507	-	1,233	27,538	757	1,936	307	4,727	476	701	1,140	-	601	-
6	4.1 Street and Area Lighting	60,357	6,250	21,951	-	142	3,169	4,846	223	1,965	544	3,046	-	-	13,217	3,846	-
7	**Total**	**6,130,827**	**1,003,492**	**3,890,688**	**-**	**22,782**	**508,707**	**156,128**	**35,758**	**63,295**	**87,330**	**98,125**	**23,948**	**38,931**	**13,217**	**123,923**	**-**
	Re-classification of Revenue-Related																
8	1.1 Domestic Diesel	-	2,067	8,004	-	47	1,048	696	74	282	180	437	77	124	-	552	-
9	1.12 Domestic All Electric	-	4,938	16,435	-	112	2,503	536	176	217	430	337	59	96	-	425	-
10	2.1 GS 0-10 kW	(0)	505	2,448	-	11	256	240	18	97	44	151	50	81	-	190	-
11	2.2 GS 10-100 kW	(0)	2,146	9,987	-	49	1,088	135	76	55	187	85	71	115	-	107	-
12	2.3 GS 110-1,000 kVa	0	692	4,109	-	16	351	10	25	4	60	6	9	15	-	8	-
13	4.1 Street and Area Lighting	-	122	430	-	3	62	95	4	38	11	60	-	-	259	75	-
14	**Total**	**(0)**	**10,470**	**41,413**	**-**	**238**	**5,308**	**1,711**	**373**	**694**	**911**	**1,075**	**265**	**430**	**259**	**1,358**	**-**
	Total Allocated Revenue Requirement																
15	1.1 Domestic Diesel	1,220,082	185,599	718,702	-	4,214	94,087	62,481	6,614	25,330	16,152	39,268	6,872	11,171	-	49,592	-
16	1.12 Domestic All Electric	2,860,900	537,873	1,790,226	-	12,211	272,668	58,383	19,166	23,669	46,809	36,693	6,421	10,439	-	46,340	-
17	2.1 GS 0-10 kW	331,960	40,967	198,654	-	930	20,768	19,472	1,460	7,894	3,565	12,238	4,021	6,537	-	15,455	-
18	2.2 GS 10-100 kW	1,235,980	188,137	875,522	-	4,271	95,374	11,795	6,704	4,782	16,373	7,413	6,188	10,060	-	9,362	-
19	2.3 GS 110-1,000 kVa	421,548	55,014	326,616	-	1,249	27,889	767	1,960	311	4,788	482	710	1,154	-	609	-
20	4.1 Street and Area Lighting	60,357	6,373	22,381	-	145	3,231	4,941	227	2,003	555	3,105	-	-	13,476	3,922	-
21	**Total**	**6,130,827**	**1,013,962**	**3,932,101**	**-**	**23,020**	**514,015**	**157,839**	**36,131**	**63,988**	**88,241**	**99,200**	**24,213**	**39,361**	**13,476**	**125,281**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
1	1.1 Domestic Diesel	12,942	645	
2	1.12 Domestic All Electric	25,018	1,247	
3	2.1 GS 0-10 kW	3,897	194	
4	2.2 GS 10-100 kW	13,429	669	
5	2.3 GS 110-1,000 kVa	5,051	252	
6	4.1 Street and Area Lighting	1,105	55	
7	**Total**	**61,442**	**3,063**	
	Re-classification of Revenue-Related			
8	1.1 Domestic Diesel	(12,942)	(645)	Re-classification to demand, energy and customer is based on rate class revenue
9	1.12 Domestic All Electric	(25,018)	(1,247)	requirements excluding revenue-related items.
10	2.1 GS 0-10 kW	(3,897)	(194)	
11	2.2 GS 10-100 kW	(13,429)	(669)	
12	2.3 GS 110-1,000 kVa	(5,051)	(252)	
13	4.1 Street and Area Lighting	(1,105)	(55)	
14	**Total**	**(61,442)**	**(3,063)**	
	Total Allocated Revenue Requirement			
15	1.1 Domestic Diesel	-	-	
16	1.12 Domestic All Electric	-	-	
17	2.1 GS 0-10 kW	-	-	
18	2.2 GS 10-100 kW	-	-	
19	2.3 GS 110-1,000 kVa	-	-	
20	4.1 Street and Area Lighting	-	-	
21	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Revenue Requirement

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount ($)	Demand ($)	Energy ($)	Demand ($)	Demand ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Demand ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)	Customer ($)
	Expenses																
1	Operating & Maintenance	6,348,048	805,433	-	479,418	603,102	1,019,660	289,719	144,917	256,516	317,353	291,022	110,750	194,514	37,854	1,390,398	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	77,323	77,323	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	196,308	196,308	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	2,363,382	1,118,595	1,244,787	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	295,141	-	-	-	295,141	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	2,839,603	322,199	-	500,598	554,049	389,769	114,341	87,536	154,946	209,744	176,101	32,078	112,130	39,432	146,680	-
	Expense Credits																
8	Sundry	(34,644)	(4,396)	-	(2,616)	(3,291)	(5,565)	(1,581)	(791)	(1,400)	(1,732)	(1,588)	(604)	(1,062)	(207)	(7,588)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(5,490)	(697)	-	(415)	(522)	(882)	(251)	(125)	(222)	(274)	(252)	(96)	(168)	(33)	(1,202)	-
12	Pole Attachments	(250,032)	-	-	-	-	(144,606)	(49,419)	-	-	(25,595)	(30,412)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(12,980)	-	-	-	-	-	-	-	-	-	-	-	-	-	(12,980)	-
16	Meter Test Revenues	(1,997)	-	-	-	-	-	-	-	-	-	-	-	(1,997)	-	-	-
17	**Total Expense Credits**	**(305,143)**	**(5,092)**	**-**	**(3,031)**	**(3,813)**	**(151,052)**	**(51,251)**	**(916)**	**(1,622)**	**(27,602)**	**(32,252)**	**(700)**	**(3,226)**	**(239)**	**(21,770)**	**-**
18	**Subtotal Expenses**	**11,814,662**	**2,514,765**	**1,244,787**	**976,985**	**1,448,480**	**1,258,378**	**352,810**	**231,537**	**409,839**	**499,496**	**434,871**	**142,128**	**303,417**	**77,046**	**1,515,307**	**-**
19	Disposal Gain / Loss	19,169	1,826	-	3,599	3,980	3,346	992	504	892	1,377	1,212	375	387	123	554	-
20	**Subtotal Revenue Requirement Ex. Return**	**11,833,830**	**2,516,592**	**1,244,787**	**980,584**	**1,452,460**	**1,261,724**	**353,802**	**232,041**	**410,732**	**500,873**	**436,083**	**142,503**	**303,804**	**77,169**	**1,515,861**	**-**
21	Return on Debt	4,135,361	411,453	-	776,108	851,965	719,254	213,094	108,254	191,619	294,745	259,394	80,624	83,112	26,382	119,357	-
22	Return on Equity	1,627,399	161,920	-	305,424	335,276	283,050	83,859	42,602	75,408	115,992	102,080	31,728	32,707	10,382	46,971	-
23	**Total Revenue Requirement**	**17,596,591**	**3,089,965**	**1,244,787**	**2,062,115**	**2,639,701**	**2,264,027**	**650,755**	**382,897**	**677,760**	**911,610**	**797,557**	**254,856**	**419,623**	**113,933**	**1,682,189**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	386,949	20,443	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	
3	Fuels-Diesel	-	-	Production - Demand
4	Fuels-Gas Turbine	-	-	Production - Demand
5	Power Purchases -CF(L)Co	-	-	Carryforward from Sch.4.4 L.8
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.9
7	Depreciation	-	-	Carryforward from Sch.2.5 L.24
	Expense Credits			
8	Sundry	(2,112)	(112)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(335)	(18)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(2,446)**	**(129)**	
18	**Subtotal Expenses**	**384,503**	**20,314**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.24
20	**Subtotal Revenue Requirement Ex. Return**	**384,503**	**20,314**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**384,503**	**20,314**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution: Substations Demand ($)	7 Distribution: Primary Lines Demand ($)	8 Distribution: Primary Lines Customer ($)	9 Distribution: Line Transformers Demand ($)	10 Distribution: Line Transformers Customer ($)	11 Distribution: Secondary Lines Demand ($)	12 Distribution: Secondary Lines Customer ($)	13 Distribution: Services Customer ($)	14 Distribution: Meters Customer ($)	15 Distribution: Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Gas Turbines	22,602,817	22,602,817	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	3,340,542	3,340,542	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**25,943,359**	**25,943,359**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	18,642,138	-	-	18,642,138	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	19,282,082	-	-	7,939,984	11,342,098	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	**37,924,220**	-	-	**26,582,122**	11,342,098	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Substations	7,379,960	-	-	-	7,379,960	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	1,067,675	-	-	-	-	804,974	102,550	-	-	93,368	66,783	-	-	-	-	-
9	Poles	25,181,324	-	-	-	-	14,563,568	4,977,139	-	-	2,577,762	3,062,855	-	-	-	-	-
10	Primary Conductor & Eqpt	3,861,003	-	-	-	-	3,424,710	436,293	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	620,107	-	-	-	-	620,107	-	-	-	-	-	-	-	-	-	-
12	Transformers	7,642,899	-	-	-	-	-	-	2,759,087	4,883,812	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	5,782,106	-	-	-	-	-	-	-	-	3,370,968	2,411,138	-	-	-	-	-
14	Services	2,108,581	-	-	-	-	-	-	-	-	-	-	2,108,581	-	-	-	-
15	Meters	1,925,243	-	-	-	-	-	-	-	-	-	-	-	1,925,243	-	-	-
16	Street Lighting	720,699	-	-	-	-	-	-	-	-	-	-	-	-	720,699	-	-
17	**Subtotal Distribution**	**56,289,597**	**-**	-	-	7,379,960	**19,413,359**	**5,515,983**	**2,759,087**	**4,883,812**	**6,042,097**	**5,540,776**	**2,108,581**	**1,925,243**	**720,699**	**-**	**-**
18	**Subttl Prod, Trans, & Dist**	**120,157,176**	**25,943,359**	**-**	**26,582,122**	18,722,058	**19,413,359**	**5,515,983**	**2,759,087**	**4,883,812**	**6,042,097**	**5,540,776**	**2,108,581**	**1,925,243**	**720,699**	**-**	**-**
19	General	12,896,305	1,440,528	-	633,926	1,083,202	2,204,842	626,469	313,359	554,671	686,222	629,285	239,479	476,605	81,852	3,925,864	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	6,706	-	-	-	6,706	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	249,163	53,797	-	55,122	38,823	40,256	11,438	5,721	10,127	12,529	11,490	4,372	3,992	1,494	-	-
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Plant**	**133,309,351**	**27,437,684**	**-**	**27,271,170**	**19,850,789**	**21,658,457**	**6,153,890**	**3,078,167**	**5,448,611**	**6,740,848**	**6,181,551**	**2,352,432**	**2,405,841**	**804,046**	**3,925,864**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.9
2	Diesel	Production - Demand, Energy ratios Sch.4.1 L.9
3	**Subtotal Production**	
	Transmission	
4	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
5	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
6	**Subtotal Transmission**	
	Distribution	
7	Substations	Production - Demand; Dist Substns - Demand
8	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
9	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
10	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
11	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
12	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
13	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
14	Services	Services Customer
15	Meters	Meters - Customer
16	Street Lighting	Street Lighting - Customer
17	**Subtotal Distribution**	
18	**Subttl Prod, Trans, & Dist**	
19	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch2.4 L.11, 12
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
23	Software - Cust Acctng	
24	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Gas Turbines	5,163,636	5,163,636	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	623,011	623,011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**5,786,647**	**5,786,647**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	8,499,292	-	-	8,499,292	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	15,007,246	-	-	4,013,174	10,994,072	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	**23,506,538**	-	-	**12,512,466**	**10,994,072**	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Substations	2,645,167	-	-	-	2,645,167	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	685,895	-	-	-	-	517,130	65,880	-	-	59,982	42,903	-	-	-	-	-
9	Poles	15,223,585	-	-	-	-	8,804,530	3,008,972	-	-	1,558,408	1,851,675	-	-	-	-	-
10	Primary Conductor & Eqpt	1,299,745	-	-	-	-	1,152,874	146,871	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	344,996	-	-	-	-	344,996	-	-	-	-	-	-	-	-	-	-
12	Transformers	4,541,959	-	-	-	-	-	-	1,639,647	2,902,312	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	5,055,022	-	-	-	-	-	-	-	-	2,947,078	2,107,944	-	-	-	-	-
14	Services	1,217,459	-	-	-	-	-	-	-	-	-	-	1,217,459	-	-	-	-
15	Meters	1,139,584	-	-	-	-	-	-	-	-	-	-	-	1,139,584	-	-	-
16	Street Lighting	396,263	-	-	-	-	-	-	-	-	-	-	-	-	396,263	-	-
17	**Subtotal Distribution**	**32,549,673**	-	-	-	**2,645,167**	**10,819,530**	**3,221,723**	**1,639,647**	**2,902,312**	**4,565,467**	**4,002,522**	**1,217,459**	**1,139,584**	**396,263**	-	-
18	**Subttl Prod, Trans, & Dist**	**61,842,858**	**5,786,647**	-	**12,512,466**	**13,639,239**	**10,819,530**	**3,221,723**	**1,639,647**	**2,902,312**	**4,565,467**	**4,002,522**	**1,217,459**	**1,139,584**	**396,263**	-	-
19	General	6,512,050	727,401	-	320,104	546,968	1,113,345	316,339	158,232	280,084	346,511	317,760	120,926	240,664	41,332	1,982,384	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	6,706	-	-	-	6,706	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	194,589	18,208	-	39,371	42,916	34,044	10,137	5,159	9,132	14,365	12,594	3,831	3,586	1,247	-	-
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Net Book Value**	**68,556,204**	**6,532,256**	-	**12,871,940**	**14,235,830**	**11,966,919**	**3,548,199**	**1,803,039**	**3,191,528**	**4,926,343**	**4,332,876**	**1,342,215**	**1,383,833**	**438,841**	**1,982,384**	-

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
							Primary Lines		Line Transformers		Secondary Lines						
Line		Total	Production	Transmission	Transmission	Substations							Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbine / Diesel	300,303	300,303	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	70,928	70,928	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**371,231**	**371,231**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
4	Transmission Lines	53,400	-	-	53,400	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	39,334	-	-	16,197	23,137	-	-	-	-	-	-	-	-	-	-	-
6	Other	133,778	-	-	93,769	40,009	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	**226,512**	**-**	**-**	**163,366**	**63,147**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
8	Other	1,591,159	-	-	-	216,000	568,198	161,444	80,754	142,941	176,843	162,170	61,715	-	21,094	-	-
9	Meters	122,823	-	-	-	-	-	-	-	-	-	-	-	122,823	-	-	-
10	**Subtotal Distribution**	**1,713,982**	**-**	**-**	**-**	**216,000**	**568,198**	**161,444**	**80,754**	**142,941**	**176,843**	**162,170**	**61,715**	**122,823**	**21,094**	**-**	**-**
11	**Subttl Prod, Trans, & Dist**	**2,311,726**	**371,231**	**-**	**163,366**	**279,146**	**568,198**	**161,444**	**80,754**	**142,941**	**176,843**	**162,170**	**61,715**	**122,823**	**21,094**	**-**	**-**
12	Customer Accounting	1,011,714	-	-	-	-	-	-	-	-	-	-	-	-	-	1,011,714	-
	Administrative & General:																
	Plant-Related:																
13	Production	146,059	146,059	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	189,942	-	-	133,136	56,807	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	416,679	-	-	-	54,630	143,706	40,832	20,424	36,152	44,726	41,015	15,609	14,251	5,335	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn & General Plt	532,244	109,546	-	108,881	79,255	86,472	24,570	12,290	21,754	26,913	24,680	9,392	9,605	3,210	15,674	-
18	Property Insurance	85,897	35,910	-	11,244	25,972	2,891	822	411	727	900	825	314	625	107	5,148	-
	Revenue-Related:																
19	Municipal Tax	386,949	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	20,443	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	1,175,559	131,311	-	57,785	98,739	200,982	57,106	28,564	50,561	62,552	57,362	21,830	43,445	7,461	357,861	-
22																	
	Prod,Trans & Distn Expense-Related	70,835	11,375	-	5,006	8,553	17,410	4,947	2,474	4,380	5,419	4,969	1,891	3,763	646	-	-
23	**Subtotal Admin & General**	**3,024,608**	**434,202**	**-**	**316,052**	**323,956**	**451,462**	**128,275**	**64,163**	**113,574**	**140,510**	**128,852**	**49,036**	**71,690**	**16,760**	**378,684**	**-**
24	**Total Operating & Maintenance Expenses**	**6,348,048**	**805,433**	**-**	**479,418**	**603,102**	**1,019,660**	**289,719**	**144,917**	**256,516**	**317,353**	**291,022**	**110,750**	**194,514**	**37,854**	**1,390,398**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense (CONT'D.)

	1	18	19	20
		Revenue Related		
Line No.	Description	Municipal Tax	PUB Assessment	Basis of Functional Classification
	Production			
1	Gas Turbine / Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L.9
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L.9
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.4
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.5
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.6
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 17, less L. 15
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.3
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L. 6
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.17
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission, Distribution Plant in Service - Sch.2.2 L. 18
17	Prod, Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.24
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.3, 5, 7, 19 - 20
	Revenue-Related:			
19	Municipal Tax	386,949	-	Revenue-related
20	PUB Assessment	-	20,443	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 11, 12
22				
	Prod,Trans & Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**386,949**	**20,443**	
24	**Total Operating & Maintenance Expenses**	**386,949**	**20,443**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Depreciation Expense

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Production																
1	Gas Turbines	243,119	243,119	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	21,377	21,377	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	264,496	264,496	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	323,185	-	-	323,185	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	532,739	-	-	146,830	385,909	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	855,924	-	-	470,015	385,909	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Substations	114,576	-	-	-	114,576	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	20,040	-	-	-	-	15,109	1,925	-	-	1,753	1,254	-	-	-	-	-
9	Poles	425,582	-	-	-	-	246,134	84,117	-	-	43,566	51,764	-	-	-	-	-
10	Primary Conductor & Eqpt	31,661	-	-	-	-	28,083	3,578	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	13,618	-	-	-	-	13,618	-	-	-	-	-	-	-	-	-	-
12	Transformers	207,011	-	-	-	-	-	-	74,731	132,280	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	233,489	-	-	-	-	-	-	-	-	136,124	97,365	-	-	-	-	-
14	Services	22,796	-	-	-	-	-	-	-	-	-	-	22,796	-	-	-	-
15	Meters	92,958	-	-	-	-	-	-	-	-	-	-	-	92,958	-	-	-
16	Street Lighting	35,848	-	-	-	-	-	-	-	-	-	-	-	-	35,848	-	-
17	**Subtotal Distribution**	1,197,579	-	-	-	114,576	302,945	89,620	74,731	132,280	181,442	150,383	22,796	92,958	35,848	-	-
18	**Subttl Prod, Trans, & Dist**	2,317,999	264,496	-	470,015	500,485	302,945	89,620	74,731	132,280	181,442	150,383	22,796	92,958	35,848	-	-
19	General	481,836	53,822	-	23,685	40,471	82,378	23,406	11,708	20,724	25,639	23,512	8,947	17,807	3,058	146,680	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	5,748	-	-	-	5,748	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	34,020	3,882	-	6,898	7,345	4,446	1,315	1,097	1,941	2,663	2,207	335	1,364	526	-	-
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Depreciation Expense**	2,839,603	322,199	-	500,598	554,049	389,769	114,341	87,536	154,946	209,744	176,101	32,078	112,130	39,432	146,680	-

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Rate Base

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and			Primary Lines		Line Transformers		Secondary Lines						Specifically
Line		Total	Production	Transmission	Transmission	Substations							Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Average Net Book Value	68,556,204	6,532,256	-	12,871,940	14,235,830	11,966,919	3,548,199	1,803,039	3,191,528	4,926,343	4,332,876	1,342,215	1,383,833	438,841	1,982,384	-
2	Cash Working Capital	258,022	24,585	-	48,446	53,579	45,039	13,354	6,786	12,012	18,541	16,307	5,052	5,208	1,652	7,461	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	51,871	51,871	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	111,572	111,572	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	1,467,872	302,117	-	300,283	218,577	238,482	67,761	33,894	59,995	74,224	68,065	25,903	26,491	8,853	43,228	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	3,164,985	301,570	-	594,250	657,215	552,468	163,807	83,240	147,341	227,431	200,033	61,965	63,886	20,260	91,519	-
8	Total Rate Base	**73,610,526**	**7,323,971**	**-**	**13,814,919**	**15,165,201**	**12,802,908**	**3,793,121**	**1,926,958**	**3,410,876**	**5,246,539**	**4,617,282**	**1,435,135**	**1,479,419**	**469,606**	**2,124,592**	**-**
9	Less: Rural Portion	-															
10	Rate Base Available for Equity Return	**73,610,526**	**7,323,971**	**-**	**13,814,919**	**15,165,201**	**12,802,908**	**3,793,121**	**1,926,958**	**3,410,876**	**5,246,539**	**4,617,282**	**1,435,135**	**1,479,419**	**469,606**	**2,124,592**	**-**
11	Return on Debt	4,135,361	411,453	-	776,108	851,965	719,254	213,094	108,254	191,619	294,745	259,394	80,624	83,112	26,382	119,357	-
12	Return on Equity	1,627,399	161,920	-	305,424	335,276	283,050	83,859	42,602	75,408	115,992	102,080	31,728	32,707	10,382	46,971	-
13	Return on Rate Base	**5,762,761**	**573,373**	**-**	**1,081,531**	**1,187,241**	**1,002,304**	**296,953**	**150,856**	**267,028**	**410,737**	**361,474**	**112,353**	**115,820**	**36,764**	**166,328**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 24
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Basis of Allocation to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
				Production and		Distribution											Specifically
Line		Total	Production	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Amounts		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
1	CFB - Goose Bay Secondary	-	-	10,749	-	-	-	-	-	-	-	-	-	-	-	-	-
2	IOCC Firm	-	69,819	280,584	62,000	-	-	1	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	-	-	7,092	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
4	1.1Domestic	-	571	2,632	507	491	491	414	466	414	466	414	414	414	-	414	-
5	1.1A Domestic All Electric	-	75,715	347,255	67,236	65,063	65,063	8,776	61,778	8,776	61,778	8,776	8,776	8,776		8,776	
6	2.1GS 0-10 kW	-	981	6,471	871	843	843	472	800	472	800	472	886	886	-	472	-
7	2.2GS 10-100 kW	-	13,749	78,851	12,210	11,815	11,815	661	11,219	661	11,219	661	3,153	3,153	-	661	-
8	2.3GS 110-1,000 kVa	-	26,233	128,408	23,295	22,543	22,543	156	21,404	156	21,404	156	1,313	1,313	-	156	-
9	2.4GS Over 1,000 kVa	-	19,854	92,977	17,630	17,061	17,061	5	16,199	5	16,199	5	42	42	-	5	-
10	4.1Street and Area Lighting	-	495	1,980	440	425	425	370	404	370	404	370	-	-	1	370	-
11	**Subtotal Rural**		**137,599**	**658,575**	**122,190**	**118,241**	**118,241**	**10,854**	**112,271**	**10,854**	**112,271**	**10,854**	**14,585**	**14,585**	**1**	**10,854**	**-**
12	**Total Labrador Interconnected**		**207,418**	**957,000**	**184,190**	**118,241**	**118,241**	**10,855**	**112,271**	**10,854**	**112,271**	**10,854**	**14,585**	**14,585**	**1**	**10,854**	**-**
	Ratios																
13	CFB - Goose Bay Boiler	-	-	0.0112	-	-	-	-	-	-	-	-	-	-	-	-	-
14	IOCC Firm	-	0.3366	0.2932	0.3366	-	-	0.0001	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	0.0074	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
16	1.1Domestic	-	0.0028	0.0028	0.0028	0.0042	0.0042	0.0381	0.0042	0.0381	0.0042	0.0381	0.0284	0.0284	-	0.0381	-
17	1.1A Domestic All Electric	-	0.3650	0.3629	0.3650	0.5503	0.5503	0.8085	0.5503	0.8085	0.5503	0.8085	0.6017	0.6017	-	0.8085	-
18	2.1GS 0-10 kW	-	0.0047	0.0068	0.0047	0.0071	0.0071	0.0435	0.0071	0.0435	0.0071	0.0435	0.0608	0.0608	-	0.0435	-
19	2.2GS 10-100 kW	-	0.0663	0.0824	0.0663	0.0999	0.0999	0.0609	0.0999	0.0609	0.0999	0.0609	0.2162	0.2162	-	0.0609	-
20	2.3GS 110-1,000 kVa	-	0.1265	0.1342	0.1265	0.1907	0.1907	0.0144	0.1907	0.0144	0.1907	0.0144	0.0901	0.0901	-	0.0144	-
21	2.4GS Over 1,000 kVa	-	0.0957	0.0972	0.0957	0.1443	0.1443	0.0005	0.1443	0.0005	0.1443	0.0005	0.0029	0.0029	-	0.0005	-
22	4.1Street and Area Lighting	-	0.0024	0.0021	0.0024	0.0036	0.0036	0.0341	0.0036	0.0341	0.0036	0.0341	-	-	1.0000	0.0341	-
23	**Subtotal Rural**		**0.6634**	**0.6882**	**0.6634**	**1.0000**	**1.0000**	**0.9999**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
24	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
	Ratios Excluding IOCC																
25	CFB - Goose Bay Boiler	-	-	0.0161	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
26	1.1Domestic	-	0.0042	0.0039	0.0042	0.0042	0.0042	0.0381	0.0042	0.0381	0.0042	0.0381	0.0284	0.0284	-	0.0381	-
27	1.1A Domestic All Electric	-	0.5503	0.5188	0.5503	0.5503	0.5503	0.8085	0.5503	0.8085	0.5503	0.8085	0.6017	0.6017	-	0.8085	-
28	2.1GS 0-10 kW	-	0.0071	0.0097	0.0071	0.0071	0.0071	0.0435	0.0071	0.0435	0.0071	0.0435	0.0608	0.0608	-	0.0435	-
29	2.2GS 10-100 kW	-	0.0999	0.1178	0.0999	0.0999	0.0999	0.0609	0.0999	0.0609	0.0999	0.0609	0.2162	0.2162	-	0.0609	-
30	2.3GS 110-1,000 kVa	-	0.1907	0.1918	0.1907	0.1907	0.1907	0.0144	0.1907	0.0144	0.1907	0.0144	0.0901	0.0901	-	0.0144	-
31	2.4GS Over 1,000 kVa	-	0.1443	0.1389	0.1443	0.1443	0.1443	0.0005	0.1443	0.0005	0.1443	0.0005	0.0029	0.0029	-	0.0005	-
32	4.1Street and Area Lighting	-	0.0036	0.0030	0.0036	0.0036	0.0036	0.0341	0.0036	0.0341	0.0036	0.0341	-	-	1.0000	0.0341	-
33	**Subtotal Rural**		**1.0000**	**0.9839**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
34	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.		18	19
		Revenue Related	
		Municipal Tax (Prior Year (Rural Revenues)	PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	CFB - Goose Bay Secondary	-	-
2	IOCC Firm	-	-
3	IOCC Non-Firm	-	-
	Rural		
4	1.1Domestic	106,557	106,557
5	1.1A Domestic All Electric	9,904,350	9,904,350
6	2.1GS 0-10 kW	381,958	381,958
7	2.2GS 10-100 kW	2,143,438	2,143,438
8	2.3GS 110-1,000 kVa	3,034,263	3,034,263
9	2.4GS Over 1,000 kVa	54,393	1,006,601
10	4.1Street and Area Lighting	292,092	292,092
11	**Subtotal Rural**	**15,917,050**	**16,869,258**
12	**Total Labrador Interconnected**	**15,917,050**	**16,869,258**
	Ratios		
13	CFB - Goose Bay Boiler	-	-
14	IOCC Firm	-	-
15	IOCC Non-Firm	-	-
	Rural		
16	1.1Domestic	0.0067	0.0063
17	1.1A Domestic All Electric	0.6222	0.5871
18	2.1GS 0-10 kW	0.0240	0.0226
19	2.2GS 10-100 kW	0.1347	0.1271
20	2.3GS 110-1,000 kVa	0.1906	0.1799
21	2.4GS Over 1,000 kVa	0.0034	0.0597
22	4.1Street and Area Lighting	0.0184	0.0173
23	**Subtotal Rural**	**1.0000**	**1.0000**
24	**Total Labrador Interconnected**	**1.0000**	**1.0000**
	Ratios Excluding IOCC		
25	CFB - Goose Bay Boiler	-	-
	Rural		
26	1.1Domestic	0.0067	0.0063
27	1.1A Domestic All Electric	0.6222	0.5871
28	2.1GS 0-10 kW	0.0240	0.0226
29	2.2GS 10-100 kW	0.1347	0.1271
30	2.3GS 110-1,000 kVa	0.1906	0.1799
31	2.4GS Over 1,000 kVa	0.0034	0.0597
32	4.1Street and Area Lighting	0.0184	0.0173
33	**Subtotal Rural**	**1.0000**	**1.0000**
34	**Total Labrador Interconnected**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
						Distribution											
				Production and		Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Specifically Assigned
Line No.	Description	Total Amount	Production Demand	Transmission Energy	Transmission Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
	Allocated Rev Reqmt Excl Return	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	CFB - Goose Bay Boiler	13,982	-	13,982	-	-	-	-	-	-	-	-	-	-	-	-	-
2	IOCC Firm	1,542,177	847,109	364,961	330,074	-	-	33	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	9,225	-	9,225	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
4	1.1Domestic	146,351	6,931	3,424	2,701	6,030	5,238	13,494	963	15,666	2,080	16,633	4,045	8,624	-	57,819	-
5	1.1A Domestic All Electric	6,341,187	918,646	451,681	357,948	799,228	694,274	286,040	127,682	332,097	275,609	352,595	85,748	182,806	-	1,225,649	-
6	2.1GS 0-10 kW	204,467	11,903	8,417	4,638	10,356	8,996	15,384	1,654	17,861	3,571	18,964	8,659	18,459	-	65,919	-
7	2.2GS 10-100 kW	995,108	166,821	102,563	65,001	145,136	126,076	21,544	23,186	25,013	50,049	26,557	30,808	65,679	-	92,315	-
8	2.3GS 110-1,000 kVa	1,422,705	318,287	167,023	124,020	276,912	240,548	5,085	44,239	5,903	95,491	6,268	12,833	27,359	-	21,787	-
9	2.4GS Over 1,000 kVa	958,124	240,886	120,937	93,861	209,572	182,051	163	33,481	189	72,270	201	411	877	-	698	-
10	4.1Street and Area Lighting	200,504	6,008	2,575	2,341	5,227	4,540	12,060	835	14,001	1,802	14,866	-	-	77,169	51,674	-
11	**Subtotal Rural**	**10,268,447**	**1,669,482**	**856,620**	**650,510**	**1,452,460**	**1,261,724**	**353,769**	**232,041**	**410,732**	**500,873**	**436,083**	**142,503**	**303,804**	**77,169**	**1,515,861**	**-**
12	**Total**	**11,833,830**	**2,516,592**	**1,244,787**	**980,584**	**1,452,460**	**1,261,724**	**353,802**	**232,041**	**410,732**	**500,873**	**436,083**	**142,503**	**303,804**	**77,169**	**1,515,861**	**-**
	Allocated Return on Debt																
13	CFB - Goose Bay Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	IOCC Firm	399,764	138,499	-	261,245	-	-	20	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
16	1.1Domestic	45,998	1,133	-	2,138	3,537	2,986	8,127	449	7,309	1,224	9,894	2,289	2,359	-	4,553	-
17	1.1A Domestic All Electric	2,251,810	150,195	-	283,307	468,801	395,775	172,281	59,568	154,934	162,186	209,733	48,514	50,011	-	96,506	-
18	2.1GS 0-10 kW	63,710	1,946	-	3,671	6,074	5,128	9,266	772	8,333	2,101	11,280	4,899	5,050	-	5,190	-
19	2.2GS 10-100 kW	359,102	27,275	-	51,447	85,132	71,871	12,976	10,817	11,669	29,452	15,797	17,430	17,968	-	7,269	-
20	2.3GS 110-1,000 kVa	552,588	52,039	-	98,159	162,427	137,126	3,062	20,639	2,754	56,193	3,728	7,261	7,485	-	1,715	-
21	2.4GS Over 1,000 kVa	399,362	39,384	-	74,288	122,928	103,780	98	15,620	88	42,528	119	233	240	-	55	-
22	4.1Street and Area Lighting	63,028	982	-	1,853	3,066	2,588	7,263	390	6,532	1,061	8,842	-	-	26,382	4,069	-
23	**Subtotal Rural**	**3,735,597**	**272,954**	**-**	**514,862**	**851,965**	**719,254**	**213,074**	**108,254**	**191,619**	**294,745**	**259,394**	**80,624**	**83,112**	**26,382**	**119,357**	**-**
24	**Total**	**4,135,361**	**411,453**	**-**	**776,108**	**851,965**	**719,254**	**213,094**	**108,254**	**191,619**	**294,745**	**259,394**	**80,624**	**83,112**	**26,382**	**119,357**	**-**
	Allocated Return on Equity																
25	CFB - Goose Bay Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	IOCC Firm	157,320	54,504	-	102,809	-	-	8	-	-	-	-	-	-	-	-	-
27	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
28	1.1Domestic	18,102	446	-	841	1,392	1,175	3,198	177	2,876	482	3,894	901	928	-	1,792	-
29	1.1A Domestic All Electric	886,160	59,107	-	111,491	184,488	155,750	67,798	23,442	60,971	63,825	82,537	19,092	19,681	-	37,978	-
30	2.1GS 0-10 kW	25,072	766	-	1,445	2,390	2,018	3,646	304	3,279	827	4,439	1,928	1,987	-	2,043	-
31	2.2GS 10-100 kW	141,318	10,733	-	20,246	33,502	28,283	5,106	4,257	4,592	11,590	6,217	6,859	7,071	-	2,860	-
32	2.3GS 110-1,000 kVa	217,461	20,479	-	38,629	63,920	53,963	1,205	8,122	1,084	22,114	1,467	2,857	2,945	-	675	-
33	2.4GS Over 1,000 kVa	157,162	15,499	-	29,235	48,376	40,841	39	6,147	35	16,736	47	92	94	-	22	-
34	4.1Street and Area Lighting	24,803	387	-	729	1,206	1,019	2,858	153	2,571	417	3,480	-	-	10,382	1,601	-
35	**Subtotal Rural**	**1,470,079**	**107,416**	**-**	**202,615**	**335,276**	**283,050**	**83,852**	**42,602**	**75,408**	**115,992**	**102,080**	**31,728**	**32,707**	**10,382**	**46,971**	**-**
36	**Total**	**1,627,399**	**161,920**	**-**	**305,424**	**335,276**	**283,050**	**83,859**	**42,602**	**75,408**	**115,992**	**102,080**	**31,728**	**32,707**	**10,382**	**46,971**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

	1	18	19	
		Revenue Related		
Line		Municipal	PUB	
No.	Description	Tax	Assessment	Basis of Proration
	Allocated Rev Reqmt Excl Return	($)	($)	
1	CFB - Goose Bay Boiler	-	-	
2	IOCC Firm	-	-	
3	IOCC Non-Firm	-	-	
	Rural:			
4	1.1Domestic	2,574	128	
5	1.1A Domestic All Electric	239,256	11,927	
6	2.1GS 0-10 kW	9,227	460	
7	2.2GS 10-100 kW	51,778	2,581	
8	2.3GS 110-1,000 kVa	73,298	3,654	
9	2.4GS Over 1,000 kVa	1,314	1,212	
10	4.1Street and Area Lighting	7,056	352	
11	**Subtotal Rural**	**384,503**	**20,314**	
12	**Total**	**384,503**	**20,314**	
	Allocated Return on Debt			
13	CFB - Goose Bay Boiler	-	-	
14	IOCC Firm	-	-	
15	IOCC Non-Firm	-	-	
	Rural:			
16	1.1Domestic	-	-	
17	1.1A Domestic All Electric	-	-	
18	2.1GS 0-10 kW	-	-	
19	2.2GS 10-100 kW	-	-	
20	2.3GS 110-1,000 kVa	-	-	
21	2.4GS Over 1,000 kVa	-	-	
22	4.1Street and Area Lighting	-	-	
23	**Subtotal Rural**	**-**	**-**	
24	**Total**	**-**	**-**	
	Allocated Return on Equity			
25	CFB - Goose Bay Boiler	-	-	
26	IOCC Firm	-	-	
27	IOCC Non-Firm	-	-	
	Rural:			
28	1.1Domestic	-	-	
29	1.1A Domestic All Electric	-	-	
30	2.1GS 0-10 kW	-	-	
31	2.2GS 10-100 kW	-	-	
32	2.3GS 110-1,000 kVa	-	-	
33	2.4GS Over 1,000 kVa	-	-	
34	4.1Street and Area Lighting	-	-	
35	**Subtotal Rural**	**-**	**-**	
36	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Total Revenue Requirement																
37	CFB - Goose Bay Boiler	13,982	-	13,982	-	-	-	-	-	-	-	-	-	-	-	-	-
38	IOCC Firm	2,099,261	1,040,112	364,961	694,128	-	-	60	-	-	-	-	-	-	-	-	-
39	IOCC Non-Firm	9,225	-	9,225	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
40	1.1Domestic	210,451	8,511	3,424	5,680	10,960	9,400	24,819	1,590	25,852	3,785	30,421	7,234	11,911	-	64,163	-
41	1.1A Domestic All Electric	9,479,157	1,127,948	451,681	752,746	1,452,517	1,245,799	526,119	210,692	548,002	501,621	644,864	153,353	252,498	-	1,360,134	-
42	2.1GS 0-10 kW	293,249	14,615	8,417	9,753	18,820	16,142	28,296	2,730	29,473	6,499	34,683	15,485	25,496	-	73,152	-
43	2.2GS 10-100 kW	1,495,529	204,829	102,563	136,695	263,769	226,231	39,627	38,261	41,275	91,092	48,571	55,097	90,718	-	102,444	-
44	2.3GS 110-1,000 kVa	2,192,754	390,805	167,023	260,807	503,259	431,637	9,352	72,999	9,741	173,798	11,463	22,951	37,789	-	24,177	-
45	2.4GS Over 1,000 kVa	1,514,647	295,769	120,937	197,384	380,877	326,672	300	55,247	312	131,534	367	736	1,211	-	775	-
46	4.1Street and Area Lighting	288,336	7,376	2,575	4,923	9,499	8,147	22,181	1,378	23,104	3,280	27,188	-	-	113,933	57,344	-
47	**Subtotal Rural**	**15,474,123**	**2,049,852**	**856,620**	**1,367,987**	**2,639,701**	**2,264,027**	**650,695**	**382,897**	**677,760**	**911,610**	**797,557**	**254,856**	**419,623**	**113,933**	**1,682,189**	**-**
48	**Total**	**17,596,591**	**3,089,965**	**1,244,787**	**2,062,115**	**2,639,701**	**2,264,027**	**650,755**	**382,897**	**677,760**	**911,610**	**797,557**	**254,856**	**419,623**	**113,933**	**1,682,189**	**-**
	Re-classification of Revenue-Related																
49	CFB - Goose Bay Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	IOCC Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
52	1.1Domestic	0	111	45	74	143	122	323	21	336	49	396	94	155	-	835	-
53	1.1A Domestic All Electric	(0)	30,702	12,295	20,490	39,537	33,910	14,321	5,735	14,916	13,654	17,553	4,174	6,873	-	37,022	-
54	2.1GS 0-10 kW	0	499	288	333	643	551	967	93	1,007	222	1,185	529	871	-	2,499	-
55	2.2GS 10-100 kW	0	7,726	3,869	5,156	9,949	8,533	1,495	1,443	1,557	3,436	1,832	2,078	3,422	-	3,864	-
56	2.3GS 110-1,000 kVa	(0)	14,214	6,075	9,486	18,303	15,699	340	2,655	354	6,321	417	835	1,374	-	879	-
57	2.4GS Over 1,000 kVa	-	494	202	330	636	546	1	92	1	220	1	1	2	-	1	-
58	4.1Street and Area Lighting	0	195	68	130	250	215	585	36	609	86	717	-	-	3,004	1,512	-
59	**Subtotal Rural**	**-**	**53,940**	**22,840**	**35,998**	**69,462**	**59,576**	**18,031**	**10,076**	**18,780**	**23,988**	**22,100**	**7,711**	**12,697**	**3,004**	**46,613**	**-**
60	**Total**	**(0)**	**53,940**	**22,840**	**35,998**	**69,462**	**59,576**	**18,031**	**10,076**	**18,780**	**23,988**	**22,100**	**7,711**	**12,697**	**3,004**	**46,613**	**-**
	Total Allocated Revenue Requirement																
61	CFB - Goose Bay Boiler	13,982	-	13,982	-	-	-	-	-	-	-	-	-	-	-	-	-
62	IOCC Firm	2,099,261	1,040,112	364,961	694,128	-	-	60	-	-	-	-	-	-	-	-	-
63	IOCC Non-Firm	9,225	-	9,225	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	1.1Domestic	210,451	8,621	3,469	5,754	11,102	9,522	25,142	1,610	26,188	3,834	30,817	7,328	12,066	-	64,998	-
65	1.1A Domestic All Electric	9,479,157	1,158,650	463,976	773,235	1,492,054	1,279,710	540,440	216,427	562,919	515,275	662,417	157,527	259,370	-	1,397,156	-
66	2.1GS 0-10 kW	293,249	15,114	8,705	10,086	19,463	16,693	29,263	2,823	30,480	6,721	35,868	16,014	26,367	-	75,651	-
67	2.2GS 10-100 kW	1,495,529	212,555	106,431	141,851	273,718	234,764	41,121	39,704	42,832	94,528	50,403	57,175	94,139	-	106,308	-
68	2.3GS 110-1,000 kVa	2,192,754	405,018	173,098	270,292	521,563	447,336	9,692	75,654	10,095	180,120	11,880	23,786	39,164	-	25,057	-
69	2.4GS Over 1,000 kVa	1,514,647	296,263	121,139	197,714	381,513	327,218	300	55,340	313	131,754	368	737	1,213	-	776	-
70	4.1Street and Area Lighting	288,336	7,571	2,643	5,052	9,749	8,362	22,766	1,414	23,713	3,367	27,905	-	-	116,937	58,856	-
71	**Subtotal Rural**	**15,474,123**	**2,103,793**	**879,460**	**1,403,984**	**2,709,163**	**2,323,604**	**668,725**	**392,973**	**696,540**	**935,598**	**819,657**	**262,567**	**432,320**	**116,937**	**1,728,802**	**-**
72	**Total**	**17,596,591**	**3,143,905**	**1,267,627**	**2,098,112**	**2,709,163**	**2,323,604**	**668,785**	**392,973**	**696,540**	**935,598**	**819,657**	**262,567**	**432,320**	**116,937**	**1,728,802**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
37	CFB - Goose Bay Boiler	-	-	
38	IOCC Firm	-	-	
39	IOCC Non-Firm	-	-	
	Rural:			
40	1.1Domestic	2,574	128	
41	1.1A Domestic All Electric	239,256	11,927	
42	2.1GS 0-10 kW	9,227	460	
43	2.2GS 10-100 kW	51,778	2,581	
44	2.3GS 110-1,000 kVa	73,298	3,654	
45	2.4GS Over 1,000 kVa	1,314	1,212	
46	4.1Street and Area Lighting	7,056	352	
47	**Subtotal Rural**	**384,503**	**20,314**	
48	**Total**	**384,503**	**20,314**	
	Re-classification of Revenue-Related			
49	CFB - Goose Bay Boiler	-	-	Re-classification to demand, energy and customer is based on rate class revenue
50	IOCC Firm	-	-	requirements excluding revenue-related items.
51	IOCC Non-Firm	-	-	
	Rural:			
52	1.1Domestic	(2,574)	(128)	
53	1.1A Domestic All Electric	(239,256)	(11,927)	
54	2.1GS 0-10 kW	(9,227)	(460)	
55	2.2GS 10-100 kW	(51,778)	(2,581)	
56	2.3GS 110-1,000 kVa	(73,298)	(3,654)	
57	2.4GS Over 1,000 kVa	(1,314)	(1,212)	
58	4.1Street and Area Lighting	(7,056)	(352)	
59	**Subtotal Rural**	**(384,503)**	**(20,314)**	
60	**Total**	**(384,503)**	**(20,314)**	
	Total Allocated Revenue Requirement			
61	CFB - Goose Bay Boiler	-	-	
62	IOCC Firm	-	-	
63	IOCC Non-Firm	-	-	
	Rural:	-	-	
64	1.1Domestic	-	-	
65	1.1A Domestic All Electric	-	-	
66	2.1GS 0-10 kW	-	-	
67	2.2GS 10-100 kW	-	-	
68	2.3GS 110-1,000 kVa	-	-	
69	2.4GS Over 1,000 kVa	-	-	
70	4.1Street and Area Lighting	-	-	
71	**Subtotal Rural**	-	-	
72	**Total**	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Functionalization & Classification Ratios

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production		Rural Prod &	Distribution											Specifically
Line		Total	Production	& Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
	Generation																	
1	Hydraulic	100%	44.61%	55.39%														
2	Hydraulic - GNP	100%	44.61%	55.39%		0.0%												
3	Holyrood	100%	77.66%	22.34%														
4	Gas Tur Island Intercnctd	100%	100.00%	0.00%														
5	Diesel Island Intercnctd - GNP	100%	100.00%	0.00%		0.0%												
6	Dsl / Gas Tur Island Isolated	100%	43.08%	56.92%														
7	Dsl / Gas Tur Labrador Isolated	100%	34.47%	65.53%														
8	Dsl / Gas Tur L'Anse au Loup	100%	100.00%	0.00%														
9	Dsl / Gas Tur Labrador Intercnctd	100%	100.00%	0.00%														
	Fuel																	
10	No. 6 Fuel	100%	0.00%	100.00%														
11	Gas Tur Island Intercnctd	100%	100.00%	0.00%														
12	Diesel Island Intercnctd - GNP	100%	100.00%	0.00%		0.0%												
13	Dsl / Gas Tur Island / Lab Isolated	100%	0.00%	100.00%														
14	Dsl / Gas Tur L'Anse au Loup	100%	0.00%	100.00%														
15	Dsl / Gas Tur Labrador Intercnctd	100%	100.00%	0.00%														
	Transmission Lines & Terminals																	
16	Lines	100%		0.00%	100%													
17	Lines - Hydraulic	100%	44.61%	55.39%														
18	Lines - Customer Specific	100%																100%
19	Terminal Stations	100%		0.00%	100%													
20	Term Stns - Hydraulic	100%	44.61%	55.39%														
21	Term Stns - Holyrood	100%	77.66%	22.34%														
22	Term Stns - Gas Tur	100%	100%															
23	Term Stns - Diesel GNP	100%	100.00%	0.00%		0.0%												
24	Terminal Stations - Distribution	100%					100%											
25	Term Stns - Custmr Specific	100%																100%
26	Rural Lines	100%				100.0%												
27	Rural Terminal Stations	100%				100.0%												

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Functionalization & Classification Ratios (CONT'D.)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
				Production		Rural Prod &	Distribution											Specifically
Line		Total	Production	& Transmission	Transmission	Transmission	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lighting	Accounting	Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
	Distribution																	
28	Substation Structures & Equipment						100%											
29	Land & Land Improvements - by Sub-function:																	
30	Primary	85%						88.7%	11.3%									
31	Secondary	15%										58.3%	41.7%					
32	Land & Land Improvements	100%						75.4%	9.6%			8.7%	6.3%					
33	Poles - by Subfunction:																	
34	3 phase - Primary	41.2%						100.0%										
35	Other Primary	36.4%						45.7%	54.3%									
36	Secondary	22.4%										45.7%	54.3%					
37	Poles	100%						57.8%	19.8%			10.2%	12.2%					
38	Primary Condctr & Equip	100%						88.7%	11.3%									
39	Submarine Conductor	100%						100.0%										
40	Transformers	100%								36.1%	63.9%							
41	Secondary Condctr & Equip	100%										58.3%	41.7%					
42	Services	100%												100.0%				
43	Meters	100%													100.0%			
44	Street Lighting	100%														100.0%		
45	Customer Accounting	100%															100.0%	

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service

System Load Factor

Line No.	1	2	3	4	5	6
		Island Interconnected	**Island Isolated**	**Labrador Isolated**	**L'Anse au Loup**	**Labrador Interconnected**
1	Sales+Losses for System Load Factor (MWh)	6,680,800	7,958	41,909	24,767	957,000
2	Hours in Year	8,760	8,760	8,760	8,760	8,760
3	Average Demand (kW)	762,648	908	4,784	2,827	109,247
4	Coincident Peak at Generation (kW)	1,376,994	1,596	7,301	5,664	207,418
5	System Load Factor	55.39%	56.92%	65.53%	49.92%	52.67%

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Holyrood Capacity Factor

	1	2	3	4	5
Line No.	Year	Net Production (kWh)	Net Capacity (MW)	Net Production Hours	Net Capacity Factor
1	**2008 Actual**	**1,080,228,648**	**466**	**8,784**	26.39%
2	**2009 Actual**	**939,865,024**	**466**	**8,760**	23.02%
3	**2010 Actual**	**803,070,465**	**466**	**8,760**	19.67%
4	**2011 Actual**	**885,313,869**	**466**	**8,760**	21.69%
5	**2012 Actual**	**855,826,207**	**466**	**8,784**	20.93%
6	5-Year Average	912,860,843	466	8,770	22.34%

NEWFOUNDLAND AND LABRADOR HYDRO
2013 Test Year Cost of Service
Total System
Power Purchases

Line No.	1	2 Total ($)	3 Production Demand ($)	4 Production & Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Transmission Demand ($)	7 Distribution Demand ($)	Basis of Functional Classification
	Island Interconnected:							
1	DLP Secondary	-		-				Production - Energy (Same as RSP Sec Load Var)
2	AP Secondary	-		-				Production - Energy (Secondary)
3	Wheeling	661,762				661,762		Rural Transmission
4	Interruptible Demand	-	-	-				Production - Demand
5	Interruptible Energy	-		-				Production - Energy
6	Non-utility Generation	51,755,780	23,090,823	28,664,957				Energy: System Load Factor
7	**Subtotal**	**52,417,542**	**23,090,823**	**28,664,957**	**-**	**661,762**	**-**	
	Labrador Interconnected:							
8	CF(L)Co	2,363,382	1,118,595	1,244,787				Energy: System Load Factor
9	Other	295,141					295,141	
10	**Subtotal**	**2,658,523**	**1,118,595**	**1,244,787**	**-**	**-**	**295,141**	
	Isolated Systems:							
11	Mary's Harbour	-		-				Production - Energy
12	L'Anse au Loup	3,353,241		3,353,241				Production - Energy
13	Ramea Wind	244,656		244,656				Production - Energy
14	**Subtotal**	**3,597,897**	**0**	**3,597,897**	**0**	**0**	**0**	
15	**Total**	**58,673,962**	**24,209,418**	**33,507,641**	**-**	**661,762**	**295,141**	

Exhibit 14

REPORT

Holyrood Thermal Generating Station
Decommissioning Study

Newfoundland and Labrador Hydro
500 Columbus Drive, P.O. Box 12800
St. John's, NL, A1B 0C9

April 16, 2013
133545705

Stantec

Table of Contents

1.0 Introduction

Newfoundland and Labrador Hydro (NLH) operates a three-unit, 490 MW (gross), thermal generating station at Holyrood, NL which supplies electricity to the Island's grid. However, with the planned implementation of the Muskrat Falls Generating Facility as part of the Lower Churchill Project, the electrical generation capability of the Holyrood Thermal Generating Station (HTGS) will no longer be required and selected portions of the station are to be decommissioned and demolished. Therefore, NLH retained the services of Stantec Consulting Ltd. (Stantec) to:

- Identify components of the station that will have to be decommissioned and demolished in light of current environmental regulatory requirements;
- Identify the station components that will be decommissioned and demolished as part of NLHs long term operational strategy; and
- Determine the associated decommissioning and demolition costs;

in support of NLH's General Rate Application to the Public Utilities Board (PUB).

1.1 BACKGROUND

The HTGS is located in the Town of Holyrood, approximately 50 kilometers south west of St. John's, on Conception Bay. The HTGS site is approximately 40 hectares in size and as shown on SK-001 in Appendix 1, it includes a: powerhouse that encompasses the three generation units (boilerhouse and turbines/generators), maintenance shops, a water treatment plant and administrative offices; two – 90 meter and one 110 meter concrete stacks; a waste water treatment system; two-cooling water intake pump houses; numerous ancillary buildings and structures including a guard house, chemical storage buildings, hydrogen storage building, materials storage warehouse, training building, gas turbine building and pipe shop; a switch yard, hazardous waste landfill, a 880,000 barrel tank farm and day tank; and a marine jetty and 2500 meter pipeline for offloading and transporting fuel to the tank farm and day tank.

The plant was constructed in two stages and in 1971 Units #1 and #2, each capable of generating 150 MW, were placed in service. In December 1979, Stage II, consisting of one generating unit (Unit #3) capable of producing 150 MW, was completed. The Unit #3 generator is capable of synchronous condenser operation to assist in grid voltage control during the off peak season.

In 1988 and 1989, Units #1 and #2 were modified to increase their output to 170 MW, bringing the total generating capacity of the station to 490 MW (gross). The plant has a firm net capacity of approximately three billion kilowatt-hours of electricity annually, which represents 37% of the Island's electricity needs.

While the HTGS has provided a significant portion of Newfoundland's electricity requirements, it has been, at times, a source of controversy and concern particularly related to air emissions and the environment. In response to these concerns and an evolving regulatory climate, NLH made process improvements and most notably decreased the allowable sulphur content in the fuel burned at the station, which successfully improved air emissions from the plant.

On December 17, 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls development. The Muskrat Falls development includes the 824 MW hydroelectric generating facility at Muskrat Falls, the 1,100 kilometer Labrador-Island Transmission Link, and the Maritime Link from the Island of Newfoundland to Nova Scotia. Once the Muskrat Falls development is brought into service, the HTGS will no longer be required to generate electricity. The HTGS will remain in a stand-by mode for a period of time and will then be used as a synchronous condensing (SC) facility for grid voltage control, utilizing components of the existing Unit #3 in SC mode, according to the following preliminary schedule:

- Present to 2017: full thermal plant operation.
- 2017 - 2020: standby thermal operation, Unit #3 in SC mode.
- 2020 - 2024: decommissioning of HTGS, Unit #3 in SC mode.

1.2 REPORT ORGANIZATION

This report presents a Class 4 opinion of probable cost (OPC) for the planned decommissioning and demolition of the HTGS, based on an operating scenario prescribed by NLH and provides background on the site, expected operations going forward, regulatory requirements, and costing assumptions and methodology.

Section 1 provides an introduction and a brief overview of the site as it exists today and a summary of expected operations at HTGS, as Muskrat Falls comes on line.

Section 2 provides a discussion of the environmental conditions at the site, including a brief overview of the existing environmental setting, the regulatory requirements for operations, and the environmental regulatory requirements that will dictate various aspects of the planned decommissioning and demolition.

Section 3 presents the general approach to the decommissioning and demolition of the HTGS, including the proposed long term operational plan for the station, key assumptions regarding which assets are to remain, and decommissioning and demolition specifics for the major components of the station. This section also includes a discussion regarding optimization of the overall approach to decommissioning and demolition.

Section 4 presents the OPC and the associated costing methodology, including assumptions and exclusions; and a five-year cash flow projection. In addition a discussion on estimated quantities of scrap metal that will be recovered during the demolition is also presented.

Section 5 presents a brief discussion on the overall project time line and decommissioning schedule.

The appendices provide supporting detail.

2.0 Environmental Conditions

This section presents the existing environmental conditions at the site, including a brief overview of environmental setting, operational regulatory requirements, and the environmental regulatory requirements that will dictate various aspects of the planned decommissioning and demolition, and in turn, the associated costs.

2.1 CURRENT ENVIRONMENTAL CONDITIONS

The HTGS has served as an operating power generation facility that has stored and burned Bunker ‘C’ fuel, with varying levels of sulphur, without emission control, for more than 40 years. Based on the length of operations, the type of operations and the regulatory environment at the time of construction and during the first 20 years of operations, the plant, site and surrounding environment have potential for the presence of a variety of contaminants including metals, petroleum hydrocarbons (PHCs), polychlorinated biphenyls (PCBs), polycyclic aromatic hydrocarbons (PAHs) and asbestos; and perhaps other compounds. Management programs are in place to address the potential for environmental contamination; however, these have evolved over the years of operation.

There have been some location specific soil contamination investigations on the site, associated with particular civil works requirements. Such investigations have included areas within the tank farm, in the area of the day tank, and the area of the waste water treatment plant; and have included removal or treatment of some soil contaminated with hydrocarbon and metals. Other civil works excavations, such as those for the sewage disposal system, have not identified any contamination of concern. There have not been site contamination investigations over the entire site, which is reasonable given that the HTGS is an operating site. The extent, significance and type of environmental impacts within the station boundaries will become better defined as analysis continues throughout the decommissioning process.

Based on a site visit and discussions with representatives from NLH, areas of potential environmental impact at the HTGS include:

- The tank farm south of the powerhouse.
- The former leach pit area between the north end of the powerhouse and the wastewater treatment equalization basins.
- The day tank area immediately adjacent to the north end of the powerhouse.
- The area immediately south of the powerhouse where the unit, and unit station service transformers are located.
- The yard east of the powerhouse where sludge and filtercake from the WWT plant is stored.

- The switchyard.

Within the plant there are a number of chemicals and materials that are will require careful management from an environmental protection perspective, to ensure they are properly handled, contained and/or disposed. These include, but are not limited to:

- Process chemicals for water and waste water treatment (caustic, acids, flocculants, etc.).
- Asbestos containing materials.
- Mercury containing devices.
- Ozone depleting substances.
- Radionuclide containing devices.
- PCBs.
- Painted surfaces potentially impacted with lead, PCBs or other compounds.
- Solvents, lubricants, oils, greases, hydraulic oils.
- Lead-acid batteries.
- Glycol.
- Bunker 'C' or diesel fuel.

It is noted that several large scale, off-site, human health risk assessments in 1999, 2004 and 2006; and examining environmental effects in 2009, have been completed. In general terms the human health risk assessments concluded that chronic adverse health effects were not expected as a result of operations. Similarly, the environmental effects monitoring concluded that effluent discharges to Conception Bay from the HTGS did not negatively impact the adjacent waters. The results of the next round of environmental effects monitoring is required to be submitted by June 2015.

However, it is anticipated that erosion, in relation to activities at HTGS, along the Conception Bay shoreline may have to be addressed.

2.2 OPERATIONAL REQUIREMENTS

The HTGS, including the powerhouse, wastewater treatment plant, hazardous waste landfill and associated works, currently operates under a *Certificate of Approval* (C of A) issued by the Newfoundland and Labrador Department of Environment and Conservation (NLDEC), pursuant to Section 83 of the provincial *Environmental Protection Act*.

The C of A identifies overall operational objectives as well as the specific monitoring requirements and environmental standards to which the facility must adhere during operations, but also includes requirements for decommissioning and restoration of the plant and site at the end of its useful operating life. The C of A references existing acts, regulations, policies and guidelines which must also be complied with including: the provincial *Environmental Protection Act* and the *Water Resources Act*; as well as the following:

Regulations:

- Air Pollution Control Regulations.
- Environmental Control Water and Sewage Regulations.
- Halocarbon Regulations.
- Storage and Handling of Gasoline and Associated Products Regulations.
- Used Oil Control Regulations.
- Storage of PCB Wastes Regulations.

Guidance Documents:

- Sampling of Water and Wastewater – Industrial Effluent Applications.
- Ambient Air Monitoring.
- Compliance Determination.
- Stack Emission Testing.
- Plume Dispersion Modelling.

In addition, the federal *Fisheries Act* applies to operations at the HTGS; as does the Transport Canada's *Consolidated Transportation of Dangerous Goods Regulations Including Amendment* under the *Transportation of Dangerous Goods Act*, which applies in Newfoundland and Labrador by virtue of a federal-provincial agreement.

2.3 REGULATORY REQUIREMENTS OF DECOMMISSIONING

Based on a review of environmental statutes in the province of Newfoundland and Labrador, there does not appear to be a single or all-encompassing piece of legislation or a single policy that addresses decommissioning and demolition from an environmental protection perspective, with the exception of the fuel oil storage tanks, dykes and pipeline which are required to be demolished. Rather, owners and operators of facilities to be decommissioned and demolished must consider a number of Acts, Regulations and Guidelines at both the federal and provincial levels, including, in particular, the requirements stipulated in their C of A, and they must consult with the appropriate regulatory officials and complete the subsequent decommissioning and demolition work accordingly.

The documents listed below are expected to be generally applicable to decommissioning and demolition at the HTGS. The name of the guiding document is provided in *italics* and is followed by a brief description of the document or the relevant/applicable sections.

- *National Guidelines for Decommissioning Industrial Sites (1991), Canadian Ministers of Environment (CCME).*

  This document presents a logical phased process for assessing and remediating industrial lands to allow other uses and manage environmental concerns at a site. There are no specific directives within, but rather general guidelines "that a site be remediated to a level which will provide long-term environmental protection and will be safe for its intended future use".

- *Environmental Codes of Practice for Steam Electric Power Generation – Decommissioning Phase (EPS 1/PG/6) (1992), Environment Canada.*

  This document is similar in nature to the Decommissioning Guidelines noted above, but is specific to the power generation industry. The Code, like the Guideline, is not a regulation and does not remove any obligation to be compliant with existing regulations. The Code of Practice provides general guidance for the planning, investigation and remediation of electric power generating sites; specific clean-up standards are not included.

- *Environmental Protection Act (SNL – 2002 c E-14.2).*

  - *Certificate of Approval to Operate for the HTGS - AA11-085563.*

    Appendix A – Part 16 requires compliance with the *Storage and Handling of Gasoline and Associated Products Regulations 58/03* which in Section 25.(3) mandates that the owner of a storage tank system to, within 30 days of abandonment, empty the system of all liquids and vapours and dismantle and remove or dispose of the tank system including the dyke and remove the impacted material to the satisfaction of the Department of Environment and Conservation.

    Appendix A - Part 21 requires that a plan to restore areas disturbed by the operation be submitted to the Department of Environment and Conservation ten months before closure.

    Appendix A – Part 45 requires that the hazardous waste landfill be operated in accordance with the Landfill Operations Manual, which specifies (Sections 10 and 11) landfill closure requirements including the preparation of a closure plan, installation of an engineered cover at the time of site closure, and post closure care including leachate monitoring, until leachate quality approaches background groundwater/surface water quality.

Appendix A – Part 55 requires groundwater monitoring at the hazardous waste landfill for a period of 25 years following closure of the landfill.

Appendix B – Provides general objectives for site decommissioning and elements to be included in the decommissioning and restoration plan. Specific clean-up criteria are not provided, but it is noted that a phased environmental investigation to identify the type, extent and degree of impacts at the site is to be undertaken, and the site is to be restored to a condition acceptable to the Department of Environment and Conservation.

- *Environmental Assessment Regulations 54/03.*

  This regulation, per Section 34.(1) and 26., requires that the decommissioning of an electric power generating facility be registered as an undertaking.

- *Storage and Handling of Gasoline and Associated Products Regulations 58/03*.

  Section 25.(3) of the regulation mandates cleaning and dismantling and disposal of the an above ground petroleum storage tank system, as described above.

- *Halocarbon Regulations 41/05.*

  Per sections 7, 22 and 27, this regulation requires the proper handling and disposal of air conditioning, refrigeration or fire extinguishing equipment before decommissioning activities occur and that refrigerants and halons be removed from air conditioning/ refrigeration equipment or fire extinguishing systems that have not been or will not be operated for a period of more than eight months.

- *Guidance Document for the Management of Impacted Sites V-1.01, 2005, Government of Newfoundland and Labrador, Department of Environment and Conservation* and the *Atlantic RBCA (Risk Based Corrective Action) for Petroleum Impacted Sites in Atlantic Canada, Version 3, July 2012*.

  These two documents provide guidance with respect to management and remediation of impacted (petroleum hydrocarbons and other contaminants) sites in NL. The *Management of Impacted Sites* document stipulates that impacted sites may be closed through adherence to a site management process which includes investigation, remediation and application of pre-established clean-up criteria or through the development of site specific criteria or the implementation of risk management techniques in relation to the management and remediation of impacted sites.

  The *RBCA* document provides further detailed technical guidance, as well as specific clean-up targets and protocols to establish site specific clean-up criteria. RBCA generally addresses petroleum hydrocarbon compounds only, unless the Site Professional can demonstrate to the regulator that "…applicable fate and transport equations and Canadian toxicological data sources are used in the risk assessment."

Adherence to these two guiding documents throughout the decommissioning phase at HTGS will be strictly required.

- *Water Resources Act, Chapter W-4.01;*

  Section 18 of the Act requires the holder of a Water Use License, which is issued under the *Act*, to apply for an amendment to that license should the water requirements change.

  It is anticipated that water use requirements at HTGS will decrease at the end of standby thermal operations and this may require NLH to seek an amendment to the terms of their Water Use License.

  It is also noted that the operational requirements of the dam and the fish passageway on Quarry Brook may also change with changes in water use requirements. Any such changes in the operations of the dam and fish passageway will have to be addressed during decommissioning.

  Section 44, requires the owner/operator of a dam to maintain it in good repair and inspect and report to the Minister on the condition of the dam.

- *Asbestos Abatement Regulation (111/98) under the Occupational Health and Safety Act.*

  This regulation prescribes detailed procedures for the safe removal of asbestos and is not repeated herein.

- *Asbestos Waste Disposal Policy(PPD-93-03)*

  This policy requires that asbestos waste be carefully managed such that it does not represent a human health hazard and in particular, Section 5 requires that asbestos waste be considered as special waste and, among other things, be landfilled in a special/hazardous waste area of an approved disposal site.

- *PCB Regulations SOR/2008-273 under the Canadian Environmental Protection Act.*

  This federal regulation dictates the management, storage and disposal of PCBs. Highlights of the regulation relating to decommissioning and demolition are noted:

  - Section 5.(1) (a) prohibits the release of PCBs in the environment in concentrations above 2 mg/kg.

  - Section 6.(b) prohibits the sale of a product containing PCBs in a concentration of 50 mg/kg or greater.

  - Section 19 stipulates that the owner of PCBs shall, within 30 days after they are no longer used, either send them for destruction or for storage at a PCB storage site.

- *Federal Fisheries Act (R.S.C., 1985, C. F-14)*

  This act, per Section 35(1) prohibits the harmful alteration, disruption or destruction (HADD) of fish habitat unless it is authorized. Therefore, if decommissioning or demolition of the HTGS extended into Conception Bay or Quarry Brook, then a HADD Authorization under Section 35(2) would be required.

A preliminary review of the new *Canadian Environmental Assessment Act* was completed and it was determined that the decommissioning and demolition of the HTGS may not trigger a registration requirement under the revised act. This will have to be confirmed.

This overview of the anticipated environmental regulatory requirements was developed based on a review of existing legislation and discussions with NLH. Input from representatives from the federal and provincial departments of Environment/Environment and Conservation, respectively, was not obtained given the preliminary nature of the decommission planning. Input from regulators will be required as the planning proceeds to ensure compliance and that all environmental issues are addressed in an appropriate manner.

3.0 Decommissioning and Demolition Plan

Section 3 presents the general approach to the decommissioning and demolition of the HTGS, including the proposed long term operational plan for the station, key assumptions regarding which assets are to remain, and decommissioning and demolition specifics for the major components of the station. This section also includes a discussion regarding optimization of the overall approach to decommissioning and demolition.

3.1 OPERATIONAL OBJECTIVES

In order to develop a decommissioning and demolition plan and to prepare an OPC, assumptions regarding the long term operational vision for the HTGS, including ownership, operational capabilities, asset retention, etc. were established, based on discussions with representatives of NLH and the HTGS.

From an operational perspective, it is assumed that:

- NLH will retain ownership of the property in the long term and it will remain as an industrial site.
- The thermal generating capability of the station will be eliminated.
- Unit #3 synchronous condensing operations will continue.
- A 50 MW gas turbine will be installed and operated for peak loading.
- The site may serve as Eastern TRO “Regional Operations Centre”.

3.2 DECOMMISSIONING AND DEMOLITION

In order to meet the operational objectives defined above, the buildings, assets, equipment and infrastructure required to support SC and future operations; and those that will no longer be necessary, were identified at a conceptual level, based on input from NLH and Station staff, referencing the detailed HTGS ‘Asset List’ provided in Appendix 2.

The Asset List identifies all assets within the station, and for the purposes of this study and for the development of the OPC, the Asset List numbering system was cross-referenced with an agreed upon work breakdown structure (WBS), which was used in an earlier iteration of a decommissioning and demolition OPC for the HTGS. The proposed WBS is commonly used in the utility industry and is routinely used for asset management as it provides a readily recognizable format to group assets at a large facility.

For convenience, the buildings and site infrastructure that is to remain, and that which is to be decommissioned/demolished is also identified on SK-001, 002, 003 and SK-5001.

It is assumed that NLH will decommission and demolish the selected components of the HTGS in a safe and cost effective manner, in compliance with applicable environmental requirements, while maximizing opportunities for the recovery and recycling of scrap metals. Based on a review of the asset list with NLH, and in consideration of the age of the assets, and their specialized applications within the HTGS, it was agreed that re-use of the equipment would not be likely.

Conceptually, it is envisioned that the decommissioning and demolition will be completed in three major phases including: planning, pre-decommissioning preparation, and demolition.

Phase 1 - Planning will include: registration of the project with the NLDEC, initiation of the environmental site assessment, completion of any required hazardous materials audits; and engineering.

Phase 2 - Pre-decommissioning will include those tasks that can be completed by Plant staff such as: de-energization of equipment, removal of fluids from equipment and modification of common services that would be affected by demolition and are required in the longer term to support future ongoing operations.

Phase 3 - Decommissioning will include: mobilization to site by the contractor, removal and abatement of hazardous materials, industrial cleaning, demolition, environmental remediation, landfill closure and final grading of the site.

Based on discussions with NLH, the following general assumptions are of particular note:

- Selective decommissioning and demolition will be undertaken within the powerhouse such that the turbine hall, lab, administrative offices, maintenance and water treatment areas remain intact.
- The existing 880,000 barrel tank farm (including the day tank), and associated marine jetty and pipeline, will no longer be required and it is assumed, from an operational perspective and for the purpose of this evaluation, that they will be decommissioned and demolished.
- The existing hazardous waste containment landfill will no longer be required upon cessation of thermal generation at Holyrood, however it will serve an important function during the decommissioning process as it is expected that it will be suitable for the disposal of some of the wastes generated during that process.
- The Wastewater Treatment Plant and Equalization Basins will no longer be required upon cessation of thermal generation however they will be relied upon to provide treatment of the wastewater generated during the decommissioning.
- The dam at Quarry Brook and the environmental monitoring and meteorological monitoring stations will remain.

The decommissioning and demolition plan presented in the following sections, correspond to the divisions of the WBS:

3.2.1 WBS Task 100 - Site and Environment

The decommissioning and demolition activities pertaining to the “site” will take place primarily in Phase 3 and include; removal of sub-grade site services such as piping, vacuum pits, oil water separators and manholes, closure of the landfill, overall site grading and landscaping. In particular:

- Sub-surface infrastructure related to pumphouse #1 cooling water will be decommissioned and demolished.
- Sub-surface infrastructure related to domestic water supply, water for fire protection, domestic wastewater treatment and cooling water supply from pumphouse #1 will be retained.
- It is assumed that piping larger than 300 millimeters in diameter will be excavated and removed, whereas smaller bore pipe will be capped in place.
- The hazardous waste landfill will be closed in accordance with the C of A which requires an engineered low permeability cap.

The decommissioning and demolition tasks pertaining to the ‘environment’ will take place throughout all three phases of the project and include: assessment, remediation and compliance activities. Site assessment can begin in Phase 1 and will include extensive intrusive investigations, boreholes, test pitting, soil sampling, groundwater monitoring, and laboratory analysis to determine the physical extent, nature and degree of contamination at the station in order to develop a remedial action plan. Depending on accessibility, site assessment activities could continue through to Phase 3.

This task will also include the registration of the decommissioning and demolition project per the provincial EIA Regulation. This will involve the preparation of a project registration document describing the decommissioning and demolition project and the expected environmental impacts. At present it is assumed that registration under the federal Canadian Environmental Assessment Act may not be required, but consultation with Environment Canada will be necessary to confirm this assumption.

Finally, remediation of the site is included in this WBS Task and it encompasses all activities to bring the HTGS site into compliance with environmental legislation. Site remediation may include: removal of petroleum hydrocarbon and metal impacted soils and on-site treatment of impacted soil and groundwater.

Activities related to removal of asbestos, PCB impacted oils, fly ash/boiler ash, industrial cleaning, chemical removal etc. are not included in WBS Task 100, but are assigned to the appropriate WBS division based on where the removal, clean-up or abatement activity occurs.

For example, removal of the asbestos from the boilers is included in WBS Task 300 – Boilers and Auxiliaries; removal of Galbestos siding from the powerhouse is included in WBS Task 200 – Buildings and Structures; and removal and management of PCB impacted oil in the transformers is included in WBS Task 500 – Electrical.

3.2.2 WBS Task 200 - Buildings and Structures

Decommissioning and demolition of the buildings and structures will take place in all three phases of the project, as it is assumed, for the purposes of this study, that some preparatory decommissioning activities such as clean up and chemical removal can be initiated in Phases 1 and 2, but most of the required industrial cleaning and hazardous material removal (i.e. asbestos abatement) this work will be completed in Phase 3, prior to demolition. In particular:

- The buildings that supported thermal generation operations – such as the new guard house, chemical storage building, hydrogen storage building, pipe shop, meter shop, training building, and Shawmount warehouse will be retained.
- Pumphouse # 2 will be retained to provide cooling water for the Unit #3 generator.
- Pumphouse # 1, which services Units #1 and #2 will be partially decommissioned, such that the fire pumps and domestic water pumps are operable.
- The boiler area of the powerhouse building will be decommissioned and demolished as shown on SK-002. The turbine hall, lab, administrative offices, maintenance and water treatment areas will remain.
- Removal of the Galbestos siding on the powerhouse as well as any asbestos containing material, dust or debris remaining on equipment or in cable trays, will require special handling and disposal procedures to ensure worker and environmental health and safety.
- It is assumed that the roof of the powerhouse contains asbestos and will require special handling and disposal procedures to ensure worker and environmental health and safety.
- It is assumed that the building and equipment foundations will be demolished to one metre below grade and the resulting concrete will be pulverized to 150 millimeters minus for rebar recovery and ease of handling.
- It is assumed that the jetty, wharf (including the dynamic fenders) and walkways will be demolished and that the piles supporting the wharf and jetty will also be demolished and removed.
- The massive concrete pedestals supporting the turbine/generators will be demolished and removed.

- Structural modifications may be required and exterior walls and cladding will have to be constructed where demolition of exterior walls of the boiler house has occurred. This construction work is included in WBS Task 800 – Construction.

3.2.3 WBS Task 300 - Boilers and Auxiliaries

The decommissioning and demolition activities pertaining to the boilers and auxiliaries will occur predominantly in Phase 3, but some cleaning and fly ash/boiler ash removal may take place in Phase 2. In addition, decommissioning and demolition of the boilers and auxiliaries will take place prior to demolition of the boilerhouse and as previously noted they will be demolished with a view to maximizing the recovery of scrap metal for sale. In particular,

- Abatement of asbestos in the boiler buckstays and any other affected areas as identified in the asbestos management plan will be completed prior to demolition of the boiler.
- All three boilers and their auxiliary components will be decommissioned and demolished. This includes, but is not limited to, the following:
  - Water walls, burners, steam drum, burner fronts, super heaters, re-heaters, economizers, soot blowers and ash pits,
  - All main steam piping and condensate piping,
  - LP and HP heaters, deaerators, deaerator storage tank, blowdown tanks and feedwater pumps,
  - Fuel oil system components including heaters, pumps heat exchangers and piping,
  - Air and gas components such as FD fans, ductwork, wind box, Lungstrom air heaters, steam coil air heaters, and
  - Flue gas components such as the boiler outlet ductwork and stacks. (It is anticipated that the stacks will be imploded.)

3.2.4 WBS Task 400 - Turbines, Generators and Auxiliaries

Decommissioning and demolition activities pertaining to the turbine/generators and auxiliaries will occur predominantly in Phase 3 and like the boilers, their decommissioning and demolition will take place prior to demolition of the boilerhouse and they will be demolished with a view to maximizing the recovery of scrap metal for sale. In particular,

- Turbine/generators and auxiliaries associated with Units #1 and #2 will be decommissioned and demolished.
- The turbine and auxiliaries associated with Unit #3 will be decommissioned and demolished.

- The generator associated with Unit #3 will be retained.
- The lube oil and seal oil systems and condensing and cooling systems associated with Units #1 and #2 will be decommissioned and removed.
- The 15 MW gas turbine, including the generator, the turbine and the clutch, the inlet air filter and the exhaust system, will be removed.

3.2.5 WBS Task 500 - Electrical

Electrical system decommissioning and demolition will include all components not required to support Unit #3 SC operations, and for the purposes of this study, it is assumed that selected electrical equipment associated with Units #1 and #2 can be safely isolated and removed while allowing SC operations to continue uninterrupted. Further study and engineering evaluation will be required to determine if this is feasible and how it will best be achieved.

The scope of electrical removals is identified on Drawing SK-5001 which is provided in Appendix 1 and it is anticipated that, subject to in-depth verification, the systems identified in red will be removed while those identified in black will remain operational.

Decommissioning and demolition of the electrical system will occur predominantly in Phase 3 and like the other equipment within the station, it will be undertaken to maximize the recovery of scrap metal for sale. The following items, in relation to the electrical demolition are of note:

- The switchyard will remain in use and will not be affected by the decommissioning activities, other than the tie-in points associated with the Unit #1 and Unit #2 outputs. This will be further refined as NLH moves to the actual decommissioning and demolition of the plant.
- Electrical decommissioning and demolition for Unit #1 and #2 will include:
  - Unit generator and associated hydrogen cooling, excitation, CO_2 purging system, protection and control systems.
  - Unit output including isolated phase bus, ground cubicle, output transformer, unit station service transformer, overhead lines to the switchyard and support structures, and associated protection and control systems.
  - Unit electrical boilerhouse and turbine hall services including: motor control centers and feeders to unit pumps, control systems cabinets and associated control room stations, miscellaneous loads and associated control systems, unit Class I and Class II distribution systems including 125VDC and 480VDC battery banks, battery chargers, UPS, distribution panels and branch circuit wiring, distribution transformers, panel boards and branch circuit for heating, lighting and miscellaneous loads.

- Electrical decommissioning and demolition for Unit #3 will be selective as it will remain and continue to function in SC mode. Decommissioning will include:
    - Unit electrical boilerhouse and turbine hall services including: motor control centers and feeders to unit pumps, miscellaneous loads and associated control systems.
    - Unit boilerhouse building electrical services including: distribution transformers, panel boards and branch circuit for heating, lighting and miscellaneous loads.
    - Selective unit control systems.
- Electrical removals associated with the existing 15 MW gas turbine (GT) will include:
    - GT output and associated transformer, unit excitation, protection and control systems.
    - GT Class I distribution systems including 125VDC battery banks, battery chargers, distribution panels and branch circuit wiring.
    - GT building electrical services including distribution transformers, panelboards and branch circuit for heating, lighting and miscellaneous loads, control systems cabinets and associated control room stations.
- Electrical decommissioning and demolition in ancillary facilities will include:
    - Electrical services associated with the water treatment plant and maintenance shops within the powerhouse, the marine jetty, pipeline and tank farm, the stacks (including the ID fans) and the waste water treatment plant.
- Electrical decommissioning and demolition relative to pumphouse #1 will be selective, because the building will remain in use for fire and domestic water pumping functions.
- Electrical services for pumphouse # 2 will be retained.

Optimization of electrical services and equipment or control system architecture and cabinets was not considered in this study, but should be undertaken as the decommissioning planning proceeds and station requirements are better defined.

The decommissioning and demolition of the electrical system will require pre-planning, not just to optimize remaining services and ensure worker and operational safety but also because it will generate a number of materials that will require the implementation of special handling and disposal procedures. In particular, there are seven known unit, unit station service and exciter transformers that at one time contained PCBs, to be decommissioned.

It is also assumed that the plastic sheathing on some older cables may contain PCBs above 50 ppm. The quantification and appropriate management of these cables will be addressed prior to demolition.

For the purposes of this study, it is assumed that the residual concentration of PCBs in the transformer oil is greater than 2 parts per million, and will require de-chlorination. It is noted that the process of de-chlorination, in the transformers containing the PCB impacted oil, will yield 'decontaminated' transformers, which will then be available as scrap metal.

Based on our site visit and discussions with HTGS staff, the following hazardous substances will be generated through demolition of the electrical system:

- PCB impacted transformer oil ~ 123,000 litres.
- Sulfuric acid in battery banks ~ 4,100 litres.
- Lead in battery banks ~ 9,100 kilograms.
- Mercury in level and temperature switches ~ 10 kilograms.
- PCBs in fluorescent and HID lighting fixture ~ 150 kilograms.
- Radionuclide materials in fire alarm and smoke detectors ~ 10 kilograms.

For the purposes of this study, decommissioning and demolition of items related to Instrumentation and Controls, is included in Task 500. Typically, Instrumentation and Controls is assigned to Task 600 in the WBS.

3.2.6 WBS Task 600 - Controls and Instrumentation

All of the decommissioning activities and costs associated with controls and instrumentation for the project have been taken into account in Task 500 – Electrical.

3.2.7 WBS Task 700 - Common Services

The common services that will be decommissioned and demolished include:

- The raw water treatment equipment, tanks and piping.
- Waste water treatment equipment - oil/water separators and equalization basins, tanks, pipes, filter press, etc.
- Cooling water equipment not required for Unit #3 SC operations.
- The various components of the heavy fuel oil system – including the four above ground Bunker "C" fuel storage tanks, the day tank and the pipeline between the marine jetty and day tank on the north side of the powerhouse.

The common services will be decommissioned and demolished in Phase 3, but cleaning of the above ground fuel storage tanks and pipeline, may take place in Phase 2. It is anticipated that the waste water treatment system will play an important part in the decommissioning of the powerhouse and the boilers and other pieces of equipment as it will be able to treat waste water generated during cleaning activities.

Many of the common services inside the boiler house may need to be reconfigured or relocated once partial demolition occurs, in order to serve the remaining areas of the plant. A detailed evaluation of these common services is outside the scope of this study but will eventually need to be completed. Affected common services include: fire protection, service air, instrument air, HVAC, cooling water, domestic water etc. Section 3.3 provides additional discussion in regards to the optimization of the boiler house demolition.

Other items to note with respect to the decommissioning and demolition of common services include:

- The light fuel oil tanks adjacent to the tank farm will remain.
- The existing crane within the powerhouse will remain.
- The lab equipment, water treatment equipment, and maintenance shop equipment within the powerhouse building, will be decommissioned and demolished.

3.2.8 WBS Task 800 – Construction

Some construction will be required during demolition as a considerable portion of the existing powerhouse structure will be retained for future operations. Construction will include structural modifications and installation of cladding at the powerhouse and the pumphouse # 1, as well relocation of electrical and mechanical systems and sub-surface water and sanitary connections.

3.3 OPTIMIZATION OF DECOMMISSIONING AND DEMOLITION

3.3.1 Selective Demolition

The long term operational mode for the HTGS and selective decommissioning and demolition was established as a result of discussions with NLH and is referred to as the “base case” within this study. The final scope of decommissioning and demolition and the project timelines will continue to be refined, as project planning proceeds and NLH moves closer to the actual demolition phase.

For example, selective demolition of the boilerhouse area of the powerhouse is the agreed upon approach, but it is known that the boilerhouse, turbine hall and office area were all constructed as an integral complex. Selectively demolishing and removing only the boilerhouse will result in additional demolition costs due to the care and attention required to remove only certain parts of the building and equipment without damaging the sections that are to remain occupied and operational. Furthermore, it is expected that additional planning, engineering, coordination and safety measures would also be required for this selective demolition approach.

Some of the items to be reviewed within the context of 'optimization' are discussed in the following sections.

3.3.2 Structural and Architectural

- The structural integrity of the remaining buildings would need to be extensively reviewed. As noted above, the power house was designed as a complex, therefore the turbine hall structure and the administration building structure may need to be reinforced or modified to accommodate a new configuration.
- A new exterior wall girt and cladding system would need to be installed on the north wall of the turbine hall to enclose the building.
- Part of the administration building wall system would need to be reviewed and/or modified as part of it will become an exterior wall as opposed to an interior wall.
- A code review would be required for egress and fire protection requirements.

3.3.3 Mechanical

All of the mechanical systems would need to be reviewed as some or all may require modification once the boilerhouse is demolished. Systems to consider would include, but not be limited to:

- Fire protection system.
- HVAC systems.
- Compressed air systems (service/instrument).
- Cooling water, service water and sanitary systems.
- Hydrogen and CO_2 supply to the Unit #3 generator.

3.3.4 Electrical

Many, if not all, of the electrical systems could be impacted by the demolition of the boilerhouse and will need to be reviewed and possibly modified. Systems to consider in an optimization study would include, but not be limited to:

- Power distribution.
- Lighting, instrumentation and controls.

- Communications, fire alarm and detection systems.

3.3.5 Optimization of Demolition

Optimization of the approach to decommissioning and demolition; and rationalization of the remaining space and services, and any associated modifications and re-construction costs should be established through a detailed engineering assessment, once the requirements for a facility, functioning within the context of a Regional Operations Centre, are understood.

Optimization of the decommissioning and demolition could also examine the following alternatives:

- Abandoning the boilerhouse and equipment in place.
- Demolition of the office, stores and lab at the same time as the boiler house and constructing a smaller and more efficient administration building, suited to a reduced staffing level that would serve as a Regional Operations Centre.
- Same as above, except constructing new offices in the turbine hall in the area previously occupied by Units #1 and #2 turbines/condensers.

Based on our review of similar type large scale industrial decommissioning and demolition projects, it is evident that there are many different ways to execute, phase and tender this type of work. Given the magnitude of the costs associated with decommissioning and demolition, the potential for optimization will continue to be refined as NLH moves to the actual decommissioning and demolition phase of the project.

4.0 Opinion of Probable Cost

Section 4 presents the OPC of the planned decommissioning and demolition including the costing methodology, assumptions and exclusions, as well as a five-year cash flow projection. In addition, a discussion on estimated quantities of scrap metal that could reasonably be recovered during the demolition is provided.

Given the level of project maturity and engineering detail at the study outset, it was agreed that a preparation of a Class 4 OPC, as defined by AACE, would be appropriate as it is consistent with industry practice for projects at this stage of development. Class 4 estimates are prepared for a variety of purposes including: strategic planning, business development, confirmation of economic and/or technical feasibility, and preliminary budget approval, and when project engineering is between 1% and 15% complete. Typical accuracy ranges for a Class 4 OPC are from -15% to -30% on the low side, to +20% to +50% on the high side, depending on the technological complexity of the project.

Therefore, a Class 4 OPC for selective decommissioning and demolition at the HTGS was developed on the basis of proposed long term operational objectives and requirements identified by NLH and described in Section 3. The estimate is conservative and is not based on detailed asset or site evaluations, but rather is a conceptual estimate to assist NLH in financial planning. When the decommissioning scope and environmental conditions of the site become more clearly defined, and the requirements of the environmental regulators are known, the OPC may be further refined.

4.1 COSTING ASSUMPTIONS AND METHODOLOGIES

The OPC presented herein, is based upon:

- The selective decommissioning and demolition scope defined by NLH.
- The assumption that the boiler house and equipment can be selectively demolished in a safe and controlled manner.
- Current regulatory requirements and current (2012) dollars.
- The assumption that, because of the age of the plant, there will be no demand for the further use of any equipment, other than that being used for SC operations.
- The assumption that some potentially significant structural modifications and re-construction work will be required to close in portions of the boiler house and re-connect common services, affected by the selective demolition.
- Drawings provided by NLH.
- Information obtained from in house files for projects of similar scope and size.

- Costing information provided in RS Means/CostWorks (Means).
- Pricing provided by local contractors and local demolition contractors.

The decommissioning and demolition cost methodologies are briefly described below.

4.1.1 The Site and Environment

In order to develop the OPC for the site and environment task, the amount of final landscaping required to restore the site and the demolition requirements for sub-surface infrastructure were considered, as were costs associated with environmental assessment, remediation and compliance.

To determine landscaping and infrastructure demolition costs, site drawings were reviewed, areas to be restored identified and piping and infrastructure quantities estimated. Once these quantities were established, the OPC was developed based on the estimated manpower, equipment and time to complete the defined work.

It is noted that the most significant components in this particular task relate to the landfill closure, environmental assessment and site remediation. While the landfill closure OPC was based on the prescribed closure design in the C of A and current NL construction costs, the assessment and remediation OPC was based on our experience in completing a similar work scope at similarly sized industrial site. It is important to note that the remediation OPC is provided as an 'order of magnitude only', as intrusive site investigations to establish the type, extent and amount of contamination at the site have not been completed.

4.1.2 Buildings and Structures

The OPC for the decommissioning and demolition of buildings and structures was based on pricing provided by an experienced demolition contractor considering the size, height and construction materials of the buildings and structures. The OPC also reflects the fact that selective demolition is to take place in the powerhouse, which requires more care and attention, and in turn more time and cost, than if the entire structure was to be demolished.

The buildings and structures OPC includes the removal and disposal of asbestos containing materials (cladding and roofing of the powerhouse as well as dust and debris on cable trays and throughout the plant), at an approved facility. The OPC is based on estimated quantities generated from the review of building plans and profiles (for the cladding and roofing only) and current abatement and disposal pricing from two contractors.

The OPC also includes the removal of process and other chemicals, and industrial cleaning of the buildings and structures, based upon in-house pricing information for a project of similar scope and size.

4.1.3 Boilers, Turbines, Generators and Auxiliaries

The OPC for the decommissioning and demolition of boilers, turbines, generators and auxiliaries was based on pricing provided by an experienced demolition contractor considering the accessibility and weight of the various components. The OPC also reflects the fact that some selective demolition of equipment, which is more costly, will be required to support planned SC operations.

Also included in the OPC is stack demolition, which is an average of pricing provided by two demolition contractors, to implode the three stacks.

The cost of removing process and other chemicals, industrial cleaning, asbestos abatement and the disposing of dust and boiler/fly ash was also included, based upon in-house pricing information for a project of similar scope and size and on the assumption that the boiler ash and fly ash could be disposed of on-site at the hazardous waste landfill.

4.1.4 Electrical

In order to develop the OPC for the electrical systems within the station, the electrical single line diagram was reviewed and the components to be removed were identified and quantified, through referencing vendor equipment catalogues. The OPC was based on the assumption that the removal of the selected electrical components would be approximately 30% of the cost of a new installation and costing information from the 2012 edition of *RS Means CostWorks* (Means).

It is important to note that the most significant component in the electrical decommissioning OPC is the requirement to dechlorinate, or remove the PCB impacted oil from each of the seven transformers that will no longer be required. Based on name plate data from the individual transformers and recent PCB management cost data, it is estimated that approximately 123,000 litres of PCB impacted oil will have to be managed. For the purposes of developing the OPC it is assumed that the transformer would be dechlorinated by a third party company licensed to complete such work and would include de-chlorination, and transportation and disposal of the residue at an approved site.

4.1.5 Common Services

The OPC for the decommissioning and demolition of common services was based on pricing provided by an experienced demolition contractor considering the accessibility and weight and/or size, and construction materials of the various common service components.

The most significant component of the common services OPC is the preparation of (cleaning) the fuel oil storage tanks for demolition. For this item, an average of tank cleaning pricing provided by two experienced contractors was obtained. The OPC also reflects the fact that some selective demolition of equipment will be required to support SC operations.

4.1.6 Construction

The construction OPC includes an allowance for structural modifications, construction of a new exterior wall and cladding to close in the powerhouse and reconfiguration of common systems within the powerhouse, affected by the demolition, and is based on estimated quantities and in house cost information.

It is noted that the construction OPC is an allowance only and further study would be required to determine what modifications will be necessary and which systems need to be reconnected to allow continued operation in the remaining areas of the powerhouse.

4.1.7 Engineering and Administration

This component of the OPC includes engineering design and construction monitoring and observation fees associated with the decommissioning and demolition project. Owner's costs, interest during construction, escalation, legal and financial costs, permits, licenses and fees are not included.

Finally, a contingency of 10% of the overall demolition cost is included as part of the OPC to fund unplanned items that often develop during a major project of this nature. The contingency provides additional budget that is not allocated to a specific WBS, but is applied to the overall project budget. Generally, contingency allows for funds that the project will utilize but are not allocated at the outset of the project. Contingency differs from estimate accuracy which is based on the level of project definition when the estimate is formulated.

4.2 OPINION OF PROBABLE COST

Based on the long term operational strategy currently envisioned by NLH, including selective demolition of the plant, on-going SC operations, and regulatory compliance; and the costing methodologies described above, the OPC for the decommissioning and demolition of the HTGS is $32,074,000. Based on the definition of a Class 4 estimate and the level of preliminary engineering carried out for this study, it is estimated that the OPC developed herein would have an accuracy range of -10% to +30%.

This OPC, which may be referred to as the 'base case' is broken down in Table 4.2.1 referencing the WBS described previously. The detailed breakdown of the OPC is provided in Appendix 3.

Table 4.2.1 – Summary of the OPC

WBS	Description	Total Cost
100	Site and Environment	$7,135,000
200	Building and Structures	$5,242,000
300	Boiler and Auxiliaries	$4,342,000
400	Turbine, Generator and Auxiliaries	$341,000
500	Electrical	$2,376,000
600	Instrumentation and Control	$0
700	Common Services	$2,692,000
800	Construction	$3,400,000
900	Engineering and Administrative	$3,630,000
	Contingency @ 10%	$2,916,000
	PROJECT TOTAL	$32,074,000

4.2.1 Decommissioning and Demolition Cash Flow

Based on the preliminary decommissioning and demolition schedule, a five-year projection of cash flows between 2020 and 2024, inclusive, was prepared. A summary of the cash flow, which is presented in 2012 dollars is provided in the table below and the detailed cash flow is provided in Appendix 4.

As expected, the forecast shows that just over half of the expenditures will occur in years three and four, when the bulk of the actual demolition and environmental remediation work is to be completed.

Table 4.2.2 – Cash Flow Summary

Year	2020	2021	2022	2023	2024	Total
Projected Expenditure	$330,000	$1,595,000	$10,201,000	$17,385,000	$2,563,000	$32,074,000

4.3 SALVAGE AND SCRAP VALUE

Based upon the age of the HTGS and discussions with potential equipment buyers, it was determined that sale of equipment within the HTGS for re-use would be unlikely and therefore, demolition would proceed on the assumption that the equipment and other assets, including structural steel and re-bar would be scrapped or salvaged for recycling purposes only.

Although a value of the salvageable metals has not been determined, as the pricing is known to vary significantly depending upon the buyer, transportation costs, and market conditions, this section provides a summary of the scrap metal quantities that would likely be generated through the demolition process.

Table 4.3.1 – Scrap Metal Quantities

Station Component	Units	Description	Quantities (Tonnes)
Boilers	#1, #2 and #3	Boiler waterwalls, superheater, reheater, economizer, steam drum, sootblowers, burner fronts, ash pit	4600
Boiler Auxiliaries	#1, #2 and #3	Main Steam piping, primary and secondary superheater inlet and outlet headers, reheater inlet and outlet headers, economizer inlet and outlet headers, HP and LP heaters, deaerator and deaerator storage tank, miscellaneous steam piping - sootblower steam, atomizing steam, aux steam etc., condensate and feedwater piping, boiler feedwater pumps, condensate pumps, condensate tank and blowdown tank, fuel oil piping systems, FD fans, ductwork, windbox and air heaters and flue gas ductwork and components	2700
Turbines	#1, #2 and #3	LP and HP rotors and LP and Casings	400
Condensers	#1, #2 and #3	Condenser and tubing, CW Pumps and condenser vacuum system	500
Generators	#1 and #2	Generator enclosure and the rotor, armature windings, stator windings and field windings	300
Generator Auxiliaries	#1, #2 and #3	Turbine lubrication system and piping, turbine Hydraulic system and piping, generator hydrogen cooling system (Units #1 & #2) and the balance of miscellaneous piping systems	100
Electrical Systems	#1 and #2 and selected components of #3	Unit output, unit station service and exciter transformers, switchgear, MCCs, motors, building electrical services, control cabinets and associated cabling	700
Powerhouse		Structural steel and rebar	3300
Tank Farm		Fuel oil storage tanks	1300
TOTAL			**13900**

5.0 Preliminary Decommissioning Schedule

A simplified project timeline and conceptual decommissioning schedule is presented in Appendix 5. The project timeline provides a snapshot of the proposed sequence of events leading to the cessation of the thermal operations and eventual decommissioning of the generating station, based upon preliminary planning completed by NLH. At present it is anticipated that decommissioning activities will not be initiated until at least the end of 2021 after Muskrat Falls is on line, the HTGS has operated in standby mode and the units are in dry lay-up.

The conceptual decommissioning schedule provides a high level list of the various major pre-decommissioning and decommissioning activities that will be required.

The duration and sequencing of each activity is based on Stantec's professional experience with projects of this nature, and does not reflect optimization of any tasks. The duration of each activity will ultimately depend on contractor availability and the level of resources that are mobilized for this project.

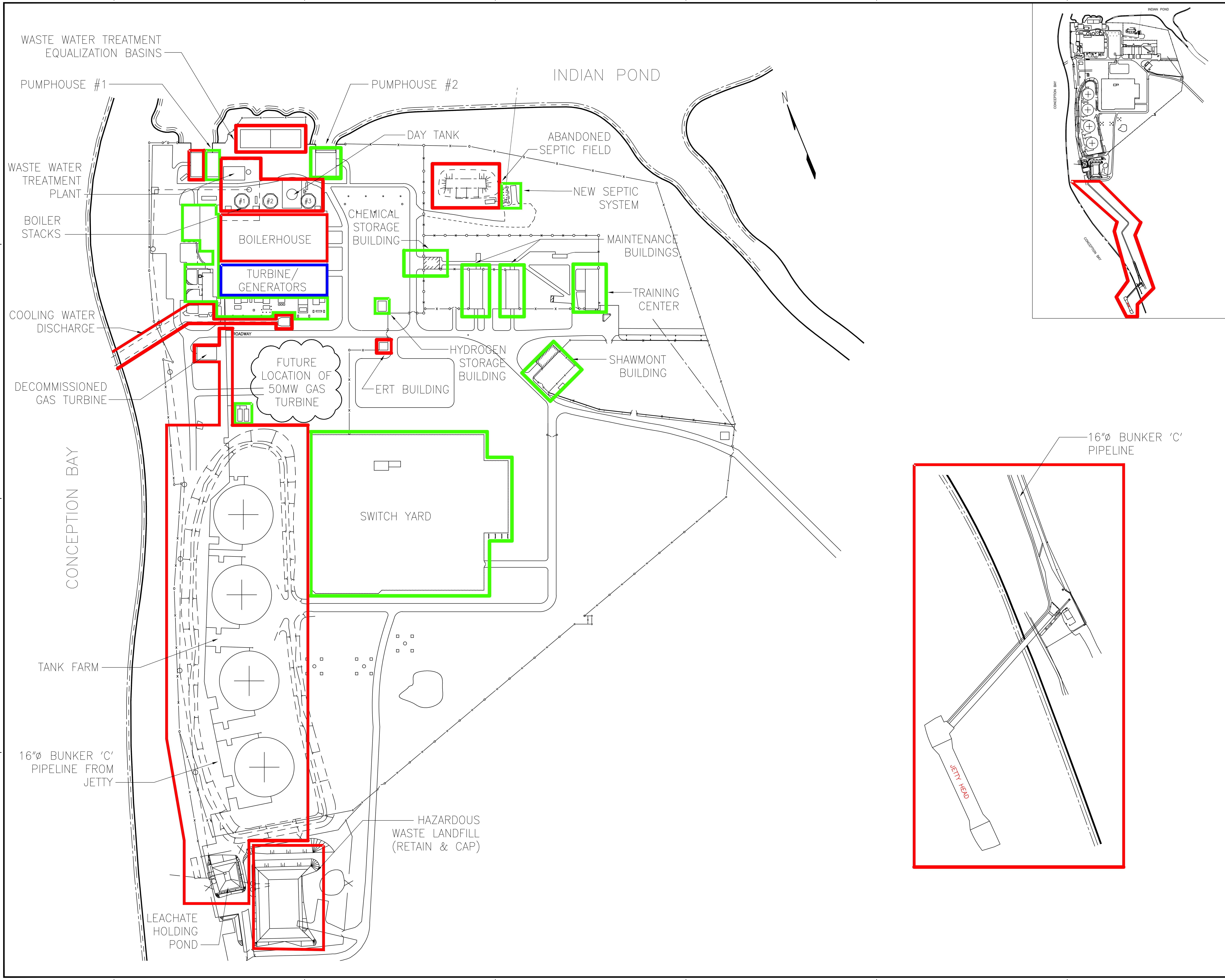
The conceptual decommissioning schedule currently indicates that decommissioning and demolition of the equipment and facilities can be executed within a five year timeframe and be complete by the end of 2024. Based on discussions with an experienced contractor, the actual demolition, after abatement of hazardous materials and industrial cleaning, is anticipated to take approximately eight months. Remediation of environmental impacts is expected to be the longest duration activity.

The schedule can be adjusted to best suit the project and NLH's requirements once additional engineering and planning is completed.

6.0 Appendices

APPENDIX 1

Drawings



REFERENCE DRAWINGS

DWG. No.	TITLE	BY

KEY PLAN

- DEMOLISH AND/OR DECOMMISSION BUILDINGS AND EQUIPMENT
- NO DEMOLITION IN THIS AREA UNLESS NOTED OTHERWISE
- DEMOLISH EQUIPMENT ONLY AS FOLLOWS:
UNIT #1 - ALL
UNIT #2 - ALL
UNIT #3 - TURBINE, CONDENSER, AND AUXILARIES

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
0	CLIENT	INFORMATION

No.	DATE	BY	REVISIONS	DES.	DFTG.

DESIGNED MDV	DRAWN JJB
CHECKED DESIGN / DFTG.	DATE NOV 20, 2012
	SCALE NTS
APPROVED	SPEC.
P.M. / P.T.	

Stantec

newfoundland labrador hydro
a nalcor energy company

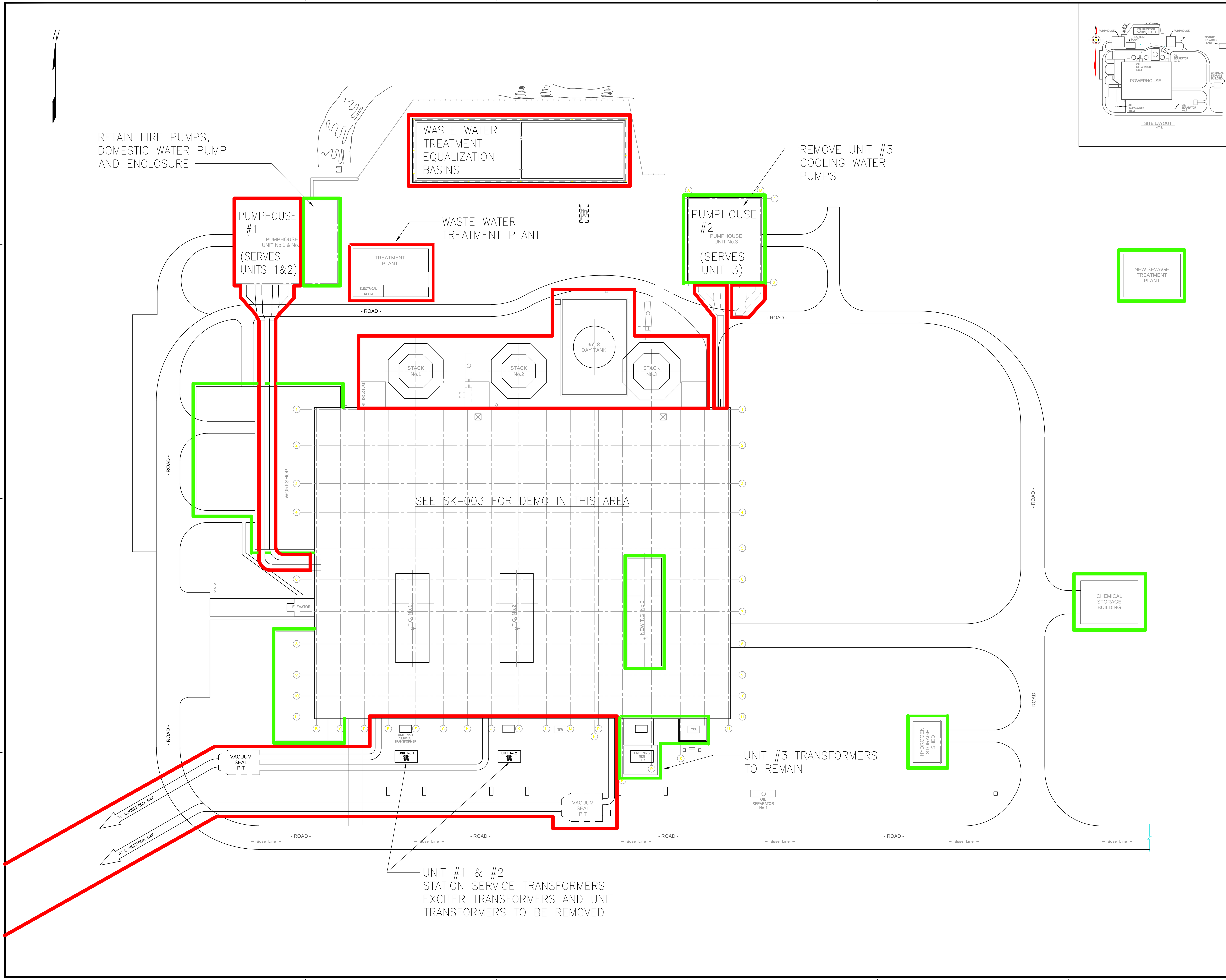
PRELIMINARY DECOMMISSIONING STUDY

HOLYROOD THERMAL GENERATING STATION OVERALL SITE PLAN

JOB No.	DWG. No.	REV
133545705	SK-001	0

U:\133545705 Holyrood Decom\15_reference_dwgs\Drawings\NL-HYDRO\From Fredericton\133545705-SK001.dwg

Jan 25, 2013 9:08am JBabin



REFERENCE DRAWINGS

DWG. No.	TITLE	BY

KEY PLAN

- DEMOLISH BUILDINGS AND EQUIPMENT
- NO DEMOLITION IN THIS AREA UNLESS NOTED OTHERWISE

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
0	CLIENT	INFORMATION

No.	DATE	BY	REVISIONS	DES.	DFTG.

DESIGNED MDV	DRAWN JJB
CHECKED DESIGN DFTG.	DATE NOV 20, 2012
	SCALE NTS
APPROVED	SPEC.
P.M. P.T.	

Stantec

newfoundland labrador hydro
a nalcor energy company

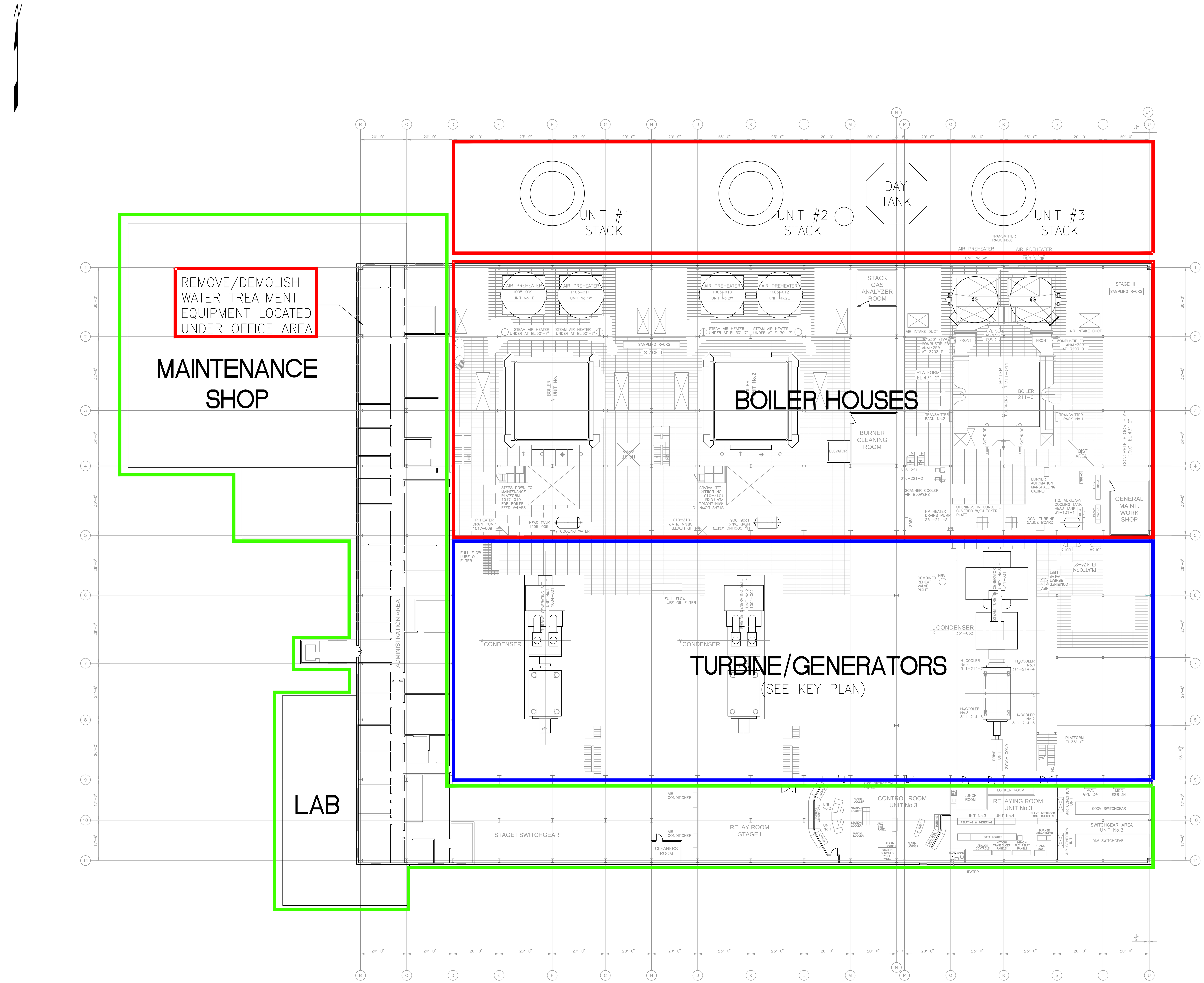
PRELIMINARY DECOMMISSIONING STUDY

HOLYROOD THERMAL GENERATING STATION POWERHOUSE AREA SITE PLAN

JOB No.	DWG. No.	REV
133545705	SK-002	0

Jan 25, 2013 9:09am JBabin

U:\133545705 Holyrood Decom\15_reference_dwgs\Drawings\NL-HYDRO\ From Fredericton\133545705-SK002.dwg



REFERENCE DRAWINGS

DWG. No.	TITLE	BY

KEY PLAN

- DEMOLISH BUILDINGS AND EQUIPMENT (red)
- DEMOLISH EQUIPMENT ONLY AS FOLLOWS: UNIT #1 – ALL, UNIT #2 – ALL, UNIT #3 – TURBINE, CONDENSER, AND AUXILARIES (blue)
- NO DEMOLITION IN THIS AREA UNLESS NOTED OTHERWISE (green)

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
0	CLIENT	INFORMATION

No.	DATE	BY	REVISIONS	DES.	DFTG.

DESIGNED	DRAWN
CHECKED (DESIGN / DFTG.)	DATE NOV 20, 2012
	SCALE NTS
APPROVED	SPEC.
P.M.	P.T.

Stantec

newfoundland labrador hydro
a nalcor energy company

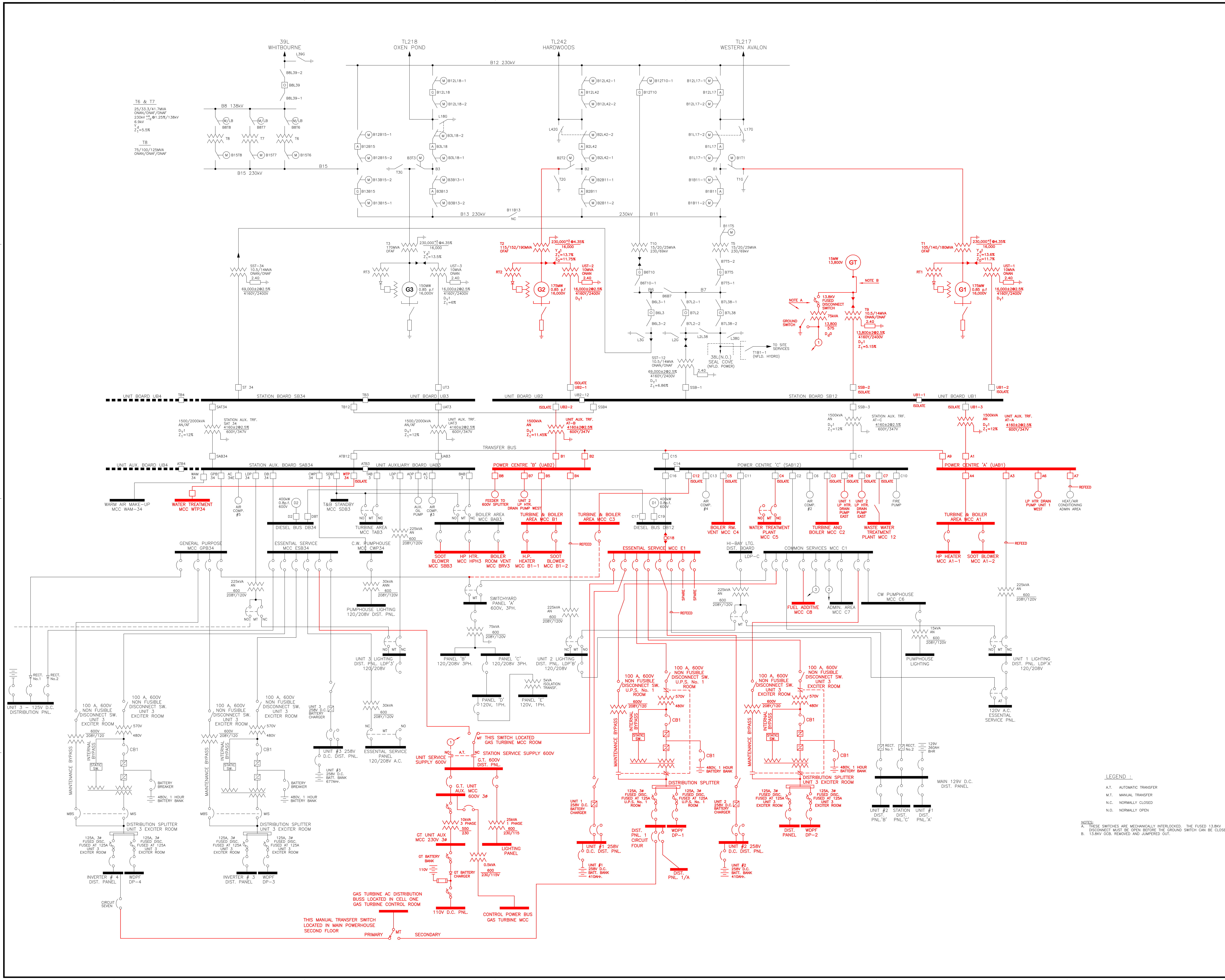
PRELIMINARY DECOMMISSIONING STUDY

HOLYROOD THERMAL GENERATING STATION POWERHOUSE/TURBINE AREA

JOB No.	DWG. No.	REV.
133545705	SK-003	0

Jan 25, 2013 9:08am JBabin

U:\133545705 Holyrood Decom\15_reference_dwgs\Drawings\NL-HYDRO\From Fredericton\133545705-SK003.dwg



REFERENCE DRAWINGS

DWG. No.	TITLE	BY

KEY PLAN

- DEMOLISH ELECTRICAL
- RETAIN ELECTRICAL

REV.	ISSUED TO	ISSUED FOR

The Contractor shall verify and be responsible for all dimensions. DO NOT scale the drawing – any errors or omissions shall be reported to Stantec without delay. The Copyrights to all designs and drawings are the property of Stantec. Reproduction or use for any purpose other than that authorized by Stantec is forbidden.

No.	DATE	BY	REVISIONS	DES.	DFTG.

DESIGNED NFB	DRAWN RKH
CHECKED	DATE NOV 23, 2012
DESIGN / DFTG.	SCALE NTS
APPROVED	SPEC.
P.M.	P.T.

Stantec

HOLYROOD DECOMMISSIONING PLAN

HOLYROOD GENERATING STATION
ELECTRICAL DEMOLITIONS

JOB No.	DWG. No.	REV
133545705	SK-5001	0

Dec 11, 2012 4:56pm kehamilton

APPENDIX 2

HTGS Asset List

Client:	**Newfoundland and Labrador Hydro**	**STANTEC CONSULTING**	Prepared by: **MDV**
Project:	**Holyrood Decommissioning**		Date: **19-Dec-12**
Project No:	**133545705**	**WBS CROSS REFERENCE**	Revision No.: **0**
			Issue Date: **19-Dec-12**
			Checked:

Stantec	**Newfoundland and Labrador Hydro Asset Registry**								**Description**	**Location**	**Unit No.**	**Comments**
WBS	**Asset**	**Asset**	**Asset**	**Asset**	**Asset**	**Asset**	**Asset**	**Asset**				
400												
	270,072	0	0	0	0	0	0	0	Holyrood Grand Plant (no WO's)	HRDUNIT1	HRD00000000	
	270,072	6,690	0	0	0	0	0	0	UNIT 1	HRDUNIT1	HRD10000000	
	270,072	6,690	6,691	0	0	0	0	0	#1 TURBINE & GENERATOR	HRDUNIT1	HRD11000000	
	270,072	6,690	6,691	6,696	0	0	0	0	U1 GENERATOR ASSEMBLY	HRDUNIT1	HRD11500000	
	270,072	6,690	6,691	6,696	6,839	0	0	0	#1 GENERATOR ROTOR	HRDUNIT1	HRD11510000	
	270,072	6,690	6,691	6,696	6,839	6,843	0	0	#1GEN. ROTOR SLIP RNGS & BRUSH	HRDUNIT1	HRD11514000	
	270,072	6,690	6,691	6,696	6,839	99,000,269	0	0	INSTALL ROTORS UNIT 1 - MFG CA	HRDPLANT		
	270,072	6,690	6,691	6,696	6,840	0	0	0	#1 GENERATOR STATOR	HRDUNIT1	HRD11520000	
	270,072	6,690	6,691	6,696	6,840	7,345	0	0	#1 GEN. STANDOFF INSULATORS	HRDUNIT1	HRD11531000	
	270,072	6,690	6,691	6,696	6,840	7,346	0	0	#1 GENERATOR P.T. CUBICLE	HRDUNIT1	HRD11593000	
	270,072	6,690	6,691	6,696	6,840	324,689	0	0	#1 GENERATOR STATOR RELAY	HRDUNIT1		
	270,072	6,690	6,691	6,696	6,840	99,006,829	0	0	50 KVA SINGLE PHASE NEUTRAL GR	HRDPLANT		
	270,072	6,690	6,691	6,696	6,840	99,041,243	0	0	DISCHARGE ANALYSIS SYSTEM	HRDPLANT		
	270,072	6,690	6,691	6,696	6,849	0	0	0	#1 GENERATOR EXCITATION SYSTEM	HRDUNIT1	HRD11610000	
	270,072	6,690	6,691	6,696	6,849	271,310	0	0	#1 EXCITER	HRDUNIT1	HRD11610001	
	270,072	6,690	6,691	6,696	6,849	271,310	99,037,514	0	exciter unit 1	HRDPLANT		
	270,072	6,690	6,691	6,696	6,849	271,311	0	0	#1 EXCITATION TRANSFORMER	HRDUNIT1	HRD11610002	
	270,072	6,690	6,691	6,696	6,849	271,312	0	0	#1 EXCITER FIELD BREAKER	HRDUNIT1	HRD11610003	
	270,072	6,690	6,691	6,696	6,849	99,000,285	0	0	BUILD DYKES AROUND EXCITATION	HRDPLANT		
	270,072	6,690	6,691	6,696	6,850	0	0	0	#1 GEN. HYDROGEN GAS SYSTEM	HRDUNIT1	HRD11620000	
	270,072	6,690	6,691	6,696	6,850	6,806	0	0	#1 GENERATOR SEAL OIL SYSTEM	HRDUNIT1	HRD11450000	
	270,072	6,690	6,691	6,696	6,850	6,806	9,596	0	#1 GEN AC SEAL OIL P/P EAST	HRDUNIT1	HRD11451010	
	270,072	6,690	6,691	6,696	6,850	6,806	9,597	0	#1 GEN AC SEAL OIL P/P WEST	HRDUNIT1	HRD11451020	
	270,072	6,690	6,691	6,696	6,850	6,806	9,600	0	#1 GEN DC SEAL OIL PUMP	HRDUNIT1	HRD11452010	
	270,072	6,690	6,691	6,696	6,850	6,806	9,602	0	#1 GEN. SEAL OIL VACUUM PUMP	HRDUNIT1	HRD11454010	
	270,072	6,690	6,691	6,696	6,850	6,851	0	0	#1 GEN. CO2 GAS PURGE SYSTEM	HRDUNIT1	HRD11630000	
	270,072	6,690	6,691	6,696	6,850	6,852	0	0	#1 GENERATOR COMPRESSED AIR	HRDUNIT1	HRD11640000	
	270,072	6,690	6,691	6,696	6,850	6,853	0	0	#1 GENERATOR HYDROGEN COOLING	HRDUNIT1	HRD11650000	
	270,072	6,690	6,691	6,696	6,850	331,939	0	0	U1 Emergency Hydrogen Venting	HRDUNIT1		
	270,072	6,690	6,691	6,696	99,000,276	0	0	0	ADDITIONAL COSTS FOR BALANCE O	HRDPLANT		
	270,072	6,690	6,691	6,696	99,003,559	0	0	0	REMOVE PCB XFRMER & INSTALL NE	HRDPLANT		
	270,072	6,690	6,691	6,733	0	0	0	0	#1 TURBINE CONDENSER SYSTEM	HRDUNIT1	HRD11160000	
	270,072	6,690	6,691	6,733	6,780	0	0	0	#1 CONDENSER AIR EXTRACTION	HRDUNIT1	HRD11340000	
	270,072	6,690	6,691	6,733	6,780	8,876	0	0	#1 CONDENSER VACUUM PUMP NORTH	HRDUNIT1	HRD11343030	
	270,072	6,690	6,691	6,733	6,780	8,877	0	0	#1 CONDENSER VACUUM PUMP SOUTH	HRDUNIT1	HRD11343031	
	270,072	6,690	6,691	6,733	271,316	0	0	0	#1 TURBINE CONDENSER	HRDUNIT1	HRD11160001	
	270,072	6,690	6,691	6,733	322,986	0	0	0	U1 Condenser Valve Actuators	HRDUNIT1		
	270,072	6,690	6,691	271,309	0	0	0	0	#1 TURBINE	HRDUNIT1	HRD11000001	
	270,072	6,690	6,691	271,309	6,695	0	0	0	#1 TURBINE OIL SYSTEMS	HRDUNIT1	HRD11400000	
	270,072	6,690	6,691	271,309	6,695	6,805	0	0	#1 TURBINE LUBE OIL SYSTEM	HRDUNIT1	HRD11430000	
	270,072	6,690	6,691	271,309	6,695	6,805	6,803	0	#1 TURB LUBE OIL TANK & EQUIP	HRDUNIT1	HRD11410000	
	270,072	6,690	6,691	271,309	6,695	6,805	6,804	0	#1 TURB. LUBE OIL PURIFICATION	HRDUNIT1	HRD11420000	
	270,072	6,690	6,691	271,309	6,695	6,805	6,804	99,039,096	Duplex Filter for Lube oil	HRDPLANT		
	270,072	6,690	6,691	271,309	6,695	6,805	6,829	0	#1 TURB LUBE AC OIL P/P SOUTH	HRDUNIT1	HRD11431131	
	270,072	6,690	6,691	271,309	6,695	6,805	6,830	0	#1 TURB LUBE AC OIL P/P NORTH	HRDUNIT1	HRD11431130	

Client:	**Newfoundland and Labrador Hydro**	**STANTEC CONSULTING**	Prepared by: **MDV**
Project:	**Holyrood Decommissioning**		Date: **19-Dec-12**
Project No:	**133545705**	**WBS CROSS REFERENCE**	Revision No.: **0**
			Issue Date: **19-Dec-12**
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	6,690	6,691	271,309	6,695	6,805	6,833	0	#1 TURBINE LUBE D.C. PUMP	HRDUNIT1	HRD11432100	
	270,072	6,690	6,691	271,309	6,695	6,805	99,000,373	0	INSTALL OIL SUPERVISORY EQUIPM	HRDPLANT		
	270,072	6,690	6,691	271,309	6,695	6,807	0	0	#1 TURB. HYDRAULIC OIL SYSTEM	HRDUNIT1	HRD11470000	
	270,072	6,690	6,691	271,309	6,695	6,807	6,835	0	#1 TURBINE HYD. OIL PUMP NORTH	HRDUNIT1	HRD11472130	
	270,072	6,690	6,691	271,309	6,695	6,807	6,836	0	#1 TURBINE HYD. OIL PUMP SOUTH	HRDUNIT1	HRD11472131	
	270,072	6,690	6,691	271,309	6,695	6,807	273,260	0	U1 NORTH EHC ACCUMULATOR	HRDUNIT1	HRD11200005	
	270,072	6,690	6,691	271,309	6,695	6,807	273,262	0	U1 SOUTH EHC ACCUMULATOR	HRDUNIT1	HRD11200006	
	270,072	6,690	6,691	271,309	6,695	99,041,696	0	0	thermocouples in turb bearings	HRDPLANT		
	270,072	6,690	6,691	271,309	6,729	0	0	0	#1 TURBINE MAIN STEAM CHEST	HRDUNIT1	HRD11110000	
	270,072	6,690	6,691	271,309	6,730	0	0	0	#1 H.P. TURBINE	HRDUNIT1	HRD11120000	
	270,072	6,690	6,691	271,309	6,731	0	0	0	#1 I.P. TURBINE	HRDUNIT1	HRD11140000	
	270,072	6,690	6,691	271,309	6,732	0	0	0	#1 L.P. TURBINE	HRDUNIT1	HRD11150000	
	270,072	6,690	6,691	271,309	6,734	0	0	0	#1 TURBINE FRONT STANDARD	HRDUNIT1	HRD11170000	
	270,072	6,690	6,691	271,309	6,766	0	0	0	#1 TURBINE RH/IP STEAM CHEST	HRDUNIT1	HRD11130000	
	270,072	6,690	6,691	271,309	6,777	0	0	0	#1 TURBINE GLAND STEAM SYSTEM	HRDUNIT1	HRD11310000	
	270,072	6,690	6,691	271,309	6,778	0	0	0	#1 TURBINE PRE-WARMING SYSTEM	HRDUNIT1	HRD11320000	
	270,072	6,690	6,691	271,309	6,779	0	0	0	#1 TURBINE TURNING GEAR	HRDUNIT1	HRD11330000	
	270,072	6,690	6,691	271,309	6,781	0	0	0	#1 TURBINE DRAINS SYSTEMS	HRDUNIT1	HRD11350000	
	270,072	6,690	6,691	271,309	6,781	342,058	0	0	Cold Reheat Condensate Pots	HRDUNIT1	HRD11350001	
	270,072	6,690	6,691	271,309	270,125	0	0	0	#1 TURBINE BLED STEAM SYSTEM	HRDUNIT1	HRD11400001	
	270,072	6,690	6,691	271,309	99,000,265	0	0	0	ADDITIONAL COSTS FOR TURBINES	HRDPLANT		
	270,072	6,690	6,691	271,309	99,000,268	0	0	0	INSTALL TURBINE PARTS & WINDER	HRDPLANT		
300												
	270,072	6,690	6,699	0	0	0	0	0	#1 BOILER PLANT	HRDUNIT1	HRD12000000	
	270,072	6,690	6,699	6,700	0	0	0	0	#1 BOILER STRUCTURE	HRDUNIT1	HRD12100000	
	270,072	6,690	6,699	6,700	99,000,137	0	0	0	ADDITIONAL COSTS FOR STEAM GEN	HRDPLANT		
	270,072	6,690	6,699	6,700	99,000,148	0	0	0	INSTALL STEAM GENERATOR FOR UP	HRDPLANT		
	270,072	6,690	6,699	6,700	99,029,562	0	0	0	OBSERVATION PORT IN THE BURNER	HRDPLANT		
	270,072	6,690	6,699	6,701	0	0	0	0	#1 BOILER F.W. & SAT'D STEAM	HRDUNIT1	HRD12200000	
	270,072	6,690	6,699	6,701	6,869	0	0	0	#1 BOILER ECONOMIZER	HRDUNIT1	HRD12210000	
	270,072	6,690	6,699	6,701	6,870	0	0	0	#1 BOILER STEAM DRUM	HRDUNIT1	HRD12220000	
	270,072	6,690	6,699	6,701	6,870	99,023,643	0	0	ELECTRONIC LEVEL GUAGE FOR DRU	HRDPLANT		
	270,072	6,690	6,699	6,701	6,871	0	0	0	#1 FURNACE	HRDUNIT1	HRD12240000	
	270,072	6,690	6,699	6,701	6,872	0	0	0	#1 BOILER FILLING AND DRAINING	HRDUNIT1	HRD12260000	
	270,072	6,690	6,699	6,701	6,872	6,706	0	0	#1 BOILER BLOWDOWN DRAINS & LP	HRDUNIT1	HRD12700000	
	270,072	6,690	6,699	6,701	6,872	6,706	7,014	0	#1 BOILER CONTINUOUS BLOWDOWN	HRDUNIT1	HRD12710000	
	270,072	6,690	6,699	6,701	6,872	6,706	359,347	0	UNIT 1 BOILER BLOWDOWN TANK	HRDUNIT1		
	270,072	6,690	6,699	6,702	0	0	0	0	#1 BLR SUPERHEAT& REHEAT ASS'Y	HRDUNIT1	HRD12300000	
	270,072	6,690	6,699	6,702	6,873	0	0	0	#1 BOILER PRIMARY SUPERHEATER	HRDUNIT1	HRD12310000	
	270,072	6,690	6,699	6,702	6,874	0	0	0	#1 BOILER SUPERHEATER ATTEMP.	HRDUNIT1	HRD12320000	
	270,072	6,690	6,699	6,702	6,876	0	0	0	#1 BOILER MAIN STEAM LINES	HRDUNIT1	HRD12340000	
	270,072	6,690	6,699	6,702	6,876	6,902	0	0	#1 BOILER STOP VALVE	HRDUNIT1	HRD12341000	
	270,072	6,690	6,699	6,702	6,876	99,000,151	0	0	INSTALL HIGH PRESSURE STEAM SY	HRDPLANT		
	270,072	6,690	6,699	6,702	6,877	0	0	0	#1BOILER REHEATER ATTEMPERATOR	HRDUNIT1	HRD12350000	
	270,072	6,690	6,699	6,702	6,878	0	0	0	#1 BOILER REHEATER	HRDUNIT1	HRD12360000	
	270,072	6,690	6,699	6,702	322,990	0	0	0	U1 Secondary Superheater	HRDUNIT1		

Client:	Newfoundland and Labrador Hydro	**STANTEC CONSULTING**	Prepared by: **MDV**
Project:	**Holyrood Decommissioning**		Date: **19-Dec-12**
Project No:	**133545705**	**WBS CROSS REFERENCE**	Revision No.: **0**
			Issue Date: **19-Dec-12**
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	6,690	6,699	6,703	0	0	0	0	#1 BOILER AIR SYSTEM	HRDUNIT1	HRD12400000	
	270,072	6,690	6,699	6,703	6,879	0	0	0	#1 BOILER AIR SUPPLY (A/H TO	HRDUNIT1	HRD12440000	
	270,072	6,690	6,699	6,703	6,879	6,979	0	0	#1 BOILER SEAL AIR FAN	HRDUNIT1	HRD12443000	
	270,072	6,690	6,699	6,703	6,879	6,982	0	0	#1 BOILER SCANNER AIR SYSTEM	HRDUNIT1	HRD12446000	
	270,072	6,690	6,699	6,703	6,880	0	0	0	#1 BOILER WINDBOX	HRDUNIT1	HRD12450000	
	270,072	6,690	6,699	6,703	8,777	0	0	0	#1 BOILER F.D. FAN SYSTEM	HRDUNIT1	HRD12410000	
	270,072	6,690	6,699	6,703	8,777	6,943	0	0	#1 BOILER F.D. FAN EAST	HRDUNIT1	HRD12413032	
	270,072	6,690	6,699	6,703	8,777	6,944	0	0	#1 BOILER F.D. FAN WEST	HRDUNIT1	HRD12413033	
	270,072	6,690	6,699	6,703	8,783	0	0	0	#1 BOILER STEAM AIR HEATER	HRDUNIT1	HRD12420000	
	270,072	6,690	6,699	6,703	8,783	6,954	0	0	#1BOILER STEAM AIR HEATER EAST	HRDUNIT1	HRD12423032	
	270,072	6,690	6,699	6,703	8,783	6,955	0	0	#1BOILER STEAM AIR HEATER WEST	HRDUNIT1	HRD12423033	
	270,072	6,690	6,699	6,703	8,783	359,348	0	0	Steam Preheater Flash Tank	HRDUNIT1		
	270,072	6,690	6,699	6,703	8,784	0	0	0	#1 BOILER MAIN AIR HEATER	HRDUNIT1	HRD12430000	
	270,072	6,690	6,699	6,703	8,784	6,914	0	0	#1 BOILER MAIN AIR HEATER EAST	HRDUNIT1	HRD12430032	
	270,072	6,690	6,699	6,703	8,784	6,915	0	0	#1 BOILER MAIN AIR HEATER WEST	HRDUNIT1	HRD12430033	
	270,072	6,690	6,699	6,703	99,031,923	0	0	0	AIR HEATER REPLACEMENT, SEE PL	HRDPLANT		
	270,072	6,690	6,699	6,704	0	0	0	0	#1 BOILER GAS SYSTEM	HRDUNIT1	HRD12500000	
	270,072	6,690	6,699	6,704	6,917	0	0	0	#1 BOILER GAS PASSES	HRDUNIT1	HRD12510000	
	270,072	6,690	6,699	6,704	6,919	0	0	0	#1 BOILER STACK	HRDUNIT1	HRD12570000	
	270,072	6,690	6,699	6,704	6,919	270,294	0	0	#1 BOILER STACK BREECHING	HRDUNIT1	HRD12570001	
	270,072	6,690	6,699	6,704	6,919	270,294	359,206	0	HRD U1 STACK BREECHING STUDY	HRDUNIT1		
	270,072	6,690	6,699	6,704	6,919	270,294	359,294	0	UNIT 1 BREECHING SUPPORT	HRDUNIT1	HRD12571100	
	270,072	6,690	6,699	6,704	6,919	359,330	0	0	Upgrade unit 1 Stack Breeching	HRDUNIT1		
	270,072	6,690	6,699	6,704	6,919	99,000,175	0	0	INSTALL STACKS UNIT #1	HRDPLANT		
	270,072	6,690	6,699	6,704	6,920	0	0	0	#1 BOILER SOOTBLOWING SYSTEM	HRDUNIT1	HRD12580000	
	270,072	6,690	6,699	6,704	6,920	6,933	0	0	#1 BOILER RETRACTABLE S/BLOWER	HRDUNIT1	S	
	270,072	6,690	6,699	6,704	6,920	6,934	0	0	#1 BOILER ROTARY SOOTBLOWERS	HRDUNIT1	HRD12584000	
	270,072	6,690	6,699	6,704	6,920	8,789	0	0	#1 BOILER AIR HEATER S/B's	HRDUNIT1	HRD12585000	
	270,072	6,690	6,699	6,705	0	0	0	0	#1 BOILER FUEL FIRING SYSTEM	HRDUNIT1	HRD12600000	
	270,072	6,690	6,699	6,705	6,987	0	0	0	#1 BOILER HEAVY OIL SYSTEM	HRDUNIT1	HRD12610000	
	270,072	6,690	6,699	6,705	6,987	6,988	0	0	#1 BOILER HEAVY OIL FIRING	HRDUNIT1	HRD12620000	
	270,072	6,690	6,699	6,705	6,987	6,994	0	0	#1 BOILER HEAVY OIL PUMP EAST	HRDUNIT1	HRD12613032	
	270,072	6,690	6,699	6,705	6,987	6,995	0	0	#1 BOILER HEAVY OIL PUMP WEST	HRDUNIT1	HRD12613033	
	270,072	6,690	6,699	6,705	6,987	6,998	0	0	U1BLR HEAVY OIL STM V/V & PIPE	HRDUNIT1	HRD12617000	
	270,072	6,690	6,699	6,705	6,987	6,999	0	0	U1 FUEL OIL ACCUMULATOR	HRDUNIT1	HRD12618000	
	270,072	6,690	6,699	6,705	6,990	0	0	0	#1 BOILER LIGHT OIL	HRDUNIT1	HRD12640000	
	270,072	6,690	6,699	6,705	6,990	6,989	0	0	#1 BOILER LIGHT OIL FIRING	HRDUNIT1	HRD12630000	
	270,072	6,690	6,699	6,705	6,990	8,976	0	0	#1 BOILER LIGHT OIL PUMP EAST	HRDUNIT1	HRD12643032	
	270,072	6,690	6,699	6,705	6,990	8,977	0	0	#1 BOILER LIGHT OIL PUMP WEST	HRDUNIT1	HRD12643033	
	270,072	6,690	6,699	6,705	99,000,170	0	0	0	INSTALL LIGHT OIL SYSTEM UNIT	HRDPLANT		
	270,072	6,690	6,699	6,707	0	0	0	0	#1 BLR AUX STM & COND SYSTEM	HRDUNIT1	HRD12800000	
	270,072	6,690	6,699	6,707	7,020	0	0	0	#1 BOILER ATOMIZING STEAM	HRDUNIT1	HRD12830000	
	270,072	6,690	6,699	6,707	7,021	0	0	0	#1BOILER AUX.STEAM MAIN SUPPLY	HRDUNIT1	HRD12810000	
	270,072	6,690	6,699	6,707	7,022	0	0	0	#1 BOILER AUXILIARY STEAM	HRDUNIT1	HRD12820000	
	270,072	6,690	6,699	6,707	8,802	0	0	0	#1 AUX STEAM CONDENSATE PUMPS	HRDUNIT1	HRD13155000	
	270,072	6,690	6,709	0	0	0	0	0	#1 CONDENSATE & F.W. SYSTEM	HRDUNIT1	HRD13000000	

Client:	Newfoundland and Labrador Hydro
Project:	Holyrood Decommissioning
Project No:	133545705

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by:	MDV
Date:	19-Dec-12
Revision No.:	0
Issue Date:	19-Dec-12
Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	6,690	6,709	6,711	0	0	0	0	#1 LOW PRESSURE FEEDWATER SYS	HRDUNIT1	HRD13200000	
	270,072	6,690	6,709	6,711	7,053	0	0	0	#1 DEAERATOR SYSTEM	HRDUNIT1	HRD13250000	
	270,072	6,690	6,709	6,711	7,056	0	0	0	#1 LOW PRESSURE FW RESERVE	HRDUNIT1	HRD13270000	
	270,072	6,690	6,709	6,711	7,056	99,000,198	0	0	INSTALL MATERIAL FOR THE RESER	HRDPLANT		
	270,072	6,690	6,709	6,711	7,056	99,031,610	0	0	TURBINE FLOW METER FOR CONDENS	HRDPLANT		
	270,072	6,690	6,709	6,711	7,059	0	0	0	#1 LOW PRESSURE HEATER 1	HRDUNIT1	HRD13213001	
	270,072	6,690	6,709	6,711	7,066	0	0	0	#1 LOW PRESSURE HEATER 2	HRDUNIT1	HRD13213002	
	270,072	6,690	6,709	6,711	7,066	99,000,208	0	0	INSTALLATION COSTS FOR YUBA HE	HRDPLANT		
	270,072	6,690	6,709	6,711	8,805	0	0	0	#1 LOW PRESSURE HTR DRAIN P/PS	HRDUNIT1	HRD13220000	
	270,072	6,690	6,709	6,711	99,000,215	0	0	0	BAL LOW PRESSURE FEED SYSTEM U	HRDPLANT		
	270,072	6,690	6,709	6,711	99,000,216	0	0	0	INSTALL BALANCE OF LOW PRESSUR	HRDPLANT		
	270,072	6,690	6,709	6,711	99,032,021	0	0	0	LP FEED SYSTEM SEE PL ASSET 21	HRDPLANT		
	270,072	6,690	6,709	6,712	0	0	0	0	#1 BOILER FEEDWATER PUMPING	HRDUNIT1	HRD13300000	
	270,072	6,690	6,709	6,712	8,835	0	0	0	#1 BOILER FEED PUMP EAST	HRDUNIT1	HRD13310032	
	270,072	6,690	6,709	6,712	8,835	7,091	0	0	#1 BOILER FEEDPUMP RECIRC.EAST	HRDUNIT1	HRD13320032	
	270,072	6,690	6,709	6,712	8,835	7,095	0	0	#1 BOILER FW PUMP LUB OIL EAST	HRDUNIT1	HRD13340032	
	270,072	6,690	6,709	6,712	8,835	99,000,234	0	0	INSTALL BOILER FEED PUMPS UNIT	HRDPLANT		
	270,072	6,690	6,709	6,712	8,835	99,000,243	0	0	INSTALL VIBRATION MONITORING E	HRDPLANT		
	270,072	6,690	6,709	6,712	8,835	99,000,245	0	0	MODIFY AND INSTALL BOILER FEED	HRDPLANT		
	270,072	6,690	6,709	6,712	8,835	99,000,253	0	0	PURCHASE 1 INNER CASE BARREL P	HRDPLANT		
	270,072	6,690	6,709	6,712	8,836	0	0	0	#1 BOILER FEED PUMP WEST	HRDUNIT1	HRD13310033	
	270,072	6,690	6,709	6,712	8,836	7,092	0	0	#1 BOILER FEEDPUMP RECIRC.WEST	HRDUNIT1	HRD13320033	
	270,072	6,690	6,709	6,712	8,836	7,096	0	0	#1 BOILER FW PUMP LUB OIL WEST	HRDUNIT1	HRD13340033	
	270,072	6,690	6,709	6,712	8,836	99,000,244	0	0	INSTALL VIBRATION MONITORING E	HRDPLANT		
	270,072	6,690	6,709	6,712	8,836	99,043,181	0	0	MODIFY AND INSTALL BOILER	HRDPLANT		
	270,072	6,690	6,709	6,712	8,836	99,043,187	0	0	PURCHASE 1 INNER CASE BARR	HRDPLANT		
	270,072	6,690	6,709	6,712	9,616	0	0	0	#1 BFP COM GLND SEAL WATER INJ	HRDUNIT1	HRD13361000	
	270,072	6,690	6,709	6,712	9,617	0	0	0	#1 BFP COM GLNDSEAL WATER XFER	HRDUNIT1	HRD13362000	
	270,072	6,690	6,709	6,713	0	0	0	0	#1 HIGH PRESSURE FEEDWATER SYS	HRDUNIT1	HRD13500000	
	270,072	6,690	6,709	6,713	7,112	0	0	0	#1 H.P. HEATER 4	HRDUNIT1	HRD13513004	
	270,072	6,690	6,709	6,713	7,113	0	0	0	#1 H.P. HEATER 5	HRDUNIT1	HRD13513005	
	270,072	6,690	6,709	6,713	7,114	0	0	0	#1 H.P. HEATER 6	HRDUNIT1	HRD13513006	
	270,072	6,690	6,709	6,713	7,128	0	0	0	#1 H.P. FEEDWATER VALVES	HRDUNIT1	HRD13531000	
	270,072	6,690	6,709	6,713	8,932	0	0	0	#1 H.P. HEATERS DRAIN PUMP	HRDUNIT1	HRD13514104	
	270,072	6,690	6,709	7,040	0	0	0	0	#1 CONDENSATE MAKE UP SYSTEM	HRDUNIT1	HRD13110000	
	270,072	6,690	6,709	8,799	0	0	0	0	#1CONDENSATE EXTRACTION SYSTEM	HRDUNIT1	HRD13120000	
	270,072	6,690	6,709	8,799	7,045	0	0	0	#1 COND EXTRACTION PUMP NORTH	HRDUNIT1	HRD13123030	
	270,072	6,690	6,709	8,799	7,045	324,290	0	0	Ext Pump N Motor Prot. Relay	HRDUNIT1		
	270,072	6,690	6,709	8,799	7,049	0	0	0	#1 COND EXTRACTION PUMP SOUTH	HRDUNIT1	HRD13123031	
	270,072	6,690	6,709	8,799	7,049	324,365	0	0	Ext. Pump S Motor Prot. Relay	HRDUNIT1		
400												
	270,072	6,690	6,715	0	0	0	0	0	#1 UNIT GENERATION SERVICES	HRDUNIT1	HRD14000000	
	270,072	6,690	6,715	6,719	0	0	0	0	#1 GENERAL SERVICE COOLING	HRDUNIT1	HRD14500000	
	270,072	6,690	6,715	6,782	0	0	0	0	#1 TURB/GEN COOLING SYSTEM	HRDUNIT1	HRD11360000	
	270,072	6,690	6,715	6,782	9,592	0	0	0	#1 T/G COOLING PUMP SOUTH	HRDUNIT1	HRD11363010	
	270,072	6,690	6,715	6,782	9,593	0	0	0	#1 T/G COOLING PUMP NORTH	HRDUNIT1	HRD11363020	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	6,690	6,715	6,782	99,000,316	0	0	0	INSTALL TURBO GENERATION AUX C	HRDPLANT		
	270,072	6,690	6,715	270,182	0	0	0	0	#1 CW SYSTEM	HRDUNIT1		
	270,072	6,690	6,715	270,182	7,134	0	0	0	#1 C.W. INTAKE	HRDUNIT1	HRD14110000	
	270,072	6,690	6,715	270,182	7,134	99,000,217	0	0	INSTALL FERROUS SULPHATE DOSIN	HRDPLANT		
	270,072	6,690	6,715	270,182	7,134	99,000,307	0	0	BALANCE OF CIRCULATING WATER S	HRDPLANT		
	270,072	6,690	6,715	270,182	7,134	99,000,308	0	0	ADDITIONAL COSTS FOR BALANCE O	HRDPLANT		
	270,072	6,690	6,715	270,182	7,134	99,031,330	0	0	FERROUS SULPHATE DOSING SYSTEM	HRDPLANT		
	270,072	6,690	6,715	270,182	7,135	0	0	0	#1 C.W. DISCHARGE TO OUTFALL	HRDUNIT1	HRD14140000	
	270,072	6,690	6,715	270,182	7,137	0	0	0	#1 C.W.TRAVELLING SCREENS EAST	HRDUNIT1	HRD14112032	
	270,072	6,690	6,715	270,182	7,138	0	0	0	#1 C.W.TRAVELLING SCREENS WEST	HRDUNIT1	HRD14112033	
	270,072	6,690	6,715	270,182	7,146	0	0	0	#1 C.W. PUMP EAST	HRDUNIT1	HRD14123032	
	270,072	6,690	6,715	270,182	7,147	0	0	0	#1 C.W. PUMP WEST	HRDUNIT1	HRD14123033	
	270,072	6,690	6,715	270,182	8,819	0	0	0	#1 C.W. SCREEN WASH SYSTEM	HRDUNIT1	HRD14130000	
	270,072	6,690	6,715	270,182	303,300	0	0	0	Anti Fouling System-Unit 1	HRDUNIT1		
500												
	270,072	6,690	6,723	0	0	0	0	0	#1 ELEC & CONTROLS SYSTEM	HRDUNIT1	HRD15000000	
	270,072	6,690	6,723	6,693	0	0	0	0	#1 TURBINE GOVERNOR SYSTEM	HRDUNIT1	HRD11200000	
	270,072	6,690	6,723	6,693	333,928	0	0	0	Holyrood U1 Mark V Auto Sync	HRDUNIT1	U1	
	270,072	6,690	6,723	6,693	99,000,260	0	0	0	INSTALL GOVENOR UNIT 1 - MFG C	HRDPLANT		
	270,072	6,690	6,723	6,693	99,000,267	0	0	0	UPGRADE TURBINE FOR TURBINE SU	HRDPLANT		
	270,072	6,690	6,723	6,693	99,041,695	0	0	0	control bearings for u1 EHC	HRDPLANT		
	270,072	6,690	6,723	6,721	0	0	0	0	#1 RELAY RM PROTECTN & CONTROL	HRDUNIT1	HRD14800000	
	270,072	6,690	6,723	6,722	0	0	0	0	#1 MAIN CONTROLS	HRDUNIT1	HRD14900000	
	270,072	6,690	6,723	6,722	99,000,384	0	0	0	INSTALL 2 PANELS FOR INSTRUMEN	HRDPLANT		
	270,072	6,690	6,723	6,722	99,000,388	0	0	0	BALANCE OF INSTRUMENTATION	HRDPLANT		
	270,072	6,690	6,723	6,722	99,000,394	0	0	0	INSTALL CED PERCISION TRANSDUC	HRDPLANT		
	270,072	6,690	6,723	6,724	0	0	0	0	#1 GENERATOR BUS DUCT & CONNS	HRDUNIT1	HRD15100000	
	270,072	6,690	6,723	6,724	99,000,328	0	0	0	REMOVE & REPLACE ISOLATED PHAS	HRDPLANT		
	270,072	6,690	6,723	6,726	0	0	0	0	#1 UNIT SERVICE POWER SYSTEM	HRDUNIT1	HRD15300000	
	270,072	6,690	6,723	6,726	7,181	0	0	0	UNIT BOARD UB-1	HRDUNIT1	HRD15310000	
	270,072	6,690	6,723	6,726	7,182	0	0	0	POWER CENTRE A	HRDUNIT1	HRD15320000	
	270,072	6,690	6,723	6,726	7,183	0	0	0	TURBINE & BOILER AREA MCC A1	HRDUNIT1	HRD15330000	
	270,072	6,690	6,723	6,726	7,183	7,399	0	0	H.P. HEATER MCC A1-1	HRDUNIT1	HRD15331000	
	270,072	6,690	6,723	6,726	7,183	7,400	0	0	SOOTBLOWER MCC A1-2	HRDUNIT1	HRD15332000	
	270,072	6,690	6,723	6,728	0	0	0	0	#1 BATTERY CHARGERS	HRDUNIT1	HRD15700000	
	270,072	6,690	6,723	6,728	99,000,354	0	0	0	ADDITIONAL COSTS FOR D.C. DIST	HRDPLANT		
	270,072	6,690	6,723	6,728	99,043,229	0	0	0	250 VOLT DC BATTERY BANK	HRDPLANT		
	270,072	6,690	6,723	6,728	99,043,230	0	0	0	250 VOLT DC BATTERY CHARGE	HRDPLANT		
	270,072	6,690	6,723	7,180	0	0	0	0	GENERATOR TRANSFORMER & AUX'S	HRDUNIT1	HRD15220000	
	270,072	6,690	6,723	7,184	0	0	0	0	TURBINE & BOILER AREA MCC C2	HRDUNIT1	HRD15550000	
	270,072	6,690	6,723	7,184	359,338	0	0	0	MCC-C2 UPGRADE	HRDUNIT1	HRD15550001	
	270,072	6,690	6,723	7,186	0	0	0	0	TURBINE & BOILER AREA MCC C3	HRDUNIT1	HRD15570000	
	270,072	6,690	6,723	7,186	359,339	0	0	0	MCC-C3 UPGRADE	HRDPLANT	HRD15570001	
	270,072	6,690	6,723	7,187	0	0	0	0	BOILER ROOM VENT MCC C4	HRDUNIT1	HRD15580000	
	270,072	6,690	6,723	7,193	0	0	0	0	U1 UPS INVERTER	HRDUNIT1	HRD15710000	
	270,072	6,690	6,723	7,193	325,164	0	0	0	SNMP Upgrade - UPS #1 - HRD	HRDUNIT1		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	6,690	6,723	270,151	0	0	0	0	#1 TURBINE SUPERVISORY SYSTEM	HRDUNIT1	HRD11200001	
	270,072	6,690	6,723	270,295	0	0	0	0	#1 SWITCHGEAR 4160/600V	HRDUNIT1		
	270,072	6,690	6,723	270,295	99,000,421	0	0	0	STUDY FOR METALCLAD SWITCHGEAR	HRDPLANT		
	270,072	6,690	6,723	270,295	99,031,936	0	0	0	UPGRADE SYNC CHECK SYSTEM, SEE	HRDPLANT		
	270,072	6,690	6,723	270,296	0	0	0	0	#1 CABLE RACEWAYS	HRDUNIT1		
	270,072	6,690	6,723	270,296	99,000,114	0	0	0	INSTALL CABLE TRENCHES AND DUC	HRDPLANT		
	270,072	6,690	6,723	270,297	0	0	0	0	#1 CONTROL CABLES	HRDUNIT1		
	270,072	6,690	6,723	270,297	99,000,336	0	0	0	REMOVAL AND REROUTING OF CONTR	HRDPLANT		
	270,072	6,690	6,723	270,298	0	0	0	0	#1 POWER CABLES	HRDUNIT1		
	270,072	6,690	6,723	270,298	99,000,340	0	0	0	INSTALL POWER CABLE #4160 V	HRDPLANT		
	270,072	6,690	6,723	270,298	99,000,342	0	0	0	INSTALL POWER CABLES #600 VOLT	HRDPLANT		
	270,072	6,690	6,723	270,298	99,034,726	0	0	0	CABLE REPLACEMENT	HRDPLANT		
	270,072	6,690	6,723	270,298	99,034,726	99,035,941	0	0	Compaq Armada 1750 Laptop	STJSHOP	FA-IC10429	
	270,072	6,690	6,723	291,668	0	0	0	0	Unit 1 DCS	HRDPLANT		
	270,072	6,690	6,723	309,894	0	0	0	0	600 V Meltric Plugs	HRDUNIT1		
	270,072	6,690	6,723	309,897	0	0	0	0	Boiler Prot & Control	HRDUNIT1		
	270,072	6,690	6,723	309,902	0	0	0	0	Dell Latitude D820 Notebook	HRDPLANT		
	270,072	6,690	6,723	343,111	0	0	0	0	#1 BURNER MANAGEMENT	HRDUNIT1	HRD14810000	
	270,072	6,690	359,302	0	0	0	0	0	UNIT 1 BLANKS AND BLINDS	HRDUNIT1		
700												
	270,072	7,199	0	0	0	0	0	0	HRD COMMON SYSTEMS	HRDPLANT	HRD90000000	
	270,072	7,199	6,727	0	0	0	0	0	STAGE 1 STATION SERVICE POWER	HRDUNIT1	HRD15500000	
	270,072	7,199	6,727	99,000,392	0	0	0	0	COMMISSION THE WIRING FOE ALL	HRDPLANT		
	270,072	7,199	6,727	99,000,404	0	0	0	0	INSTALL STATION SERVICE TRANSF	HRDPLANT		
	270,072	7,199	6,769	0	0	0	0	0	HEATING AND VENTILATION	HRDPLANT	HRD98700000	
	270,072	7,199	6,769	303,242	0	0	0	0	Exciter Room West	HRDPLANT		
	270,072	7,199	6,769	303,270	0	0	0	0	Exciter Room East A/C Unit	HRDPLANT		
	270,072	7,199	6,769	303,271	0	0	0	0	Stage 1 Relay Room North	HRDPLANT		
	270,072	7,199	6,769	303,272	0	0	0	0	Stage 1 Relay Room South	HRDPLANT		
	270,072	7,199	6,769	303,273	0	0	0	0	Stage 2 Relay Room North	HRDPLANT		
	270,072	7,199	6,769	303,274	0	0	0	0	Stage 2 Relay Room South	HRDPLANT		
	270,072	7,199	6,904	0	0	0	0	0	COMPUTERS FOXBORO	HRDPLANT	HRD97900000	
	270,072	7,199	6,904	301,712	0	0	0	0	STATION SERVICE DCS	HRDPLANT		
	270,072	7,199	6,904	358,121	0	0	0	0	WATER TREATMENT PLANT CONTROLS	HRDPLANT	HRD97910000	
	270,072	7,199	7,189	0	0	0	0	0	STATION BOARD SB-12	HRDUNIT1	HRD15510000	
	270,072	7,199	7,190	0	0	0	0	0	DIESEL BUS DB12	HRDUNIT1	HRD15520000	
	270,072	7,199	7,191	0	0	0	0	0	ESSENTIAL SERVICE MCC E1	HRDUNIT1	HRD15540000	
	270,072	7,199	7,192	0	0	0	0	0	POWER CENTER C	HRDUNIT1	HRD15530000	
	270,072	7,199	7,192	7,188	0	0	0	0	COMMON SERVICES MCC C1	HRDUNIT1	HRD15590000	
	270,072	7,199	7,192	7,411	0	0	0	0	C.W. PUMPHOUSE MCC C6	HRDUNIT1	HRD15591000	
	270,072	7,199	7,192	7,413	0	0	0	0	WORKSHOP AREA MCC C9	HRDUNIT1	HRD15593000	
	270,072	7,199	7,192	7,414	0	0	0	0	ADMINISTRATION AREA MCC C7	HRDUNIT1	HRD15594000	
	270,072	7,199	7,195	0	0	0	0	0	STAGE 1 129V D.C.SUPPLY SYSTEM	HRDUNIT1	HRD15770000	
	270,072	7,199	7,195	303,344	0	0	0	0	129 VDC Stage 1 Batteries	HRDPLANT		
	270,072	7,199	7,195	303,345	0	0	0	0	129 VDC Charger A	HRDPLANT		
	270,072	7,199	7,195	303,346	0	0	0	0	129 VDC Charger A	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,199	7,195	303,350	0	0	0	0	129 VDC Charger A	HRDPLANT		
	270,072	7,199	7,195	303,351	0	0	0	0	129 VDC Charger B	HRDPLANT		
	270,072	7,199	7,204	0	0	0	0	0	HEAVY OIL & FUEL ADDITIVE	HRDPLANT	HRD97200000	
	270,072	7,199	7,204	7,222	0	0	0	0	HEAVY OIL RECEPT EQUIP & ELEC	HRDPLANT	HRD97210000	
	270,072	7,199	7,204	7,222	99,000,419	0	0	0	INSTALL LIGHTNING ARRESTORS FO	HRDPLANT		
	270,072	7,199	7,204	7,222	99,000,420	0	0	0	INSTALL LIGHTNING ARRESTORS HO	HRDPLANT		
	270,072	7,199	7,204	7,223	0	0	0	0	*HEAVY OIL TRANSFER TO STORAGE	HRDPLANT	HRD97220000	
	270,072	7,199	7,204	7,223	99,000,024	0	0	0	ADDITIONAL COSTS FOR TERMNIAL	HRDPLANT		
	270,072	7,199	7,204	7,223	99,000,025	0	0	0	PROVIDE PIPING FOR UNLOADING A	HRDPLANT		
	270,072	7,199	7,204	7,223	99,000,026	0	0	0	INSTALL 18" FUEL OIL ISOLATION	HRDPLANT		
	270,072	7,199	7,204	7,223	99,029,561	0	0	0	MAS 18" FLOWSEAL VALVES C/W AC	HRDPLANT		
	270,072	7,199	7,204	7,224	0	0	0	0	HEAVY OIL STORAGE & PIPING	HRDPLANT	HRD97230000	
	270,072	7,199	7,204	7,224	7,439	0	0	0	HEAVY OIL DAY TANK	HRDPLANT	HRD97241000	
	270,072	7,199	7,204	7,224	7,439	99,000,169	0	0	HEAVY OIL FLOWMETER NORTH OF D	HRDPLANT		
	270,072	7,199	7,204	7,224	7,441	0	0	0	HEAVY OIL - #1 TANK	HRDPLANT	HRD97252000	
	270,072	7,199	7,204	7,224	7,441	99,003,554	0	0	TANK FROM DYKE MODIFICATIONS	HRDPLANT		
	270,072	7,199	7,204	7,224	7,442	0	0	0	HEAVY OIL - #2 TANK	HRDPLANT	HRD97253000	
	270,072	7,199	7,204	7,224	7,442	324,377	0	0	Tank Farm Upgrade	HRDPLANT		
	270,072	7,199	7,204	7,224	7,442	99,043,205	0	0	TANK FARM DYKE MODIFICATION	HRDPLANT		
	270,072	7,199	7,204	7,224	7,443	0	0	0	HEAVY OIL - #3 TANK	HRDPLANT	HRD97254000	
	270,072	7,199	7,204	7,224	7,444	0	0	0	HEAVY OIL - #4 TANK	HRDPLANT	HRD97255000A	
	270,072	7,199	7,204	7,224	7,444	342,394	0	0	HEAVY OIL - #4 TANK	HRDPLANT	HRD97255000	
	270,072	7,199	7,204	7,224	7,444	342,395	0	0	HEAVY OIL - #4 TANK	HRDPLANT	HRD97255001	
	270,072	7,199	7,204	7,224	99,000,164	0	0	0	OIL STORAGE TANKS UNIT #3 (#4	HRDPLANT		
	270,072	7,199	7,204	7,224	99,000,166	0	0	0	BALANCE OF OIL STORAGE SYSTEM	HRDPLANT		
	270,072	7,199	7,204	7,224	99,000,167	0	0	0	BALANCE OF OIL STORAGE SYSTEM	HRDPLANT		
	270,072	7,199	7,204	7,224	99,000,168	0	0	0	BALANCE OF OIL STORAGE SYSTEM	HRDPLANT		
	270,072	7,199	7,204	7,229	0	0	0	0	HEAVY OIL SLOPS SYSTEM	HRDPLANT	HRD97280000	
	270,072	7,199	7,204	271,814	0	0	0	0	HRD TANK FARM DYKES & LINERS	HRDPLANT	HRD97230001	
	270,072	7,199	7,204	286,055	0	0	0	0	FUEL ADDITIVE SYSTEMS	HRDPLANT		
	270,072	7,199	7,204	286,055	6,991	0	0	0	#1 BOILER FUEL ADDITIVE SYSTEM	HRDUNIT1	HRD12650000	
	270,072	7,199	7,204	286,055	6,991	99,031,826	0	0	MODIFY FUEL ADDITIVE SYSTEM, S	HRDPLANT		
	270,072	7,199	7,204	286,055	7,227	0	0	0	F/A STORAGE TANK & PUMPS	HRDPLANT	HRD97260000	
	270,072	7,199	7,204	286,055	7,412	0	0	0	FUEL ADDITIVE MCC C8	HRDUNIT1	HRD15592000	
	270,072	7,199	7,204	286,055	7,940	0	0	0	#2 BOILER FUEL ADDITIVE SYSTEM	HRDUNIT2	HRD22650000	
	270,072	7,199	7,204	286,055	7,940	99,031,829	0	0	MODIFY FUEL ADDITIVE SYSTEM, U	HRDPLANT		
	270,072	7,199	7,204	286,055	8,489	0	0	0	#3 BOILER FUEL ADDITIVE SYSTEM	HRDUNIT3	HRD32650000	
	270,072	7,199	7,204	286,055	8,489	99,000,184	0	0	FUEL OIL ADDITIVES SYSTEM UNIT	HRDPLANT		
	270,072	7,199	7,204	286,055	8,489	99,031,830	0	0	MODIFY FUEL ADDITIVE SYSTEM, S	HRDPLANT		
	270,072	7,199	7,205	0	0	0	0	0	COMPRESSED AIR SYSTEMS	HRDPLANT	HRD97300000	
	270,072	7,199	7,205	7,231	0	0	0	0	AIR COMPRESSORS	HRDPLANT	HRD97310000	
	270,072	7,199	7,205	7,231	8,918	0	0	0	#1 ATLAS COPCO ROTARY COMP	HRDPLANT	HRD97311003	
	270,072	7,199	7,205	7,231	8,918	99,000,061	0	0	OIL FREE ROTORY AIR COMPRESSOR	HRDPLANT		
	270,072	7,199	7,205	7,231	8,918	99,000,080	0	0	BALANCE OF COMPRESSED AIR SYST	HRDPLANT		
	270,072	7,199	7,205	7,231	8,918	99,029,554	0	0	AIR COMPRESSOR VIBRATION PROBE	HRDPLANT		
	270,072	7,199	7,205	7,231	9,488	0	0	0	#2 ATLAS COPCO ROTARY COMP	HRDPLANT	HRD97311002	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,199	7,205	7,231	9,488	99,023,634	0	0	AIR COMPRESSOR, SEE PL ASSET 0	HRDPLANT		
	270,072	7,199	7,205	7,231	9,488	99,031,332	0	0	AIR COMPRESSOR ,SEE PL ASSET 2	HRDPLANT		
	270,072	7,199	7,205	7,231	325,028	0	0	0	#3 ATLAS COPCO ROTARY COMP	HRDPLANT		
	270,072	7,199	7,205	7,231	99,000,081	0	0	0	BALANCE OF AIR COMPRESSORS STA	HRDPLANT		
	270,072	7,199	7,205	7,234	0	0	0	0	COMPRESSED AIR DRYERS SYSTEMS	HRDPLANT	HRD97340000	
	270,072	7,199	7,205	7,234	99,000,078	0	0	0	REPLACE BREAKER FOR INSTRUMENT	HRDPLANT		
	270,072	7,199	7,205	7,234	99,000,079	0	0	0	INSTRUMENT AIR DRYER - MFG PAL	HRDPLANT		
	270,072	7,199	7,205	7,234	99,026,193	0	0	0	COMP AIR SYS-INSTR AIR DRYER 5	HRDPLANT		
	270,072	7,199	7,205	7,235	0	0	0	0	COMPRESSED AIR RECEIVERS	HRDPLANT	HRD97350000	
	270,072	7,199	7,205	7,235	99,000,063	0	0	0	AIR RECIEVERS - MANU DRUMMOND	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,065	0	0	0	AIR RECIEVER - MANU CLEMMER (S	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,066	0	0	0	AIR RECIEVER - MANU CLEMMER (	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,067	0	0	0	AIR RECIEVERS - MANU CLEMMER (	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,073	0	0	0	AIR RECIEVER - MFG DRUMMOND (I	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,074	0	0	0	AIR RECIEVER - MFG DRUMMOND (S	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,075	0	0	0	AIR RECIEVER - MFG DRUMMOND (	HRDPLANT		
	270,072	7,199	7,205	7,235	99,000,076	0	0	0	AIR RECIEVER - MFG FERRO METAL	HRDPLANT		
	270,072	7,199	7,206	0	0	0	0	0	GAS STORAGE SYSTEMS	HRDPLANT	HRD97400000	
	270,072	7,199	7,206	7,236	0	0	0	0	HYDROGEN STORAGE AND SUPPLY	HRDPLANT	HRD97410000	
	270,072	7,199	7,206	7,237	0	0	0	0	CARBON DIOXIDE STORAGE/SUPPLY	HRDPLANT	HRD97420000	
	270,072	7,199	7,206	7,237	99,000,085	0	0	0	HYDROGEN AND CO2 SYSTEM	HRDPLANT		
	270,072	7,199	7,206	7,238	0	0	0	0	NITROGEN STORAGE/SUPPLY SYSTEM	HRDPLANT	HRD97430000	
	270,072	7,199	7,208	0	0	0	0	0	AUXILIARY STEAM SYSTEM	HRDPLANT	HRD97600000	
	270,072	7,199	7,208	342,405	0	0	0	0	Steam Flow Transmitter	HRDPLANT	HRD97600001	
	270,072	7,199	7,208	99,000,093	0	0	0	0	AUXILIARY STEAM SYSTEM	HRDPLANT		
	270,072	7,199	7,209	0	0	0	0	0	LIGHT OIL SYSTEM	HRDPLANT	HRD97800000	
	270,072	7,199	7,209	334,475	0	0	0	0	Fuel Storage Facility Drainage	HRDPLANT		
	270,072	7,199	7,209	99,029,565	0	0	0	0	FUEL TRANSFER CATCHMENT BASINS	HRDPLANT		
	270,072	7,199	7,209	99,034,713	0	0	0	0	OIL STORAGE TANK	HRDPLANT		
	270,072	7,199	7,251	0	0	0	0	0	FIRE PROTECTION SYSTEMS	HRDPLANT	HRD98200000	
	270,072	7,199	7,251	7,270	0	0	0	0	GAS FIRE SUPPRESSION SYSTEMS	HRDPLANT	HRD98250000	
	270,072	7,199	7,251	7,270	299,429	0	0	0	Inergen Fire Suppression Sys.	HRDPLANT	COMM. RM	
	270,072	7,199	7,251	7,270	304,675	0	0	0	Inergen (Fire Suspresion)	HRDGRDHSE		
	270,072	7,199	7,251	7,270	99,039,086	0	0	0	Fire Protection System c/w	HRDGT		
	270,072	7,199	7,251	7,271	0	0	0	0	FIRE ALARM SYSTEM	HRDPLANT	HRD98260000	
	270,072	7,199	7,251	7,486	0	0	0	0	FIRE PUMPS - ELECTRIC	HRDPLANT	HRD98211000	
	270,072	7,199	7,251	7,487	0	0	0	0	FIRE PUMPS - DIESEL	HRDPLANT	HRD98212000	
	270,072	7,199	7,251	327,186	0	0	0	0	Fire Protection System Upgrade	HRDPLANT		
	270,072	7,199	7,251	99,000,045	0	0	0	0	DELUGE SYSTEM TRANSFORMERS FOR	HRDPLANT		
	270,072	7,199	7,251	99,000,046	0	0	0	0	DELUGE SYSTEM TRANSFORMERS FOR	HRDPLANT		
	270,072	7,199	7,251	99,000,047	0	0	0	0	INSTALL A 3 HOUR PENRATION FIR	HRDPLANT		
	270,072	7,199	7,251	99,000,048	0	0	0	0	UPGRADING FOR UNITS 1 & 2	HRDPLANT		
	270,072	7,199	7,251	99,000,049	0	0	0	0	INSTALL FIRE ALARM,CONTROL PAN	HRDPLANT		
	270,072	7,199	7,251	99,000,051	0	0	0	0	POWERHOUSE FIRE PROTECTION STA	HRDPLANT		
	270,072	7,199	7,251	99,000,052	0	0	0	0	POWERHOUSE FIRE PROTECTION IMP	HRDPLANT		
	270,072	7,199	7,251	99,000,053	0	0	0	0	POWERHOUSE FIRE PROTECTION UPG	HRDPLANT		

Client:	**Newfoundland and Labrador Hydro**	**STANTEC CONSULTING**	Prepared by: **MDV**
Project:	**Holyrood Decommissioning**		Date: **19-Dec-12**
Project No:	**133545705**	**WBS CROSS REFERENCE**	Revision No.: **0**
			Issue Date: **19-Dec-12**
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,199	7,251	99,000,054	0	0	0	0	BALANCE OF FIRE FIGHTING SYSTE	HRDPLANT		
	270,072	7,199	7,251	99,000,055	0	0	0	0	INSTALL 2 FIRE HOUSES AND EQUI	HRDPLANT		
	270,072	7,199	7,251	99,031,922	0	0	0	0	ADDT'L COSTS UPGRADE 1 & 2, SE	HRDPLANT		
	270,072	7,199	7,251	99,032,480	0	0	0	0	SPRINKLER SYSTEM UNIT 1	HRDPLANT		
	270,072	7,199	7,251	99,032,481	0	0	0	0	SPRINKLER SYSTEM UNIT 2	HRDPLANT		
	270,072	7,199	7,251	99,032,482	0	0	0	0	SPRINKLER SYSTEM UNIT 3	HRDPLANT		
	270,072	7,199	7,251	99,036,223	0	0	0	0	Wet Sprinkler System	HRDPLANT		
	270,072	7,199	7,253	0	0	0	0	0	COMMUNICATION SYSTEMS	HRDPLANT	HRD98400000	
	270,072	7,199	7,256	0	0	0	0	0	CRANES AND HOISTS	HRDPLANT	HRD98800000	
	270,072	7,199	7,256	271,815	0	0	0	0	HRD POWERHOUSE CRANE	HRDPLANT	HRD98800001	
	270,072	7,199	7,256	271,815	99,000,255	0	0	0	ADDITIONAL COSTS FOR CRANE	HRDPLANT		
	270,072	7,199	7,256	271,816	0	0	0	0	HRD BOILER ROOM HOISTS	HRDPLANT	HRD98800002	
	270,072	7,199	7,256	271,817	0	0	0	0	HRD PUMPHOUSE CRANE STAGE 1	HRDPLANT	HRD98800003	
	270,072	7,199	7,256	271,818	0	0	0	0	HRD PUMPHOUSE CRANE STAGE 2	HRDPLANT	HRD98800004	
	270,072	7,199	7,256	271,818	99,000,257	0	0	0	PUMPHOUSE CRANE	HRDPLANT		
	270,072	7,199	7,256	342,409	0	0	0	0	Unit One Stack Winch	HRDUNIT1	HRD98800011	
	270,072	7,199	7,256	342,423	0	0	0	0	Unit Two Stack Winch	HRDUNIT2	HRD98800012	
	270,072	7,199	7,256	342,424	0	0	0	0	Unit Three Stack Winch	HRDUNIT3	HRD98800013	
	270,072	7,199	7,256	99,000,108	0	0	0	0	INSTALL HOIST FOR UNIT #3	HRDPLANT		
	270,072	7,199	7,259	0	0	0	0	0	VIBRATION READINGS	HRDPLANT	HRD98120000	
	270,072	7,199	7,297	0	0	0	0	0	WARM AIR MAKE-UP	HRDPLANT	HRD98790000	
	270,072	7,199	7,297	7,023	0	0	0	0	#1 WARM AIR MAKE-UP SYSTEM	HRDUNIT1	HRD12870000	
	270,072	7,199	7,297	7,023	303,241	0	0	0	Unit 1 North Wall WAM	HRDPLANT		
	270,072	7,199	7,297	7,023	303,263	0	0	0	Unit 1 South Wall WAM	HRDPLANT		
	270,072	7,199	7,297	7,023	303,264	0	0	0	Unit 1 South Wall WAM	HRDPLANT		
	270,072	7,199	7,297	7,023	303,264	359,292	0	0	Unit1 Air Handling Enclosures	HRDPLANT		
	270,072	7,199	7,297	7,023	303,264	359,349	0	0	Unit 1 WAM Air Handling	HRDUNIT1		
	270,072	7,199	7,297	7,972	0	0	0	0	#2 WARM AIR MAKE-UP SYSTEM	HRDUNIT2	HRD22870000	
	270,072	7,199	7,297	7,972	303,265	0	0	0	Unit 2 North Wall WAM	HRDPLANT		
	270,072	7,199	7,297	7,972	303,266	0	0	0	Unit 2 South Wall WAM	HRDPLANT		
	270,072	7,199	7,297	7,972	303,267	0	0	0	Unit 2 South Wall WAM	HRDPLANT		
	270,072	7,199	7,297	7,972	303,267	359,299	0	0	Unit2 Air Handling Enclosures	HRDPLANT		
	270,072	7,199	7,297	7,972	303,267	359,350	0	0	Unit 2 WAM Air Handling	HRDUNIT2		
	270,072	7,199	7,297	8,522	0	0	0	0	#3 WARM AIR MAKE-UP SYSTEM	HRDUNIT3	HRD32870000	
	270,072	7,199	7,297	8,522	303,268	0	0	0	Unit 3 North Wall WAM	HRDPLANT		
	270,072	7,199	7,297	8,522	303,269	0	0	0	Unit 3 South Wall WAM	HRDPLANT		
	270,072	7,199	7,297	8,522	303,278	0	0	0	Unit 3 North Wall WAM	HRDPLANT		
	270,072	7,199	7,297	8,522	303,279	0	0	0	Unit 3 South Wall WAM Louvers	HRDPLANT		
	270,072	7,199	7,297	8,522	303,279	359,300	0	0	Unit3 Air Handling Enclosures	HRDPLANT		
	270,072	7,199	7,297	8,522	303,279	359,351	0	0	Unit 3 WAM Air Handling	HRDUNIT3		
	270,072	7,199	8,680	0	0	0	0	0	STAGE 2 AUX. DIESEL GENERATOR	HRDUNIT3	HRD34300000	
	270,072	7,199	8,680	99,000,314	0	0	0	0	INSTALL EMERGENCY DIESEL UNIT	HRDPLANT		
	270,072	7,199	8,680	99,000,315	0	0	0	0	INSTALL WOODWARD DIESEL UNIT U	HRDPLANT		
	270,072	7,199	8,680	99,000,396	0	0	0	0	INSTALL RELAYS FOR UNIT 3	HRDPLANT		
	270,072	7,199	8,680	99,031,801	0	0	0	0	DIESEL SYNCHRONIZER, SEE PL AS	HRDPLANT		
	270,072	7,199	8,730	0	0	0	0	0	#3STATION SERVICE POWER SYSTEM	HRDUNIT3	HRD35500000	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec WBS	Newfoundland and Labrador Hydro Asset Registry Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Description	Location	Unit No.	Comments
	270,072	7,199	8,730	7,410	0	0	0	0	WARM AIR MAKEUP MCC-WAM-34	HRDUNIT1	HRD35580000	
	270,072	7,199	8,730	8,731	0	0	0	0	STATION SERVICE BOARD SB-34	HRDUNIT3	HRD35510000	
	270,072	7,199	8,730	8,732	0	0	0	0	STATION AUXILIARY BOARD SAB-34	HRDUNIT3	HRD35520000	
	270,072	7,199	8,730	8,738	0	0	0	0	GENERAL PURPOSE MCC GPB-34	HRDUNIT3	HRD35530000	
	270,072	7,199	8,730	8,738	99,038,707	0	0	0	SIEMENS BREAKER MCC GPB34	HRDPLANT		
	270,072	7,199	8,730	8,738	99,038,708	0	0	0	SIEMENS BREAKER MCC GPB34	HRDPLANT		
	270,072	7,199	8,730	8,738	99,038,709	0	0	0	SIEMENS BREAKER MCC GPB34	HRDPLANT		
	270,072	7,199	8,730	8,738	99,038,710	0	0	0	SIEMENS BREAKER MCC GPB34	HRDPLANT		
	270,072	7,199	8,730	8,738	99,038,711	0	0	0	SIEMENS BREAKER MCC GPB34	HRDPLANT		
	270,072	7,199	8,730	8,740	0	0	0	0	TURB & BLR STANDBY MCC SDB-34	HRDUNIT3	HRD35540000	
	270,072	7,199	8,730	8,740	358,127	0	0	0	MCC-SDB UPGRADE	HRDUNIT3	HRD35540001	
	270,072	7,199	8,730	8,742	0	0	0	0	DIESEL BUS DB-34	HRDUNIT3	HRD35550000	
	270,072	7,199	8,730	8,743	0	0	0	0	ESSENTIAL SERVICES MCC ESB-34	HRDUNIT3	HRD35551000	
	270,072	7,199	8,730	8,746	0	0	0	0	C.W. PUMPHOUSE MCC CWP-34	HRDUNIT3	HRD35560000	
	270,072	7,199	8,730	8,746	358,108	0	0	0	C.W. SCREEN WASH RELAY PANEL	HRDUNIT3	HRD35562000	
	270,072	7,199	8,730	8,746	359,340	0	0	0	C.W. PUMPHOUSE MCC CWP-34	HRDUNIT3	HRD35561000	
	270,072	7,199	8,730	99,000,405	0	0	0	0	INSTALL STATION SERVICE TRANSF	HRDPLANT		
	270,072	7,199	8,771	0	0	0	0	0	STAGE 2 129V D.C. SUPPLY	HRDUNIT3	HRD35770000	
	270,072	7,199	8,771	99,000,355	0	0	0	0	INSTALL D.C. DISTRIBUTION BOAR	HRDPLANT		
	270,072	7,199	8,771	99,029,568	0	0	0	0	C & D 60 CELL BATTERY BANK	HRDPLANT		
	270,072	7,199	273,390	0	0	0	0	0	UHF PORTABLE HANDIE TALKIE	HRDPLANT	TC10054	
	270,072	7,199	286,056	0	0	0	0	0	BOILER GAS ANALYZING SYSTEMS	HRDPLANT		
	270,072	7,199	286,056	6,926	0	0	0	0	#1 BOILER GAS ANALYZING	HRDUNIT1	HRD12537000	
	270,072	7,199	286,056	7,162	0	0	0	0	DEW POINT MONITORING	HRDPLANT	HRD98180000	
	270,072	7,199	286,056	7,898	0	0	0	0	#2 BOILER GAS ANALYZING	HRDUNIT2	HRD22537000	
	270,072	7,199	286,056	8,446	0	0	0	0	#3 BOILER GAS ANALYZING	HRDUNIT3	HRD32537000	
	270,072	7,199	303,240	0	0	0	0	0	Stage 1 Emergency Diesel	HRDPLANT		
	270,072	7,199	359,306	0	0	0	0	0	COMMON BLANKS AND BLINDS	HRDPLANT		
	270,072	7,202	0	0	0	0	0	0	GAS TURBINE SYSTEM	HRDPLANT	HRD99000000	
	270,072	7,202	7,058	0	0	0	0	0	GAS TURBINE POWER TURB & G/B	HRDPLANT	HRD99200000	
	270,072	7,202	7,058	99,003,600	0	0	0	0	POWER TURBINE FOR HRD. GAS TUR	HRDGT		
	270,072	7,202	7,058	99,003,601	0	0	0	0	MATERIALS TO UPGRADE POWER TUR	HRDGT		
	270,072	7,202	7,308	0	0	0	0	0	GAS TURBINE AVON JET ENGINE	HRDPLANT	HRD99100000	
	270,072	7,202	7,308	99,003,605	0	0	0	0	JET ENGINE; ROLLS ROYCE	HRDGT		
	270,072	7,202	7,309	0	0	0	0	0	GAS TURBINE GENERATOR	HRDPLANT	HRD99300000	
	270,072	7,202	7,309	99,003,606	0	0	0	0	ROTOR FOR GENERATOR AT HRD. GA	HRDGT		
	270,072	7,202	7,309	99,003,607	0	0	0	0	STATOR FOR GENERATOR AT HRD. G	HRDGT		
	270,072	7,202	7,309	99,003,608	0	0	0	0	BALANCE OF GENERATOR FOR HRD.	HRDGT		
	270,072	7,202	7,309	99,003,609	0	0	0	0	UPGRADE BALANCE OF GENERATOR A	HRDGT		
	270,072	7,202	7,310	0	0	0	0	0	HRD GAS TURB ELECT & CONTROL	HRDPLANT	HRD99400000	
	270,072	7,202	7,310	333,927	0	0	0	0	HRD GAS TURB DCS CONTROL	HRDGT		
	270,072	7,202	7,310	99,003,597	0	0	0	0	BILLING, METERING, RELAY CONTR	HRDGT		
	270,072	7,202	7,310	99,003,598	0	0	0	0	UPGRADE CONTROL SYSTEM (GAS TU	HRDGT		
	270,072	7,202	7,311	0	0	0	0	0	GAS TURBINE AUXILIARY SYSTEMS	HRDPLANT	HRD99500000	
	270,072	7,202	7,311	99,003,591	0	0	0	0	COMPRESSED AIR SYSTEM (TANK, D	HRDGT		
	270,072	7,202	7,311	99,003,599	0	0	0	0	UPGRADE MAIN LUBE OIL SET (GAS	HRDGT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,202	7,311	99,003,602	0	0	0	0	AIR INLET PLENUM CHAMBER	HRDGT		
	270,072	7,202	7,311	99,003,603	0	0	0	0	UPGRADE INLET PLENUM AT HRD DU	HRDGT		
	270,072	7,202	7,311	99,027,851	0	0	0	0	110 VOLT C & D BATTERY BANK	HRDGT		
	270,072	7,202	7,311	99,027,852	0	0	0	0	120 VDC BATTERY CHARGER	HRDGT		
	270,072	7,202	359,204	0	0	0	0	0	HOLYROD GAS TURBINE STUDY	HRDGT		
	270,072	7,202	99,027,850	0	0	0	0	0	UPGRADE GAS TURBINE CONTROL PA	HRDGT		
200												
	270,072	7,255	0	0	0	0	0	0	HRD BUILDINGS AND SITE	HRDPLANT	HRD98600000	
	270,072	7,255	7,133	0	0	0	0	0	HRD MARINE TERMINAL STRUCTURE	HRDPLANT	HRD98640000	
	270,072	7,255	7,133	291,152	0	0	0	0	Dock upgrading-Security Projec	HRDPLANT		
	270,072	7,255	7,133	324,311	0	0	0	0	U/G Bldg. Ventilation	HRDPLANT	MARINE TERM.	
	270,072	7,255	7,133	334,476	0	0	0	0	Marine Capstan Lifting Frames	HRDPLANT		
	270,072	7,255	7,133	359,205	0	0	0	0	HOLYROOD MARINE TERMINAL STUDY	HRDPLANT		
	270,072	7,255	7,133	99,000,017	0	0	0	0	ADDITIONAL COSTS FOR INSURANCE	HRDPLANT		
	270,072	7,255	7,133	99,000,018	0	0	0	0	ENHANCEMENT TO WHARF	HRDPLANT		
	270,072	7,255	7,133	99,000,019	0	0	0	0	CATHODIC PROTECTION FOR THE DO	HRDPLANT		
	270,072	7,255	7,133	99,000,106	0	0	0	0	CONSTRUCTION OF NEW PUMPHOUSE	HRDPLANT		
100												
	270,072	7,255	7,257	0	0	0	0	0	HRD LAND	HRDPLANT	HRD98900000	
	270,072	7,255	7,257	7,609	0	0	0	0	HRD GREEN ACRES SITE LAND	HRDPLANT	HRD98944000	
	270,072	7,255	7,257	7,610	0	0	0	0	HRD BUTTERPOT SITE LAND	HRDPLANT	HRD98945000	
	270,072	7,255	7,257	7,611	0	0	0	0	HRD LAWRENCE POND SITE LAND	HRDPLANT	HRD98946000	
	270,072	7,255	7,257	7,612	0	0	0	0	HRD INDIAN POND SITE LAND	HRDPLANT	HRD98947000	
	270,072	7,255	7,257	272,254	0	0	0	0	HRD LAND IMPROVEMENTS	HRDPLANT	HRD98900001	
	270,072	7,255	7,257	272,254	291,150	0	0	0	Site improvements-Sec. project	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,002	0	0	0	LAND IMPROVEMNETS	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,003	0	0	0	LAND IMPROVEMENTS	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,004	0	0	0	LAND IMPROVEMENTS STAGE III	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,005	0	0	0	LAND IMPROVEMENTS	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,006	0	0	0	PARKING FACILITIES ON WESTERN	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,007	0	0	0	PROTECTION AT INTERSECTION OF	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,009	0	0	0	LAND IMPROVEMENTS AT TANK FARM	HRDPLANT		
	270,072	7,255	7,257	272,254	99,000,010	0	0	0	SODS AND TOPSOIL	HRDPLANT		
	270,072	7,255	7,257	272,254	99,003,525	0	0	0	LAND IMPROVEMENTS FOR WASTE WA	HRDPLANT		
	270,072	7,255	7,257	272,254	99,027,843	0	0	0	LAND IMPROVEMENTS AT GREEN ACR	HRDPLANT		
	270,072	7,255	7,257	272,254	99,032,483	0	0	0	LAND IMPROVEMENTS	HRDPLANT		
	270,072	7,255	7,257	99,018,718	0	0	0	0	LANDSCAPE AREA ADJACENT TO ACC	HRDOFFICE		
	270,072	7,255	7,257	99,041,210	0	0	0	0	LAND	HRDPLANT		
200												
	270,072	7,255	253,041	0	0	0	0	0	HRD CAR WASH SYSTEM	HRDPLANT	HRD98970000	
	270,072	7,255	253,041	99,039,071	0	0	0	0	Foundations and civil work	HRDPLANT		
	270,072	7,255	272,255	0	0	0	0	0	HRD BUILDINGS	HRDPLANT	HRD98900002	
	270,072	7,255	272,255	7,283	0	0	0	0	HRD MAIN POWERHOUSE	HRDPLANT	HRD98610000	
	270,072	7,255	272,255	7,283	7,306	0	0	0	HRD BUILDING SERVICES ELEVATOR	HRDPLANT	HRD98960000	
	270,072	7,255	272,255	7,283	299,949	0	0	0	HRD FALL PROTECTION EQUIPMENT	HRDPLANT		
	270,072	7,255	272,255	7,283	333,646	0	0	0	Safety Egress Lighting	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,255	272,255	7,283	342,604	0	0	0	Emergency Ladders	HRDPLANT		
	270,072	7,255	272,255	7,283	343,143	0	0	0	Platform, Special Valve	HRDPLANT		
	270,072	7,255	272,255	7,283	359,329	0	0	0	Weatherhoods for Vent Fans	HRDPLANT		
	270,072	7,255	272,255	7,284	0	0	0	0	HRD TRAINING CENTRE	HRDPLANT	HRD98620000	
	270,072	7,255	272,255	7,284	99,000,105	0	0	0	INSTALL INSULATION & HEATING F	HRDPLANT		
	270,072	7,255	272,255	7,285	0	0	0	0	HRD STAGE 1 PUMPHOUSE	HRDPLANT	HRD98630000	
	270,072	7,255	272,255	7,285	99,003,590	0	0	0	FENCING AT HRD GAS TURBINE	HRDGT		
	270,072	7,255	272,255	7,286	0	0	0	0	HRD STAGE 2 PUMPHOUSE	HRDPLANT	HRD98650000	
	270,072	7,255	272,255	7,286	299,950	0	0	0	FALL PROTECTION EQUIPMENT P#2	HRDPLANT		
	270,072	7,255	272,255	7,286	359,341	0	0	0	STAGE II PUMPHOUSE MCC ROOM	HRDPLANT	HRD98651000	
	270,072	7,255	272,255	7,287	0	0	0	0	HRD GUARDHOUSE	HRDPLANT	HRD98660000	
	270,072	7,255	272,255	7,287	324,052	0	0	0	HD Security Camera Systems	HRDOFFICE		
	270,072	7,255	272,255	7,287	334,498	0	0	0	Security Camera Systems - HRD	HRDOFFICE		
	270,072	7,255	272,255	7,287	359,534	0	0	0	HD Security Camera Systems	HRDOFFICE		
	270,072	7,255	272,255	7,288	0	0	0	0	HRD H2 & CO2 STORAGE BUILDING	HRDPLANT	HRD98670000	
	270,072	7,255	272,255	7,302	0	0	0	0	HRD SHAWMONT BUILDING	HRDPLANT	HRD98910000	
	270,072	7,255	272,255	7,303	0	0	0	0	HRD MAIN WAREHOUSE	HRDPLANT	HRD98920000	
	270,072	7,255	272,255	7,303	324,512	0	0	0	3M x 30M Outdoor Storage Ramps	HRDWHYARD		
	270,072	7,255	272,255	7,303	99,002,058	0	0	0	STORAGE RACKS AT HOLYROOD WARE	HRDOFFICE		
	270,072	7,255	272,255	7,303	99,026,217	0	0	0	STEEL SHELVING - MAIN WAREHOUS	HRDOFFICE		
	270,072	7,255	272,255	7,303	99,032,820	0	0	0	PIPE STORAGE RACK	HRDOFFICE		
	270,072	7,255	272,255	7,304	0	0	0	0	HRD WWT PLANT BUILDING	HRDPLANT	HRD98930000	
	270,072	7,255	272,255	7,305	0	0	0	0	HRD WWT BASINS BUILDING	HRDPLANT	HRD98950000	
	270,072	7,255	272,255	7,307	0	0	0	0	HRD GAS TURBINE BUILDING	HRDPLANT	HRD98940000	
	270,072	7,255	272,255	7,307	99,003,595	0	0	0	FOUNDATION (CONCRETE) FOR EQUI	HRDGT		
	270,072	7,255	272,255	7,307	99,003,613	0	0	0	GROUNDING FOR HRD. GAS TURBINE	HRDGT		
	270,072	7,255	272,255	272,256	0	0	0	0	HRD WATER TREATMENT BUILDING	HRDPLANT	HRD98950001	
	270,072	7,255	272,255	291,143	0	0	0	0	Guard house marine terminal	HRDPLANT		
	270,072	7,255	272,255	303,237	0	0	0	0	Guardhouse	HRDGRDHSE		
	270,072	7,255	272,255	303,237	304,497	0	0	0	Furniture	HRDGRDHSE		
	270,072	7,255	272,255	303,237	304,674	0	0	0	Emergency Power Building	HRDGRDHSE		
	270,072	7,255	272,255	303,237	304,677	0	0	0	Air Conditioners	HRDGRDHSE		
	270,072	7,255	272,255	305,735	0	0	0	0	Fall Arrest equip-holyrood	HRDPLANT		
	270,072	7,255	272,255	310,010	0	0	0	0	Fall Arrest Equip-Holyrood	HRDPLANT		
	270,072	7,255	272,255	324,826	0	0	0	0	Fall Arrest Equip-Holyrood	HRDPLANT		
	270,072	7,255	272,255	324,828	0	0	0	0	Fall Arrest Equip-Holyrood	HRDPLANT		
	270,072	7,255	272,255	324,829	0	0	0	0	Fall Arrest Equip-Holyrood	HRDPLANT		
	270,072	7,255	272,255	342,406	0	0	0	0	East Elec. Panel Enclosure	HRDPLANT		
	270,072	7,255	272,255	342,407	0	0	0	0	West Elec. panel Enclosure	HRDPLANT		
	270,072	7,255	272,255	357,449	0	0	0	0	HRD OVERHEAD DOORS	HRDPLANT		
	270,072	7,255	272,255	357,449	357,958	0	0	0	#1 - MAIN POWERHOUSE - WEST	HRDPLANT	HRD98910001	
	270,072	7,255	272,255	357,449	357,959	0	0	0	#2 - MAIN POWERHOUSE - NORTH	HRDPLANT	HRD98910002	
	270,072	7,255	272,255	357,449	357,960	0	0	0	#3 - MAIN POWERHOUSE - NORTH	HRDPLANT	HRD98910004	
	270,072	7,255	272,255	357,449	357,961	0	0	0	#4 - MAIN POWERHOUSE - NORTH	HRDPLANT	HRD98910005	
	270,072	7,255	272,255	357,449	357,962	0	0	0	#5 - MAIN POWERHOUSE - EAST	HRDPLANT	HRD98910006	
	270,072	7,255	272,255	357,449	357,963	0	0	0	#6 - MAIN POWERHOUSE - EAST	HRDPLANT	HRD98910007	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,255	272,255	357,449	357,964	0	0	0	#7 - MAIN POWERHOUSE - EAST	HRDPLANT	HRD98910008	
	270,072	7,255	272,255	357,449	357,965	0	0	0	#8 - MAIN POWERHOUSE - SOUTH	HRDPLANT	HRD98910009	
	270,072	7,255	272,255	357,449	357,966	0	0	0	#9 - MAIN POWERHOUSE - WEST	HRDPLANT	HRD98910010	
	270,072	7,255	272,255	357,449	357,967	0	0	0	#10 - PUMPHOUSE #1 - WEST	HRDPLANT	HRD98910011	
	270,072	7,255	272,255	357,449	357,968	0	0	0	#11 - PUMPHOUSE #1 - SOUTH	HRDPLANT	HRD98910012	
	270,072	7,255	272,255	357,449	357,971	0	0	0	#12 - WASTE WATER TREATMENT	HRDPLANT	HRD98910013	
	270,072	7,255	272,255	357,449	357,972	0	0	0	#13 - PUMPHOUSE #2	HRDPLANT	HRD98910014	
	270,072	7,255	272,255	357,449	357,973	0	0	0	#14 - CHEMICAL STORAGE BLDG.	HRDPLANT	HRD98910015	
	270,072	7,255	272,255	357,449	357,974	0	0	0	#15 - CHEMICAL STORAGE BLDG.	HRDPLANT	HRD98910016	
	270,072	7,255	272,255	357,449	357,975	0	0	0	#16 - PIPE SHOP - NORTH	HRDPLANT	HRD98910017	
	270,072	7,255	272,255	357,449	357,976	0	0	0	#17 - TRAINING CENTER	HRDPLANT	HRD98910018	
	270,072	7,255	272,255	357,449	357,977	0	0	0	#18 - WAREHOUSE	HRDPLANT	HRD98910019	
	270,072	7,255	272,255	357,449	357,978	0	0	0	#19 - PIPE SHOP - SOUTH	HRDPLANT	HRD98910020	
	270,072	7,255	272,255	357,449	357,979	0	0	0	#20 - SHAWMOUNT WAREHOUSE	HRDPLANT	HRD98910021	
	270,072	7,255	272,255	357,449	357,980	0	0	0	#21 - HYDROGEN SHED	HRDPLANT	HRD98910022	
	270,072	7,255	272,255	357,449	357,981	0	0	0	#22 - GAS TURBINE BUILDING	HRDPLANT	HRD98910023	
	270,072	7,255	272,255	357,449	359,342	0	0	0	#2A - MAIN POWERHOUSE - NORTH	HRDPLANT	HRD98910003	
	270,072	7,255	272,255	357,449	359,343	0	0	0	#23 - POWERHOUSE INTERIOR	HRDPLANT	HRD98910024	
	270,072	7,255	272,255	359,222	0	0	0	0	HRD FIXED FALL ARREST EQUIP.	HRDPLANT		
	270,072	7,255	272,255	359,222	359,446	0	0	0	HRD-STACK 1 FIXED FALL ARREST	HRDUNIT1		
	270,072	7,255	272,255	359,222	359,447	0	0	0	HRD-STACK 2 FIXED FALL ARREST	HRDUNIT2		
	270,072	7,255	272,255	359,222	359,448	0	0	0	HRD-STACK 3 FIXED FALL ARREST	HRDUNIT3		
	270,072	7,255	272,255	360,018	0	0	0	0	HRD BUILDINGS EXIT DOORS	HRDPLANT	HRD98910100	
	270,072	7,255	272,255	99,027,841	0	0	0	0	GREEN ACRES MONITORING SITE	HRDPLANT		
	270,072	7,255	272,255	99,027,842	0	0	0	0	FOUNDATION FOR WOODEN BLDG AT	HRDPLANT		
100												
	270,072	7,255	272,257	0	0	0	0	0	HRD ROADS & SITE LIGHTING	HRDPLANT	HRD98600001	
	270,072	7,255	272,257	99,000,012	0	0	0	0	ROADS AT THERMAL PLANT	HRDPLANT		
	270,072	7,255	272,257	99,000,013	0	0	0	0	UPGRADE AT TANKER DOCK	HRDPLANT		
	270,072	7,255	272,257	99,000,014	0	0	0	0	PROVIDE SITE ROADS FOR HOLYROO	HRDPLANT		
	270,072	7,255	272,257	99,000,015	0	0	0	0	REPAIR ROADS, WORK ORDER 0035	HRDPLANT		
	270,072	7,255	272,257	99,000,056	0	0	0	0	LIGHTING SYSTEM - OUTDOOR	HRDPLANT		
	270,072	7,255	272,257	99,000,057	0	0	0	0	COSTS TRANSFERED FROM OPERATIN	HRDPLANT		
	270,072	7,255	272,257	99,000,422	0	0	0	0	INSTALL 250WATT STREET LIGHTS	HRDPLANT		
	270,072	7,255	272,257	99,000,423	0	0	0	0	ADDITIONAL COSTS FOR STREET LI	HRDPLANT		
	270,072	7,255	272,257	99,027,844	0	0	0	0	ACCESS ROAD TO GREEN ACRES MON	HRDPLANT		
	270,072	7,255	272,258	0	0	0	0	0	HRD FENCING	HRDPLANT	HRD98600002	
	270,072	7,255	272,258	291,146	0	0	0	0	Fencing - Security Project	HRDPLANT		
	270,072	7,255	272,258	334,492	0	0	0	0	Fence, Security - HRD	HRDPLANT		
	270,072	7,255	272,258	99,000,029	0	0	0	0	CHAIN LINK FENCING	HRDPLANT		
	270,072	7,255	272,258	99,000,030	0	0	0	0	CHAIN LINK FENCING AROUND STOR	HRDPLANT		
	270,072	7,255	272,258	99,000,031	0	0	0	0	CHAIN LINK FENCING,SEE PL ASSE	HRDPLANT		
	270,072	7,255	272,258	99,000,032	0	0	0	0	CHAIN LINK FENCING	HRDPLANT		
	270,072	7,255	272,258	99,000,033	0	0	0	0	REMOVE AND REPLACE FENCING	HRDPLANT		
	270,072	7,255	272,258	99,027,840	0	0	0	0	CHAIN LINK FENCING	HRDPLANT		
	270,072	7,255	272,258	99,027,849	0	0	0	0	GALVANIZED CHAIN LINK FENCING	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	
Project:	Holyrood Decommissioning	
Project No:	133545705	

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by: **MDV**
Date: **19-Dec-12**
Revision No.: **0**
Issue Date: **19-Dec-12**
Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,255	272,259	0	0	0	0	0	HRD STORM DRAINAGE	HRDPLANT	HRD98600003	
	270,072	7,255	272,259	341,794	0	0	0	0	Catch Basins on East and North	HRDPLANT		
	270,072	7,255	272,259	99,000,035	0	0	0	0	STORM AND YARD DRAINAGE STAGE	HRDPLANT		
	270,072	7,255	272,259	99,000,036	0	0	0	0	PLANT DRAINAGE MODIFICATIONS	HRDPLANT		
	270,072	7,255	272,259	99,000,037	0	0	0	0	INSTALL SUB-SURFACE DRAINS STA	HRDPLANT		
	270,072	7,255	272,259	99,003,526	0	0	0	0	POWERHOUSE DRAINAGE SYSTEM	HRDPLANT		
	270,072	7,255	291,154	0	0	0	0	0	Fibre Line to docks-Sec Proj	HRDPLANT		
	270,072	7,255	291,155	0	0	0	0	0	Camera and security-dock	HRDPLANT		
	270,072	7,255	292,266	0	0	0	0	0	HRD DIST SERVICES	HRDPLANT		
	270,072	7,255	292,266	291,153	0	0	0	0	Distribution line-sec proj	HRDPLANT		
	270,072	7,255	292,266	99,000,406	0	0	0	0	INSTALL WOOD POLE STRUCTURES D	HRDPLANT		
	270,072	7,255	292,266	99,000,407	0	0	0	0	WOOD POLE STRUCTURES FOR HOLYR	HRDPLANT		
	270,072	7,255	292,266	99,000,408	0	0	0	0	ADDITIONAL COSTS FOR WOOD POLE	HRDPLANT		
	270,072	7,255	292,266	99,000,409	0	0	0	0	INSTALL DISTRIBUTION TRANSFORM	HRDPLANT		
	270,072	7,255	292,266	99,023,675	0	0	0	0	WOOD POLE STRUCTURES	HRDPLANT		
	270,072	7,255	292,266	99,023,677	0	0	0	0	150 WATT HPS STREETLIGHTS	HRDPLANT		
	270,072	7,255	292,266	99,023,680	0	0	0	0	WESTINGHOUSE 10 KVA POLE TRANS	HRDPLANT		
	270,072	7,255	292,266	99,023,682	0	0	0	0	WESTINGHOUSE 15 KVA POLE TYPE	HRDPLANT	FA-T30007	
	270,072	7,255	292,266	99,023,684	0	0	0	0	WESTINGHOUSE 15 KVA POLE TYPE	HRDPLANT	FA-T5184	
	270,072	7,255	292,266	99,023,687	0	0	0	0	GENERAL ELECTRIC 25 KVA POLE T	HRDPLANT		
	270,072	7,255	292,266	99,027,647	0	0	0	0	POLE HARDWARE	HRDPLANT		
	270,072	7,255	292,266	99,027,648	0	0	0	0	#1/0 AASC PRIMARY CONDUCTOR	HRDPLANT		
	270,072	7,255	292,266	99,027,649	0	0	0	0	#1/0 PEWP SECONDARY CONDUCTOR	HRDPLANT		
	270,072	7,255	292,266	99,027,650	0	0	0	0	30' WOOD POLES	HRDPLANT		
	270,072	7,255	292,266	99,027,651	0	0	0	0	40' WOOD POLES	HRDPLANT		
	270,072	7,255	292,266	99,027,652	0	0	0	0	#2 QUAD SERVICE CONDUCTOR	HRDPLANT		
	270,072	7,255	292,266	99,027,653	0	0	0	0	25KVA TRANSFORMERS	HRDPLANT		
	270,072	7,255	292,266	99,029,569	0	0	0	0	UPGRADE SITE SERVICES HOLYROOD	HRDPLANT		
	270,072	7,255	292,266	99,032,022	0	0	0	0	WOOD POLE STRUCTURES, SEE PL A	HRDPLANT		
200												
	270,072	7,255	99,002,057	0	0	0	0	0	FIRE TRAINING GROUNDS FOR HOLY	HRDOFFICE		
	270,072	7,255	99,023,635	0	0	0	0	0	TRANSPORTABLE AMBIENT MONITORI	HRDPLANT		
	270,072	7,255	99,023,636	0	0	0	0	0	TRANSPORTABLE AMBIENT MONITORI	HRDPLANT		
	270,072	7,255	99,023,637	0	0	0	0	0	TRANSPORTABLE AMBIENT MONITORI	HRDPLANT		
	270,072	7,255	99,039,841	0	0	0	0	0	SECURITY SURVEILLANCE SYSTEM	HRDOFFICE		
700												
	270,072	7,505	0	0	0	0	0	0	HRD TOOLS & EQUIPMENT	HRDPLANT	HRD98355000	
	270,072	7,505	7,265	0	0	0	0	0	SAFETY EQUIPMENT AND PPE	HRDPLANT	HRD98190000	
	270,072	7,505	7,265	7,267	0	0	0	0	FIRE FIGHTING EQUIPMENT	HRDPLANT	HRD98220000	
	270,072	7,505	7,265	7,267	358,922	0	0	0	Foam Cart #1	HRDPLANT		
	270,072	7,505	7,265	7,267	358,923	0	0	0	Foam Cart #2	HRDPLANT		
	270,072	7,505	7,265	7,267	99,004,724	0	0	0	ROSCO SMOKE GENERATOR C/W CASE	HRDOFFICE	FA-03227	
	270,072	7,505	7,265	7,267	99,004,760	0	0	0	BREATHING APPARATUS MODEL - MO	HRDOFFICE	FA-01936	
	270,072	7,505	7,265	7,267	99,004,761	0	0	0	BREATHING APPARATUS MODEL - MO	HRDOFFICE	FA-1935	
	270,072	7,505	7,265	7,267	99,004,762	0	0	0	SCOTT 2.2 SELF CONTAINED BREAT	HRDOFFICE	FA-03418	
	270,072	7,505	7,265	7,267	99,004,763	0	0	0	SCOTT GO-NO-GO REGULATOR TESTE	HRDOFFICE	FA-003189	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,505	7,265	7,267	99,004,783	0	0	0	BAUER BREATHING AIR COMPRESSOR	HRDOFFICE	FA-01911	
	270,072	7,505	7,265	7,267	99,004,792	0	0	0	2.2 PRESSURE DEMAND AIR PAK -	HRDOFFICE	FA-03416	
	270,072	7,505	7,265	7,267	99,018,387	0	0	0	PIONEER 60 MINUTE CYLINDER - M	HRDOFFICE	FA-003188	
	270,072	7,505	7,265	7,267	99,023,423	0	0	0	#3 ANGUS MOBILE FOAM CART UNIT	HRDOFFICE	FA-01902	
	270,072	7,505	7,265	7,267	99,023,427	0	0	0	SCOT 60 MINUTE AIR PAK C/W 2 C	HRDOFFICE	FA-03417	
	270,072	7,505	7,265	7,267	99,026,210	0	0	0	SCBA 60 MIN E-Z FLO AIR-PAKS	HRDOFFICE	FA-003186	
	270,072	7,505	7,265	7,267	99,026,211	0	0	0	SCBA 88 CU. FT CYLINDER & VALV	HRDOFFICE	FA-003185	
	270,072	7,505	7,265	7,267	99,034,124	0	0	0	SCBA 60 MIN E-Z FLO AIR-PA	HRDOFFICE	FA-003187	
	270,072	7,505	7,265	7,267	99,034,204	0	0	0	BAUER BREATHING AIR COMPRESSOR	HRDOFFICE	FA-01912	
	270,072	7,505	7,265	7,267	99,034,205	0	0	0	BAUER BREATHING AIR COMPRESSOR	HRDOFFICE	FA-01913	
	270,072	7,505	7,265	7,267	99,034,206	0	0	0	BAUER BREATHING AIR COMPRESSOR	HRDOFFICE	FA-01914	
	270,072	7,505	7,265	7,267	99,034,207	0	0	0	BAUER BREATHING AIR COMPRESSOR	HRDOFFICE	FA-01915	
	270,072	7,505	7,265	7,267	99,039,951	0	0	0	Scott SCUBA Packs	HRDOFFICE		
	270,072	7,505	7,265	333,647	0	0	0	0	Fall Protection	HRDPLANT	5903	
	270,072	7,505	7,265	333,648	0	0	0	0	Fall Protection	HRDPLANT		
	270,072	7,505	7,265	333,649	0	0	0	0	Fall Protection	HRDPLANT	5902	
	270,072	7,505	7,265	333,650	0	0	0	0	Fall Protection	HRDPLANT		
	270,072	7,505	7,265	359,442	0	0	0	0	HRD Fall Protection Stack1	HRDPLANT		
	270,072	7,505	7,265	359,443	0	0	0	0	HRD Fall Protection Stack2	HRDPLANT		
	270,072	7,505	7,265	359,444	0	0	0	0	HRD Fall Protection Stack3	HRDPLANT		
	270,072	7,505	7,265	99,004,737	0	0	0	0	LAERDAL RESUSCI ANNE & BABY C/	HRDOFFICE	FA-01909	
	270,072	7,505	7,265	99,034,050	0	0	0	0	Heat Stress Monitor	HRDOFFICE	FA-03422	
	270,072	7,505	7,471	0	0	0	0	0	OIL SPILL RESPONSE EQUIPMENT	HRDPLANT	HRD98135000	
	270,072	7,505	7,471	99,029,551	0	0	0	0	EMERGENCY OIL POLLUTION CLEAN	HRDPLANT		
	270,072	7,505	7,471	99,029,551	99,037,382	0	0	0	1996 WALTRON UTILITY TRAILER	HRDPLANT	FA-V8801	
	270,072	7,505	7,471	99,029,551	99,037,383	0	0	0	1996 WALTRON UTILITY TRAILER	HRDPLANT	FA-V8802	
	270,072	7,505	9,551	0	0	0	0	0	SHOPS EQUIPMENT	HRDPLANT	HRD98351200	
	270,072	7,505	9,551	287,503	0	0	0	0	Fume Extractor	HRDPLANT		
	270,072	7,505	9,551	288,505	0	0	0	0	Marine Oil Boom, 50Ft X 24	HRDPLANT		
	270,072	7,505	9,551	290,935	0	0	0	0	Current G.F.I..	HRDPLANT		
	270,072	7,505	9,551	299,314	0	0	0	0	Gas Detector	HRDPLANT		
	270,072	7,505	9,551	299,315	0	0	0	0	Gas Detector	HRDPLANT		
	270,072	7,505	9,551	299,316	0	0	0	0	Gas Dectector	HRDPLANT		
	270,072	7,505	9,551	299,449	0	0	0	0	Bench Top PH Meter	HRDOFFICE		
	270,072	7,505	9,551	303,347	0	0	0	0	4.16kV Grounding Truck	HRDPLANT		
	270,072	7,505	9,551	303,348	0	0	0	0	4.16kV Grounding Truck	HRDPLANT		
	270,072	7,505	9,551	307,741	0	0	0	0	Riding Lawn Mower	HRDOFFICE		
	270,072	7,505	9,551	307,741	308,698	0	0	0	Riding Lawn Mower	HRDOFFICE		
	270,072	7,505	9,551	307,777	0	0	0	0	OIL CONTAINMENT BOOM POLEMAR	HRDPLANT		
	270,072	7,505	9,551	319,794	0	0	0	0	Epoke Sand & Salt Spreader	HRDOFFICE		
	270,072	7,505	9,551	324,762	0	0	0	0	4.16kv grounding truck	HRDPLANT		
	270,072	7,505	9,551	324,763	0	0	0	0	4.16 Kv grounding truck	HRDPLANT		
	270,072	7,505	9,551	331,920	0	0	0	0	Hydraulic Wrench	HRDPLANT		
	270,072	7,505	9,551	333,368	0	0	0	0	Boom Style Hydraulic Lift	HRDPLANT	TOOLS	
	270,072	7,505	9,551	333,370	0	0	0	0	Snowthrower	HRDPLANT		
	270,072	7,505	9,551	333,371	0	0	0	0	Lawn Mower	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,505	9,551	333,408	0	0	0	0	Hydraulic Scissor Lift	HRDPLANT	MAINT. TOOLS	
	270,072	7,505	9,551	334,345	0	0	0	0	Instrumentation Calibrator	HRDPLANT		
	270,072	7,505	9,551	359,186	0	0	0	0	VIBRATION DATA COLLECTOR KIT	HRDPLANT		
	270,072	7,505	9,551	359,187	0	0	0	0	PRESSURE CALIBRATOR	HRDPLANT		
	270,072	7,505	9,551	359,188	0	0	0	0	FLUKE PROCESS CALIBRATOR	HRDPLANT		
	270,072	7,505	9,551	359,189	0	0	0	0	#1 FLOOR SCRUBBER	HRDPLANT		
	270,072	7,505	9,551	359,190	0	0	0	0	#2 FLOOR SCRUBBER	HRDPLANT		
	270,072	7,505	9,551	359,191	0	0	0	0	#3 FLOOR SCRUBBER	HRDPLANT		
	270,072	7,505	9,551	359,192	0	0	0	0	#4 FLOOR SCRUBBER	HRDPLANT		
	270,072	7,505	9,551	359,301	0	0	0	0	HART 375 Field Communicator	HRDPLANT		
	270,072	7,505	9,551	359,437	0	0	0	0	Laser Alignment Equipment	HRDPLANT		
	270,072	7,505	9,551	364,779	0	0	0	0	Public Address System	HRDOFFICE		
	270,072	7,505	9,551	99,001,539	0	0	0	0	METAL CUTTING LATHE	HRDOFFICE	FA-003463	
	270,072	7,505	9,551	99,001,548	0	0	0	0	DEADWEIGHT TESTER	HRDPLANT	FA-003429	
	270,072	7,505	9,551	99,001,551	0	0	0	0	DIALARC AC/DC WELDER	HRDPLANT	FA-003461	
	270,072	7,505	9,551	99,001,849	0	0	0	0	1981 35HP JOHNSON OUTBOARD	HRDOFFICE	FA-003062	
	270,072	7,505	9,551	99,001,850	0	0	0	0	1981 PRINCECRAFT JUMBO ALUMINU	HRDOFFICE	FA-003071	
	270,072	7,505	9,551	99,002,059	0	0	0	0	PCB STORAGE CONTAINER AT HOLYR	HRDOFFICE		
	270,072	7,505	9,551	99,004,048	0	0	0	0	DEWDICATOR DELUXE SILCONE CHIP	HRDOFFICE	FA-003124	
	270,072	7,505	9,551	99,004,051	0	0	0	0	RADIUS TAPER GAUGE	HRDOFFICE	FA-01231	
	270,072	7,505	9,551	99,004,075	0	0	0	0	BIDDLE DIGITAL LOW RESISTANCE	HRDOFFICE	FA-003115	
	270,072	7,505	9,551	99,004,246	0	0	0	0	BRUEL & KJAER VIBRATION METER	HRDOFFICE	FA-003123	
	270,072	7,505	9,551	99,004,247	0	0	0	0	PORTABLE ACID DEW POINT METER	HRDOFFICE	FA-003139	
	270,072	7,505	9,551	99,004,249	0	0	0	0	HUNTON DIGITAL LOGIC CHECKER -	HRDOFFICE	FA-003129	
	270,072	7,505	9,551	99,004,260	0	0	0	0	MICROSCANNER "D" SERIES C/W LE	HRDOFFICE	FA-003012	
	270,072	7,505	9,551	99,004,261	0	0	0	0	DRAEGER RZ25 UNIVERSAL TEST SE	HRDOFFICE	FA-01918	
	270,072	7,505	9,551	99,004,264	0	0	0	0	DDT-USD TEST SET	HRDOFFICE	FA-003118	
	270,072	7,505	9,551	99,004,347	0	0	0	0	IRD VIBRATION PICKUP CALIBRATO	HRDOFFICE	FA-4400	
	270,072	7,505	9,551	99,004,703	0	0	0	0	LAPPING TABLE C/W STAND - MODE	HRDOFFICE	FA-01601	
	270,072	7,505	9,551	99,004,704	0	0	0	0	ENERPAC MOBILE HYDRAULIC FLOOR	HRDOFFICE	FA-01844	
	270,072	7,505	9,551	99,004,705	0	0	0	0	SEMI-UNIVERSAL INDEX & STANDAR	HRDOFFICE	FA-01847A	
	270,072	7,505	9,551	99,004,706	0	0	0	0	VERTICAL TURRETT MILLING MACHI	HRDOFFICE	FA-01864	
	270,072	7,505	9,551	99,004,707	0	0	0	0	SHELL MILLING CUTTER C/W SLITT	HRDOFFICE	FA-01847	
	270,072	7,505	9,551	99,004,708	0	0	0	0	FIBERSCOPE C/W CAMERA & OLYMPU	HRDOFFICE	FA-3394	
	270,072	7,505	9,551	99,004,711	0	0	0	0	LOT BOILER ACCESS SCAFFOLDING	HRDOFFICE		
	270,072	7,505	9,551	99,004,711	290,477	0	0	0	SCAFFOLDING	HRDPLANT		
	270,072	7,505	9,551	99,004,712	0	0	0	0	ULTRASONIC CORROSION GAUGE - M	HRDOFFICE	FA-3396	
	270,072	7,505	9,551	99,004,713	0	0	0	0	ELECTRIC WIRE ROPE HOIST - MOD	HRDOFFICE	FA-1844A	
	270,072	7,505	9,551	99,004,714	0	0	0	0	INTEGRATED SOUND LEVEL METERIN	HRDOFFICE	FA-01857	
	270,072	7,505	9,551	99,004,715	0	0	0	0	DIMENSION 400 POWER SOURCE ARC	HRDOFFICE	FA-01602	
	270,072	7,505	9,551	99,004,716	0	0	0	0	17" AUTOMATIC FLOOR SCRUBBER -	HRDOFFICE	FA-01188	
	270,072	7,505	9,551	99,004,719	0	0	0	0	1 1/2 " HYTORQ RATCHET WRENCH	HRDOFFICE	FA-003028	
	270,072	7,505	9,551	99,004,722	0	0	0	0	HIGH PRESSURE WATERWASH SYSTEM	HRDOFFICE	FA-003081	
	270,072	7,505	9,551	99,004,723	0	0	0	0	PORTABLE NOMONOX BREATHING SYS	HRDOFFICE	FA-003079	
	270,072	7,505	9,551	99,004,727	0	0	0	0	GOODWELL FUNCTION GENERATOR -	HRDOFFICE	FA-003127	
	270,072	7,505	9,551	99,004,728	0	0	0	0	TOA AUDIO AMPLIFIER	HRDOFFICE	FA-003140	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,505	9,551	99,004,733	0	0	0	0	SELECT-A-TORQ RATCHET TOOL C/W	HRDOFFICE	FA-02076	
	270,072	7,505	9,551	99,004,734	0	0	0	0	HYDRAULIC CONSOLE MODULE - MOD	HRDOFFICE	FA-02076A	
	270,072	7,505	9,551	99,004,735	0	0	0	0	3 TON CM PULLER - MODEL 640	HRDOFFICE	FA-02989	
	270,072	7,505	9,551	99,004,740	0	0	0	0	WORKSHOP BENCHES C/W HEAVY DUT	HRDOFFICE	FA-003036	
	270,072	7,505	9,551	99,004,749	0	0	0	0	ESS 500 ARC SPEED WELDER SSYTE	HRDOFFICE	FA-003113	
	270,072	7,505	9,551	99,004,750	0	0	0	0	PORTABLE AIR WINCH C/W 150' WI	HRDOFFICE	FA-02077	
	270,072	7,505	9,551	99,004,751	0	0	0	0	SHOP WORK BENCHES W/ 4 DRAWERS	HRDOFFICE	FA-003031	
	270,072	7,505	9,551	99,004,756	0	0	0	0	REUTER STOKES HEAT STRESS MONI	HRDOFFICE	FA-01853	
	270,072	7,505	9,551	99,004,765	0	0	0	0	PELTON CRANE VALIDATOR	HRDOFFICE	FA-01851	
	270,072	7,505	9,551	99,004,766	0	0	0	0	STRESSTEL ULTRASONIC THICKNESS	HRDOFFICE	FA-3395	
	270,072	7,505	9,551	99,004,767	0	0	0	0	DIALARC 250 AC/DC WELDER C/W R	HRDOFFICE	FA-01610	
	270,072	7,505	9,551	99,004,769	0	0	0	0	HILTI HAMMER DRILL C/W CARBIDE	HRDOFFICE	FA-F2289	
	270,072	7,505	9,551	99,004,770	0	0	0	0	CANADIANA 12 HP SNOWBLOWER	HRDOFFICE	FA-003064	
	270,072	7,505	9,551	99,004,772	0	0	0	0	CONNAL LAPPING TOOL	HRDOFFICE	FA-01841	
	270,072	7,505	9,551	99,004,775	0	0	0	0	JANCY MAGNETIC BASE PORTABLE	HRDOFFICE	FA-F2274	
	270,072	7,505	9,551	99,004,776	0	0	0	0	300 AMP ELECTRIC WELDING MACHI	HRDOFFICE	FA-01605	
	270,072	7,505	9,551	99,004,777	0	0	0	0	HILTI ELECTRIC JACKHAMMER - MO	HRDOFFICE	FA-004216	
	270,072	7,505	9,551	99,004,780	0	0	0	0	1/2 TON BUDGIT ELECTRIC CHAIN	HRDOFFICE	FA-01867	
	270,072	7,505	9,551	99,004,781	0	0	0	0	CHECKER BOOM JIB CRANE	HRDOFFICE	FA-01866	
	270,072	7,505	9,551	99,004,782	0	0	0	0	RECORDING RESUCSI ANNE C/W REC	HRDOFFICE	FA-01949	
	270,072	7,505	9,551	99,004,784	0	0	0	0	SURFACE GRINDER C/W ACCESSORIE	HRDOFFICE	FA-01870	
	270,072	7,505	9,551	99,004,785	0	0	0	0	TRANSMATION CALIBRATOR	HRDOFFICE	FA-003144	
	270,072	7,505	9,551	99,004,789	0	0	0	0	12" SINGLE PHASE RADIAL ARM SA	HRDOFFICE	FA-003077	
	270,072	7,505	9,551	99,004,791	0	0	0	0	TEKTRONIX OSCILLOSCOPE C/W ACC	HRDOFFICE	FA-003138	
	270,072	7,505	9,551	99,004,794	0	0	0	0	8' STEEL STANDARD HAND BENDING	HRDOFFICE	FA-003030	
	270,072	7,505	9,551	99,004,796	0	0	0	0	PORTABLE OIL FILTER C/W CARTRI	HRDOFFICE	FA-003015	
	270,072	7,505	9,551	99,004,802	0	0	0	0	TORQUE RATCHET WRENCH & LINK	HRDOFFICE	FA-003029	
	270,072	7,505	9,551	99,004,803	0	0	0	0	HIGH SPEED ELECTRIC POWER PACK	HRDOFFICE	FA-003210	
	270,072	7,505	9,551	99,004,804	0	0	0	0	INSULATOR RESISTANCE TESTER	HRDOFFICE	FA-003117	
	270,072	7,505	9,551	99,004,805	0	0	0	0	FRISKUS FUME EXTRACTOR	HRDOFFICE	FA-003431	
	270,072	7,505	9,551	99,004,806	0	0	0	0	5 TON HOIST HITACHI JET MODEL	HRDOFFICE	FA-02078	
	270,072	7,505	9,551	99,004,807	0	0	0	0	ELECTRIC CHAIN HOIST - MODEL P	HRDOFFICE	FA-01069	
	270,072	7,505	9,551	99,004,809	0	0	0	0	INDUCTION HEATER C/W STANDARD	HRDOFFICE	FA-003114	
	270,072	7,505	9,551	99,018,379	0	0	0	0	10" TABLE SAW	HRDOFFICE	FA-003076	
	270,072	7,505	9,551	99,018,380	0	0	0	0	SHOPMASTER WELDING MACHINE	HRDOFFICE	FA-01607	
	270,072	7,505	9,551	99,018,381	0	0	0	0	SHOPMASTER WELDING MACHINE	HRDOFFICE	FA-003026	
	270,072	7,505	9,551	99,018,382	0	0	0	0	VARIABLE AC POWER SUPPLY	HRDOFFICE	FA-003145	
	270,072	7,505	9,551	99,018,383	0	0	0	0	PRECISION PRESSURE TRANSMITTER	HRDOFFICE	FA-003142	
	270,072	7,505	9,551	99,018,389	0	0	0	0	BAR & TUBE PRINTER KIT	HRDOFFICE	FA-01190	
	270,072	7,505	9,551	99,018,392	0	0	0	0	THERMOPROBE - MODEL TP-3	HRDOFFICE	FA-003013	
	270,072	7,505	9,551	99,018,395	0	0	0	0	IGNITOR TEST BOX	HRDOFFICE	FA-003206	
	270,072	7,505	9,551	99,021,841	0	0	0	0	TOA CHART RECORDER	HRDOFFICE	FA-003141	
	270,072	7,505	9,551	99,021,843	0	0	0	0	HYDROGEN METER - MODEL 380	HRDOFFICE	FA-003130	
	270,072	7,505	9,551	99,021,844	0	0	0	0	DIGITAL PRECISION POWER SUPPLY	HRDOFFICE	FA-003125	
	270,072	7,505	9,551	99,021,846	0	0	0	0	JOFRA OVEN - MODEL 600S	HRDOFFICE	FA-003135	
	270,072	7,505	9,551	99,021,847	0	0	0	0	MICOM 800/2 DATA CONCENTRATOR	HRDOFFICE	FA-003136	

Client: **Newfoundland and Labrador Hydro**
Project: **Holyrood Decommissioning**
Project No: **133545705**

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by: **MDV**
Date: **19-Dec-12**
Revision No.: **0**
Issue Date: **19-Dec-12**
Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,505	9,551	99,021,848	0	0	0	0	BLACK BOX MODEM - MODEL MD935B	HRDOFFICE	FA-003122	
	270,072	7,505	9,551	99,021,849	0	0	0	0	H/P DIGITAL MULTIMETER - MODEL	HRDOFFICE	FA-003128	
	270,072	7,505	9,551	99,021,854	0	0	0	0	PHILLIPS FUNCTION GENERATOR -	HRDOFFICE	FA-003148	
	270,072	7,505	9,551	99,021,856	0	0	0	0	HP POWER SUPPLY - MODEL 6296A	HRDOFFICE	FA-003209	
	270,072	7,505	9,551	99,021,857	0	0	0	0	FURNACE EFFICIENCY UNIT	HRDOFFICE	FA-003146	
	270,072	7,505	9,551	99,023,420	0	0	0	0	HYDROGEN PURITY METER/ANALYZER	HRDOFFICE	FA-003014	
	270,072	7,505	9,551	99,023,421	0	0	0	0	ULTRASONIC METER	HRDOFFICE	FA-003003	
	270,072	7,505	9,551	99,023,422	0	0	0	0	STROBE KIT FOR 890 DATA - MODE	HRDOFFICE	FA-02293	
	270,072	7,505	9,551	99,023,424	0	0	0	0	1 1/2" AIR IMPACT WRENCH	HRDOFFICE	FA-003027A	
	270,072	7,505	9,551	99,023,425	0	0	0	0	FRISKUS PORTABLE EXHAUST FAN	HRDOFFICE		
	270,072	7,505	9,551	99,023,426	0	0	0	0	FRISKUS PORTABLE EXHAUST FAN	HRDOFFICE		
	270,072	7,505	9,551	99,023,430	0	0	0	0	DC ADJUSTABLE POWER SUPPLY	HRDOFFICE	FA-003149	
	270,072	7,505	9,551	99,023,431	0	0	0	0	SCOPEMETER MODEL FLUKE97	HRDOFFICE	FA-003208	
	270,072	7,505	9,551	99,023,432	0	0	0	0	HIPOTRONICS INSULATION RESISTA	HRDOFFICE	FA-003116	
	270,072	7,505	9,551	99,023,669	0	0	0	0	GILLIBRATOR TOP LOADING VARIAB	HRDOFFICE	FA-03299	
	270,072	7,505	9,551	99,024,430	0	0	0	0	WDPF CRIMPING TOOL FOR COAXIAL	HRDOFFICE	FA-003204	
	270,072	7,505	9,551	99,026,212	0	0	0	0	PORTABLE FLOOR CRANE MODEL #42	HRDOFFICE	FA-003119	
	270,072	7,505	9,551	99,026,871	0	0	0	0	HEAVY DUTY SELF DUMPING HOPPER	HRDOFFICE	FA-003069	
	270,072	7,505	9,551	99,026,874	0	0	0	0	SECTIONAL SCAFFOLDING FOR BOIL	HRDOFFICE		
	270,072	7,505	9,551	99,026,875	0	0	0	0	MENTOR DYNAMIC JIB CRANE C/W E	HRDOFFICE	FA-03428	
	270,072	7,505	9,551	99,028,546	0	0	0	0	4000 LB AIR WINCH TUGGER	HRDOFFICE	FA-03427	
	270,072	7,505	9,551	99,028,556	0	0	0	0	GOLDSTAR WELDING MACHINE	HRDOFFICE	FA-4259	
	270,072	7,505	9,551	99,028,559	0	0	0	0	FILTERCART VENT CART	HRDOFFICE	FA-03486	
	270,072	7,505	9,551	99,028,642	0	0	0	0	PORTABLE DRUM UNLOADING PUMP	HRDOFFICE	FA-03465	
	270,072	7,505	9,551	99,030,071	0	0	0	0	AERIAL WORK PLATFORM	HRDOFFICE	FA-03425	
	270,072	7,505	9,551	99,030,073	0	0	0	0	WARFUM TUR-630A/120 METAL LATH	HRDOFFICE	FA-001849	
	270,072	7,505	9,551	99,030,077	0	0	0	0	PORTABLE PRESSURE INDICATOR	HRDOFFICE	FA-4016	
	270,072	7,505	9,551	99,030,395	0	0	0	0	FIBERSCOPE C/W CAMERA OLYMPUS	HRDOFFICE	FA-3393	
	270,072	7,505	9,551	99,030,396	0	0	0	0	WDFP CRIMPING TOOL FOR COAXIAL	HRDOFFICE	FA-003203	
	270,072	7,505	9,551	99,030,397	0	0	0	0	WDFP CRIMPING TOOL FOR COAXIAL	HRDOFFICE	FA-03202	
	270,072	7,505	9,551	99,032,080	0	0	0	0	KUBOTA DUMP CART, CATCHER,	HRDOFFICE	FA-003073A	
	270,072	7,505	9,551	99,032,817	0	0	0	0	DECADE BOX	HRDOFFICE	FA-003430	
	270,072	7,505	9,551	99,032,818	0	0	0	0	PRESSURE CALIBRATOR	HRDOFFICE	FA-4278	
	270,072	7,505	9,551	99,032,821	0	0	0	0	TOOL & EQUIPMENT STORAGE	HRDOFFICE		
	270,072	7,505	9,551	99,032,822	0	0	0	0	TOOL & EQUIPMENT STORAGE	HRDOFFICE		
	270,072	7,505	9,551	99,032,823	0	0	0	0	ENCORE AUTO FLOOR SCRUBBER	HRDOFFICE		
	270,072	7,505	9,551	99,032,824	0	0	0	0	ABRASIVE BLASTER	HRDOFFICE	FA-03365	
	270,072	7,505	9,551	99,034,046	0	0	0	0	Olympus Videoscope System	HRDOFFICE	FA-4411	
	270,072	7,505	9,551	99,034,625	0	0	0	0	LASER ALIGNMENT KIT:CSI ULTRA	HRDOFFICE	FA-003367	
	270,072	7,505	9,551	99,034,638	0	0	0	0	STEEL DUMPSTERS	HRDPLANT		
	270,072	7,505	9,551	99,034,647	0	0	0	0	OIL PRESSURE TEST PUMP	HRDOFFICE	FA-003366	
	270,072	7,505	9,551	99,035,122	0	0	0	0	Graphic Sign Maker General	HRDPLANT	FA-003183	
	270,072	7,505	9,551	99,035,712	0	0	0	0	Impact Wrench 1 1/2' Drive	HRDPLANT	FA-5242	
	270,072	7,505	9,551	99,035,713	0	0	0	0	Diesel Engine Driven Welder	HRDPLANT	FA-001604	
	270,072	7,505	9,551	99,035,751	0	0	0	0	MK5 Gas Detector Monitor	HRDPLANT	FA-003420	
	270,072	7,505	9,551	99,035,752	0	0	0	0	MK5 Gas Detector Monitor	HRDPLANT	FA-003421	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,505	9,551	99,035,780	0	0	0	0	Mikata Electric Jackhammer	HRDPLANT	FA-05245	
	270,072	7,505	9,551	99,035,785	0	0	0	0	Air Impact Socket Set 1 1/2"	HRDPLANT	FA-4424	
	270,072	7,505	9,551	99,036,388	0	0	0	0	Battery Test Device	HRDOFFICE	FA-003466	
	270,072	7,505	9,551	99,036,389	0	0	0	0	Portable Hydraulic Calibrator	HRDOFFICE		
	270,072	7,505	9,551	99,036,393	0	0	0	0	AIRBORNE CONTAMINANTS	HRDOFFICE	FA-003419	
	270,072	7,505	9,551	99,036,394	0	0	0	0	Pipe Bevelling tool Climax	HRDOFFICE	FA-5244	
	270,072	7,505	9,551	99,036,954	0	0	0	0	OIL CONTAINMENT BOOM VERSATECH	HRDPLANT		
	270,072	7,505	9,551	99,037,530	0	0	0	0	Portable Pipe Threader	HRDPLANT		
	270,072	7,505	9,551	99,037,531	0	0	0	0	Relay Test Set Model	HRDPLANT	FA-003467	
	270,072	7,505	9,551	99,037,533	0	0	0	0	COBRASAW Vertical BAnd Saw	HRDPLANT		
	270,072	7,505	9,551	99,037,624	0	0	0	0	Battery Ground Fault Locator	HRDOFFICE	FA-5205	
	270,072	7,505	9,551	99,037,629	0	0	0	0	Replace PH Meter	HRDOFFICE		
	270,072	7,505	9,551	99,038,629	0	0	0	0	HandHels Scaner & Communicator	HRDPLANT	FA-5333	
	270,072	7,505	9,551	99,039,176	0	0	0	0	TRANSMATION CALIBRATOR - MODEL	HRDOFFICE	FA-003143	
	270,072	7,505	9,551	99,039,177	0	0	0	0	LAMBDA POWER SUPPLY	HRDOFFICE	FA-003147	
	270,072	7,505	9,551	99,039,545	0	0	0	0	DEFIBRILLATOR HSFR2 W/CASE	HRDPLANT		
	270,072	7,505	9,551	99,039,949	0	0	0	0	Floor Model Drill Press	HRDPLANT		
	270,072	7,505	9,551	99,040,813	0	0	0	0	INTEGRATED SOUND LEVEL	HRDOFFICE	FA-003357	
	270,072	7,505	9,551	99,040,814	0	0	0	0	INTEGRATED SOUND LEVEL	HRDOFFICE	FA-01858	
	270,072	7,505	9,551	99,040,827	0	0	0	0	Waste Dumpsters	HRDOFFICE		
	270,072	7,505	9,551	99,040,828	0	0	0	0	Waste Dumpsters	HRDOFFICE		
	270,072	7,505	9,551	99,040,861	0	0	0	0	FLOODLIGHT 150 W INCANDESCENT	HRDPLANT		
	270,072	7,505	9,551	99,040,862	0	0	0	0	FLOODLIGHT 150 W INCANDESCENT	HRDPLANT		
	270,072	7,505	9,551	99,041,355	0	0	0	0	3M MULTIMEDIA PROJECTOR	HRDOFFICE		
	270,072	7,505	9,551	99,041,374	0	0	0	0	Conductivity Digital Myron	HRDOFFICE		
	270,072	7,505	9,551	99,041,375	0	0	0	0	Conductivity Digital Myron	HRDOFFICE		
	270,072	7,505	9,551	99,041,376	0	0	0	0	Flourtube Disposal	HRDOFFICE		
	270,072	7,505	9,551	99,041,379	0	0	0	0	Emergency Response Equipment	HRDPLANT		
	270,072	7,505	257,678	0	0	0	0	0	BOTTLED WATER	HRDOFFICE		
	270,072	7,505	271,851	0	0	0	0	0	HRD VEHICLES & MOBILE EQUIPMT	HRDPLANT	HRD98355001	
	270,072	7,505	271,851	42,316	0	0	0	0	Retired V9786,88 FORKLIFT	BIFAUCTION	V9786R	
	270,072	7,505	271,851	166,415	0	0	0	0	V9813,99 CAT 416C FEL BACK-HOE	HRDOFFICE	V9813	
	270,072	7,505	271,851	244,397	0	0	0	0	Retired V2555, 00 DODGE 15 PAX	BIFAUCTION	V2555R	
	270,072	7,505	271,851	254,097	0	0	0	0	V9822,01 CAT FRKLIFT MDL 3P30K	HRDOFFICE	V9822	
	270,072	7,505	271,851	293,432	0	0	0	0	Retired V7025,05 KAWASAKI MULE	HRDOFFICE	V7025R	
	270,072	7,505	271,851	317,951	0	0	0	0	V2638, 08 DODGE DAKOTA	HRDOFFICE	V2638	
	270,072	7,505	271,852	0	0	0	0	0	HRD OFFICE EQUIPMENT	HRDPLANT	HRD98351201	
	270,072	7,505	271,852	325,086	0	0	0	0	Fitness Equipment	HRDPLANT		
	270,072	7,505	271,852	325,087	0	0	0	0	Fitness Equipment	HRDPLANT		
	270,072	7,505	271,852	99,001,340	0	0	0	0	OFFICE SAFE - SENTRY 6330	HRDOFFICE	FA-01275	
	270,072	7,505	271,852	99,002,419	0	0	0	0	3M OVERHEAD PROJECTOR - MODEL	HRDOFFICE	FA-01717	
	270,072	7,505	271,852	99,002,460	0	0	0	0	CANON NP2020 PHOTOCOPIER	HRDOFFICE	FA-01326	
	270,072	7,505	271,852	99,004,736	0	0	0	0	GARDEX FIREPFOOF RECORDS SAFE	HRDOFFICE	FA-01274	
	270,072	7,505	271,852	99,039,952	0	0	0	0	Modular Furniture	HRDOFFICE		
	270,072	7,505	288,300	0	0	0	0	0	HRD OPERATIONS TOOLS & EQUIP	HRDPLANT		
	270,072	7,505	288,300	288,384	0	0	0	0	EASI DRIVE	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,505	288,300	305,708	0	0	0	0	Arc Flash Suits, Category 4	HRDPLANT		
	270,072	7,505	288,300	305,709	0	0	0	0	Remote Racking Device	HRDPLANT		
	270,072	7,505	288,300	99,034,231	0	0	0	0	OIL STORAGE TANKS	HRDPLANT		
	270,072	7,505	357,725	0	0	0	0	0	LTAP DEPT TOOLS AND EQUIPMENT	HRDPLANT		
	270,072	7,505	357,725	359,208	0	0	0	0	Canon iPF710 Plotter	HRDOFFICE		
	270,072	7,505	359,459	0	0	0	0	0	Speed Scrub 32" Autoscrubber	HRDPLANT		
	270,072	7,505	359,461	0	0	0	0	0	Vibration Data Collector	HRDPLANT		
	270,072	7,505	359,467	0	0	0	0	0	Tools And Equipement	HRDPLANT		
	270,072	7,505	362,198	0	0	0	0	0	Fume Extractor	HRDPLANT		
	270,072	7,505	99,023,660	0	0	0	0	0	PORTABLE HAND HELD COLORIMETER	HRDPLANT		
	270,072	7,505	99,023,662	0	0	0	0	0	FISHER SCIENTIFIC ISOTEMP OVEN	HRDPLANT	FA-003445	
400												
	270,072	7,635	0	0	0	0	0	0	UNIT 2	HRDUNIT2	HRD20000000	
	270,072	7,635	7,636	0	0	0	0	0	#2 TURBINE & GENERATOR	HRDUNIT2	HRD21000000	
	270,072	7,635	7,636	7,664	0	0	0	0	#2 TURBINE CONDENSER SYSTEM	HRDUNIT2	HRD21160000	
	270,072	7,635	7,636	7,664	7,694	0	0	0	#2 CONDENSER AIR EXTRACTION	HRDUNIT2	HRD21340000	
	270,072	7,635	7,636	7,664	7,694	8,884	0	0	#2 CONDENSER AIR VAC P/P NORTH	HRDUNIT2	HRD21343030	
	270,072	7,635	7,636	7,664	7,694	8,891	0	0	#2 CONDENSER AIR VAC P/P SOUTH	HRDUNIT2	HRD21343031	
	270,072	7,635	7,636	7,664	271,326	0	0	0	#2 TURBINE CONDENSER	HRDUNIT2	HRD21160001	
	270,072	7,635	7,636	7,664	322,987	0	0	0	U2 Condenser Actuators	HRDUNIT3		
	270,072	7,635	7,636	7,699	0	0	0	0	#2 TURBINE DRAINS SYSTEMS	HRDUNIT2	HRD21350000	
	270,072	7,635	7,636	7,753	0	0	0	0	U2 GENERATOR	HRDUNIT2	HRD21500000	
	270,072	7,635	7,636	7,753	7,754	0	0	0	#2 GENERATOR ROTOR	HRDUNIT2	HRD21510000	
	270,072	7,635	7,636	7,753	7,754	7,755	0	0	#2GENERATOR ROTOR SLIP RINGS &	HRDUNIT2	HRD21514000	
	270,072	7,635	7,636	7,753	7,759	0	0	0	#2 GENERATOR STATOR	HRDUNIT2	HRD21520000	
	270,072	7,635	7,636	7,753	7,759	7,763	0	0	#2 GEN STANDOFF INSULATORS	HRDUNIT2	HRD21531000	
	270,072	7,635	7,636	7,753	7,759	7,765	0	0	#2 GENERATOR P.T. CUBICLE	HRDUNIT2	HRD21593000	
	270,072	7,635	7,636	7,753	7,759	324,690	0	0	#2 GENERATOR STATOR RELAY	HRDUNIT2		
	270,072	7,635	7,636	7,753	7,759	99,003,560	0	0	REMOVE PCB XFRMER & INSTALL NE	HRDPLANT		
	270,072	7,635	7,636	7,753	7,768	0	0	0	#2 GEN HYDROGEN GAS SYSTEM	HRDUNIT2	HRD21620000	
	270,072	7,635	7,636	7,753	7,768	7,732	0	0	#2 GENERATOR SEAL OIL SYSTEM	HRDUNIT2	HRD21450000	
	270,072	7,635	7,636	7,753	7,768	7,732	9,626	0	#2 TURB AC SEAL OIL PUMP EAST	HRDUNIT2	HRD21451010	
	270,072	7,635	7,636	7,753	7,768	7,732	9,628	0	#2 GEN AC SEAL OIL PUMP WEST	HRDUNIT2	HRD21451020	
	270,072	7,635	7,636	7,753	7,768	7,732	9,630	0	#2 GEN DC SEAL OIL PUMP	HRDUNIT2	HRD21452010	
	270,072	7,635	7,636	7,753	7,768	7,732	9,632	0	#2 GEN SEAL OIL VACUUM PUMP	HRDUNIT2	HRD21454010	
	270,072	7,635	7,636	7,753	7,768	7,773	0	0	#2 GEN CO2 GAS PURGE SYSTEM	HRDUNIT2	HRD21630000	
	270,072	7,635	7,636	7,753	7,768	7,776	0	0	#2 GENER COMPRESSED AIR PURGE	HRDUNIT2	HRD21640000	
	270,072	7,635	7,636	7,753	7,768	7,777	0	0	#2 GENERATOR HYDROGEN COOLING	HRDUNIT2	HRD21650000	
	270,072	7,635	7,636	7,753	99,034,724	0	0	0	PARTIAL DISCHARGE ANALYSIS SYS	HRDPLANT		
	270,072	7,635	7,636	7,753	99,043,191	0	0	0	ADDITIONAL COSTS FOR BALAN	HRDPLANT		
	270,072	7,635	7,636	7,767	0	0	0	0	#2 GENERATOR EXCITATION SYSTEM	HRDUNIT2	HRD21610000	
	270,072	7,635	7,636	7,767	271,322	0	0	0	#2 EXCITER	HRDUNIT2	HRD21610001	
	270,072	7,635	7,636	7,767	271,322	99,036,228	0	0	Exciter Unit #2	HRDPLANT		
	270,072	7,635	7,636	7,767	271,324	0	0	0	#2 EXCITATION TRANSFORMER	HRDUNIT2	HRD21610002	
	270,072	7,635	7,636	7,767	271,325	0	0	0	#2 EXCITER FIELD BREAKER	HRDUNIT2	HRD21610003	
	270,072	7,635	7,636	271,317	0	0	0	0	#2 TURBINE	HRDUNIT2	HRD21000001	

Client:	Newfoundland and Labrador Hydro
Project:	Holyrood Decommissioning
Project No:	133545705

Stantec

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by:	**MDV**
Date:	**19-Dec-12**
Revision No.:	**0**
Issue Date:	**19-Dec-12**
Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,635	7,636	271,317	7,638	0	0	0	#2 TURBINE MAIN STEAM CHEST	HRDUNIT2	HRD21110000	
	270,072	7,635	7,636	271,317	7,643	0	0	0	#2 H.P. TURBINE	HRDUNIT2	HRD21120000	
	270,072	7,635	7,636	271,317	7,647	0	0	0	#2 TURB REHEAT/IP STEAM CHEST	HRDUNIT2	HRD21130000	
	270,072	7,635	7,636	271,317	7,652	0	0	0	#2 I.P. TURBINE	HRDUNIT2	HRD21140000	
	270,072	7,635	7,636	271,317	7,658	0	0	0	#2 L.P. TURBINE	HRDUNIT2	HRD21150000	
	270,072	7,635	7,636	271,317	7,671	0	0	0	#2 TURBINE FRONT STANDARD	HRDUNIT2	HRD21170000	
	270,072	7,635	7,636	271,317	7,686	0	0	0	#2 TURBINE GLAND STEAM SYSTEM	HRDUNIT2	HRD21310000	
	270,072	7,635	7,636	271,317	7,690	0	0	0	#2 TURBINE PRE-WARMING SYSTEM	HRDUNIT2	HRD21320000	
	270,072	7,635	7,636	271,317	7,692	0	0	0	#2 TURBINE TURNING GEAR	HRDUNIT2	HRD21330000	
	270,072	7,635	7,636	271,317	7,711	0	0	0	#2 TURBINE OIL SYSTEMS	HRDUNIT2	HRD21400000	
	270,072	7,635	7,636	271,317	7,711	7,719	0	0	#2 TURBINE LUBE OIL SYSTEM	HRDUNIT2	HRD21430000	
	270,072	7,635	7,636	271,317	7,711	7,719	7,712	0	#2 TURB LUBE OIL TANK & EQUIP	HRDUNIT2	HRD21410000	
	270,072	7,635	7,636	271,317	7,711	7,719	7,715	0	#2 TURB LUBE OIL PURIFICATION	HRDUNIT2	HRD21420000	
	270,072	7,635	7,636	271,317	7,711	7,719	7,715	99,039,097	Duplex Filter for Lube oil	HRDPLANT		
	270,072	7,635	7,636	271,317	7,711	7,719	7,720	0	#2 TURB LUBE A.C. OIL P/P NORT	HRDUNIT2	HRD21431130	
	270,072	7,635	7,636	271,317	7,711	7,719	7,721	0	#2 TURB LUBE A.C. OIL P/P SOUT	HRDUNIT2	HRD21431131	
	270,072	7,635	7,636	271,317	7,711	7,719	7,725	0	#2 TURBINE LUBE D.C. PUMP	HRDUNIT2	HRD21432100	
	270,072	7,635	7,636	271,317	7,711	7,741	0	0	#2TURBINE HYDRAULIC OIL SYSTEM	HRDUNIT2	HRD21470000	
	270,072	7,635	7,636	271,317	7,711	7,741	7,743	0	#2 TURBINE HYD. OIL PUMP NORTH	HRDUNIT2	HRD21472130	
	270,072	7,635	7,636	271,317	7,711	7,741	7,744	0	#2 TURBINE HYD. OIL PUMP SOUTH	HRDUNIT2	HRD21472131	
	270,072	7,635	7,636	271,317	7,711	7,741	273,263	0	U2 NORTH EHC ACCUMULATOR	HRDUNIT2	HRD21200005	
	270,072	7,635	7,636	271,317	7,711	7,741	273,265	0	U2 SOUTH EHC ACCUMULATOR	HRDUNIT2	HRD21200006	
	270,072	7,635	7,636	271,317	271,319	0	0	0	#2 TURBINE BLED STEAM SYSTEM	HRDUNIT2	HRD21000002	
	270,072	7,635	7,636	271,317	334,451	0	0	0	#2 TURBINE DRAINS SYSTEMS	HRDUNIT2		
	270,072	7,635	7,636	271,317	99,043,190	0	0	0	INSTALL TURBINE PARTS & WI	HRDPLANT		
300												
	270,072	7,635	7,786	0	0	0	0	0	#2 BOILER PLANT	HRDUNIT2	HRD22000000	
	270,072	7,635	7,786	7,787	0	0	0	0	#2 BOILER STRUCTURE	HRDUNIT2	HRD22100000	
	270,072	7,635	7,786	7,787	99,029,563	0	0	0	OBSERVATION PORT IN THE BURNER	HRDPLANT		
	270,072	7,635	7,786	7,787	99,043,174	0	0	0	INSTALL STEAM GENERATOR FO	HRDPLANT		
	270,072	7,635	7,786	7,787	99,043,175	0	0	0	ADDITIONAL COSTS FOR STEAM	HRDPLANT		
	270,072	7,635	7,786	7,789	0	0	0	0	#2 BOILER FW & SAT'D STEAM SYS	HRDUNIT2	HRD22200000	
	270,072	7,635	7,786	7,789	7,790	0	0	0	#2 BOILER ECONOMIZER	HRDUNIT2	HRD22210000	
	270,072	7,635	7,786	7,789	7,794	0	0	0	#2 BOILER STEAM DRUM	HRDUNIT2	HRD22220000	
	270,072	7,635	7,786	7,789	7,794	99,023,642	0	0	DRUM LEVEL MONITORING - UNIT 2	HRDPLANT		
	270,072	7,635	7,786	7,789	7,801	0	0	0	#2 FURNACE	HRDUNIT2	HRD22240000	
	270,072	7,635	7,786	7,789	7,806	0	0	0	#2 BOILER FILLING AND DRAINING	HRDUNIT2	HRD22260000	
	270,072	7,635	7,786	7,789	7,806	7,945	0	0	#2 BLR BLOW DWN DRAINS&LP PIPE	HRDUNIT2	HRD22700000	
	270,072	7,635	7,786	7,789	7,806	7,945	7,946	0	#2 BOILER CONTINUOUS BLOWDOWN	HRDUNIT2	HRD22710000	
	270,072	7,635	7,786	7,789	7,806	7,945	359,346	0	UNIT 2 BOILER BLOWDOWN TANK	HRDUNIT2		
	270,072	7,635	7,786	7,810	0	0	0	0	#2 BOILER SUPERHEATER & REHEAT	HRDUNIT2	HRD22300000	
	270,072	7,635	7,786	7,810	7,811	0	0	0	#2 BOILER PRIMARY SUPERHEATER	HRDUNIT2	HRD22310000	
	270,072	7,635	7,786	7,810	7,813	0	0	0	#2 BOILER SUPERHEATER ATTEMP'R	HRDUNIT2	HRD22320000	
	270,072	7,635	7,786	7,810	7,823	0	0	0	#2 BOILER MAIN STEAM LINES	HRDUNIT2	HRD22340000	
	270,072	7,635	7,786	7,810	7,823	322,451	0	0	#2 Boiler Stop Valve	HRDUNIT2		
	270,072	7,635	7,786	7,810	7,830	0	0	0	#2BOILER REHEATER ATTEMPERATOR	HRDUNIT2	HRD22350000	

Client: **Newfoundland and Labrador Hydro**
Project: **Holyrood Decommissioning**
Project No: **133545705**

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by: **MDV**
Date: **19-Dec-12**
Revision No.: **0**
Issue Date: **19-Dec-12**
Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,635	7,786	7,810	7,835	0	0	0	#2 BOILER REHEATER	HRDUNIT2	HRD22360000	
	270,072	7,635	7,786	7,810	309,158	0	0	0	#2 Blr Sec. Superhtr upgrade	HRDUNIT2		
	270,072	7,635	7,786	7,838	0	0	0	0	#2 BOILER AIR SYSTEM	HRDUNIT2	HRD22400000	
	270,072	7,635	7,786	7,838	7,879	0	0	0	#2 BLR AIR SUPPLY (A/H TO WIND	HRDUNIT2	HRD22440000	
	270,072	7,635	7,786	7,838	7,879	7,882	0	0	#2 BLR AIR SUPPLY SEAL AIR FAN	HRDUNIT2	HRD22443000	
	270,072	7,635	7,786	7,838	7,879	7,885	0	0	#2 BOILER SCANNER AIR	HRDUNIT2	HRD22446000	
	270,072	7,635	7,786	7,838	7,886	0	0	0	#2 BOILER WINDBOX	HRDUNIT2	HRD22450000	
	270,072	7,635	7,786	7,838	8,781	0	0	0	#2 BOILER F.D. FAN ASSEMBLY	HRDUNIT2	HRD22410000	
	270,072	7,635	7,786	7,838	8,781	7,843	0	0	#2 BOILER F.D. FAN EAST	HRDUNIT2	HRD22413032	
	270,072	7,635	7,786	7,838	8,781	7,844	0	0	#2 BOILER F.D. FAN WEST	HRDUNIT2	HRD22413033	
	270,072	7,635	7,786	7,838	8,785	0	0	0	#2 BOILER STEAM AIR HEATER	HRDUNIT2	HRD22420000	
	270,072	7,635	7,786	7,838	8,785	7,855	0	0	#2BOILER STEAM AIR HEATER EAST	HRDUNIT2	HRD22423032	
	270,072	7,635	7,786	7,838	8,785	7,856	0	0	#2BOILER STEAM AIR HEATER WEST	HRDUNIT2	HRD22423033	
	270,072	7,635	7,786	7,838	8,785	359,352	0	0	Steam Preheater Flash Tank	HRDUNIT2		
	270,072	7,635	7,786	7,838	8,786	0	0	0	#2 BOILER MAIN AIR HEATER	HRDUNIT2	HRD22430000	
	270,072	7,635	7,786	7,838	8,786	7,863	0	0	#2 BOILER MAIN AIR HEATER EAST	HRDUNIT2	HRD22430032	
	270,072	7,635	7,786	7,838	8,786	7,863	331,941	0	U2 APHE HOT END BRG SEAL COVER	HRDUNIT2		
	270,072	7,635	7,786	7,838	8,786	7,863	331,943	0	U2 APHE COLD END REPAIRS	HRDUNIT2		
	270,072	7,635	7,786	7,838	8,786	7,864	0	0	#2 BOILER MAIN AIR HEATER WEST	HRDUNIT2	HRD22430033	
	270,072	7,635	7,786	7,838	8,786	7,864	331,942	0	U2 APHW HOT END BRG SEAL COVER	HRDUNIT2		
	270,072	7,635	7,786	7,838	8,786	7,864	331,944	0	U2 APHW COLD END REPAIRS	HRDUNIT2		
	270,072	7,635	7,786	7,838	99,000,149	0	0	0	INSTALL SCANNER AIR FILTERS ON	HRDPLANT		
	270,072	7,635	7,786	7,838	99,034,284	0	0	0	COMBUSTION AIR HEATING SYSTEM	HRDPLANT		
	270,072	7,635	7,786	7,890	0	0	0	0	#2 BOILER GAS SYSTEM	HRDUNIT2	HRD22500000	
	270,072	7,635	7,786	7,890	7,891	0	0	0	#2 BOILER GAS PASSES	HRDUNIT2	HRD22510000	
	270,072	7,635	7,786	7,890	7,900	0	0	0	#2 BOILER STACK	HRDUNIT2	HRD22570000	
	270,072	7,635	7,786	7,890	7,900	271,327	0	0	#2 STACK BREECHING	HRDUNIT2	HRD22570001	
	270,072	7,635	7,786	7,890	7,900	271,327	359,207	0	HRD U2 STACK BREECHING STUDY	HRDUNIT2		
	270,072	7,635	7,786	7,890	7,900	299,552	0	0	Boiler Stack Liner Unit 2	HRDPLANT		
	270,072	7,635	7,786	7,890	7,904	0	0	0	#2 BOILER SOOTBLOWING SYSTEM	HRDUNIT2	HRD22580000	
	270,072	7,635	7,786	7,890	7,904	7,907	0	0	#2 BOILER RETRACTABLE S/B'S	HRDUNIT2	HRD22583000	
	270,072	7,635	7,786	7,890	7,904	7,908	0	0	#2 BOILER ROTARY SOOTBLOWERS	HRDUNIT2	HRD22584000	
	270,072	7,635	7,786	7,890	7,904	8,790	0	0	#2 BOILER AIR HEATER S/B'S	HRDUNIT2	HRD22585000	
	270,072	7,635	7,786	7,912	0	0	0	0	#2 BOILER FUEL FIRING SYSTEM	HRDUNIT2	HRD22600000	
	270,072	7,635	7,786	7,912	7,913	0	0	0	#2 BOILER HEAVY OIL SYSTEM	HRDUNIT2	HRD22610000	
	270,072	7,635	7,786	7,912	7,913	7,582	0	0	#2 BOILER HEAVY OIL FIRING	HRDUNIT2	HRD22620000	
	270,072	7,635	7,786	7,912	7,913	7,916	0	0	#2 BOILER HEAVY OIL PUMP EAST	HRDUNIT2	HRD22613032	
	270,072	7,635	7,786	7,912	7,913	7,917	0	0	#2 BOILER HEAVY OIL PUMP WEST	HRDUNIT2	HRD22613033	
	270,072	7,635	7,786	7,912	7,913	7,920	0	0	U2 BLR HVY OIL STM V/V & PIPE	HRDUNIT2	HRD22617000	
	270,072	7,635	7,786	7,912	7,913	7,921	0	0	U2 FUEL OIL ACCUMULATOR	HRDUNIT2	HRD22618000	
	270,072	7,635	7,786	7,912	7,935	0	0	0	#2 BOILER LIGHT OIL	HRDUNIT2	HRD22640000	
	270,072	7,635	7,786	7,912	7,935	7,933	0	0	#2 BOILER LIGHT OIL FIRING	HRDUNIT2	HRD22630000	
	270,072	7,635	7,786	7,912	7,935	8,980	0	0	#2 BOILER LIGHT OIL PUMP EAST	HRDUNIT2	HRD22643032	
	270,072	7,635	7,786	7,912	7,935	8,981	0	0	#2 BOILER LIGHT OIL PUMP WEST	HRDUNIT2	HRD22643033	
	270,072	7,635	7,786	7,912	99,000,171	0	0	0	INSTALL LIGHT OIL SYSTEM UNIT	HRDPLANT		
	270,072	7,635	7,786	7,953	0	0	0	0	#2 BLR AUX STEAM & CONDENSATE	HRDUNIT2	HRD22800000	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,635	7,786	7,953	7,954	0	0	0	#2 BOILER AUX. STEAM MAIN	HRDUNIT2	HRD22810000	
	270,072	7,635	7,786	7,953	7,960	0	0	0	#2 BOILER AUXILIARY STEAM	HRDUNIT2	HRD22820000	
	270,072	7,635	7,786	7,953	7,968	0	0	0	#2 BOILER ATOMIZING STEAM	HRDUNIT2	HRD22830000	
	270,072	7,635	7,786	7,953	8,803	0	0	0	#2 AUXSTEAM CONDENSATE & P/P'S	HRDUNIT2	HRD23155000	
	270,072	7,635	7,978	0	0	0	0	0	#2 CONDENSATE & F.W. SYSTEM	HRDUNIT2	HRD23000000	
	270,072	7,635	7,978	7,980	0	0	0	0	#2 CONDENSATE MAKE UP SYSTEM	HRDUNIT2	HRD23110000	
	270,072	7,635	7,978	7,992	0	0	0	0	#2 L P FEEDWATER SYSTEM	HRDUNIT2	HRD23200000	
	270,072	7,635	7,978	7,992	7,997	0	0	0	#2 LOW PRESSURE HEATER 1	HRDUNIT2	HRD23213001	
	270,072	7,635	7,978	7,992	7,998	0	0	0	#2 LOW PRESSURE HEATER 2	HRDUNIT2	HRD23213002	
	270,072	7,635	7,978	7,992	7,998	99,000,218	0	0	REPLACEMENT OF TUBE BUNDLE IN	HRDPLANT		
	270,072	7,635	7,978	7,992	7,998	99,003,556	0	0	ADD'L COST TO ADD REDUCERS TO	HRDPLANT		
	270,072	7,635	7,978	7,992	8,017	0	0	0	#2 DEAERATOR SYSTEM	HRDUNIT2	HRD23250000	
	270,072	7,635	7,978	7,992	8,032	0	0	0	#2 RESERVE FW SYSTEM	HRDUNIT2	HRD23270000	
	270,072	7,635	7,978	7,992	8,032	99,031,611	0	0	TURBINE FLOW METER WITH VALVES	HRDPLANT		
	270,072	7,635	7,978	7,992	8,032	99,043,176	0	0	INSTALL MATERIAL FOR THE R	HRDPLANT		
	270,072	7,635	7,978	7,992	8,807	0	0	0	#2 LOW PRESSURE HTR DRAIN P/PS	HRDUNIT2	HRD23220000	
	270,072	7,635	7,978	7,992	99,043,177	0	0	0	BAL LOW PRESSURE FEED SYST	HRDPLANT		
	270,072	7,635	7,978	7,992	99,043,178	0	0	0	INSTALL BALANCE OF LOW PRE	HRDPLANT		
	270,072	7,635	7,978	8,037	0	0	0	0	#2 BOILER FEEDWATER PUMPING	HRDUNIT2	HRD23300000	
	270,072	7,635	7,978	8,037	8,847	0	0	0	#2 BOILER FEED PUMP WEST	HRDUNIT2	HRD23310033	
	270,072	7,635	7,978	8,037	8,847	8,039	0	0	#2 BOILER FEEDPUMP RECIRC.WEST	HRDUNIT2	HRD23320033	
	270,072	7,635	7,978	8,037	8,847	8,051	0	0	#2 BLR FW PUMP LUBE OIL WEST	HRDUNIT2	HRD23340033	
	270,072	7,635	7,978	8,037	8,847	99,000,242	0	0	INSTALL VIBRATON MONITORING EQ	HRDPLANT		
	270,072	7,635	7,978	8,037	8,847	99,043,183	0	0	MODIFY AND INSTALL BOILER	HRDPLANT		
	270,072	7,635	7,978	8,037	8,847	99,043,189	0	0	PURCHASE 1 INNER CASE BARR	HRDPLANT		
	270,072	7,635	7,978	8,037	8,848	0	0	0	#2 BOILER FEED PUMP EAST	HRDUNIT2	HRD23310032	
	270,072	7,635	7,978	8,037	8,848	8,038	0	0	#2 BOILER FEEDPUMP RECIRC.EAST	HRDUNIT2	HRD23320032	
	270,072	7,635	7,978	8,037	8,848	8,050	0	0	#2 BLR FW PUMP LUBE OIL EAST	HRDUNIT2	HRD23340032	
	270,072	7,635	7,978	8,037	8,848	99,000,241	0	0	INSTALL VIBRATION MONITORING E	HRDPLANT		
	270,072	7,635	7,978	8,037	8,848	99,043,182	0	0	MODIFY AND INSTALL BOILER	HRDPLANT		
	270,072	7,635	7,978	8,037	8,848	99,043,188	0	0	PURCHASE 1 INNER CASE BARR	HRDPLANT		
	270,072	7,635	7,978	8,037	9,639	0	0	0	#2 BFP COM GLAND SEALWATER INJ	HRDUNIT2	HRD23361000	
	270,072	7,635	7,978	8,037	9,640	0	0	0	#2 BFP COM GLANDSEALWATER XFER	HRDUNIT2	HRD23362000	
	270,072	7,635	7,978	8,059	0	0	0	0	#2 H.P. FEEDWATER SYSTEM	HRDUNIT2	HRD23500000	
	270,072	7,635	7,978	8,059	8,066	0	0	0	#2 H.P. HEATER 4	HRDUNIT2	HRD23513004	
	270,072	7,635	7,978	8,059	8,067	0	0	0	#2 H.P. HEATER 5	HRDUNIT2	HRD23513005	
	270,072	7,635	7,978	8,059	8,068	0	0	0	#2 H.P. HEATER 6	HRDUNIT2	HRD23513006	
	270,072	7,635	7,978	8,059	8,087	0	0	0	#2 H.P. FEEDWATER VALVES	HRDUNIT2	HRD23531000	
	270,072	7,635	7,978	8,059	8,903	0	0	0	#2 H.P. HEATERS DRAIN PUMP	HRDUNIT2	HRD23514104	
	270,072	7,635	7,978	8,059	331,938	0	0	0	U2 HP Heater 5 2009 Replace	HRDUNIT2		
	270,072	7,635	7,978	8,800	0	0	0	0	#2 CONDENSATE EXTRACTION SYST	HRDUNIT2	HRD23120000	
	270,072	7,635	7,978	8,800	7,986	0	0	0	#2 COND EXTRACTION PUMP NORTH	HRDUNIT2	HRD23123030	
	270,072	7,635	7,978	8,800	7,986	324,367	0	0	C. Ext Pump N Prot. Relay	HRDUNIT2		
	270,072	7,635	7,978	8,800	7,987	0	0	0	#2 COND.EXTRACTION PUMP SOUTH	HRDUNIT2	HRD23123031	
	270,072	7,635	7,978	8,800	7,987	324,369	0	0	C. Ext. Pmp S. Mot Prot Relay	HRDUNIT2		
400												

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,635	8,093	0	0	0	0	0	#2 UNIT GENERATION SERVICES	HRDUNIT2	HRD24000000	
	270,072	7,635	8,093	7,703	0	0	0	0	#2 TURB/GEN COOLING SYSTEM	HRDUNIT2	HRD21360000	
	270,072	7,635	8,093	7,703	9,622	0	0	0	#2 T/G COOLING PUMP SOUTH	HRDUNIT2	HRD21363010	
	270,072	7,635	8,093	7,703	9,624	0	0	0	#2 T/G COOLING PUMP NORTH	HRDUNIT2	HRD21363020	
	270,072	7,635	8,093	7,703	299,550	0	0	0	Unit 2 CW Travelling Structure	HRDPLANT		
	270,072	7,635	8,093	7,703	299,551	0	0	0	Unit 2 CW Travelling Structure	HRDPLANT		
	270,072	7,635	8,093	8,132	0	0	0	0	#2 GENERAL SERVICE COOLING	HRDUNIT2	HRD24500000	
	270,072	7,635	8,093	271,486	0	0	0	0	#2 CW SYSTEM	HRDUNIT2	HRD24000001	
	270,072	7,635	8,093	271,486	8,095	0	0	0	#2 C.W. INTAKE SYSTEM	HRDUNIT2	HRD24110000	
	270,072	7,635	8,093	271,486	8,095	99,043,179	0	0	INSTALL FERROUS SULPHATE D	HRDPLANT		
	270,072	7,635	8,093	271,486	8,095	99,043,192	0	0	BALANCE OF CIRCULATING WAT	HRDPLANT		
	270,072	7,635	8,093	271,486	8,095	99,043,224	0	0	FERROUS SULPHATE DOSING SY	HRDPLANT		
	270,072	7,635	8,093	271,486	8,097	0	0	0	#2 C.W.TRAVELLING SCREENS EAST	HRDUNIT2	HRD24112032	
	270,072	7,635	8,093	271,486	8,098	0	0	0	#2 C.W.TRAVELLING SCREENS WEST	HRDUNIT2	HRD24112033	
	270,072	7,635	8,093	271,486	8,106	0	0	0	#2 C.W. PUMP EAST	HRDUNIT2	HRD24123032	
	270,072	7,635	8,093	271,486	8,107	0	0	0	#2 C.W. PUMP WEST	HRDUNIT2	HRD24123033	
	270,072	7,635	8,093	271,486	8,120	0	0	0	#2 C.W. DISCHARGE TO OUTFALL	HRDUNIT2	HRD24140000	
	270,072	7,635	8,093	271,486	8,821	0	0	0	#2 C.W. SCREEN WASH SYSTEM	HRDUNIT2	HRD24130000	
	270,072	7,635	8,093	271,486	303,301	0	0	0	Anti Fouling System Unit 2	HRDUNIT2		
500												
	270,072	7,635	8,152	0	0	0	0	0	#2 ELECTRICAL & CONTROLS SYS	HRDUNIT2	HRD25000000	
	270,072	7,635	8,152	7,677	0	0	0	0	#2 TURBINE GOVERNOR SYSTEM	HRDUNIT2	HRD21200000	
	270,072	7,635	8,152	7,677	324,486	0	0	0	Elec trip Device	HRDUNIT2	FA-2	
	270,072	7,635	8,152	7,677	333,931	0	0	0	HRD U2 MARK V AUTO SYNC	HRDUNIT2	2	
	270,072	7,635	8,152	7,677	99,000,377	0	0	0	INSTALL ADDITIONAL TURBINE SUP	HRDPLANT		
	270,072	7,635	8,152	7,677	99,034,709	0	0	0	ELECTROHYDRAULIC CONTROL	HRDPLANT		
	270,072	7,635	8,152	7,677	99,036,221	0	0	0	Inverter	HRDPLANT		
	270,072	7,635	8,152	8,138	0	0	0	0	#2 RELAY RM PROTECT & CONTROL	HRDUNIT2	HRD24800000	
	270,072	7,635	8,152	8,144	0	0	0	0	#2 MAIN CONTROLS	HRDUNIT2	HRD24900000	
	270,072	7,635	8,152	8,144	99,043,197	0	0	0	INSTALL 2 PANELS FOR INSTR	HRDPLANT		
	270,072	7,635	8,152	8,144	99,043,199	0	0	0	BALANCE OF INSTRUMENTATION	HRDPLANT		
	270,072	7,635	8,152	8,144	99,043,200	0	0	0	INSTALL CED PERCISION TRAN	HRDPLANT		
	270,072	7,635	8,152	8,153	0	0	0	0	#2 GEN. BUS DUCTS & CONN'S	HRDUNIT2	HRD25100000	
	270,072	7,635	8,152	8,153	99,043,193	0	0	0	REMOVE & REPLACE ISOLATED	HRDPLANT		
	270,072	7,635	8,152	8,155	0	0	0	0	#2 GEN. TRANSFORMER & AUX'S	HRDUNIT2	HRD25220000	
	270,072	7,635	8,152	8,156	0	0	0	0	#2 UNIT SERVICE POWER SYSTEM	HRDUNIT2	HRD25300000	
	270,072	7,635	8,152	8,156	8,157	0	0	0	UNIT BOARD UB-2	HRDUNIT2	HRD25310000	
	270,072	7,635	8,152	8,156	8,162	0	0	0	POWER CENTRE B	HRDUNIT2	HRD25320000	
	270,072	7,635	8,152	8,156	8,168	0	0	0	TURBINE & BOILER AREA MCC B1	HRDUNIT2	HRD25330000	
	270,072	7,635	8,152	8,156	8,169	0	0	0	H.P. HEATER MCC B1-1	HRDUNIT2	HRD25331000	
	270,072	7,635	8,152	8,156	8,170	0	0	0	SOOTBLOWER MCC B1-2	HRDUNIT2	HRD25332000	
	270,072	7,635	8,152	8,173	0	0	0	0	#2 BATTERY CHARGERS	HRDUNIT2	HRD25700000	
	270,072	7,635	8,152	8,173	99,000,349	0	0	0	INSTALL BATTERY CHARGER	HRDPLANT		
	270,072	7,635	8,152	8,173	99,032,476	0	0	0	250 VOLT DC BATTERY BANK	HRDPLANT		
	270,072	7,635	8,152	8,173	99,032,478	0	0	0	250 VOLT DC BATTERY CHARGER	HRDPLANT		
	270,072	7,635	8,152	8,174	0	0	0	0	UPS 2, INVERTER	HRDUNIT2	HRD25710000	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning	WBS CROSS REFERENCE	Date: 19-Dec-12
Project No:	133545705		Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	7,635	8,152	8,174	325,165	0	0	0	SNMP Upgrade - UPS #2 - HRD	HRDUNIT2		
	270,072	7,635	8,152	8,174	99,029,560	0	0	0	INVERTER DISTRIBUTION UNIT #2	HRDPLANT		
	270,072	7,635	8,152	8,186	0	0	0	0	#2 BATTERY BANKS	HRDUNIT2	HRD25750000	
	270,072	7,635	8,152	8,186	99,032,477	0	0	0	250 VOLT BATTERY BANK	HRDPLANT		
	270,072	7,635	8,152	8,186	99,032,479	0	0	0	250 VOLT DC BATTERY CHARGER	HRDPLANT		
	270,072	7,635	8,152	271,475	0	0	0	0	#2 CABLE RACEWAYS	HRDUNIT2	HRD25000001	
	270,072	7,635	8,152	271,475	99,000,333	0	0	0	INSTALL CONDUIT FOR BOILER CON	HRDPLANT		
	270,072	7,635	8,152	271,475	99,043,173	0	0	0	INSTALL CABLE TRENCHES AND	HRDPLANT		
	270,072	7,635	8,152	271,476	0	0	0	0	#2 CONTROL CABLES	HRDUNIT2	HRD25000002	
	270,072	7,635	8,152	271,476	99,000,338	0	0	0	INSTALL CONTROL CABLES FOR GEN	HRDPLANT		
	270,072	7,635	8,152	271,476	99,000,339	0	0	0	INSTALL CONTROL CABLES FOR BOI	HRDPLANT		
	270,072	7,635	8,152	271,477	0	0	0	0	#2 POWER CABLES	HRDUNIT2	HRD25000003	
	270,072	7,635	8,152	271,477	99,043,194	0	0	0	INSTALL POWER CABLE #4160	HRDPLANT		
	270,072	7,635	8,152	271,477	99,043,195	0	0	0	INSTALL POWER CABLES #600	HRDPLANT		
	270,072	7,635	8,152	271,477	99,043,228	0	0	0	CABLE REPLACEMENT	HRDPLANT		
	270,072	7,635	8,152	271,478	0	0	0	0	#2 SWITCHGEAR 4160 & 600 VOLT	HRDUNIT2	HRD25000004	
	270,072	7,635	8,152	271,478	99,043,202	0	0	0	STUDY FOR METALCLAD SWITCH	HRDPLANT		
	270,072	7,635	8,152	271,478	99,043,226	0	0	0	UPGRADE SYNC CHECK SYSTEM,	HRDPLANT		
	270,072	7,635	8,152	271,479	0	0	0	0	#2 TSI	HRDUNIT2	HRD25000005	
	270,072	7,635	8,152	299,451	0	0	0	0	Unit 2 DCS	HRDPLANT		
	270,072	7,635	8,152	309,895	0	0	0	0	600 V Meltric Plugs	HRDUNIT2		
	270,072	7,635	8,152	309,898	0	0	0	0	Boiler Prot & Control	HRDUNIT2		
	270,072	7,635	8,152	343,112	0	0	0	0	#2 BURNER MANAGEMENT	HRDUNIT2	HRD24810000	
	270,072	7,635	359,303	0	0	0	0	0	UNIT 2 BLANKS AND BLINDS	HRDUNIT2		
400												
	270,072	8,193	0	0	0	0	0	0	UNIT 3	HRDUNIT3	HRD30000000	
	270,072	8,193	8,194	0	0	0	0	0	#3 TURBINE & GENERATOR	HRDUNIT3	HRD31000000	
	270,072	8,193	8,194	8,223	0	0	0	0	#3 TURBINE CONDENSER SYSTEM	HRDUNIT3	HRD31160000	
	270,072	8,193	8,194	8,223	8,252	0	0	0	#3 CONDENSER AIR EXTRACTION	HRDUNIT3	HRD31340000	
	270,072	8,193	8,194	8,223	8,252	8,892	0	0	#3 CONDENSR AIR VAC PUMP NORTH	HRDUNIT3	HRD31343030	
	270,072	8,193	8,194	8,223	8,252	8,893	0	0	#3 CONDENSR AIR VAC PUMP SOUTH	HRDUNIT3	HRD31343031	
	270,072	8,193	8,194	8,223	8,252	99,000,295	0	0	CONDENSER AIR REMOVAL SYSTEM S	HRDPLANT		
	270,072	8,193	8,194	8,223	271,677	0	0	0	#3 TURBINE CONDENSER	HRDUNIT3	HRD31160001	
	270,072	8,193	8,194	8,223	271,677	99,000,292	0	0	INSTALL ONE CONDENSER TUBE LEA	HRDPLANT		
	270,072	8,193	8,194	8,223	271,677	99,000,293	0	0	INSTALL CONDENSER STAGE III	HRDPLANT		
	270,072	8,193	8,194	8,223	322,988	0	0	0	U3 Condenser Actuators	HRDUNIT3		
	270,072	8,193	8,194	8,223	99,000,297	0	0	0	BALANCE OF CONDENSER SYSTEM ST	HRDPLANT		
	270,072	8,193	8,194	8,298	0	0	0	0	U3 GENERATOR	HRDUNIT3	HRD31500000	
	270,072	8,193	8,194	8,298	8,299	0	0	0	#3 GENERATOR ROTOR	HRDUNIT3	HRD31510000	
	270,072	8,193	8,194	8,298	8,299	8,300	0	0	#3GEN ROTOR SLIP RINGS & BRUSH	HRDUNIT3	HRD31514000	
	270,072	8,193	8,194	8,298	8,299	99,000,271	0	0	INSTALL ROTOR UNIT 3 - MFG HIT	HRDPLANT		
	270,072	8,193	8,194	8,298	8,304	0	0	0	#3 GENERATOR STATOR	HRDUNIT3	HRD31520000	
	270,072	8,193	8,194	8,298	8,304	8,308	0	0	#3 GEN. STANDOFF INSULATORS	HRDUNIT3	HRD31531000	
	270,072	8,193	8,194	8,298	8,304	8,310	0	0	#3 GENERATOR P.T. CUBICLE	HRDUNIT3	HRD31593000	
	270,072	8,193	8,194	8,298	8,304	324,691	0	0	#3 GENERATOR STATOR RELAY	HRDUNIT3		
	270,072	8,193	8,194	8,298	8,304	99,000,274	0	0	INSTALL STATOR UNIT 3 - MFG HI	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,194	8,298	8,313	0	0	0	#3 GEN.HYDROGEN GAS SYSTEM	HRDUNIT3	HRD31620000	
	270,072	8,193	8,194	8,298	8,313	8,288	0	0	#3 GENERATOR SEAL OIL SYSTEM	HRDUNIT3	HRD31450000	
	270,072	8,193	8,194	8,298	8,313	8,288	9,662	0	#3 GEN AC SEAL OIL PUMP	HRDUNIT3	HRD31451010	
	270,072	8,193	8,194	8,298	8,313	8,288	9,664	0	#3 GEN DC SEAL OIL PUMP	HRDUNIT3	HRD31452010	
	270,072	8,193	8,194	8,298	8,313	8,288	9,666	0	#3 GEN SEAL OIL VAC PUMP	HRDUNIT3	HRD31454010	
	270,072	8,193	8,194	8,298	8,313	8,318	0	0	#3 GENERATOR CO2 GAS PURGE	HRDUNIT3	HRD31630000	
	270,072	8,193	8,194	8,298	8,313	8,321	0	0	#3 GENERATOR COMPRESSED AIR	HRDUNIT3	HRD31640000	
	270,072	8,193	8,194	8,298	8,322	0	0	0	#3 GENERATOR HYDROGEN COOLING	HRDUNIT3	HRD31650000	
	270,072	8,193	8,194	8,298	99,000,277	0	0	0	BALANCE OF GENERATORS	HRDPLANT		
	270,072	8,193	8,194	8,298	99,039,100	0	0	0	Partial Discharge Analysis	HRDPLANT	FA-IC03468	
	270,072	8,193	8,194	8,312	0	0	0	0	#3 GENERATOR EXCITATION SYSTEM	HRDUNIT3	HRD31610000	
	270,072	8,193	8,194	8,312	271,679	0	0	0	#3 EXCITER	HRDUNIT3	HRD31610001	
	270,072	8,193	8,194	8,312	271,679	99,000,281	0	0	INSTALL EXCITER UNIT 3 - MFG W	HRDPLANT		
	270,072	8,193	8,194	8,312	271,680	0	0	0	#3 EXCITATION TRANSFORMER	HRDUNIT3	HRD31610002	
	270,072	8,193	8,194	8,312	271,680	99,000,284	0	0	INSTALL EXCITATION TRANSFORMER	HRDPLANT		
	270,072	8,193	8,194	8,312	271,681	0	0	0	#3 FIELD BREAKER	HRDUNIT3	HRD31610003	
	270,072	8,193	8,194	8,312	271,681	99,000,288	0	0	INSTALL EXCITATION FIELD BREAK	HRDPLANT		
	270,072	8,193	8,194	8,312	99,000,290	0	0	0	BALANCE OF EXCITATION SYSTEM S	HRDPLANT		
	270,072	8,193	8,194	8,326	0	0	0	0	#3 GENERATOR SYNCRONOUS COND	HRDPLANT	HRD31660000	
	270,072	8,193	8,194	271,675	0	0	0	0	#3 TURBINE	HRDUNIT3	HRD31000001	
	270,072	8,193	8,194	271,675	8,196	0	0	0	#3 TURBINE MAIN STEAM CHEST	HRDUNIT3	HRD31110000	
	270,072	8,193	8,194	271,675	8,201	0	0	0	#3 H.P. TURBINE	HRDUNIT3	HRD31120000	
	270,072	8,193	8,194	271,675	8,206	0	0	0	#3 TURB REHEAT/IP STEAM CHEST	HRDUNIT3	HRD31130000	
	270,072	8,193	8,194	271,675	8,211	0	0	0	#3 I.P. TURBINE	HRDUNIT3	HRD31140000	
	270,072	8,193	8,194	271,675	8,217	0	0	0	#3 L.P. TURBINE	HRDUNIT3	HRD31150000	
	270,072	8,193	8,194	271,675	8,230	0	0	0	#3 TURBINE FRONT STANDARD	HRDUNIT3	HRD31170000	
	270,072	8,193	8,194	271,675	8,236	0	0	0	#3 TURBINE GOVERNOR SYSTEM	HRDUNIT3	HRD31200000	
	270,072	8,193	8,194	271,675	8,236	99,000,262	0	0	INSTALL GOVENOR UNIT 3 - MFG H	HRDPLANT		
	270,072	8,193	8,194	271,675	8,236	99,023,644	0	0	TURBINE ROTOR MOVEMENT MONITOR	HRDPLANT		
	270,072	8,193	8,194	271,675	8,244	0	0	0	#3 TURBINE GLAND STEAM SYSTEM	HRDUNIT3	HRD31310000	
	270,072	8,193	8,194	271,675	8,248	0	0	0	#3 TURBINE PRE-WARMING SYSTEM	HRDUNIT3	HRD31320000	
	270,072	8,193	8,194	271,675	8,250	0	0	0	#3 TURBINE TURNING GEAR	HRDUNIT3	HRD31330000	
	270,072	8,193	8,194	271,675	8,257	0	0	0	#3 TURBINE DRAINS SYSTEMS	HRDUNIT3	HRD31350000	
	270,072	8,193	8,194	271,675	8,270	0	0	0	#3 TURBINE OIL SYSTEMS	HRDUNIT3	HRD31400000	
	270,072	8,193	8,194	271,675	8,270	8,275	0	0	#3 TURBINE LUBE OIL SYSTEM	HRDUNIT3	HRD31430000	
	270,072	8,193	8,194	271,675	8,270	8,275	8,271	0	#3 TURB LUBE OIL TANK & EQUIP	HRDUNIT3	HRD31410000	
	270,072	8,193	8,194	271,675	8,270	8,275	8,274	0	#3 TURB LUBE OIL PURIFICATION	HRDUNIT3	HRD31420000	
	270,072	8,193	8,194	271,675	8,270	8,275	8,276	0	#3 TURB AC FLUSHING OIL PUMP	HRDUNIT3	HRD31431130	
	270,072	8,193	8,194	271,675	8,270	8,275	8,281	0	#3 TURBINE LUBE D.C. PUMP	HRDUNIT3	HRD31432100	
	270,072	8,193	8,194	271,675	8,270	8,275	9,546	0	#3 TURBINE AUXILIARY OIL PUMP	HRDUNIT3	HRD31434100	
	270,072	8,193	8,194	271,675	8,270	8,294	0	0	#3 TURBINE JACKING OIL SYSTEM	HRDUNIT3	HRD31460000	
	270,072	8,193	8,194	271,675	8,270	8,294	8,295	0	#3 TURBINE JACKING OIL PUMP	HRDUNIT3	HRD31461000	
	270,072	8,193	8,194	271,675	8,270	99,039,523	0	0	Fire Protection System for	HRDPLANT		
	270,072	8,193	8,194	271,675	271,676	0	0	0	#3 TURBINE BLED STEAM	HRDUNIT3	HRD31000002	
	270,072	8,193	8,194	271,675	271,676	99,000,319	0	0	INSTALL BLED - STEAM SYSTEMS U	HRDPLANT		
	270,072	8,193	8,194	271,675	303,298	0	0	0	Metric Tools Unit #3	HRDUNIT3		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,194	271,675	308,871	0	0	0	Upgrade to Unit #3 Turbine	HRDUNIT3		
	270,072	8,193	8,194	271,675	331,940	0	0	0	U3 SS Regulator System 2009	HRDUNIT3		
	270,072	8,193	8,194	271,675	99,000,266	0	0	0	INSTALL TURBINE UNIT 3 - MFG H	HRDPLANT		
	270,072	8,193	8,194	271,675	99,027,839	0	0	0	DRILL TAP BEARINGS FOR TURBINE	HRDPLANT		
	270,072	8,193	8,194	99,000,322	0	0	0	0	SPECIAL TOOLS - UNIT #3 -HOLYR	HRDPLANT		
300												
	270,072	8,193	8,336	0	0	0	0	0	#3 BOILER PLANT	HRDUNIT3	HRD32000000	
	270,072	8,193	8,336	8,337	0	0	0	0	#3 BOILER STRUCTURE	HRDUNIT3	HRD32100000	
	270,072	8,193	8,336	8,337	99,000,138	0	0	0	INSTALL SOOT BLOWERS	HRDPLANT		
	270,072	8,193	8,336	8,337	99,000,139	0	0	0	STEAM GENERATOR	HRDPLANT		
	270,072	8,193	8,336	8,337	99,000,140	0	0	0	STEAM GENERATOR	HRDPLANT		
	270,072	8,193	8,336	8,337	99,000,141	0	0	0	PRESSURIZED OIL GUNS	HRDPLANT		
	270,072	8,193	8,336	8,337	99,000,142	0	0	0	STEAM GENERATORS	HRDPLANT		
	270,072	8,193	8,336	8,337	99,003,553	0	0	0	FOUR FABRIC TYPE EXPANSION JOI	HRDPLANT		
	270,072	8,193	8,336	8,337	99,029,564	0	0	0	OBSERVATION PORT IN THE BURNER	HRDPLANT		
	270,072	8,193	8,336	8,339	0	0	0	0	#3 BOILER FW & SAT'D STEAM SYS	HRDUNIT3	HRD32200000	
	270,072	8,193	8,336	8,339	8,340	0	0	0	#3 BOILER ECONOMIZER	HRDUNIT3	HRD32210000	
	270,072	8,193	8,336	8,339	8,344	0	0	0	#3 BOILER STEAM DRUM	HRDUNIT3	HRD32220000	
	270,072	8,193	8,336	8,339	8,344	99,000,397	0	0	YARWAY AQUARIAN 300 ELECTRONIC	HRDPLANT		
	270,072	8,193	8,336	8,339	8,344	99,023,641	0	0	SOLID STATE DRUM LEVEL MONITOR	HRDPLANT		
	270,072	8,193	8,336	8,339	8,351	0	0	0	#3 FURNACE	HRDUNIT3	HRD32240000	
	270,072	8,193	8,336	8,339	8,355	0	0	0	#3 BOILER FILLING AND DRAINING	HRDUNIT3	HRD32260000	
	270,072	8,193	8,336	8,339	8,355	8,494	0	0	#3 BOILER BLOWDOWN DRAINS & LP	HRDUNIT3	HRD32700000	
	270,072	8,193	8,336	8,339	8,355	8,494	8,495	0	#3 BOILER CONTINUOUS BLOWDOWN	HRDUNIT3	HRD32710000	
	270,072	8,193	8,336	8,339	8,355	8,494	359,345	0	UNIT 3 BOILER BLOWDOWN TANK	HRDUNIT3		
	270,072	8,193	8,336	8,339	8,355	99,000,182	0	0	BOILER VENTS AND DUCTS UNIT #3	HRDPLANT		
	270,072	8,193	8,336	8,359	0	0	0	0	#3 BOILER SUPERHEATER & REHEAT	HRDUNIT3	HRD32300000	
	270,072	8,193	8,336	8,359	8,360	0	0	0	#3 BOILER PRIMARY SUPERHEATER	HRDUNIT3	HRD32310000	
	270,072	8,193	8,336	8,359	8,362	0	0	0	#3 BOILER SUPERHEATER ATTEMP	HRDUNIT3	HRD32320000	
	270,072	8,193	8,336	8,359	8,362	99,000,145	0	0	INSTALL #3 BOILER SUPERHEATER	HRDUNIT2		
	270,072	8,193	8,336	8,359	8,366	0	0	0	#3BOILER SECONDARY SUPERHEATER	HRDUNIT3	HRD32330000	
	270,072	8,193	8,336	8,359	8,372	0	0	0	#3 BOILER MAIN STEAM LINES	HRDUNIT3	HRD32340000	
	270,072	8,193	8,336	8,359	8,372	8,373	0	0	#3 BOILER STOP VALVE	HRDUNIT3	HRD32341000	
	270,072	8,193	8,336	8,359	8,372	99,000,154	0	0	HIGH PRESSURE STEAM SYSTEM	HRDPLANT		
	270,072	8,193	8,336	8,359	8,372	99,000,155	0	0	HIGH PRESSURE STEAM SYSTEM UNI	HRDPLANT		
	270,072	8,193	8,336	8,359	8,379	0	0	0	#3BOILER REHEATER ATTEMPERATOR	HRDUNIT3	HRD32350000	
	270,072	8,193	8,336	8,359	8,384	0	0	0	#3 BOILER REHEATER	HRDUNIT3	HRD32360000	
	270,072	8,193	8,336	8,387	0	0	0	0	#3 BOILER AIR SYSTEM	HRDUNIT3	HRD32400000	
	270,072	8,193	8,336	8,387	8,426	0	0	0	#3 BOILER AIR SUPPLY (A/H TO	HRDUNIT3	HRD32440000	
	270,072	8,193	8,336	8,387	8,426	8,429	0	0	#3 BOILER AIR SUPPLY SEAL AIR	HRDUNIT3	HRD32443000	
	270,072	8,193	8,336	8,387	8,426	8,432	0	0	#3 BOILER SCANNER AIR SYSTEM	HRDUNIT3	HRD32446000	
	270,072	8,193	8,336	8,387	8,433	0	0	0	#3 BOILER WINDBOX	HRDUNIT3	HRD32450000	
	270,072	8,193	8,336	8,387	8,782	0	0	0	#3 BOILER F.D. FAN SYSTEM	HRDUNIT3	HRD32410000	
	270,072	8,193	8,336	8,387	8,782	8,392	0	0	#3 BOILER F.D. FAN EAST	HRDUNIT3	HRD32413032	
	270,072	8,193	8,336	8,387	8,782	8,392	324,380	0	FDF East Mot Prot Relay	HRDUNIT3		
	270,072	8,193	8,336	8,387	8,782	8,393	0	0	#3 BOILER F.D. FAN WEST	HRDUNIT3	HRD32413033	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,336	8,387	8,782	8,393	324,382	0	FDF West Mot Prot Relay	HRDUNIT3		
	270,072	8,193	8,336	8,387	8,787	0	0	0	#3 BOILER STEAM AIR HEATER	HRDUNIT3	HRD32420000	
	270,072	8,193	8,336	8,387	8,787	8,404	0	0	#3BOILER STEAM AIR HEATER EAST	HRDUNIT3	HRD32423032	
	270,072	8,193	8,336	8,387	8,787	8,405	0	0	#3BOILER STEAM AIR HEATER WEST	HRDUNIT3	HRD32423033	
	270,072	8,193	8,336	8,387	8,787	309,899	0	0	#3 Blr stm air htr drains east	HRDUNIT3		
	270,072	8,193	8,336	8,387	8,787	309,900	0	0	#3 blr stm air htr drains west	HRDUNIT3		
	270,072	8,193	8,336	8,387	8,787	359,353	0	0	Steam Preheater Flash Tank	HRDUNIT3	3	
	270,072	8,193	8,336	8,387	8,788	0	0	0	#3 BOILER MAIN AIR HEATER	HRDUNIT3	HRD32430000	
	270,072	8,193	8,336	8,387	8,788	8,410	0	0	#3 BOILER MAIN AIR HEATER EAST	HRDUNIT3	HRD32430032	
	270,072	8,193	8,336	8,387	8,788	8,411	0	0	#3 BOILER MAIN AIR HEATER WEST	HRDUNIT3	HRD32430033	
	270,072	8,193	8,336	8,437	0	0	0	0	#3 BOILER GAS SYSTEM	HRDUNIT3	HRD32500000	
	270,072	8,193	8,336	8,437	8,438	0	0	0	#3 BOILER GAS PASSES	HRDUNIT3	HRD32510000	
	270,072	8,193	8,336	8,437	8,448	0	0	0	#3 BOILER STACK	HRDUNIT3	HRD32570000	
	270,072	8,193	8,336	8,437	8,448	271,682	0	0	#3 STACK BREECHING	HRDUNIT3	HRD32570001	
	270,072	8,193	8,336	8,437	8,448	271,682	99,003,555	0	UNIT #3 STACK BREECHING, SEE P	HRDPLANT		
	270,072	8,193	8,336	8,437	8,448	99,000,177	0	0	INSTALL STACKS UNIT #3	HRDPLANT		
	270,072	8,193	8,336	8,437	8,452	0	0	0	#3 BOILER SOOTBLOWING SYSTEM	HRDUNIT3	HRD32580000	
	270,072	8,193	8,336	8,437	8,452	8,455	0	0	#3 BOILER RETRACTABLE S/B'S	HRDUNIT3	HRD32583000	
	270,072	8,193	8,336	8,437	8,452	8,456	0	0	#3 BOILER ROTARY SOOTBLOWERS	HRDUNIT3	HRD32584000	
	270,072	8,193	8,336	8,437	8,452	8,791	0	0	#3 BLR AIR HEATER SOOTBLOWERS	HRDUNIT3	HRD32585000	
	270,072	8,193	8,336	8,437	8,452	253,040	0	0	#3 BOILER WATERLANCE	HRDUNIT3	HRD32587000	
	270,072	8,193	8,336	8,437	8,452	99,039,065	0	0	high pressure water lances	HRDPLANT		
	270,072	8,193	8,336	8,437	8,452	99,039,066	0	0	high pressure water lances	HRDPLANT		
	270,072	8,193	8,336	8,437	8,452	99,039,067	0	0	high pressure water lances	HRDPLANT		
	270,072	8,193	8,336	8,437	8,452	99,039,068	0	0	SUNFLO SERIES P2000 PUMP	HRDPLANT	FA-04208	
	270,072	8,193	8,336	8,437	8,452	99,039,069	0	0	thermatel thermal dispersion	HRDPLANT		
	270,072	8,193	8,336	8,437	8,452	99,039,070	0	0	thermatel thermal dispersion	HRDPLANT		
	270,072	8,193	8,336	8,460	0	0	0	0	#3 BOILER FUEL FIRING SYSTEM	HRDUNIT3	HRD32600000	
	270,072	8,193	8,336	8,460	8,461	0	0	0	#3 BOILER HEAVY OIL SYSTEM	HRDUNIT3	HRD32610000	
	270,072	8,193	8,336	8,460	8,461	8,464	0	0	#3 BOILER HEAVY OIL PUMP EAST	HRDUNIT3	HRD32613032	
	270,072	8,193	8,336	8,460	8,461	8,465	0	0	#3 BOILER HEAVY OIL PUMP WEST	HRDUNIT3	HRD32613033	
	270,072	8,193	8,336	8,460	8,461	8,468	0	0	U3 BLR HVYOIL P/P STM,VLV,PIPE	HRDUNIT3	HRD32617000	
	270,072	8,193	8,336	8,460	8,461	8,471	0	0	#3 BOILER HEAVY OIL FIRING	HRDUNIT3	HRD32620000	
	270,072	8,193	8,336	8,460	8,461	359,344	0	0	U3 Fuel Oil Accumulator	HRDUNIT3		
	270,072	8,193	8,336	8,460	8,484	0	0	0	#3 BOILER LIGHT OIL SYSTEM	HRDUNIT3	HRD32640000	
	270,072	8,193	8,336	8,460	8,484	7,740	0	0	#3 BOILER LIGHT OIL PUMP WEST	HRDUNIT3	HRD32643033	
	270,072	8,193	8,336	8,460	8,484	8,481	0	0	#3 BOILER LIGHT OIL FIRING	HRDUNIT3	HRD32630000	
	270,072	8,193	8,336	8,460	8,484	8,481	99,000,144	0	INSTALL 9 LIGHT OIL IGNITORS F	HRDPLANT		
	270,072	8,193	8,336	8,460	8,484	8,983	0	0	#3 BOILER LIGHT OIL PUMP EAST	HRDUNIT3	HRD32643032	
	270,072	8,193	8,336	8,460	99,000,158	0	0	0	FUEL OIL SYSTEM UNIT #3	HRDPLANT		
	270,072	8,193	8,336	8,460	99,000,172	0	0	0	INSTALL LIGHT OIL SYSTEM UNIT	HRDPLANT		
	270,072	8,193	8,336	8,503	0	0	0	0	#3 BLR AUX STEAM & CONDENSATE	HRDUNIT3	HRD32800000	
	270,072	8,193	8,336	8,503	8,504	0	0	0	#3 BOILER AUX. STEAM MAIN	HRDUNIT3	HRD32810000	
	270,072	8,193	8,336	8,503	8,510	0	0	0	#3 BOILER AUXILIARY STEAM	HRDUNIT3	HRD32820000	
	270,072	8,193	8,336	8,503	8,518	0	0	0	#3 BOILER ATOMIZING STEAM	HRDUNIT3	HRD32830000	
	270,072	8,193	8,336	8,503	8,543	0	0	0	#3 AUXILIARY STEAM CONDENSATE	HRDUNIT3	HRD33150000	

Client: **Newfoundland and Labrador Hydro**
Project: **Holyrood Decommissioning**
Project No: **133545705**

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by: **MDV**
Date: **19-Dec-12**
Revision No.: **0**
Issue Date: **19-Dec-12**
Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,528	0	0	0	0	0	#3 CONDENSATE & F.W. SYSTEM	HRDUNIT3	HRD33000000	
	270,072	8,193	8,528	8,530	0	0	0	0	#3 CONDENSATE MAKE UP SYSTEM	HRDUNIT3	HRD33110000	
	270,072	8,193	8,528	8,546	0	0	0	0	#3 LOW PRESSURE FEEDWATER	HRDUNIT3	HRD33200000	
	270,072	8,193	8,528	8,546	8,551	0	0	0	#3 LOW PRESSURE HEATER 1	HRDUNIT3	HRD33213001	
	270,072	8,193	8,528	8,546	8,551	99,000,206	0	0	INSTALL LOW PRESSURE FEED SYST	HRDPLANT		
	270,072	8,193	8,528	8,546	8,552	0	0	0	#3 LOW PRESSURE HEATER 2	HRDUNIT3	HRD33213002	
	270,072	8,193	8,528	8,546	8,552	99,000,207	0	0	INSTALL LOW PRESSURE FEED SYST	HRDPLANT		
	270,072	8,193	8,528	8,546	8,571	0	0	0	#3 DEAERATOR SYSTEM	HRDUNIT3	HRD33250000	
	270,072	8,193	8,528	8,546	8,586	0	0	0	#3 LOW PRESSURE F.W. RESERVE	HRDUNIT3	HRD33270000	
	270,072	8,193	8,528	8,546	8,586	99,000,199	0	0	COSTS INCURRED FOR RESERVE FEE	HRDPLANT		
	270,072	8,193	8,528	8,546	8,586	99,000,200	0	0	INSTALL SPARE PARTS FOR RESERV	HRDPLANT		
	270,072	8,193	8,528	8,546	8,586	99,031,612	0	0	TURBINE FLOW METER WITH VALVES	HRDPLANT		
	270,072	8,193	8,528	8,546	8,809	0	0	0	#3 L P HEATER DRAIN PUMPS	HRDUNIT3	HRD33220000	
	270,072	8,193	8,528	8,590	0	0	0	0	#3 BOILER FEEDWATER PUMPING	HRDUNIT3	HRD33300000	
	270,072	8,193	8,528	8,590	8,859	0	0	0	#3 BOILER FEED PUMP - EAST	HRDUNIT3	HRD33310032	
	270,072	8,193	8,528	8,590	8,859	8,591	0	0	#3 BOILER FEEDPUMP RECIRC EAST	HRDUNIT3	HRD33320032	
	270,072	8,193	8,528	8,590	8,859	8,603	0	0	#3 BOILER FW P/P LUBE OIL EAST	HRDUNIT3	HRD33340032	
	270,072	8,193	8,528	8,590	8,859	324,412	0	0	BFP East Mot Prot Relay	HRDUNIT3		
	270,072	8,193	8,528	8,590	8,859	99,000,239	0	0	INSTALL BOILER FEED PUMP UNIT	HRDPLANT		
	270,072	8,193	8,528	8,590	8,859	99,000,246	0	0	INSTALL VIBRATION MONITOR FOR	HRDPLANT		
	270,072	8,193	8,528	8,590	8,860	0	0	0	#3 BOILER FEED PUMP - WEST	HRDUNIT3	HRD33310033	
	270,072	8,193	8,528	8,590	8,860	8,592	0	0	#3 BOILER FEEDPUMP RECIRC WEST	HRDUNIT3	HRD33320033	
	270,072	8,193	8,528	8,590	8,860	8,604	0	0	#3 BLR FW PUMP LUBE OIL WEST	HRDUNIT3	HRD33340033	
	270,072	8,193	8,528	8,590	8,860	324,414	0	0	BFP West Mot Prot. Relay	HRDUNIT3		
	270,072	8,193	8,528	8,590	8,860	99,000,240	0	0	INSTALL BOILER FEED PUMP UNIT	HRDPLANT		
	270,072	8,193	8,528	8,590	8,860	99,000,247	0	0	INSTALL VIBRATION MONITOR FOR	HRDPLANT		
	270,072	8,193	8,528	8,590	9,675	0	0	0	#3 BFP COM GLAND SEAL WATR INJ	HRDUNIT3	HRD33361000	
	270,072	8,193	8,528	8,590	9,676	0	0	0	#3 BFP COM GLNDSEAL WTR TRANSF	HRDUNIT3	HRD33362000	
	270,072	8,193	8,528	8,590	99,034,739	0	0	0	BFP RECIRCULATION SYSTEM	HRDPLANT		
	270,072	8,193	8,528	8,611	0	0	0	0	#3 H.P. FEEDWATER SYSTEM	HRDUNIT3	HRD33500000	
	270,072	8,193	8,528	8,611	8,618	0	0	0	#3 H.P. HEATER 4	HRDUNIT3	HRD33513004	
	270,072	8,193	8,528	8,611	8,618	99,031,613	0	0	HIGH PRESSURE FEEDWATER HEATER	HRDPLANT		
	270,072	8,193	8,528	8,611	8,619	0	0	0	#3 H.P. HEATER 5	HRDUNIT3	HRD33513005	
	270,072	8,193	8,528	8,611	8,619	99,031,614	0	0	HIGH PRESSURE FEEDWATER HEATER	HRDPLANT		
	270,072	8,193	8,528	8,611	8,620	0	0	0	#3 H.P. HEATER 6	HRDUNIT3	HRD33513006	
	270,072	8,193	8,528	8,611	8,620	99,031,615	0	0	HIGH PRESSURE FEEDWATER HEATER	HRDPLANT		
	270,072	8,193	8,528	8,611	8,639	0	0	0	#3 H.P. FEEDWATER VALVES	HRDUNIT3	HRD33531000	
	270,072	8,193	8,528	8,611	8,933	0	0	0	#3 H.P. HEATERS DRAIN PUMP	HRDUNIT3	HRD33514104	
	270,072	8,193	8,528	8,611	99,000,161	0	0	0	REPLACE HP HEAT EXCHANGERS	HRDPLANT		
	270,072	8,193	8,528	8,611	99,000,249	0	0	0	BALANCE OF HIGH PRESSURE FEED	HRDPLANT		
	270,072	8,193	8,528	8,801	0	0	0	0	#3 CONDENSATE EXTRACTION SYST	HRDUNIT3	HRD33120000	
	270,072	8,193	8,528	8,801	8,536	0	0	0	#3 CONDENS EXTRACT'N P/P NORTH	HRDUNIT3	HRD33123030	
	270,072	8,193	8,528	8,801	8,536	324,370	0	0	C. Ext. Pmp N Mot Prot Relay	HRDUNIT3		
	270,072	8,193	8,528	8,801	8,536	99,000,210	0	0	INSTALL MATERIAL FOR CONDENSAT	HRDPLANT		
	270,072	8,193	8,528	8,801	8,536	99,000,211	0	0	INSTALL CONDENSATE EXTRACTION	HRDPLANT		
	270,072	8,193	8,528	8,801	8,537	0	0	0	#3 CONDENS EXTRACT'N P/P SOUTH	HRDUNIT3	HRD33123031	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,528	8,801	8,537	324,372	0	0	C Ext Pump S Mot Prot Relay	HRDUNIT3		
	270,072	8,193	8,528	8,801	8,537	99,000,212	0	0	INSTALL CONDENSATE EXTRACTION	HRDPLANT		
	270,072	8,193	8,528	8,801	8,537	99,000,213	0	0	CONDENSATE RETUREN SYSTEM	HRDPLANT		
400												
	270,072	8,193	8,645	0	0	0	0	0	#3 UNIT GENERATION SERVICES	HRDUNIT3	HRD34000000	
	270,072	8,193	8,645	8,262	0	0	0	0	#3 TURB/GEN WATER COOLING SYS	HRDUNIT3	HRD31360000	
	270,072	8,193	8,645	8,262	9,658	0	0	0	#3 T/G COOLING WATER PUMP EAST	HRDUNIT3	HRD31363010	
	270,072	8,193	8,645	8,262	9,660	0	0	0	#3 T/G COOLING WATER PUMP WEST	HRDUNIT3	HRD31363020	
	270,072	8,193	8,645	8,691	0	0	0	0	#3 GENERAL SERVICE COOLING	HRDUNIT3	HRD34500000	
	270,072	8,193	8,645	271,678	0	0	0	0	#3 CW SYSTEM	HRDUNIT3	HRD34000001	
	270,072	8,193	8,645	271,678	8,647	0	0	0	#3 C.W. INTAKE SYSTEM	HRDUNIT3	HRD34110000	
	270,072	8,193	8,645	271,678	8,647	99,000,306	0	0	INSTALL 2 INTAKE SCREEN & DRIV	HRDPLANT		
	270,072	8,193	8,645	271,678	8,647	99,000,309	0	0	BALANCE OF CIRCULATING WATER S	HRDPLANT		
	270,072	8,193	8,645	271,678	8,647	99,043,180	0	0	INSTALL FERROUS SULPHATE D	HRDPLANT		
	270,072	8,193	8,645	271,678	8,647	99,043,225	0	0	FERROUS SULPHATE DOSING SY	HRDPLANT		
	270,072	8,193	8,645	271,678	8,649	0	0	0	#3 CW TRAVELLING SCREENS EAST	HRDUNIT3	HRD34112032	
	270,072	8,193	8,645	271,678	8,650	0	0	0	#3 CW TRAVELLING SCREENS WEST	HRDUNIT3	HRD34112033	
	270,072	8,193	8,645	271,678	8,658	0	0	0	#3 C.W. PUMP EAST	HRDUNIT3	HRD34123032	
	270,072	8,193	8,645	271,678	8,658	324,374	0	0	CWP East Mot Prot Relay	HRDUNIT3		
	270,072	8,193	8,645	271,678	8,659	0	0	0	#3 C.W. PUMP WEST	HRDUNIT3	HRD34123033	
	270,072	8,193	8,645	271,678	8,659	324,378	0	0	CWP West Mot. Prot Relay	HRDUNIT3		
	270,072	8,193	8,645	271,678	8,676	0	0	0	#3 C.W. DISCHARGE TO OUTFALL	HRDUNIT3	HRD34140000	
	270,072	8,193	8,645	271,678	8,823	0	0	0	#3 C.W. SCREEN WASH SYSTEM	HRDUNIT3	HRD34130000	
	270,072	8,193	8,645	271,678	8,823	99,000,303	0	0	INSTALL SCREEN WASH PUMP UNIT	HRDPLANT		
	270,072	8,193	8,645	271,678	279,782	0	0	0	SYNCH CONDENSER AUX CW SYSTEM	HRDUNIT3		
	270,072	8,193	8,645	271,678	303,295	0	0	0	Anti Fouling System U3	HRDUNIT3		
	270,072	8,193	8,645	271,678	99,000,300	0	0	0	INSTALL 2 CIRCULATING WATER PU	HRDPLANT		
500												
	270,072	8,193	8,712	0	0	0	0	0	#3 ELECTRICAL SYSTEM & CONTROL	HRDUNIT3	HRD35000000	
	270,072	8,193	8,712	8,698	0	0	0	0	U3 RELAY RM PROTECTION&CONTROL	HRDUNIT3	HRD34800000	
	270,072	8,193	8,712	8,698	99,000,324	0	0	0	INSTALL PROTECTIVE CONTROL AND	HRDPLANT		
	270,072	8,193	8,712	8,698	99,000,325	0	0	0	INSTALL EQUIPMENT TO PROVIDE E	HRDPLANT		
	270,072	8,193	8,712	8,699	0	0	0	0	#3 BURNER MANAGEMENT	HRDUNIT3	HRD34810000	
	270,072	8,193	8,712	8,699	99,024,413	0	0	0	C.I.U. PANEL FOR BURNER MANAGE	HRDPLANT		
	270,072	8,193	8,712	8,704	0	0	0	0	#3 MAIN CONTROLS	HRDUNIT3	HRD34900000	
	270,072	8,193	8,712	8,704	99,000,385	0	0	0	INSTALL 1 PANEL FOR INSTRUM &	HRDPLANT		
	270,072	8,193	8,712	8,704	99,000,386	0	0	0	PROVIDE UNIT RELIABILITY AND I	HRDPLANT		
	270,072	8,193	8,712	8,704	99,000,389	0	0	0	BALANCE OF INSTRUMENTATION STA	HRDPLANT		
	270,072	8,193	8,712	8,704	99,031,989	0	0	0	ADDITIONAL COST , PANEL SEE PL	HRDPLANT		
	270,072	8,193	8,712	8,704	99,043,201	0	0	0	INSTALL CED PERCISION TRAN	HRDPLANT		
	270,072	8,193	8,712	8,713	0	0	0	0	#3 GENERATOR BUS DUCT & CONN'S	HRDUNIT3	HRD35100000	
	270,072	8,193	8,712	8,713	99,000,327	0	0	0	INSTALL BUS DUCT (GENERATOR)	HRDPLANT		
	270,072	8,193	8,712	8,715	0	0	0	0	#3 GEN. TRANSFORMER & AUX	HRDUNIT3	HRD35220000	
	270,072	8,193	8,712	8,716	0	0	0	0	#3 UNIT SERVICE POWER SYSTEM	HRDUNIT3	HRD35300000	
	270,072	8,193	8,712	8,716	8,717	0	0	0	UNIT BOARD UB-3	HRDUNIT3	HRD35310000	
	270,072	8,193	8,712	8,716	8,718	0	0	0	UNIT AUX. BOARD UAB-3	HRDUNIT3	HRD35320000	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,712	8,716	8,722	0	0	0	TURBINE AREA MCC TAB-34	HRDUNIT3	HRD35330000	
	270,072	8,193	8,712	8,716	8,724	0	0	0	BOILER AREA BAB-3	HRDUNIT3	HRD35340000	
	270,072	8,193	8,712	8,716	8,725	0	0	0	H.P. HEATER MCC HPH-3	HRDUNIT3	HRD35341000	
	270,072	8,193	8,712	8,716	8,726	0	0	0	SOOTBLOWER MCC SB3	HRDUNIT3	HRD35342000	
	270,072	8,193	8,712	8,716	8,728	0	0	0	BOILER ROOM VENT MCC BRV-3	HRDUNIT3	HRD35344000	
	270,072	8,193	8,712	8,750	0	0	0	0	#3 BATTERY CHARGERS	HRDUNIT3	HRD35700000	
	270,072	8,193	8,712	8,750	358,100	0	0	0	#2 - 129 VDC 3 PHASE CHARGER	HRDUNIT3	HRD35702000	
	270,072	8,193	8,712	8,750	359,337	0	0	0	#1 - 129 VDC 3 PHASE CHARGER	HRDUNIT3		
	270,072	8,193	8,712	8,750	99,000,351	0	0	0	INSTALL BATTERY CHARGER STAGE	HRDPLANT		
	270,072	8,193	8,712	8,750	99,000,352	0	0	0	INSTALL BATTERY CHARGER STAGE	HRDPLANT		
	270,072	8,193	8,712	8,751	0	0	0	0	UPS 3 INVERTER	HRDUNIT3	HRD35710000	
	270,072	8,193	8,712	8,751	325,166	0	0	0	SNMP Upgrade - UPS #3 - HRD	HRDUNIT3		
	270,072	8,193	8,712	8,751	99,038,700	0	0	0	UNINTERRUPTIBLE POWER SUPPLY	HRDPLANT		
	270,072	8,193	8,712	8,751	99,038,702	0	0	0	DISTRIBUTION PANELBOARD	HRDPLANT		
	270,072	8,193	8,712	8,751	99,038,703	0	0	0	DISTRIBUTION PANELBOARD	HRDPLANT		
	270,072	8,193	8,712	8,757	0	0	0	0	UPS 4 INVERTER	HRDUNIT3	HRD35720000	
	270,072	8,193	8,712	8,757	325,167	0	0	0	SNMP Upgrade - UPS #4 - HRD	HRDUNIT3		
	270,072	8,193	8,712	8,757	99,038,704	0	0	0	DISTRIBUTION PANELBOARD	HRDPLANT		
	270,072	8,193	8,712	8,757	99,038,705	0	0	0	DISTRIBUTION PANELBOARD	HRDPLANT		
	270,072	8,193	8,712	8,763	0	0	0	0	#3 BATTERY BANKS	HRDUNIT3	HRD35750000	
	270,072	8,193	8,712	8,763	99,000,356	0	0	0	INSTALL D.C. DISTRIBUTION BOAR	HRDPLANT		
	270,072	8,193	8,712	8,763	99,029,566	0	0	0	C & D 120 CELL BATTERY BANK	HRDPLANT		
	270,072	8,193	8,712	8,763	99,029,567	0	0	0	C & D 120 CELL BATTERY BANK	HRDPLANT		
	270,072	8,193	8,712	8,763	99,038,706	0	0	0	BATTERY CHARGER	HRDPLANT		
	270,072	8,193	8,712	271,763	0	0	0	0	U3 CABLE RACEWAYS	HRDUNIT3	HRD34800001	
	270,072	8,193	8,712	271,763	99,000,115	0	0	0	INSTALL CABLE TRENCHES AND DUC	HRDPLANT		
	270,072	8,193	8,712	271,763	99,000,330	0	0	0	INSTALL CABLE TRAYS AND CONDUI	HRDPLANT		
	270,072	8,193	8,712	271,763	99,024,411	0	0	0	CABLE TRAY - 2 FT WIDTH	HRDPLANT		
	270,072	8,193	8,712	271,763	99,024,412	0	0	0	METAL CONDUIT 3/4" DIAMETER	HRDPLANT		
	270,072	8,193	8,712	271,764	0	0	0	0	U3 CONTROL CABLES	HRDUNIT3	HRD34800002	
	270,072	8,193	8,712	271,764	99,000,335	0	0	0	INSTALL CONTROL CABLES STAGE I	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,417	0	0	0	#14 AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,418	0	0	0	#16 AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,419	0	0	0	#12-2 CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,420	0	0	0	#12 AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,421	0	0	0	#16 AWG INSTRUMENT CONTROL CAB	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,422	0	0	0	#16 AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,423	0	0	0	#16AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,424	0	0	0	#16 AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,425	0	0	0	#14 AWG CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,426	0	0	0	#16 AWG TYPE TX CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,764	99,024,427	0	0	0	#16 AWG TYPE KX CONTROL CABLE	HRDPLANT		
	270,072	8,193	8,712	271,765	0	0	0	0	U3 POWER CABLES	HRDUNIT3	HRD34800003	
	270,072	8,193	8,712	271,765	99,000,341	0	0	0	INSTALL POWER CABLE #4160 VOLT	HRDPLANT		
	270,072	8,193	8,712	271,765	99,000,343	0	0	0	INSTALL POWER CABLES #600 VOLT	HRDPLANT		
	270,072	8,193	8,712	271,765	99,024,428	0	0	0	#4 AWG POWER CABLE	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	8,193	8,712	271,765	99,024,429	0	0	0	#16 AWG POWER CABLE	HRDPLANT		
	270,072	8,193	8,712	271,766	0	0	0	0	U3 SWITCHGEAR 4160 & 600 VOLT	HRDUNIT3	HRD34800005	
	270,072	8,193	8,712	271,766	99,000,363	0	0	0	INSTALL METALCLAD SWITCHGEAR C	HRDPLANT		
	270,072	8,193	8,712	271,766	99,031,935	0	0	0	CONTROL SYSTEM, SEE PL ASSET 0	HRDPLANT		
	270,072	8,193	8,712	271,766	99,043,203	0	0	0	STUDY FOR METALCLAD SWITCH	HRDPLANT		
	270,072	8,193	8,712	271,766	99,043,227	0	0	0	UPGRADE SYNC CHECK SYSTEM,	HRDPLANT		
	270,072	8,193	8,712	271,767	0	0	0	0	U3 TSI	HRDUNIT3	HRD34800006	
	270,072	8,193	8,712	271,767	99,024,410	0	0	0	BENTLEY NEVADA TURBINE SUPERVI	HRDPLANT		
	270,072	8,193	8,712	301,711	0	0	0	0	UNIT 3 DCS	HRDPLANT		
	270,072	8,193	8,712	309,896	0	0	0	0	600 V Meltric Plugs	HRDUNIT3		
	270,072	8,193	8,712	309,901	0	0	0	0	Boiler prot & Control	HRDUNIT3		
	270,072	8,193	359,304	0	0	0	0	0	UNIT 3 BLANKS AND BLINDS	HRDUNIT3		
700												
	270,072	9,739	0	0	0	0	0	0	HRD WATER TREATMENT &ENVIRONMT	HRDPLANT	HRD97131200	
	270,072	9,739	7,203	0	0	0	0	0	HRD WATER TREATMENT PLANT	HRDPLANT	HRD97100000	
	270,072	9,739	7,203	7,210	0	0	0	0	HRD RAW WATER SYSTEM	HRDPLANT	HRD97110000	
	270,072	9,739	7,203	7,210	7,534	0	0	0	QUARRY BROOK DAM & FISHWAY SYS	HRDPLANT	HRD98652000	
	270,072	9,739	7,203	7,210	8,937	0	0	0	RAW WATER PUMP SOUTH	HRDPLANT	HRD97111031	
	270,072	9,739	7,203	7,210	8,975	0	0	0	RAW WATER PUMP NORTH	HRDPLANT	HRD97111030	
	270,072	9,739	7,203	7,210	99,000,041	0	0	0	PORTABLE DOMESTIC WELL	HRDPLANT		
	270,072	9,739	7,203	7,210	99,000,042	0	0	0	BALANCE OF WATER SUPPLY SYSTEM	HRDPLANT		
	270,072	9,739	7,203	7,210	99,000,043	0	0	0	SUPPLY WATER TO PLANT	HRDPLANT		
	270,072	9,739	7,203	7,211	0	0	0	0	HRD DOMESTIC WATER SYSTEM	HRDPLANT	HRD97140000	
	270,072	9,739	7,203	7,247	0	0	0	0	WT PLANT & ETAPRO COMPUTERS	HRDPLANT	HRD97930000	
	270,072	9,739	7,203	7,247	99,034,737	0	0	0	PERFORMANCE MONITORING UNITS	HRDPLANT		
	270,072	9,739	7,203	9,857	0	0	0	0	GENERAL SERVICE COOLING WATER	HRDPLANT	HRD97112031	
	270,072	9,739	7,203	9,857	99,000,090	0	0	0	GENERAL SERVICE COOLING SYSTEM	HRDPLANT		
	270,072	9,739	7,203	286,051	0	0	0	0	ANALYICAL SYSTEMS	HRDENVSITES		
	270,072	9,739	7,203	286,051	6,720	0	0	0	#1 ANALYTICAL SYSTEMS	HRDUNIT1	HRD14600000	
	270,072	9,739	7,203	286,051	8,135	0	0	0	#2 ANALYTICAL SYSTEMS	HRDUNIT2	HRD24600000	
	270,072	9,739	7,203	286,051	8,695	0	0	0	#3 ANALYTICAL SYSTEMS	HRDUNIT3	HRD34600000	
	270,072	9,739	7,203	286,052	0	0	0	0	CHEMICAL DOSING SYSTEMS	HRDENVSITES		
	270,072	9,739	7,203	286,052	7,055	0	0	0	#1 CHEMICAL DOSING SYSTEM	HRDUNIT1	HRD13260000	
	270,072	9,739	7,203	286,052	7,055	99,000,250	0	0	INSTALL CHEMICAL FEED SYSTEM -	HRDPLANT		
	270,072	9,739	7,203	286,052	7,055	99,000,252	0	0	INSTALL CHEMICAL FEED PUMPS ON	HRDPLANT		
	270,072	9,739	7,203	286,052	7,055	99,000,387	0	0	INSTALL RECORDING INSTRUMENT F	HRDPLANT		
	270,072	9,739	7,203	286,052	7,055	99,031,324	0	0	ADDITIONAL COSTS TO CHEMICAL F	HRDPLANT		
	270,072	9,739	7,203	286,052	8,026	0	0	0	#2 CHEMICAL DOSING SYSTEM	HRDUNIT2	HRD23260000	
	270,072	9,739	7,203	286,052	8,026	99,043,184	0	0	INSTALL CHEMICAL FEED SYST	HRDPLANT		
	270,072	9,739	7,203	286,052	8,026	99,043,185	0	0	INSTALL CHEMICAL FEED PUMP	HRDPLANT		
	270,072	9,739	7,203	286,052	8,026	99,043,198	0	0	INSTALL RECORDING INSTRUME	HRDPLANT		
	270,072	9,739	7,203	286,052	8,580	0	0	0	#3 CHEMICAL DOSING SYSTEM	HRDUNIT3	HRD33260000	
	270,072	9,739	7,203	286,052	8,580	99,000,251	0	0	INSTALL CHEMICAL FEED SYSTEM S	HRDPLANT		
	270,072	9,739	7,203	286,052	8,580	99,043,186	0	0	INSTALL CHEMICAL FEED PUMP	HRDPLANT		
	270,072	9,739	7,203	286,053	0	0	0	0	CONDENSATE POLISHERS	HRDENVSITES		
	270,072	9,739	7,203	286,053	6,967	0	0	0	#1 CONDENSATE POLISHER PLANT	HRDUNIT1	HRD14410000	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	9,739	7,203	286,053	7,401	0	0	0	CONDENSATE POLISHER MCC A1-3	HRDUNIT1	HRD15333000	
	270,072	9,739	7,203	286,053	8,127	0	0	0	#2 CONDENSATE POLISHER PLANT	HRDUNIT2	HRD24410000	
	270,072	9,739	7,203	286,053	8,171	0	0	0	CONDENSATE POLISHER MCC B1-3	HRDUNIT2	HRD25333000	
	270,072	9,739	7,203	286,053	8,686	0	0	0	#3 CONDENSATE POLISHER PLANT	HRDUNIT3	HRD34410000	
	270,072	9,739	7,203	286,053	8,727	0	0	0	CONDENSATE POLISHER BAB 3-3	HRDUNIT3	HRD35343000	
	270,072	9,739	7,203	286,053	99,000,214	0	0	0	INSTALL CONDENSATION POLISHERS	HRDPLANT		
	270,072	9,739	7,203	286,054	0	0	0	0	FERROUS SULPHATE SYSTEMS	HRDENVSITES		
	270,072	9,739	7,203	286,054	9,509	0	0	0	UNIT #1 FER/SULP TANK & PIPING	HRDPLANT	HRD98175210	
	270,072	9,739	7,203	286,054	9,510	0	0	0	UNIT #2 FER/SULP TANK & PIPING	HRDPLANT	HRD98175220	
	270,072	9,739	7,203	286,054	9,511	0	0	0	UNIT #3 FER/SULP TANK & PIPING	HRDPLANT	HRD98175230	
	270,072	9,739	7,203	286,057	0	0	0	0	WATER TREATMENT PLANT SYSTEMS	HRDENVSITES		
	270,072	9,739	7,203	286,057	6,802	0	0	0	W.T.P. BRINE SYSTEM	HRDPLANT	HRD97170000	
	270,072	9,739	7,203	286,057	7,185	0	0	0	WATER TREAT & MCC C5	HRDUNIT1	HRD15560000	
	270,072	9,739	7,203	286,057	7,212	0	0	0	W.T.P. SULFURIC ACID SYSTEM	HRDPLANT	HRD97160000	
	270,072	9,739	7,203	286,057	7,213	0	0	0	WTP FLOCULANT CHEMICAL INJECT.	HRDPLANT	HRD97180000	
	270,072	9,739	7,203	286,057	7,214	0	0	0	W.T.P. PRIMARY TRAINS	HRDPLANT	HRD97131000	
	270,072	9,739	7,203	286,057	7,220	0	0	0	W.T.P. MIXED BEDS	HRDPLANT	HRD97137000	
	270,072	9,739	7,203	286,057	7,422	0	0	0	W.T.P. CLARIFIER SYSTEM	HRDPLANT	HRD97121000	
	270,072	9,739	7,203	286,057	8,748	0	0	0	W T P & AUX. BLR MCC WTP-34	HRDUNIT3		
	270,072	9,739	7,203	286,057	9,864	0	0	0	W.T.P. SAND FILTER SYSTEM	HRDPLANT	HRD97122100	
	270,072	9,739	7,203	286,057	9,879	0	0	0	W.T.P. CLEARWELL SYSTEM	HRDPLANT	HRD97123000	
	270,072	9,739	7,203	286,057	9,995	0	0	0	6400 CHEMICAL INJECTION	HRDPLANT	HRD97181332	
	270,072	9,739	7,203	286,057	10,037	0	0	0	W.T.P. CAUSTIC SYSTEM	HRDPLANT	HRD97150000	
	270,072	9,739	7,203	309,729	0	0	0	0	ANALYTICAL BALANCE	HRDOFFICE		
	270,072	9,739	7,203	309,825	0	0	0	0	ICP OES 6500 DUO MASS SPEC.	HRDOFFICE		
	270,072	9,739	7,203	324,333	0	0	0	0	Lab Instr.	HRDPLANT		
	270,072	9,739	7,203	331,925	0	0	0	0	METTLER ANALYTICAL BALANCE	HRDOFFICE		
	270,072	9,739	7,203	359,305	0	0	0	0	WTP BLANKS AND BLINDS	HRDPLANT		
	270,072	9,739	7,203	99,000,188	0	0	0	0	ACID TREATMENT PLANT UNIT #3	HRDPLANT		
	270,072	9,739	7,203	99,000,189	0	0	0	0	INSTALL ACID & CAUSTIC TREATME	HRDPLANT		
	270,072	9,739	7,203	99,000,191	0	0	0	0	INSTALL BALANCE OF PLANT(WATER	HRDPLANT		
	270,072	9,739	7,203	99,000,192	0	0	0	0	INSTALL BALANCE OF PLANT(WATE	HRDPLANT		
	270,072	9,739	7,203	99,000,193	0	0	0	0	BALANCE OF PLANT UNIT #3 (WATE	HRDPLANT		
	270,072	9,739	7,203	99,000,196	0	0	0	0	BALANCE OF PLANT FOR WATER TRE	HRDPLANT		
	270,072	9,739	7,203	99,000,197	0	0	0	0	INSTALL STORM DRAINAGE PIPE FO	HRDPLANT		
	270,072	9,739	7,203	99,004,050	0	0	0	0	PRECISION SCIENTIFIC SAYBOLT	HRDOFFICE	FA-003095	
	270,072	9,739	7,203	99,004,710	0	0	0	0	WILL MICROSCOPE C/W HYGENION L	HRDOFFICE	FA-003098	
	270,072	9,739	7,203	99,004,773	0	0	0	0	METTLER ANALYTICAL BALANCE	HRDOFFICE	FA-003093	
	270,072	9,739	7,203	99,004,799	0	0	0	0	METTLER ELECTRONIC BALANCE	HRDOFFICE	FA-003094	
	270,072	9,739	7,203	99,026,876	0	0	0	0	NEOTRONICS MINIGAS NICAD	HRDOFFICE	FA-02276	
	270,072	9,739	7,203	99,028,541	0	0	0	0	CONSOLIDATED CONTINENTAL S-C-T	HRDOFFICE	FA-003096	
	270,072	9,739	7,203	99,028,542	0	0	0	0	CONSOLIDATED CONTINENTAL PORTA	HRDOFFICE	FA-003381	
	270,072	9,739	7,203	99,028,543	0	0	0	0	CONSOLIDATED CONTINENTAL PORTA	HRDOFFICE	FA-003432	
	270,072	9,739	7,203	99,028,544	0	0	0	0	BRANSON ULTRASONIC CLEANER	HRDOFFICE	FA-003433	
	270,072	9,739	7,203	99,029,555	0	0	0	0	UPGRADE WASTE WATER TREATMENT	HRDPLANT		
	270,072	9,739	7,203	99,030,074	0	0	0	0	DIGITAL LAB TESTER STIRRER, PR	HRDOFFICE	FA-003104	

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by: MDV
Project:	Holyrood Decommissioning		Date: 19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.: 0
			Issue Date: 19-Dec-12
			Checked:

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	9,739	7,203	99,030,076	0	0	0	0	FISHER ACCUMBT PH METER 50	HRDOFFICE	FA-003099	
	270,072	9,739	7,203	99,030,401	0	0	0	0	GRASEBY HI-VOL CALIBRATOR	HRDOFFICE	FA-04433	
	270,072	9,739	7,203	99,031,785	0	0	0	0	BALANCE OF WATER TREATMENT PLA	HRDPLANT		
	270,072	9,739	7,203	99,031,926	0	0	0	0	ADDT'L COST, BAL OF WATER TREA	HRDPLANT		
	270,072	9,739	7,203	99,032,816	0	0	0	0	SCIENTECH ANALYTICAL BALANCE	HRDOFFICE	FA-003459	
	270,072	9,739	7,203	99,034,126	0	0	0	0	FISHER VERSA BATH	HRDOFFICE	FA-003100	
	270,072	9,739	7,203	99,034,283	0	0	0	0	UPGRADE WATER TREATMENT PLANT	HRDPLANT		
	270,072	9,739	7,203	99,035,816	0	0	0	0	GAS ANALYZER - DATALOGGER	HRDOFFICE	FA-003447	
	270,072	9,739	7,203	99,039,368	0	0	0	0	SO2 ANALYZER	HRDOFFICE		
	270,072	9,739	7,203	99,039,948	0	0	0	0	SPECTROPHOTOMETER DR4000	HRDOFFICE		
	270,072	9,739	7,203	99,040,811	0	0	0	0	NEOTRONICS MINIGAS NICAD	HRDOFFICE	FA-02274	
100												
	270,072	9,739	7,260	0	0	0	0	0	ENVIRONMENTAL MONITORING	HRDPLANT	HRD98130000	
	270,072	9,739	7,260	7,472	0	0	0	0	MET STATION - GREEN ACRES	HRDPLANT	HRD98136000	
	270,072	9,739	7,260	7,472	324,336	0	0	0	Upgrade Meteorological Station	HRDENVSITES	ENV. SITE	
	270,072	9,739	7,260	9,725	0	0	0	0	EMISS MON STN BUTTERPOT RD	HRDPLANT	HRD98131100	
	270,072	9,739	7,260	9,725	291,515	0	0	0	AIR MONITORING SYSTEM	HRDPLANT		
	270,072	9,739	7,260	9,725	324,310	0	0	0	Upgrade SO2 Monitors	HRDENVSITES		
	270,072	9,739	7,260	9,725	99,023,658	0	0	0	SO2 SULPHER DIOXIDE AMBIENT	HRDPLANT		
	270,072	9,739	7,260	9,725	99,023,663	0	0	0	YOKOGAWA STRIP CHART RECORDER	HRDPLANT		
	270,072	9,739	7,260	9,725	99,023,664	0	0	0	BEL-ART DESSICATING CABINET C/	HRDPLANT		
	270,072	9,739	7,260	9,725	99,023,668	0	0	0	HIGH VOLUME AIR SAMPLING EQUIP	HRDPLANT		
	270,072	9,739	7,260	9,725	99,023,672	0	0	0	DATA LOGGERS C/W TEMPERATURE S	HRDPLANT		
	270,072	9,739	7,260	9,725	99,027,847	0	0	0	YOKOGAWA STRIP CHART RECORDER	HRDPLANT		
	270,072	9,739	7,260	9,725	99,027,848	0	0	0	CITADEL LINE CONDITIONERS	HRDPLANT		
	270,072	9,739	7,260	9,726	0	0	0	0	EMISS MON STN GREEN ACRES	HRDPLANT	HRD98131200	
	270,072	9,739	7,260	9,726	291,534	0	0	0	AIR MONITORING SYSTEM	HRDPLANT		
	270,072	9,739	7,260	9,726	325,152	0	0	0	Upgrade SO2 Monitors	HRDENVSITES		
	270,072	9,739	7,260	9,726	99,023,666	0	0	0	HIGH VOLUME AIR SAMPLING EQUIP	HRDPLANT		
	270,072	9,739	7,260	9,726	99,023,667	0	0	0	HIGH VOLUME AIR SAMPLING EQUIP	HRDPLANT		
	270,072	9,739	7,260	9,726	99,027,845	0	0	0	PRESSURE TRANSDUCER/FLOW METER	HRDPLANT		
	270,072	9,739	7,260	9,726	99,027,846	0	0	0	FLOURESCENT SULPHUR DIOXIDE AN	HRDPLANT		
	270,072	9,739	7,260	9,726	99,043,206	0	0	0	SO2 SULPHER DIOXIDE AMBIEN	HRDPLANT		
	270,072	9,739	7,260	9,726	99,043,209	0	0	0	YOKOGAWA STRIP CHART RECOR	HRDPLANT		
	270,072	9,739	7,260	9,726	99,043,212	0	0	0	BEL-ART DESSICATING CABINE	HRDPLANT		
	270,072	9,739	7,260	9,726	99,043,215	0	0	0	DATA LOGGERS C/W TEMPERATU	HRDPLANT		
	270,072	9,739	7,260	9,726	99,043,218	0	0	0	YOKOGAWA STRIP CHART RECOR	HRDPLANT		
	270,072	9,739	7,260	9,726	99,043,221	0	0	0	CITADEL LINE CONDITIONERS	HRDPLANT		
	270,072	9,739	7,260	9,727	0	0	0	0	EMISS MON STN INDIAN POND RD	HRDPLANT	HRD98131300	
	270,072	9,739	7,260	9,727	291,535	0	0	0	AIR MONITORING SYSTEM	HRDPLANT		
	270,072	9,739	7,260	9,727	325,153	0	0	0	Upgrade SO2 Monitors	HRDENVSITES		
	270,072	9,739	7,260	9,727	99,023,670	0	0	0	HIGH VOLUME AIR SAMPLING EQUIP	HRDPLANT		
	270,072	9,739	7,260	9,727	99,043,207	0	0	0	SO2 SULPHER DIOXIDE AMBIEN	HRDPLANT		
	270,072	9,739	7,260	9,727	99,043,210	0	0	0	YOKOGAWA STRIP CHART RECOR	HRDPLANT		
	270,072	9,739	7,260	9,727	99,043,213	0	0	0	BEL-ART DESSICATING CABINE	HRDPLANT		
	270,072	9,739	7,260	9,727	99,043,216	0	0	0	DATA LOGGERS C/W TEMPERATU	HRDPLANT		

Client:	Newfoundland and Labrador Hydro	STANTEC CONSULTING	Prepared by:	MDV
Project:	Holyrood Decommissioning		Date:	19-Dec-12
Project No:	133545705	WBS CROSS REFERENCE	Revision No.:	0
			Issue Date:	19-Dec-12
			Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	9,739	7,260	9,727	99,043,219	0	0	0	YOKOGAWA STRIP CHART RECOR	HRDPLANT		
	270,072	9,739	7,260	9,727	99,043,222	0	0	0	CITADEL LINE CONDITIONERS	HRDPLANT		
	270,072	9,739	7,260	9,728	0	0	0	0	EMISS MON STN LAWRENCE POND RD	HRDPLANT	HRD98131400	
	270,072	9,739	7,260	9,728	291,536	0	0	0	AIR MONITORING SYSTEM	HRDPLANT		
	270,072	9,739	7,260	9,728	325,154	0	0	0	Upgrade SO2 Monitors	HRDENVSITES		
	270,072	9,739	7,260	9,728	99,023,671	0	0	0	HIGH VOLUME AIR SAMPLING EQUIP	HRDPLANT		
	270,072	9,739	7,260	9,728	99,043,208	0	0	0	SO2 SULPHER DIOXIDE AMBIEN	HRDPLANT		
	270,072	9,739	7,260	9,728	99,043,211	0	0	0	YOKOGAWA STRIP CHART RECOR	HRDPLANT		
	270,072	9,739	7,260	9,728	99,043,214	0	0	0	BEL-ART DESSICATING CABINE	HRDPLANT		
	270,072	9,739	7,260	9,728	99,043,217	0	0	0	DATA LOGGERS C/W TEMPERATU	HRDPLANT		
	270,072	9,739	7,260	9,728	99,043,220	0	0	0	YOKOGAWA STRIP CHART RECOR	HRDPLANT		
	270,072	9,739	7,260	9,728	99,043,223	0	0	0	CITADEL LINE CONDITIONERS	HRDPLANT		
	270,072	9,739	7,260	278,551	0	0	0	0	CONTINUOUS EMISSIONS MONITOR	HRDPLANT		
	270,072	9,739	7,260	278,551	278,552	0	0	0	STACK PROBES	HRDPLANT		
	270,072	9,739	7,260	278,551	278,553	0	0	0	TUBE BUNDLES	HRDPLANT		
	270,072	9,739	7,260	278,551	278,554	0	0	0	GAS ANALYZER/SWITCHING CABINET	HRDPLANT		
	270,072	9,739	7,260	278,551	278,555	0	0	0	PC DATA ACQUISTION SYSTEM	HRDPLANT		
	270,072	9,739	7,260	278,551	278,555	342,549	0	0	CEMS DATA ACQUISITION SYSTEM	HRDPLANT		
	270,072	9,739	7,260	278,551	278,556	0	0	0	DCW AND ETAPRO	HRDPLANT		
	270,072	9,739	7,260	278,551	278,557	0	0	0	CAL GAS STORAGE AND	HRDPLANT		
	270,072	9,739	7,260	278,551	333,651	0	0	0	Fall Protection	HRDPLANT		
	270,072	9,739	7,260	278,551	333,659	0	0	0	CEMS Ventilation System	HRDPLANT		
	270,072	9,739	7,260	278,551	342,548	0	0	0	GAS ANALYSER/CABINET (PG-7)	HRDPLANT		
	270,072	9,739	7,260	324,289	0	0	0	0	Volumetric Air Flow Calibrator	HRDPLANT		
	270,072	9,739	7,260	324,334	0	0	0	0	BAM Enclosure	HRDENVSITES		
	270,072	9,739	7,260	325,151	0	0	0	0	EMISS MON STN MOBILE SITE	HRDPLANT		
	270,072	9,739	7,260	325,151	325,155	0	0	0	Upgrade SO2 Monitors	HRDENVSITES		
	270,072	9,739	7,260	99,023,673	0	0	0	0	MISCELLANEOUS SPARE PARTS	HRDPLANT		
	270,072	9,739	7,260	99,036,224	0	0	0	0	Opacity Emissions Monitoring	HRDPLANT		
	270,072	9,739	7,260	99,036,225	0	0	0	0	Opacity Emissions Monitoring	HRDPLANT		
	270,072	9,739	7,260	99,036,226	0	0	0	0	Opacity Emissions Monitoring	HRDPLANT		
	270,072	9,739	7,260	99,038,620	0	0	0	0	Thermatel Thermal Dispersion	HRDPLANT		
	270,072	9,739	7,260	99,038,621	0	0	0	0	Thermatel Thermal Dispersion	HRDPLANT		
	270,072	9,739	7,260	99,041,230	0	0	0	0	MOBILE AMBIENT MONITORIN SYSTE	HRDPLANT		
700												
	270,072	9,739	10,038	0	0	0	0	0	HRD WASTE WATER TREATMNT SYSTM	HRDPLANT	HRD98164000	
	270,072	9,739	10,038	7,258	0	0	0	0	SEWAGE DISPOSAL	HRDPLANT	HRD98110000	
	270,072	9,739	10,038	7,258	99,000,039	0	0	0	SEWAGE DISPOSAL SYSTEM STAGE I	HRDPLANT		
	270,072	9,739	10,038	7,258	99,000,040	0	0	0	INSTALL SEWAGE DISPOSAL SYSTEM	HRDPLANT		
	270,072	9,739	10,038	7,258	99,039,422	0	0	0	Sewage disposal system	HRDPLANT		
	270,072	9,739	10,038	7,263	0	0	0	0	OIL/WATER SEPARATORS	HRDPLANT	HRD98160000	
	270,072	9,739	10,038	7,263	99,003,534	0	0	0	OIL SEPARATOR SYSTEM	HRDPLANT		
	270,072	9,739	10,038	7,405	0	0	0	0	WASTE WATER TREATMENT MCC C12	HRDUNIT1	HRD15531000	
	270,072	9,739	10,038	7,473	0	0	0	0	SUMPS & PUMPS/PIPING	HRDPLANT	HRD98161000	
100												
	270,072	9,739	10,038	10,053	0	0	0	0	CONTROL WASTE LANDFILL	HRDPLANT	HRD98167100	

Client:	Newfoundland and Labrador Hydro
Project:	Holyrood Decommissioning
Project No:	133545705

STANTEC CONSULTING

WBS CROSS REFERENCE

Prepared by:	MDV
Date:	19-Dec-12
Revision No.:	0
Issue Date:	19-Dec-12
Checked:	

Stantec	Newfoundland and Labrador Hydro Asset Registry								Description	Location	Unit No.	Comments
WBS	Asset	Asset	Asset	Asset	Asset	Asset	Asset	Asset				
	270,072	9,739	10,038	10,053	303,248	0	0	0	Landfill Sampling Apparatus	HRDENVSITES		
	270,072	9,739	10,038	10,053	99,032,475	0	0	0	SOLID WASTE DISPOSAL SITE	HRDPLANT		
	270,072	9,739	10,038	10,053	99,032,833	0	0	0	WASTE DUMPSTERS FOR INTERIM	HRDOFFICE		
	270,072	9,739	10,038	10,053	99,034,289	0	0	0	SOLID WASTE DISPOSAL SITE	HRDPLANT		
	270,072	9,739	10,038	303,249	0	0	0	0	Regen Waste Treatment Study	HRDENVSITES		
700												
	270,072	9,739	10,038	99,003,527	0	0	0	0	CONCRETE BASINS FOR W.W.T.S.	HRDPLANT		
	270,072	9,739	10,038	99,003,528	0	0	0	0	CLARIFIER SYSTEM FOR W.W.T.S.	HRDPLANT		
	270,072	9,739	10,038	99,003,529	0	0	0	0	CAUSTIC SODA STORAGE SYSTEM FO	HRDPLANT		
	270,072	9,739	10,038	99,003,530	0	0	0	0	FILTER PRESS SYSTEM AT W.W.T.S	HRDPLANT		
	270,072	9,739	10,038	99,003,531	0	0	0	0	BALANCE OF WASTE WATER TREATME	HRDPLANT		
	270,072	9,739	10,038	99,026,251	0	0	0	0	DOSING TANK & AGITATION SYSTEM	HRDPLANT		

APPENDIX 3

Opinion of Probable Cost

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

Stantec

STANTEC CONSULTING
Opinion of Probable Construction Cost
Summary

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	ASSET #	DESCRIPTION	APPROXIMATE SCRAP METAL UNIT	APPROXIMATE SCRAP METAL QUANTITY	TOTAL COST
	1	270072	PROJECT TOTAL DECOMMISSIONING COSTS		15212	$29,158,300
100	2		SITE AND ENVIRONMENT		25	$7,135,000
200	3		BUILDINGS AND STRUCTURES		3534	$5,241,700
300	4		BOILER AND AUXILIARIES		8058	$4,342,000
400	5		TURBINE, GENERATOR AND AUXILIARIES		1500	$341,300
500	6		ELECTRICAL		720	$2,376,300
600	8		INSTRUMENTATION & CONTROL		0	$0
700	9		COMMON SERVICES		1375	$2,692,000
800	10		CONSTRUCTION			$3,400,000
900	11		ENGINEERING & ADMINISTRATION			$3,630,000
	12					
-	13					
-	14					
-	15					
-	16					
-	17					
-	18					
-	19					
-	20					
-	21					
-	25					
-	26					
-	27					
-	28					
-	29					
-	30					
-	31					
-	32					
-	33					
	34					
-	35					
-	36					
-	37					
-	38					
-	39					
-	40					

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Site and Environment
WBS 100

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour					Material		Labour & Material		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
100	0			**SITE AND ENVIRONMENT - Total Cost**					0		0		0		7,135,000	25	7,135,000
100	1			**SITE ROUGH GRADING AND LANDSCAPING**					0		0		0		600,000	0	600,000
	2			THIS ITEM INCLUDES	1	LS			0		0		0	600,000	600,000	0	600,000
				-Rehabilitate Area after Road to Marine Terminal is Removed					0				0		0	0	0
	3			-Filling of all Depressions, Pits, Trenches, Basements, etc with Crushed Concrete					0		0		0		0	0	0
	5			-Rough Grading of Fuel Tank Farm Area					0		0		0		0	0	0
	6			-Rehabilitation of Fuel Tank Farm Area					0		0		0		0	0	0
	7			-Rough Grading of the Area of the Site on the North Side of the Plant					0		0		0		0	0	0
	8			-Rehabilitation of the Area of the Site on the North Side of the Plant					0		0		0		0	0	0
	9								0		0		0		0	0	0
100	10			**SITE ACCESS (Roads, Parking, Fencing)**					0		0		0		120,000	0	120,000
	11			THIS ITEM INCLUDES	1	LS			0		0		0	120,000	120,000	0	120,000
				-Removal of Road from Marine Terminal to the Tank Farm													
	13			-Rehabilitation of the East-West road on the North side of the Plant.					0		0		0		0	0	0
	14			-Rehabilitatation of the East-West road on the South side of the Plant.					0		0		0		0	0	0
	15			-Rehabilitation of the North South Road on the East Side of the Plant					0		0		0		0	0	0
	16								0		0		0		0	0	0
	17								0		0		0		0	0	0
100	18			**SITE SERVICES**					0		0		0		100,000	25	100,000
				THIS ITEM INCLUDES	1	LS			0				0	100,000	100,000	0	100,000
	20			- Removal of 84" Diameter CMP From West Vacuum Pit to Conception Bay					0		0		0		0	0	0
	21			-Removal of Grating & Steel Frame from Top of Vacuum Pit					0		0		0		0	0	0
	22			-Removal of Concrete Walls of Pit to 3 ft Below Grade					0		0		0		0	0	0
	23			-Removal of 42" Diameter Concrete Pipe on West/North Side of Plant (Warm Water Recirculation)					0		0		0		0	0	0
	24			-Removal of 42" Dia. Concrete Pipe on South/East/North Side of Plant (Warm Water Recirculation)					0		0		0		0	0	0
	35			-Remove 60" Diameter Concrete Pipe on West Side of Plant (CW Supply Line to Unit No. 2)					0		0		0		0	0	0
	36			-Remove of 60" Diameter Concrete Pipe on West Side of Plant (CW Supply Line to Unit No. 1)					0		0		0		0	0	0
	37			-Removal of 60" Diameter Concrete Pipe on North Side of Plant (CW Supply Line to Unit No. 3)					0		0		0		0	0	0
	38			-Removal of 18" Diameter Drain on North Side of Plant					0		0		0		0	0	0
	39			-Removal of Oil/Water Seperators Nos 2 & 3					0		0		0		0	0	0
	40			-Remove Approximately 15 Manholes					0		0		0		0	0	0
	41			-Open Ends of Pipes 12" Diameter and Smaller to be Plugged with Concrete & may be Abandoned					0		0		0		0	0	0
	32			-Removal of Utilidor Between Power House and Pump House #1					0		0		0		0	0	0
				-Crushing Concrete Rubble to 6" Minus & Removal of Reinforcing Steel					0		0		0		0	25	
									0		0		0		0	0	
	35								0		0		0		0	0	0
100	36			**WASTE LANDFILL**					0		0		0		390,000	0	390,000
	37			**THIS ITEM INCLUDES**	1	LS			0		0		0	390,000	390,000	0	390,000
				-Installation of Cover/Cap on the Solid Waste Landfill													
	39			-Removal Leachate Holding Pond after Cover/Cap is Installed on the Solid Waste Landfill Site					0		0		0		0	0	0
	40								0		0		0		0	0	0
	41								0		0		0		0	0	0
100	42			**ENVIRONMENTAL ASSESSMENT, REMEDIATION & COMPLIANCE**					0		0		0		5,925,000	0	5,925,000
	43			Environmental Site Assessment	1	LS			0		0		0	1,275,000	1,275,000	0	1,275,000
	44			Environmental Impact Assessment RegistrationSite Assessment	1	LS			0		0		0	50,000	50,000	0	50,000
	45			Site Remediation	1	LS			0		0		0	4,600,000	4,600,000	0	4,600,000
	46								0		0		0		0	0	0
	74								0		0		0		0	0	

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
WBS 200

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour: hr per Unit	Labour: Prod. Factor	Labour: Total Hours	Labour: Rate	Labour: Cost	Material: Unit Cost	Material: Cost	Labour & Material: Unit Cost	Labour & Material: Cost	Metals: Ton	Total Cost
200	0			**TOTAL FOR BUILDINGS and STRUCTURES**							0		0		5,241,700	3,534	5,241,700
	1		7283	**MAIN POWERHOUSE**											1,775,900	3,115	1,775,900
	2			REMOVAL OF ACM MATERIALS													
	3			-Cladding	1	LS					0		0	281,100	281,100	0	281,100
	4			-Roofing	1	LS								113,000	113,000	0	113,000
	5			DEMOLITION OF REMAINDER OF POWERHOUSE BUILDING INCLUDING	1	LS								1,381,800	1,381,800	3,000	1,381,800
	6			-Removal of Overhead Doors							0		0		0	0	0
	7			-Removal of Structural Steel							0		0		0	0	0
	8			-Removal of Miscellaneous Metals							0		0		0	0	0
	9			-Removal of Concrete Building Foundations							0		0		0	0	0
	10			-Removal of Concrete Equipment Foundations							0		0		0	0	0
	11			-Removal of Concrete Slabs on Grade					0		0		0		0	0	0
	12			-Crushing Concrete Rubble to 6" Minus & Removal of Reinforcing Steel					0		0		0		0	115	0
	13			-Fill Depressions and Cavities with Crushed Concrete					0		0		0		0	0	0
	14								0		0		0		0	0	0
	15								0		0		0		0	0	0
200	16			**COMMON SERVICES BUILDINGS (WW TREATMENT & PORTION OF PUMPHOUSE #1)**					0		0		0		571,200	176	571,200
	17			DEMOLITION OF COMMON SERVICES BUILDINGS	1	LS			0		0		0	571,200	571,200	0	571,200
	18			-Removal of Structural Steel					0		0		0		0	132	0
	19			-Removal of Miscellaneous Metals					0		0		0		0	0	0
	20			- Removal of Concrete Building Foundations					0		0		0		0	0	0
	21			-Removal of Concrete Equipment Foundations					0		0		0		0	0	0
	22			-Removal of Concrete Slabs on Grade					0		0		0		0	0	0
	23			-Crushing Concrete Rubble to 6" Minus & Removal of Reinforcing Steel					0		0		0		0	44	0
	24			-Fill Depressions & Cavities with Crushed Concrete					0		0		0		0	0	0
	25								0		0		0		0	0	0
	26								0		0		0		0	0	0
200	27			**MARINE STRUCTURES**					0		0		0		810,600	148	810,600
	28			THIS ITEM INCLUDES	1	LS			0		0		0	810,600	810,600	120	810,600
				-Removal of Jetty					0		0					0	0
	30			-Removal of Bridge to Jetty					0		0		0		0	0	0
	31			-Removal of Walkway along Shoreline					0		0		0		0	0	0
	32			-Removal of Guard House					0		0		0		0	0	0
	33			-Removal of Fencing					0		0		0		0	0	0
	34			-Recoverery of All Debris from Water					0		0		0		0	0	0
	35			-Crushing of Concrete Rubble to 6" Minus & Remove Reinforcing Steel					0		0		0		0	28	0
	36			-Filling Depressions & Cavities with Crushed Concrete					0		0		0		0	0	0
	37								0		0		0		0	0	0
	38								0		0		0		0	0	0
200	39			**HRD AUXILARY BUILDINGS**					0		0		0		60,000	38	60,000
	40			THIS ITEM INCLUDES	1	LS			0		0		0	60,000	60,000	27	60,000
	41			-Removal of Complete Gas Turbine building and Foundation to 3 ft below Grade					0		0		0		0	0	0
	42			-Removal of ERT Center (Old Guard House) Building and Foundation to 3ft Below Grade					0		0		0		0	0	0
	43			-Crushing Concrete Rubble to 6" Minus & Removal of Reinforcing Steel					0		0		0		0	11	0
	44			-Filling Depressions & Cavities with Crushed Concrete					0		0		0		0	0	0
200				TURBINE GENERATOR BUILDING											252,000	62	252,000

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Buildings and Structures
WBS 200

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour					Material		Labour & Material		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
				THIS ITEM INCLUDES	1	LS								252,000	252,000		252,000
				-Removal of Concrete Turbine /Generator Pedestal Foundations Units 1 & 2												0	
				-Crushing Concrete Rubble to 6" Minus & Removal of Reinforcing Steel												62	
															0		
	52								0		0		0		0		0
200	53			DEMOLITION FACILITY DECOMMISSIONING					0		0		0		1,772,000	0	1,772,000
	51			-Chemical Removal	1	LS			0		0		0	150,000	150,000	0	150,000
	52			-Industrial Cleaning	1	LS			0		0		0	1,447,000	1,447,000	0	1,447,000
	53			-Asbestos Abatement	1	LS			0		0		0	175,000	175,000	0	175,000
	57								0		0		0		0	0	0
	58								0		0		0		0	0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

Stantec

STANTEC CONSULTING
Opinion of Probable Construction Cost
Boiler and Auxilaries
WBS 300

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour					Material		Labour & Materials		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
300	0			BOILERS AND AUXILARIES - TOTAL DEMOLITION COST					0		0		0		4,342,000	8,058	4,342,000
	1			SUBTOTAL FOR BOILER COMPONENTS INDICATED	1	LS								2,694,500	2,694,500	7,500	2,694,500
	2		6699	BOILER PLANT (Units 1, 2, & 3)					0		0		0		0	0	IN SUBTOTAL
	3			THIS ITEM INCLUDES					0		0		0		0		0
			6700	-Removal of the Complete Boilers Including Water Walls, Burner Fronts and Ash Pits													
	5			-Removal of Boiler Fronts and Rear Wall Headers					0		0		0		0	0	0
	6								0		0		0		0	0	0
300	7			BOILER AUXILLARIES (Units 1, 2, & 3)					0		0		0		0	IN SUBTOTAL	IN SUBTOTAL
	8			THIS ITEM INCLUDES					0		0		0		0	0	0
	18			-Removal of the Reheater and Super heater Sections and Piping									0		0	0	0
	10			-Removal of the Steam Drums and Associated Piping					0		0		0		0	0	0
	11			-Removal of the Main Steam Lines to Turbines					0		0		0		0	0	0
	12			-Remove Econimizer and Condensate Tank					0		0		0		0	0	0
	13			-Removal of the Miscellaneous Steam and Condensate Piping					0		0		0		0	0	0
	14			-Removal of the Boiler Blow Down Tank and Blowdown Piping					0		0		0		0	0	0
	15								0		0		0		0	0	0
300	16			FUEL HANDLING SYSTEMS (units 1, 2, &3)					0		0		0		0	IN SUBTOTAL	IN SUBTOTAL
	17		6987	THIS ITEM INCLUDES					0		0		0		0	0	0
				-Removal of the Main Heavy Fuel Oil Pumps									0		0	0	0
	19			-Remove Heavy Fuel Oil Heat Exchangers and Miscellaneous Equipment					0		0		0		0	0	0
	20			-Removal of the Heavy Fuel Oil Piping					0		0		0		0	0	0
	21			-Remove Light Oil Pumps					0		0		0		0	0	0
	22			-Remove Light oil Piping					0		0		0		0	0	0
	23								0		0		0		0	0	0
300	24			BOILER AIR SYSTEMS Units 1, 2, &3)					0		0		0		0	IN SUBTOTAL	IN SUBTOTAL
	25		6703	THIS ITEM INCLUDES					0		0		0		0	0	0
				-Removal of FD Fan					0				0		0	0	0
	27			-Removal of the Air Supply Ductwork to FD Fan and to Windbox					0		0		0		0	0	0
	28			-Removal of the Boiler Windbox					0		0		0		0	0	0
	29			-Removal of the Steam Coil Airheaters					0		0		0		0	0	0
	30			- Removal of the Main Lungstrom Airheaters					0		0		0		0	0	0
	31								0		0		0		0	0	0
300	32			BOILER GAS SYSTEMS AND STACKS (Units 1, 2, &3)					0		0		0		1,313,500	558	1,313,500
	33		6704	THIS ITEM INCLUDES	1	LS			0		0		0	1,313,500	1,313,500	0	1,313,500
			6704	-Removal of Boiler Outlet Gas Ductwork to Stack												0	0
	35			-Removal of Stacks					0		0		0		0	230	0
	36			-Removal of the Boiler Soot blowers					0		0		0		0	0	0
	37			-Crushing Concrete Rubble to 6" Minus & Removal of Reinforcing Steel					0		0		0		0	328	0
	38								0		0		0		0	0	0
300	39			BOILER CONDENSATE SYSTEM (Units 1, 2, &3)					0		0		0		0	IN SUBTOTAL	IN SUBTOTAL
	40			THIS ITEM INCLUDES	1	LS			0		0		0		0	0	0
				-Removal of theLow Pressure Feedwater Heaters													
	42			-Removal of the Boiler Dearator Tank and Piping					0		0		0		0	0	0
	43			- Removal of the Boiler Feedwater Pumps and Piping					0		0		0		0	0	0
	44			-Removal of the Boiler High Pressure Feedwater Heaters					0		0		0		0	0	0
	45			-Removal of the Boiler Condensate Pumps and Extraction System					0		0		0		0	0	0
	46			-Removal of the Condensate Piping					0		0		0		0	0	0
	63																

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Boiler and Auxilaries
WBS 300

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour					Material		Labour & Materials		Metals	Total
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	Cost
	64																
300	65			PREDEMOLITION FACILITY DECOMMISSIONING											334,000	0	334,000
	66			-Disposal of Dust/Fly Ash/Boiler Ash (on Site in Hazardous Waste Landfill)	1,800	Ton								5	9,000		9,000
				-Asbestos Abatement of Boiler	1	LS			0		0			325,000	325,000		325,000
300																	
	56								0		0		0		0	0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Turbines, Generators and Auxillaries
WBS 400

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour					Material		Labour & Material		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
400	0			**TOTAL FOR TURBINES, GENERATORS AND AUXILLARIES**					0		0		0		341,300	1,500	341,300
				THIS ITEM INCLUDES	1	LS								341,300	341,300	1,500	
	2			**TURBINE GENERATORS (Units 1 & 2)**					0		0		0		0	0	INCL ABOVE
	3			-Removal of the Generator Stators					0		0		0		0	0	0
	4			-Removal of the Hydrogen Gas and Lube Systems					0		0		0		0	0	0
	5			-Removal of the Excitation Systems					0		0		0		0	0	0
	6								0		0		0		0	0	0
	7								0		0		0		0	0	0
400	8			**CONDENSING SYSTEM (Units 1, 2, &3)**					0		0		0		0	0	INCL ABOVE
	9			-Removal of the Main Unit Condenser					0		0		0		0	0	0
	10			-Removal and/or Filling of the Condenser Outfall Piping to Seal Pit					0		0		0		0	0	0
	11			-Remove and /or Fill in Condenser Seal Pits					0		0		0		0	0	0
	12			-Remove and/or Fill in Condenser Seal Pit Outfall Piping.					0		0		0		0	0	0
	13								0		0		0		0	0	0
	14								0		0		0		0	0	0
400	15			**TURBINES AND AUXILLARIES (Units 1, 2, & 3)**					0		0		0		0	0	INCL ABOVE
	16			-Removal of the Main LP and HP Turbines and Auxillaries					0		0		0		0	0	0
	17			-Removal of the Turbine Lubrication and Hydraulic Systems					0		0		0		0	0	0
	18								0		0		0		0	0	0
	19								0		0		0		0	0	0
	20								0		0		0		0	0	0
400	21			**COOLING WATER SYSTEM (Units 1, 2, &3)**					0		0		0		0	0	INCL ABOVE
	22			-Removal of the Main Cooling Water Pumps (2 each per unit) located in the Pumphouses)					0		0		0		0	0	0
	23			-Removal of the Turbine Generator Cooling Pumps and Piping for Units 1 & 2)					0		0		0		0	0	0
	24			-Remove/Fill in Main Cooling Water Piping to Condensers					0		0		0		0	0	0
	25			-Removal of the Cooling Water Piping to Turbine Generators for Units 1 & 2.					0		0		0		0	0	0
	26								0		0		0		0	0	0
	27								0		0		0		0	0	0
	28								0		0		0		0	0	0
	29								0		0		0		0	0	0
	30								0		0		0		0	0	0
	31								0		0		0		0	0	0
	32								0		0		0		0	0	0
	33								0		0		0		0	0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical
WBS 500

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date: **0-Jan-00**
Checked:

WBS	Line	Rev.	Asset	Description	Qty	Unit	Labour					Material		Labour & Materials		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
500	**0**			**TOTAL ELECTRICAL COST**					**0**		**0**		**0**		**0**	**720**	**2,376,300**
	1			**SITE DISTRIBUTION**		**Lot**			**0**		**0**		**0**		**0**	**8**	**26,400**
	2			Removal of Overhead Lines between Unit Transformers and Switchyard					0		0		0		0	3	18,000
	3			Removal of GT Output Services					0		0		0		0	1	1,000
	4			Removal of Marine Jetty and Wharf Services					0		0		0		0	4	7,400
	5								0		0		0		0	0	0
	6								0		0		0		0	0	0
	7								0		0		0		0	0	0
	8								0		0		0		0	0	0
	9								0		0		0		0	0	0
	10								0		0		0		0	0	0
	11								0		0		0		0	0	0
	12								0		0		0		0	0	0
	13								0		0		0		0	0	0
	14								0		0		0		0	0	0
	15			**ELECTRICAL POWER SYSTEMS**		**Lot**			**0**		**0**		**0**		**0**	**239**	**528,100**
	16			Removal of Switchgear and Protection Relays					0		0		0		0	6	21,200
	17			Removal of Switchgear Power Cables					0		0		0		0	26	17,500
	18			Removal of CT and PT Cables					0		0		0		0	1	3,600
	19			Removal of MCCs					0		0		0		0	55	44,000
	20			Removal of Electric Motors					0		0		0		0	27	45,100
	21			Removal of MCC Power Cables					0		0		0		0	64	161,900
	22			Removal of Building Electrical Services					0		0		0		0	11	82,600
	23			Removal of building Electrical Services Power Cables					0		0		0		0	14	66,800
	24			Removal of Cable Trays and Grounding					0		0		0		0	17	35,700
	25			Removal & Disposal of Battery Banks					0		0		0		0	18	44,800
	26			Removal & Disposal of Battery Acid					0		0		0		0	0	4,900
	27								0		0		0		0	0	0
	28			**TRANSFORMERS AND AUXILLARIES**		**Lot**			**0**		**0**		**0**		**0**	**375**	**1,138,100**
	29			Dechlorination of Oil Filled Transformers (Includes Disposal of Transformer Oil)					0		0		0		0	0	1,098,700
	30			Removal of Isolated Phase Bus					0		0		0		0	10	13,200
	31			Removal of Secondary Cables					0		0		0		0	7	5,200
	32			Removal of Oil Filled Transformers					0		0		0		0	358	21,000
	33								0		0		0		0	0	0
	34								0		0		0		0	0	0
	35								0		0		0		0	0	0
	36			**CONTROLS**		**Lot**			**0**		**0**		**0**		**0**	**98**	**683,700**
	37			Removal of Control Cabinets					0		0		0		0	24	42,200
	38			Removal of Control Cables					0		0		0		0	61	465,500
	39			Removal of Instrumentation					0		0		0		0	4	29,800
	40			Removal of Instrumentation Cables					0		0		0		0	9	146,200
	41								0		0		0		0	0	0
	42								0		0		0		0	0	0
	43								0		0		0		0	0	0
	44								0		0		0		0	0	0
	45								0		0		0		0	0	0
	46								0		0		0		0	0	0
	47								0		0		0		0	0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

Stantec

STANTEC CONSULTING
Opinion of Probable Construction Cost
Electrical
WBS 500

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date: **0-Jan-00**
Checked:

WBS	Line	Rev.	Asset	Description	Qty	Unit	Labour					Material		Labour & Materials		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
	48								0		0		0		0	0	0
	49								0		0		0		0	0	0
	50								0		0		0		0	0	0
	51								0		0		0		0	0	0
	52								0		0		0		0	0	0
	53								**0**		**0**		**0**		**0**	**0**	**0**
	54								0		0		0		0	0	0
	55								0		0		0		0	0	0
	56								0		0		0		0	0	0
	57								0		0		0		0	0	0
	58								0		0		0		0	0	0
	59								**0**		**0**		**0**		**0**	**0**	**0**
	60								0		0		0		0	0	0
	61								0		0		0		0	0	0
	62								0		0		0		0	0	0
	63								0		0		0		0	0	0
	64								0		0		0		0	0	0
	65								0		0		0		0	0	0
	66								0		0		0		0	0	0
	67								0		0		0		0	0	0
	68								0		0		0		0	0	0
	69								0		0		0		0	0	0
	70								0		0		0		0	0	0
	71								0		0		0		0	0	0
	72								0		0		0		0	0	0
	73								0		0		0		0	0	0
	74								0		0		0		0	0	0
	75								0		0		0		0	0	0
	76								0		0		0		0	0	0
	77								0		0		0		0	0	0
	78								0		0		0		0	0	0
	79								0		0		0		0	0	0
	80								0		0		0		0	0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Instrumentation & Control
NOT USED

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour hr per Unit	Labour Prod. Factor	Labour Total Hours	Labour Rate	Labour Cost	Material Unit Cost	Material Cost	Labour & Material Unit Cost	Labour & Material Cost	Metals Ton	Total Cost
600	0								0		0		0			9	0
									0		0		0		0	9	0
	2								0		0		0		0	0	0
	3								0		0		0		0	0	0
	4								0		0		0		0	0	0
	5								0		0		0		0	0	0
	6								0		0		0		0	0	0
	7								0		0		0		0	0	0
	8								0		0		0		0	0	0
	9								0		0		0		0	0	0
	10								0		0		0		0	0	0
	11								0		0		0		0	0	0
	12								0		0		0		0	0	0
	13								0		0		0		0	0	0
	14								0		0		0		0	0	0
	15								0		0		0		0	0	0
	16								0		0		0		0	0	0
	17								0		0		0		0	0	0
	18								0		0		0		0	0	0
	19								0		0		0		0	0	0
	20								0		0		0		0	0	0
	21								0		0		0		0	0	0
	22								0		0		0		0	0	0
	23								0		0		0		0	0	0
	24								0		0		0		0	0	0
	25								0		0		0		0	0	0
	26								0		0		0		0	0	0
	27								0		0		0		0	0	0
	28								0		0		0		0	0	0
	29								0		0		0		0	0	0
	30								0		0		0		0	0	0
	31								0		0		0		0	0	0
	32								0		0		0		0	0	0
	33								0		0		0		0	0	0
	34								0		0		0		0	0	0
	35								0		0		0		0	0	0
	36								0		0		0		0	0	0
	37								0		0		0		0	0	0
	38								0		0		0		0	0	0
	39								0		0		0		0	0	0
	40								0		0		0		0	0	0
	41								0		0		0		0	0	0
	42								0		0		0		0	0	0
	43								0		0		0		0	0	0
	44								0		0		0		0	0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Common Services
WBS 700

Prepared by:
Date: **25-Jan-13**
Revision No.: **0**
Issue Date: **0-Jan-00**
Checked:

Area	Line	Rev.	WBS	Description	Qty	Unit	Labour					Material		Labour & Material		Metals	Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Ton	
700	**0**			**COMMON SERVICES - TOTAL DEMOLITION COST**					**0**		**0**		**0**		**2,692,000**	**1,375**	**2,692,000**
	1			**RAW WATER AND WATER TREATMENT**					**0**		**0**		**0**		**66,000**	**0**	**66,000**
	2			-Removal of Complete Water Treatment Plant Equipment Including Pumps, Tanks and Piping	1	LS			0		0		0	66,000	66,000	0	66,000
	3								0		0		0		0	0	0
	4								0		0		0		0	0	0
700	**5**			**WASTE WATER TREATMENT**					**0**		**0**		**0**		**70,000**	**25**	**70,000**
	6			THIS ITEM INCLUDES	1	LS			0		0		0	70,000	70,000	0	70,000
				-Removal of the Oil Water Separators for Units 1 & 2 (Oil Water Separator for Unit #3 to Remain)												0	
	8			-Removal of the Oil Water Seperator Sumps, Pumps and Piping					0		0		0		0	0	0
	9			-Removal of Water Retention Basins 1 & 2					0		0		0		0	0	0
	10			-Removal of Waste Water Treatment Plant Tanks, Filters, Pumps and Piping					0		0		0		0	0	0
	11			-Crushing of Concrete Rubble to 6" Minus & Removal of Reinforcing Steel					0		0		0		0	25	0
	12								0		0		0		0	0	0
700	13			CLEANING TANKS & PIPELINE					0		0		0		2,021,500	0	2,021,500
	14			THIS ITEM INCLUDES	1	LS			0		0		0	2,021,500	2,021,500	0	2,021,500
				-Cleaning Main Tanks 1, 2, 3, & 4					0		0		0		0	0	0
	16			-Cleaning of Pipelines from Marine Terminal to Tank Farm					0		0		0		0	0	0
	17			-Cleaning of Day Tank and Pipeline from Tank Farm To the Power House					0		0		0		0	0	0
	18								0		0		0		0	0	0
	19								0		0		0		0	0	0
	20								0		0		0		0	0	0
	21								0		0		0		0	0	0
700	**22**			**HEAVY FUEL OIL SYSTEM**					**0**		**0**		**0**		**534,500**	**1,350**	**534,500**
	23			THIS ITEM INCLUDES BUT IS NOT LIMITED TO	1	LS			0		0		0	534,500	534,500	1,350	534,500
	24			-Removal of Heavy Fuel Oil Unloading Pumps, Piping and Systems on the Marine Terminal					0		0		0		0	0	0
	25			-Removal of Heavy Fuel Oil Piping from the Marine Terminal to the Tank Farm					0		0		0		0	0	0
	26			-Removal of Heavy Fuel Oil Storage Tanks 1, 2, 3 & 4					0		0		0		0	0	0
	27			-Removal of the Heavy Fuel Oil Piping from the Storage Tanks to the Power House					0		0		0		0	0	0
	28			-Removal of the Day Storage Tank adjacent to the Power House					0		0		0		0	0	0
	29								0		0		0		0	0	0
	30								0		0		0		0	0	0
	31								0		0		0		0	0	0
	32								0		0		0		0	0	0
	33								0		0		0		0	0	0
	34								0		0		0		0	0	0
	35								0		0		0		0	0	0
	36								0		0		0		0	0	0
	37								0		0		0		0	0	0
	38								0		0		0		0	0	0
	39								0		0		0		0	0	0
	40								0		0		0		0	0	0
	41								0		0		0		0	0	0
	42								0		0		0		0	0	0
	43								0		0		0		0	0	0
	44																

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

STANTEC CONSULTING
Opinion of Probable Construction Cost
Construction
WBS 800

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour					Material		Labour & Material		Metals		Total Cost
							hr per Unit	Prod. Factor	Total Hours	Rate	Cost	Unit Cost	Cost	Unit Cost	Cost	Unit Cost	Cost	
800	0			CONSTRUCTION - TOTAL COST					0		0		0		3,400,000		0	3,400,000
	1			CAPITAL INVESTMENT ALLOWANCE					0		0		0		3,400,000		0	3,400,000
	2			THIS ITEM INCLUDES BUT IS NOT LIMITED TO					0		0		0		0		0	0
	3			-Structural Modification and Wall Closure at the Turbine Building	1	LS			0		0		0	1,000,000	1,000,000		0	1,000,000
	4			-Structural Modifications and Wall Closure at Pump House #1	1	LS			0		0		0	300,000	300,000		0	300,000
	5			-Relocation and Modification of Electrical & Mechanical Systems	1	LS			0		0		0	2,000,000	2,000,000		0	2,000,000
	6			-Relocation and Modification of Underground Water and Sewer Systems	1	LS			0		0		0	100,000	100,000		0	100,000
	7								0		0		0		0		0	0
	8								0		0		0		0		0	0
	9								0		0		0		0		0	0
	10								0		0		0		0		0	0
	11								0		0		0		0		0	0
	12								0		0		0		0		0	0
	13								0		0		0		0		0	0
	14								0		0		0		0		0	0
	15								0		0		0		0		0	0
	16								0		0		0		0		0	0
	17								0		0		0		0		0	0
	18								0		0		0		0		0	0
	19								0		0		0		0		0	0
	20								0		0		0		0		0	0
	21								0		0		0		0		0	0
	22								0		0		0		0		0	0
	23								0		0		0		0		0	0
	24								0		0		0		0		0	0
	25								0		0		0		0		0	0
	26								0		0		0		0		0	0
	27								0		0		0		0		0	0
	28								0		0		0		0		0	0
	29								0		0		0		0		0	0
	30								0		0		0		0		0	0
	31								0		0		0		0		0	0
	32								0		0		0		0		0	0
	33								0		0		0		0		0	0
	34								0		0		0		0		0	0
	35								0		0		0		0		0	0
	36								0		0		0		0		0	0
	37								0		0		0		0		0	0
	38								0		0		0		0		0	0
	39								0		0		0		0		0	0
	40								0		0		0		0		0	0
	41								0		0		0		0		0	0
	42								0		0		0		0		0	0
	43								0		0		0		0		0	0

Client: **Newfoundland and Labrador Hydro**
Project: **Decommissioning Holyrood Thermal Plant**
Project No: **133545705**
Currency: **CAD**

Stantec

STANTEC CONSULTING
Opinion of Probable Construction Cost
Engineering & Administration
WBS 900

Prepared by: **GRM**
Date: **25-Jan-13**
Revision No.: **0**
Issue Date:
Checked:

WBS	LINE	REV	ASSET	DESCRIPTION	Qty	Unit	Labour hr per Unit	Labour Prod. Factor	Labour Total Hours	Labour Rate	Labour Cost	Material Unit Cost	Material Cost	Labour & Material Unit Cost	Labour & Material Cost	Metals Unit Cost	Metals Cost	Total Cost
900	**0**			**ENGINEERING & ADMINISTRATION - TOTAL COST**					**0**		**0**		**0**		**3,630,000**		**0**	**3,630,000**
	1			**ENGINEERING**					**0**		**0**		**0**		**2,420,000**		**0**	**2,420,000**
	2			THIS ITEM INCLUDES BUT NOT LIMITED TO	1	LS			0		0		0	2,420,000	2,420,000		0	2,420,000
	3			-Design of Wall Closure at Pump House #1					0		0		0		0		0	0
	4			-Design of Wall Closure at Turbine Building					0		0		0		0		0	0
	5			-Design of Solid Waste Landfill Cover					0		0		0		0		0	0
	6			-Engineering for Site Remediation					0		0		0		0		0	0
	7			-Preparation of Final Site Grading and Landscapind Drawing					0		0		0		0		0	0
	8			-Any Other Engineering that may be Required to Decommission the Site					0		0		0		0		0	0
	9			-Preparation of Tender Documents					0		0		0		0		0	0
	10								0		0		0		0		0	0
	11								0		0		0		0		0	0
	12								0		0		0		0		0	0
	13								0		0		0		0		0	0
	14								0		0		0		0		0	0
	15			**COMPLIANCE MONITORING/INSPECTION AND REPORTING**					**0**		**0**		**0**		**1,210,000**		**0**	**1,210,000**
	16			THIS ITEM INCLUDES	1	LS			0		0		0	1,210,000	1,210,000		0	1,210,000
	17			-Removal and Disposal of Galbestos Siding					0		0		0		0		0	0
	18			-Removal and Disposal of ACM Roofing					0		0		0		0		0	0
	19			-Cleaning of Main Heavy Fuel Oil Tanks					0		0		0		0		0	0
	20			-Cleaning of Pipeline from the marine Terminal to the Tank Farm					0		0		0		0		0	0
	21			-Cleaning of Day Tank and Pipeline from the Tank Farm to the Day Tank					0		0		0		0		0	0
	22			-Demolition and Removal of Pipeline					0		0		0		0		0	0
	23			-Demolition and Removal of Stacks					0		0		0		0		0	0
	24			-Capping of Solid Waste Landfill Cell					0		0		0		0		0	0
	25			-Inspection of New Construction					0		0		0		0		0	0
	26			-All Other Work Required to Decommission the Plant and Site					0		0		0		0		0	0
	27								0		0		0		0		0	0
	28								**0**		**0**		**0**		**0**		**0**	**0**
	29								0		0		0		0		0	0
	30								0		0		0		0		0	0
	31								0		0		0		0		0	0
	32								0		0		0		0		0	0
	33								0		0		0		0		0	0
	34								0		0		0		0		0	0
	35								0		0		0		0		0	0
	36								**0**		**0**		**0**		**0**		**0**	**0**
	37								0		0		0		0		0	0
	38								0		0		0		0		0	0
	39								0		0		0		0		0	0
	40								0		0		0		0		0	0
	41								0		0		0		0		0	0
	42								0		0		0		0		0	0
	43								0		0		0		0		0	0
	44								0		0		0		0		0	0

APPENDIX 4

Detailed Cash Flow

NEWFOUNDLAND AND LABRADOR HYDRO
HTGS DECOMMISSIONING STUDY
DECOMMISSIONING AND DEMOLITION COST CASH FLOW (2012 $)

WBS	Area Description	Total Cost	2020	2021	2022	2023	2024
100		$ 7,135,000	$ -	$ 550,000	$ 2,375,000	$ 2,100,000	$ 2,110,000
	SITE ROUGH GRADING AND LANDSCAPING	$ 600,000	$ -	$ -	$ -	$ -	$ 600,000
	SITE ACCESS (Roads, Parking, Fencing)	$ 120,000	$ -	$ -	$ -	$ -	$ 120,000
	SITE SERVICES	$ 100,000	$ -	$ -	$ -	$ 100,000	$ -
	WASTE LANDFILL	$ 390,000	$ -	$ -	$ -	$ -	$ 390,000
	ENVIRONMENTAL ASSESSMENT, REMEDIATION & COMPLIANCE	$ 5,925,000	$ -	$ 550,000	$ 2,375,000	$ 2,000,000	$ 1,000,000
200		$ 5,241,700		$ -	$ 1,700,000	$ 3,541,700	$ -
	MAIN POWERHOUSE	$ 1,775,900	$ -	$ -	$ -	$ 1,775,900	$ -
	COMMON SERVICES BUILDINGS	$ 571,200	$ -	$ -	$ -	$ 571,200	$ -
	MARINE STRUCTURES	$ 810,600	$ -	$ -	$ -	$ 810,600	$ -
	HRD AUXILARY BUILDINGS	$ 60,000	$ -	$ -	$ -	$ 60,000	$ -
	TURBINE GENERATOR BUILDING	$ 252,000	$ -	$ -	$ -	$ 252,000	$ -
	FACILITY DECOMMISSIONING	$ 1,772,000	$ -	$ -	$ 1,700,000	$ 72,000	$ -
300		$ 4,342,000	$ -	$ -	$ 334,000	$ 4,008,000	$ -
	BOILER PLANT and AUXILLARIES (Units 1, 2, & 3)	$ 2,694,500	$ -	$ -	$ -	$ 2,694,500	$ -
	BOILER AUXILLARIES (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
	FUEL HANDLING SYSTEMS (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
	BOILER AIR SYSTEMS (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
	BOILER GAS SYSTEMS AND STACKS (Units 1, 2, &3)	$ 1,313,500	$ -	$ -	$ -	$ 1,313,500	$ -
	BOILER CONDENSATE SYSTEM (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
	FACILITY DECOMMISSIONING	$ 334,000	$ -	$ -	$ 334,000	$ -	$ -
400		$ 341,300	$ -	$ -	$ -	$ 341,300	$ -
	TURBINE GENERATORS (Units 1 & 2)	$ 341,300	$ -	$ -	$ -	$ 341,300	$ -
	CONDENSING SYSTEM (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
	TURBINES AND AUXILLARIES (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
	COOLING WATER SYSTEM (Units 1, 2, & 3) - Incl Above	$ -	$ -	$ -	$ -	$ -	$ -
500		$ 2,376,300	$ -	$ -	$ 1,099,000	$ 1,277,300	$ -
	SITE DISTRIBUTION	$ 26,400	$ -	$ -	$ -	$ 26,400	$ -
	ELECTRICAL POWER SYSTEMS	$ 528,100	$ -	$ -	$ -	$ 528,100	$ -
	TRANSFORMERS AND AUXILLARIES	$ 1,138,100	$ -	$ -	$ 1,099,000	$ 39,100	$ -
	CONTROLS	$ 683,700	$ -	$ -	$ -	$ 683,700	$ -
600							
	Included in 500 Electrical	$ -	$ -	$ -	$ -	$ -	$ -
700		$ 2,692,000	$ -	$ -	$ 2,556,000	$ 136,000	$ -
	RAW WATER AND WATER TREATMENT	$ 66,000	$ -	$ -	$ -	$ 66,000	$ -
	WASTE WATER TREATMENT	$ 70,000	$ -	$ -	$ -	$ 70,000	$ -
	CLEANING TANKS & PIPELINE	$ 2,021,500	$ -	$ -	$ 2,021,500	$ -	$ -
	HEAVY FUEL OIL SYSTEM	$ 534,500	$ -	$ -	$ 534,500	$ -	$ -
800		$ 3,400,000		$ -	$ -	$ 3,400,000	$ -
	CONSTRUCTION	$ 3,400,000	$ -	$ -	$ -	$ 3,400,000	$ -
900		$ 3,630,000	$ 300,000	$ 900,000	$ 1,210,000	$ 1,000,000	$ 220,000
	ENGINEERING	$ 2,420,000	$ 300,000	$ 900,000	$ 800,000	$ 300,000	$ 120,000
	COMPLIANCE MONITORING/INSPECTION AND REPORTING	$ 1,210,000	$ -	$ -	$ 410,000	$ 700,000	$ 100,000
	SUB-TOTAL (excluding contingency):	$ 29,158,300	$ 300,000	$ 1,450,000	$ 9,274,000	$ 15,804,300	$ 2,330,000
	CONTINGENCY ALLOWANCE	$ 2,915,830	$ 30,000	$ 145,000	$ 927,400	$ 1,580,430	$ 233,000
	GRAND TOTAL:	**$ 32,074,130**	**$ 330,000**	**$ 1,595,000**	**$ 10,201,400**	**$ 17,384,730**	**$ 2,563,000**

APPENDIX 5

Project Schedules

Newfoundland and Labrador Hydro
Holyrood Thermal Generating Station - Decommissioning

Project Timeline

Revision: 1 - January 25, 2013

Task No.	Task Description	2013				2014				2015				2016				2017				2018				2019			
	Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	Unit Operation Timeline																												
1	Unit #1,2 &3 Normal Operation	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧								
2	Unit #3 Synchronous Operation	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧
3	Lower Churchill Project comes On-Line																				♦ - Dec 2017								
4	Unit #1,2 & 3 Operates in Standby Mode																					🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧
5	Unit #1,2 & 3 in Dry Layup																												
6	Decommissioing Engineering and Planning																												
7	Pre-Decommissioning Activities																												
8	Decommissioning Activities																												
9	Decommissioning Complete																												

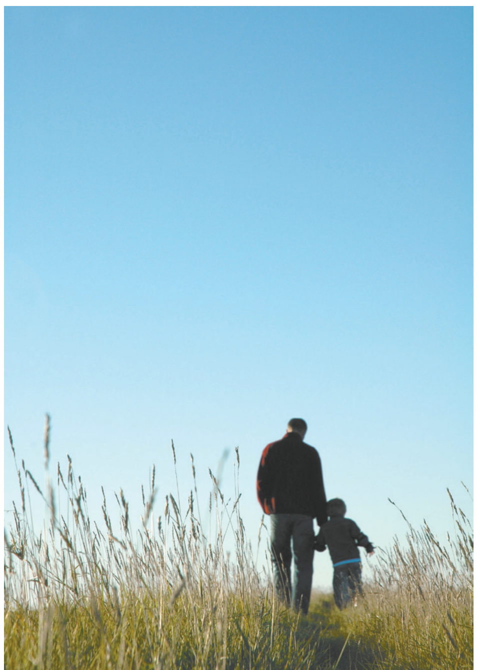
Task No.	Task Description	2020				2021				2022				2023				2024				2025				2026			
	Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	Unit Operation Timeline																												
1	Unit #1,2 &3 Normal Operation																												
2	Unit #3 Synchronous Operation	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧
3	Lower Churchill Project comes On-Line																												
4	Unit #1,2 & 3 Operates in Standby Mode																												
5	Unit #1,2 & 3 in Dry Layup	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧																				
6	Decommissioing Engineering and Planning	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧																
7	Pre-Decommissioning Activities					🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧																
8	Decommissioning Activities													🟧	🟧	🟧	🟧	🟧	🟧	🟧	🟧								
9	Decommissioning Complete																				♦ - Dec 2024								

Newfoundland and Labrador Hydro
Holyrood Thermal Generating Station - Decommissioning

Conceptual Decommissioning Schedule

Revision: 1 - January 25, 2013

Task No.	Task Description	2020				2021				2022				2023				2024				2025			
	Quarter:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	Decommissioning Engineering and Planning																								
1	Closure Confirmation					♦ - Jan 1 2021																			
2	Project Registration					♦ - Jan 2 2021																			
3	Project Registration Review Period by NL Dept of Env.																								
4	Environmental Site Assessments																								
5	Hazardous Material Audit																								
6	Decommissioning Engineering and Planning																								
7	Issue Decommissioning Tenders and Award																								
	Pre-Decommissioning Activities (Plant)																								
8	De-Energize all Equipment																								
9	Remove fluids from all equipment																								
10	Remove remaining Oil from Pipeline and Tanks																								
11	Relocate/Install common services impacted by demolition																								
	Decommissioning Activities (Contractor(s))																								
12	Site Environmental Remediation																								
13	Decommissioning Inspection and Inventory																								
14	Chemical Removal and Industrial Cleaning																								
15	Hazardous Material Abatement																								
16	Demolish/Remove Equipment (includes fuel oil system, tanks, boiler and auxiliaries, turbine/generators and auxiliaries, Water Treatment System, Waste Water Treatment System, etc.)																								
17	Demolish Building and Structures (Includes, fuel receiving jetty, boiler house, stacks, pumphouse(partial) etc.																								
18	Install new wall systems as required to close-in affected buildings																								
19	Material Disposal																								
20	Remove and/or remediate seal pits and underground piping/conduits																								
22	Final Site Grading and Landscaping																								
23	Demobilization																				♦ - Dec 2024				



ONE TEAM. INFINITE SOLUTIONS.

Stantec Consulting Ltd.

845 Prospect Street
Fredericton, NB E3B2T7

Tel: (506) 452-7000
Fax: (506) 452-0112

133545705
PR-CO-FRE-2013APR16-P1V1