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DELIVERED BY HAND

September 8, 2015

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

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

**Re: Newfoundland and Labrador Hydro's 2013 Amended General Rate Application**

Enclosed are the original and 12 copies of the following documents, on which Newfoundland Power wishes to cross-examine Hydro's witness, Mr. Ed Martin, at the hearing of the Application:

1. Hydro's report, *TL 267 Project – 230 kV Transmission, Bay d'Espoir to Western Avalon*, filed as Appendix B to the *2016 - 2020 Capital Plan*, Volume I of Hydro's 2016 Capital Budget Application.

2. Hydro's report, *2014 Annual Report on Key Performance Indicators*, filed as Appendix E to *Hydro's Quarterly Regulatory Report for the Quarter Ended December 31, 2014.*

These documents are filed in accordance with the requirements of paragraph 15(6) of the Rules of Procedure set out in Order No. P.U. 28 (2013).

Copies of the enclosure and this correspondence have been forwarded directly to the parties indicated below.

If you have any questions in relation to the above, please contact the undersigned.

Yours very truly,

Gerard Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

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Yvonne Jones, MP
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# APPENDIX B

## TL 267 PROJECT – 230 kV Transmission

## Bay d'Espoir to Western Avalon

## Report

## SUMMARY

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

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

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

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

# TABLE OF CONTENTS

SUMMARY ....................................................................................................................i
1 INTRODUCTION ........................................................................................ 1
2 PROJECT DESCRIPTION ............................................................................ 2
3 ENGINEERING ............................................................................................ 4
4 ENVIROMENTAL ASSESSMENT ................................................................ 7
5 PROCUREMENT .......................................................................................... 9
6 CONSTRUCTION ........................................................................................ 10
7 COST .......................................................................................................... 11
8 SCHEDULE .................................................................................................. 12
9 DRAWINGS AND PHOTOS ........................................................................ 13
APPENDIX A ................................................................................................... A1

# 1 INTRODUCTION

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

## 2 PROJECT DESCRIPTION

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

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

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

The two sub-projects are:

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

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

# 3 ENGINEERING

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

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

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

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

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

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

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

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

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

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

# 4 ENVIROMENTAL ASSESSMENT

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

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

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

The primary route for TL 267 is parallel and adjacent to existing transmission lines along the entire 188 km to minimize the environmental impact. As part of the EA, alternative routes will be considered and assessed. The primary route is located within the BDNWR for 13 km. The reserve was established as a Wilderness Reserve under the Newfoundland and Labrador Wilderness and Ecological Reserve Act in 1990. Although it contains two existing transmission lines constructed in the mid-1960s, the Wilderness Reserve Regulations do not allow for the construction of a new transmission line through the BDNWR.  Provisions in the Act outline the process to allow for the Lieutenant-Governor in Council to reduce the size of the reserve. In order to allow for line construction through the BDNWR, the proposed right of way, 40 m wide and 13 km long, would have to be removed from the BDNWR.  The process required for this removal was initiated in May 2015, and is currently ongoing.  A decision regarding the BDNWR is expected in 7 to 8 months, and will be run concurrently with the EA process.  Final release will occur when both processes are complete.

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

## 5. PROCUREMENT

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

## 6. CONSTRUCTION

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

## 7. COST

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

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

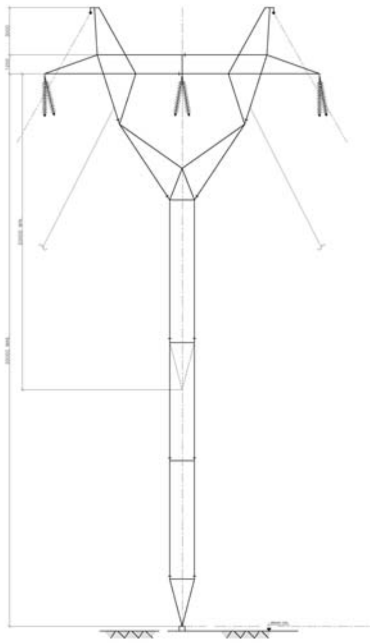
## 8. SCHEDULE

The updated milestone schedule is in Appendix A.

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

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

# 9. DRAWINGS AND PHOTOS



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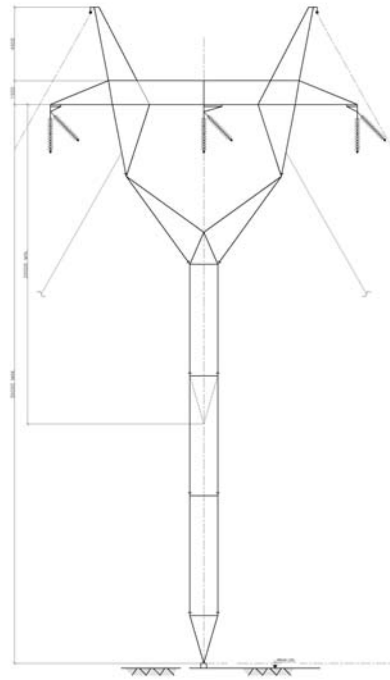
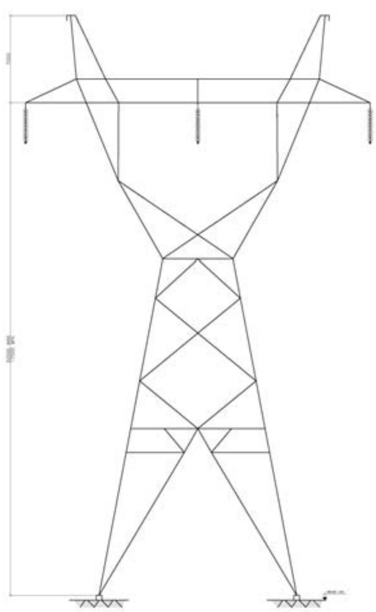
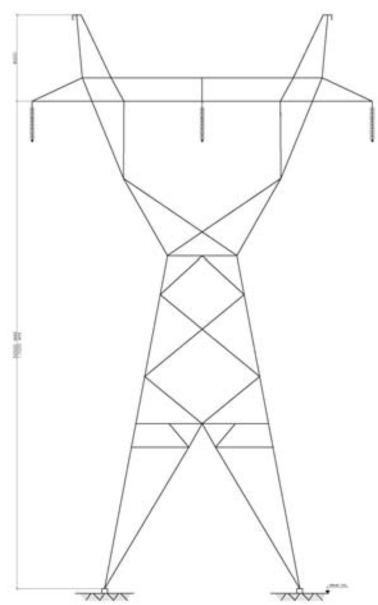


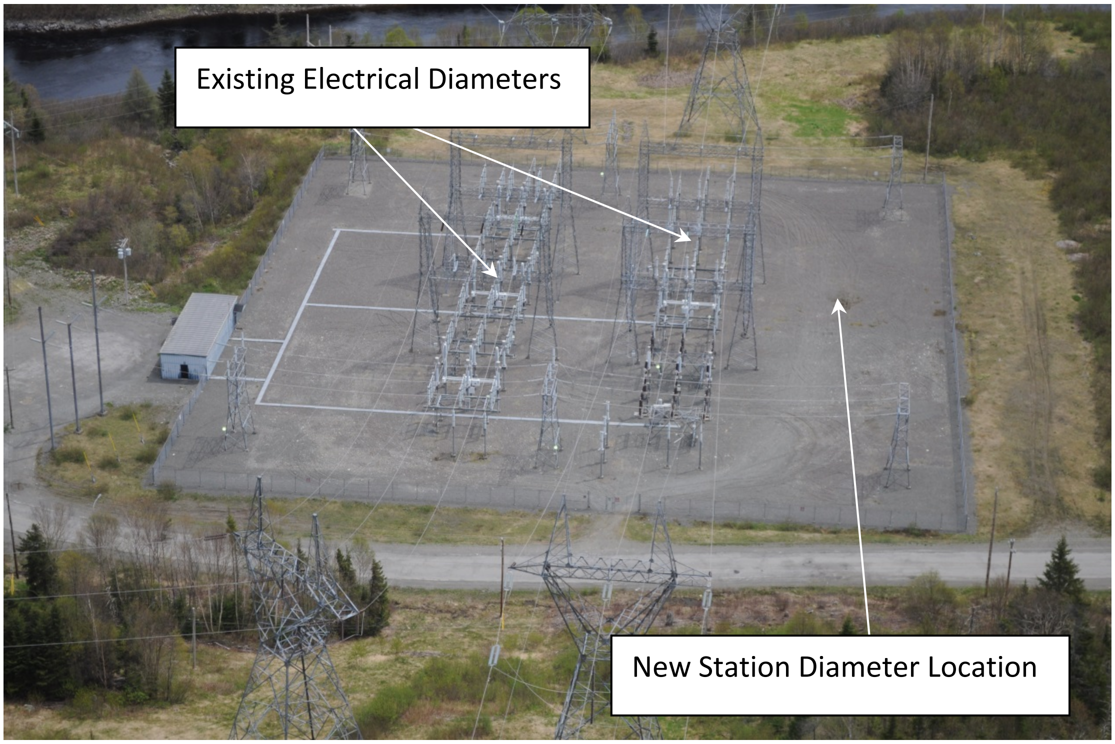
**Tower Type B**



**Tower Type C**



**Tower Type D**




**Bay d'Espoir Terminal Station 2**

**Western Avalon Terminal Station**

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

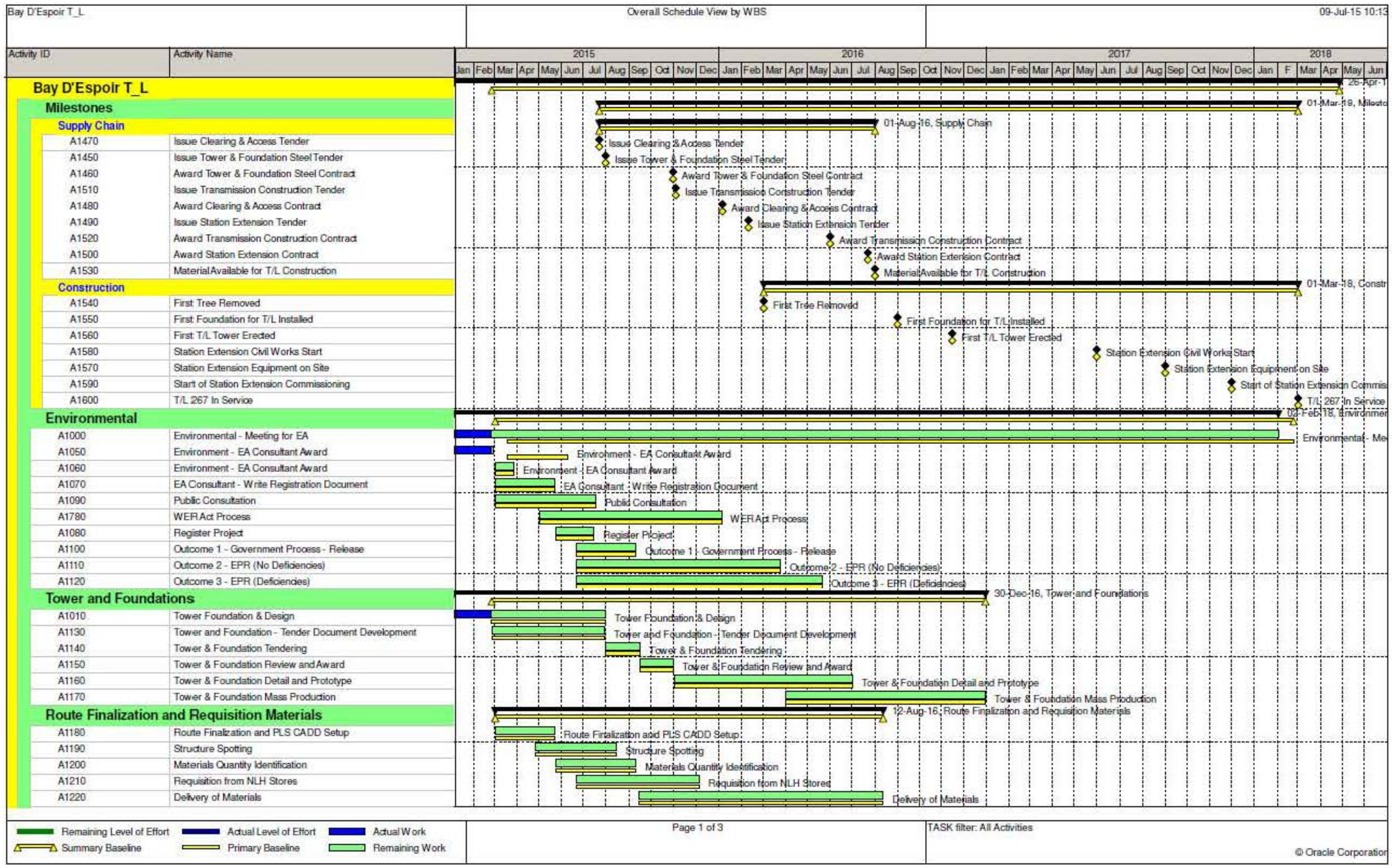
**Typical TL 202/TL 206 right of way near BDE; TL 267 will be on the right**

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

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

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

# APPENDIX A


Bay D'Espoir T_L
Overall Schedule View by WBS
09-Jul-15 10:13
Activity ID
Activity Name
2015
2016
2017
2018
Bay D'Espoir T_L
Milestones
Supply Chain
A1470 Issue Clearing & Access Tender
A1450 Issue Tower & Foundation Steel Tender
A1460 Award Tower & Foundation Steel Contract
A1510 Issue Transmission Construction Tender
A1480 Award Clearing & Access Contract
A1490 Issue Station Extension Tender
A1520 Award Transmission Construction Contract
A1500 Award Station Extension Contract
A1530 Material Available for T/L Construction
Construction
A1540 First Tree Removed
A1550 First Foundation for T/L Installed
A1560 First T/L Tower Erected
A1580 Station Extension Civil Works Start
A1570 Station Extension Equipment on Site
A1590 Start of Station Extension Commissioning
A1600 T/L 267 In Service
Environmental
A1000 Environmental - Meeting for EA
A1050 Environment - EA Consultant Award
A1060 Environment - EA Consultant Award
A1070 EA Consultant - Write Registration Document
A1090 Public Consultation
A1780 WERAct Process
A1080 Register Project
A1100 Outcome 1 - Government Process - Release
A1110 Outcome 2 - EPR (No Deficiencies)
A1120 Outcome 3 - EPR (Deficiencies)
Tower and Foundations
A1010 Tower Foundation & Design
A1130 Tower and Foundation - Tender Document Development
A1140 Tower & Foundation Tendering
A1150 Tower & Foundation Review and Award
A1160 Tower & Foundation Detail and Prototype
A1170 Tower & Foundation Mass Production
Route Finalization and Requisition Materials
A1180 Route Finalization and PLS CADD Setup
A1190 Structure Spotting
A1200 Materials Quantity Identification
A1210 Requisition from NLH Stores
A1220 Delivery of Materials
01-Mar-19, Milestones
01-Aug-16, Supply Chain
01-Mar-18, Construction
02-Feb-18, Environmental
30-Dec-16, Tower and Foundations
12-Aug-16, Route Finalization and Requisition Materials
Remaining Level of Effort
Actual Level of Effort
Actual Work
Summary Baseline
Primary Baseline
Remaining Work
Page 1 of 3
TASK filter: All Activities
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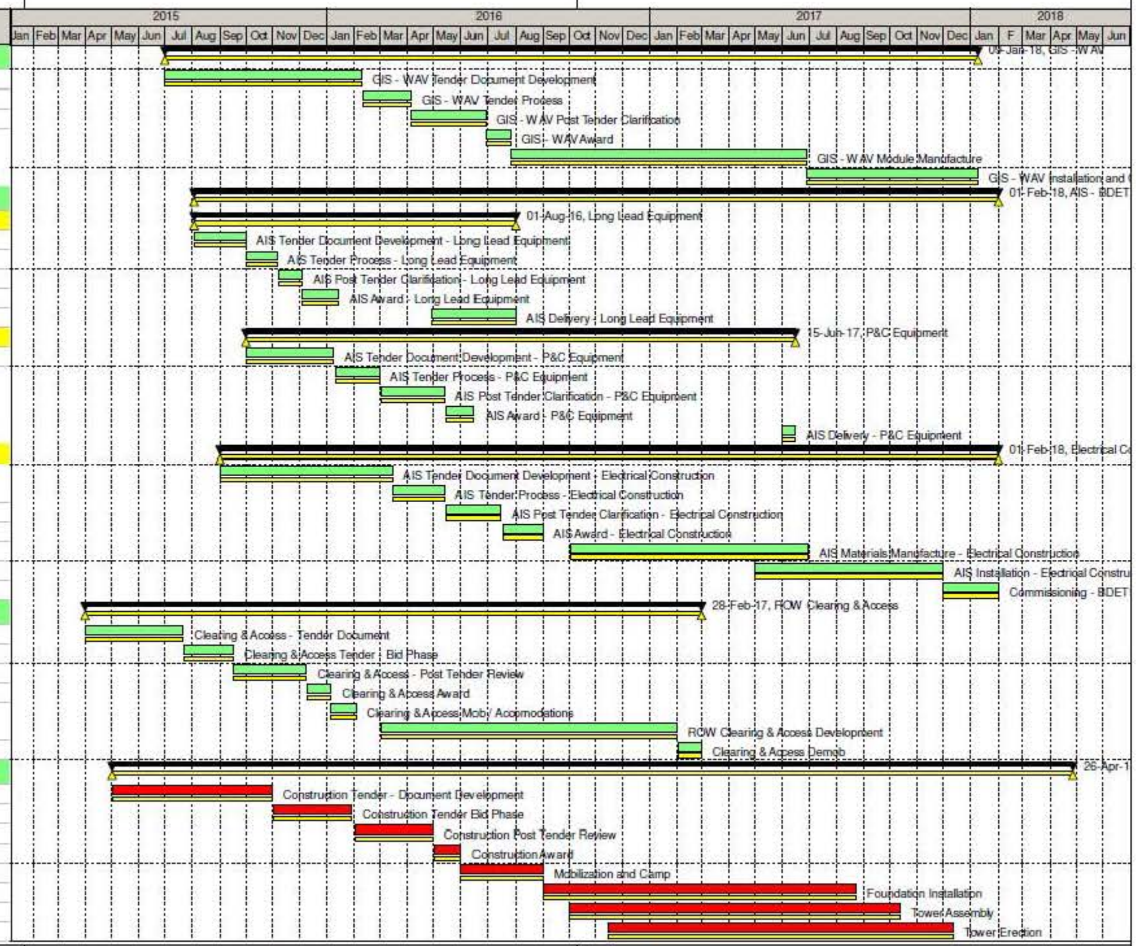
Bay D'Espoir T_L | Overall Schedule View by WBS | 09-Jul-15 10:13

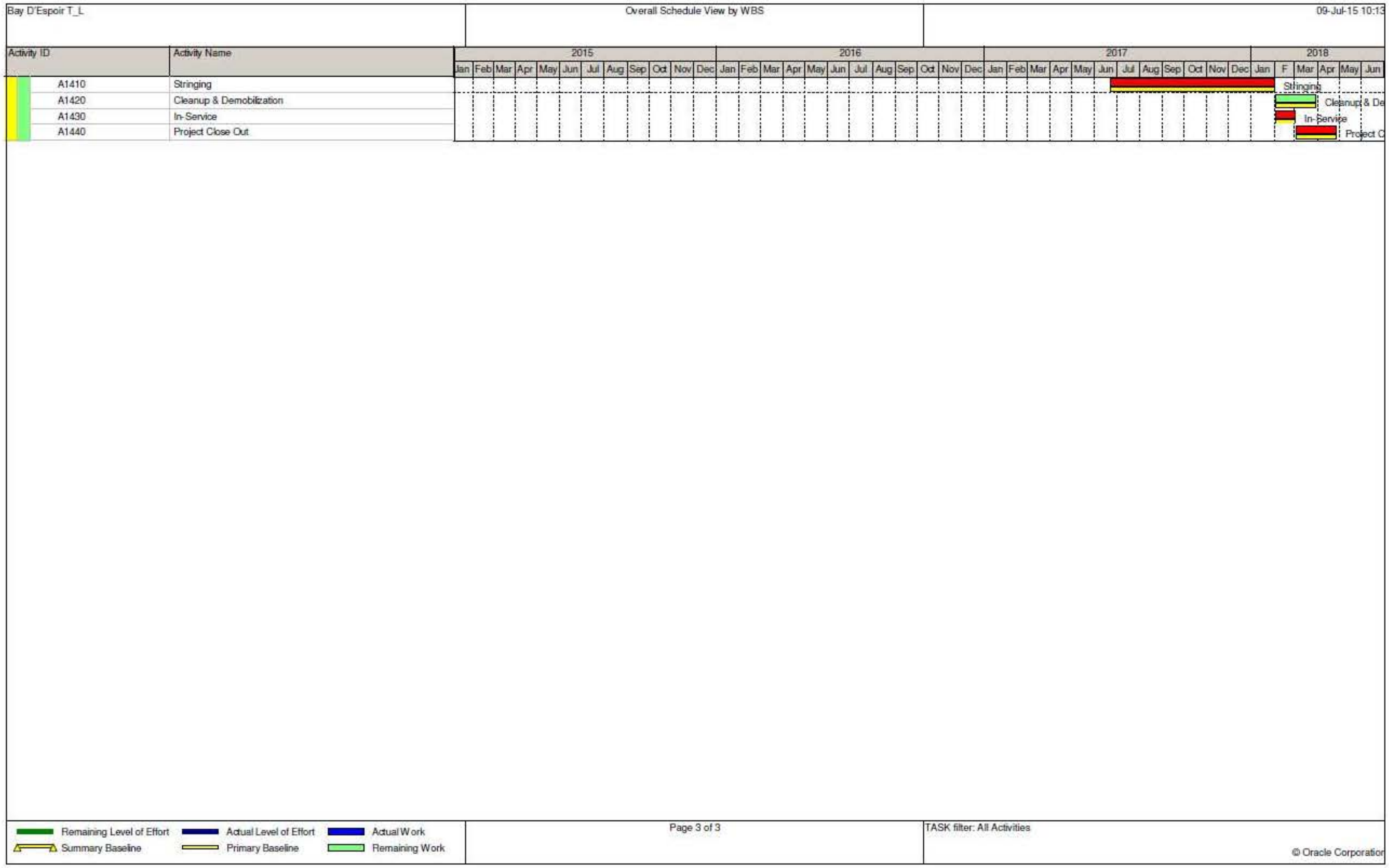
| Activity ID | Activity Name |
|---|---|
| **GIS - WAV** | |
| A1020 | GIS - WAV Tender Document Development |
| A1230 | GIS - WAV Tender Process |
| A1240 | GIS - WAV Post Tender Clarification |
| A1250 | GIS - WAV Award |
| A1260 | GIS - WAV Module Manufacture |
| A1270 | GIS - WAV Installation and Commissioning |
| **AIS - BDETS2** | |
| **Long Lead Equipment** | |
| A1610 | AIS Tender Document Development - Long Lead Equipment |
| A1620 | AIS Tender Process - Long Lead Equipment |
| A1630 | AIS Post Tender Clarification - Long Lead Equipment |
| A1640 | AIS Award - Long Lead Equipment |
| A1650 | AIS Delivery - Long Lead Equipment |
| **P&C Equipment** | |
| A1660 | AIS Tender Document Development - P&C Equipment |
| A1670 | AIS Tender Process - P&C Equipment |
| A1680 | AIS Post Tender Clarification - P&C Equipment |
| A1690 | AIS Award - P&C Equipment |
| A1700 | AIS Delivery - P&C Equipment |
| **Electrical Construction** | |
| A1710 | AIS Tender Document Development - Electrical Construction |
| A1720 | AIS Tender Process - Electrical Construction |
| A1730 | AIS Post Tender Clarification - Electrical Construction |
| A1740 | AIS Award - Electrical Construction |
| A1750 | AIS Materials Manufacture - Electrical Construction |
| A1760 | AIS Installation - Electrical Construction |
| A1770 | Commissioning - BDETS2 Extension |
| **ROW Clearing & Access** | |
| A1030 | Clearing & Access - Tender Document |
| A1280 | Clearing & Access Tender - Bid Phase |
| A1290 | Clearing & Access - Post Tender Review |
| A1300 | Clearing & Access Award |
| A1310 | Clearing & Access Mob / Accomodations |
| A1320 | ROW Clearing & Access Development |
| A1330 | Clearing & Access Demob |
| **Construction** | |
| A1040 | Construction Tender - Document Development |
| A1340 | Construction Tender Bid Phase |
| A1350 | Construction Post Tender Review |
| A1360 | Construction Award |
| A1370 | Mobilization and Camp |
| A1380 | Foundation Installation |
| A1390 | Tower Assembly |
| A1400 | Tower Erection |




Remaining Level of Effort | Actual Level of Effort | Actual Work
Summary Baseline | Primary Baseline | Remaining Work

Page 2 of 3

TASK filter: All Activities


Bay D'Espoir T_L
Overall Schedule View by WBS
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Activity Name
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2016
2017
2018
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A1410 Stringing
A1420 Cleanup & Demobilization
A1430 In-Service
A1440 Project Close Out
Stringing
Cleanup & De
In-Service
Project C
Remaining Level of Effort
Actual Level of Effort
Actual Work
Summary Baseline
Primary Baseline
Remaining Work
Page 3 of 3
TASK filter: All Activities
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**A REPORT TO**
**THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES**

# 2014 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 ........ 3
2 Overview of Key Performance Indicator Results ........ 4
2.1 Overview ........ 4
2.2 Performance in 2014 versus 2014 Target ........ 5
3 Performance Indices ........ 6
3.1 Reliability Performance Indicators ........ 6
*3.1.1 Reliability KPI: Generation* ........ 6
*3.1.2 Reliability KPI: Transmission* ........ 10
*3.1.3 Reliability KPI: Distribution* ........ 17
*3.1.4 Reliability KPI: Other* ........ 23
3.2 Operating Performance Indicators ........ 26
*3.2.1 Operating KPI: Generation* ........ 26
3.3 Financial Performance Indicators ........ 29
3.4 Customer-Related Performance Indicators ........ 29

Appendix A: Rationale for Hydro's 2014 KPI Targets
Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance
Appendix C1: Significant Transmission Events – 2014
Appendix C2: Significant Distribution Events – 2014 (Excluding Fourth Quarter)
Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)
Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

# 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. At the time of this report, CEA data has been published only to 2013. 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 2014 compared with the prior year as well as a comparison of actual KPI results compared with targets.

Section 3 of this report provides a detailed analysis of each individual KPI within the four categories named above in Section 3. In addition, it provides fourth quarter data for transmission and distribution reliability which is routinely included in Hydro's quarterly regulatory reports.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available. In addition, it provides fourth quarter data for transmission and distribution reliability which is routinely reported in quarterly regulatory reports.

The 2014 financial data and 2015 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 2015 target levels have been established.

# 2 Overview of Key Performance Indicator Results

## *2.1 Overview*

A number of key indices measured by Hydro showed improvement when compared to 2013 or the targets for 2014. All indices are discussed in the following sections of this Appendix. Some highlights are below.

- Residential Customer Satisfaction was 84% in 2014 compared to a target of 80%.

- There was an improvement in generation availability in 2014 when compared to 2013. Hydro's Weighted Capability factor, which measures generating unit availability, was 79.7% in 2014 compared to 75.5% in 2.13. The availability of the Holyrood thermal plant improved to 63% in 2014, compared to 46% in 2013. The availability of gas turbines improved to 80%, compared to 62% in 2013. The availability of Hydro's hydraulic plants was 88% in 2014, compared to 92% in 2013. With the exception of Unit 6 at the Bay d'Espoir generating station, Hydro's hydraulic units' availability was consistent with historic performance. Impacting on the overall hydraulic unit availability was a failure of a rectifying transformer Unit 6 and the subsequent failure of the spare during the winter months. These transformer issues resulted in an extended outage to Unit 6 that impacted hydraulic availability.

- Derating-Adjusted Forced Outage Rate (*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*)
- Hydro's DAFOR performance was 8.2% in 2014, compared to 13.7% in 2013.
- The frequency of transmission delivery point outages improved in 2014, compared to 2013. The forced outage component of transmission delivery point outages also improved in 2014, compared to 2013.
- The hydraulic conversion factor at Bay d'Espoir improved in 2014 from 2013. In 2014, the water levels experienced in the reservoirs were generally lower. This allowed greater output flexibility resulting in improved water utilization at the Bay d'Espoir plant. The target was met in 2014 for this measure.

Other indices did not exhibit the same improvement in comparison to the 2013 performance or target.

- There were 14 underfrequency load shedding events in 2014. This is compared to a 2014 target of six events and a 2013 performance of seven events.
- Transmission and Distribution reliability were impacted by the significant disturbances on January 4 and 5 which were precipitated by a transformer failure at Sunnyside Terminal Station and subsequent breaker failures. Additionally, there were a number of severe weather related outages, primarily occurring in the Central region in February and April.

The 2014 operating KPI for energy conversion at Holyrood was primarily impacted by the low heating content in the fuel consumed at the plant, in addition to a lower average unit loading.

A review of all indices are contained in the following sections.

*Hydro's 2014 operating and maintenance costs are not available at this time. Financial KPI data will be provided at a later date.*

## 2.2 Performance in 2014 versus 2014 Target

The table below summarizes Hydro's KPI performance in 2014. The rationale for the 2014 targets was summarized in the February 2014 report to the Board entitled *2013 Annual Report on Key Performance Indicators*. The 2014 rationale is included in this report as Appendix A.

| Category | KPI | Units | 2014 Target | 2014 Results |
|---|---|---|---|---|
| Reliability | Weighted Capability Factor (WCF) | % | 84.0[1] | 79.7 |
| | DAFOR | % | 2.7 | 8.2 |
| | T-SAIDI | Minutes/Point | 180[2] | 458 |
| | T-SAIFI | Number/Point | 1.6 | 3.8 |
| | T-SARI | Minutes/Outage | 114 | 121 |
| | SAIDI | Hours/Customer | 5.9 | 19.56 |
| | SAIFI | Number/Customer | 3.6 | 6.77 |
| | Underfrequency Load Shedding | # of events | 6 | 14 |
| Operating | Hydraulic CF | GWh/MCM | 0.433 | 0.433 |
| | Thermal CF | kWh/BBL | 615 | 584 |
| Financial | Controllable Unit Cost | $/MWh | Not Available | |
| Other | Customer Satisfaction (Residential) | Max=100% | 80% | 84% |

[1] The Weighted Capability Factor target is based on planned annual maintenance outages, an allowance for other short duration maintenance outages and targeted forced outage durations.
[2] Transmission and distribution reliability targets were set on combined planned and unplanned outages.

# 3 Performance Indices

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

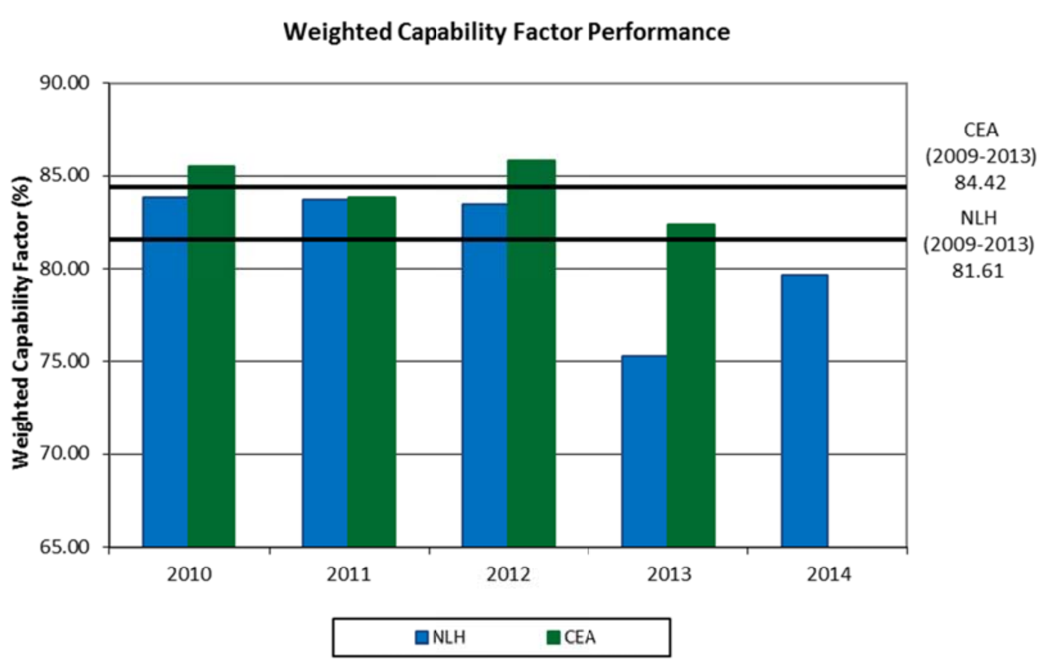
## *3.1 Reliability Performance Indicators*

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 2014, Hydro's WCF was 79.7%, compared to 75.5% in 2013 and a target of 84%. The 2009 to 2013 Hydro five-year average is 81.6%. The annual target for availability includes the time that units are out for maintenance. Therefore, the capability in any year is affected by the maintenance and capital work planned for that year.



Thermal unit WCF was 63% in 2014 compared to 46% in 2013. The overall 2014 Thermal WCF target was 67%. Holyrood Unit 3 had a capability factor of 69%, Unit 2 had a capability factor of 61%, and Unit 1 had a capability factor of 60%. Holyrood unit maintenance and planned outages were completed within the intended timeframes. A Holyrood unit was operated throughout the summer months in 2014 in order to support the transmission into the Avalon Peninsula.

Overall, the hydraulic unit WCF performance was 88%, compared to 92% in 2013 and a target of 92%. The primary driver for the 88% WCF is the failure of two rectifying transformers on Bay d'Espoir Unit 6. The in-service rectifying transformer failed on January 30 and the unit was returned to service on February 1, using the spare transformer. This spare transformer failed on February 17 and, with no other spares available, a new transformer was required to be built. The unit was returned to service on August 5 with a new rectifying transformer. Removing the impact of the rectifying transformer failure from the hydraulic WCF, results in an annual hydraulic WCF outcome which is approximately equal to the target of 92%.

Gas turbine availability improved to 80% in 2014 from 62% in 2013. The 2014 gas turbine WCF target was 86%.

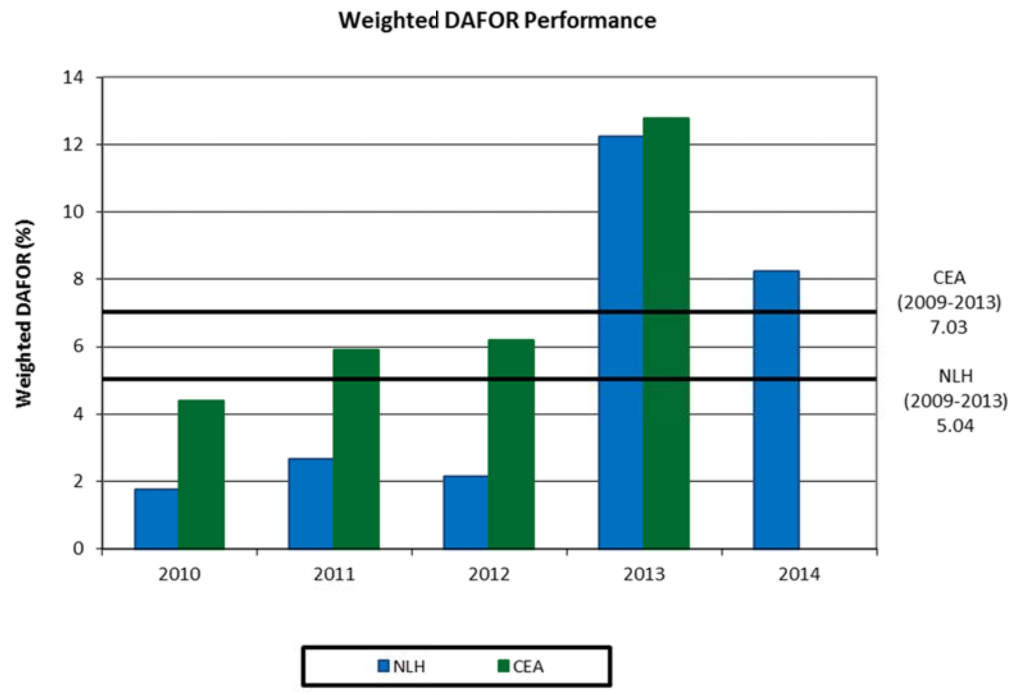
Calculation details for weighted capability as well as a list of factors that can impact KPI performance are included in Appendix B of this report.

**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 2014, Hydro's weighted DAFOR was 8.2%, compared to 12.2% in 2013 and a target of 2.7%. The thermal DAFOR for 2014 was 13.7%, compared to 36.6% in 2013 and a target of 8.0%. The variance from target for the thermal units was not attributed to any major failures on any one unit, but rather a series of minor failures of one to three days in duration. The hydraulic DAFOR was 5.9% compared to 0.55% in 2013 and a target of 0.6%. The hydraulic DAFOR was impacted by the failures of the rectifying transformers on Bay d'Espoir Unit 6, as described in the previous section. These failures contributed approximately 83% of the overall 2014 hydraulic DAFOR.

Hydro's overall weighted DAFOR for the period 2009 to 2013 is 5.0%, 2.0% better than the equivalently weighted national average of 7.0% for the same period.

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




## 3.1.1 c) Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2013 and for the latest CEA national average for the period 2009-2013 are included for comparison.

| Generation Performance Indices | | | | |
|---|---|---|---|---|
| **Index** | | **Hydro** | **Thermal** | **Gas Turbine** |
| **Failure Rate**<br>(Forced Outages per 8,760 operating hours) | NLH 2014<br>NLH 2013<br>CEA '09-'13 | 2.67<br>1.42<br>2.01 | 11.72<br>8.84<br>7.12 | 160.36<br>144.46<br>22.39 |
| **Incapability Factor**<br>(Percent of Time) | NLH 2014<br>NLH 2013<br>CEA '09-'13 | 11.30<br>7.97<br>10.27 | 36.41<br>53.96<br>26.76 | 17.36<br>35.64<br>13.33 |
| **Derating Adjusted Forced Outage Rate**<br>(Percent of Time) | NLH 2014<br>NLH 2013<br>CEA '09-'13 | 5.87<br>0.55<br>4.17 | 13.74<br>36.58<br>12.69 | |
| **Utilization Forced Outage Probability** (Percent of Time) | NLH 2014<br>NLH 2013<br>CEA '09-'13 | | | 14.34<br>28.07<br>13.07 |

**Hydraulic Unit Performance**

The extended forced outage to Unit 6 at Bay d'Espoir resulting from the rectifying transformer failures impacted all hydraulic unit measures in 2014, when compared to 2013 and to the national five year averages. In excluding these transformer failures, the performance of the remaining hydraulic units was consistent with past performance.

**Thermal Unit Performance**

Thermal unit performance improved in 2014 in the areas of Incapability Factor and DAFOR, when compared to 2013. Failure rate performance in 2014, when compared to 2013, was impacted by a series of minor vibration issues at Unit 2 which occurred during startup of the unit following its annual maintenance. These vibration issues were addressed in the fourth quarter of 2014.

**Gas Turbine Unit Performance**

The Incapability Factor and Utilization Forced Outage Probability (UFOP) performance of Hydro's gas turbines improved in 2014 when compared to 2013. In comparison to the national average, the Failure Rate is high due to the normally low operating hour requirements of Hydro's gas turbines. Units across the country are often used on a more frequent basis and therefore their failure rate percentage is lower than those of a standby unit. Of particular importance to Hydro's gas turbines fleet is the UFOP which measure the degree to which a standby unit can be called upon to supply load when requested. The UFOP in 2014 was 14.3%, compared to 28.1% in 2013 and the CEA five year average of 13.1%.

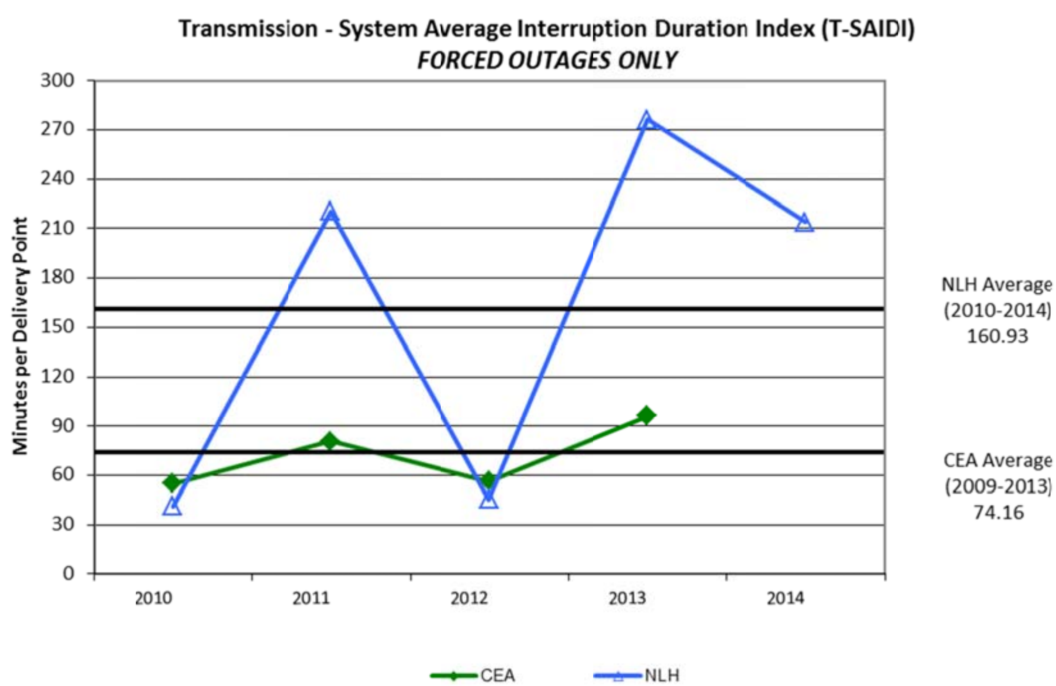
### *3.1.2 Reliability KPI: Transmission*

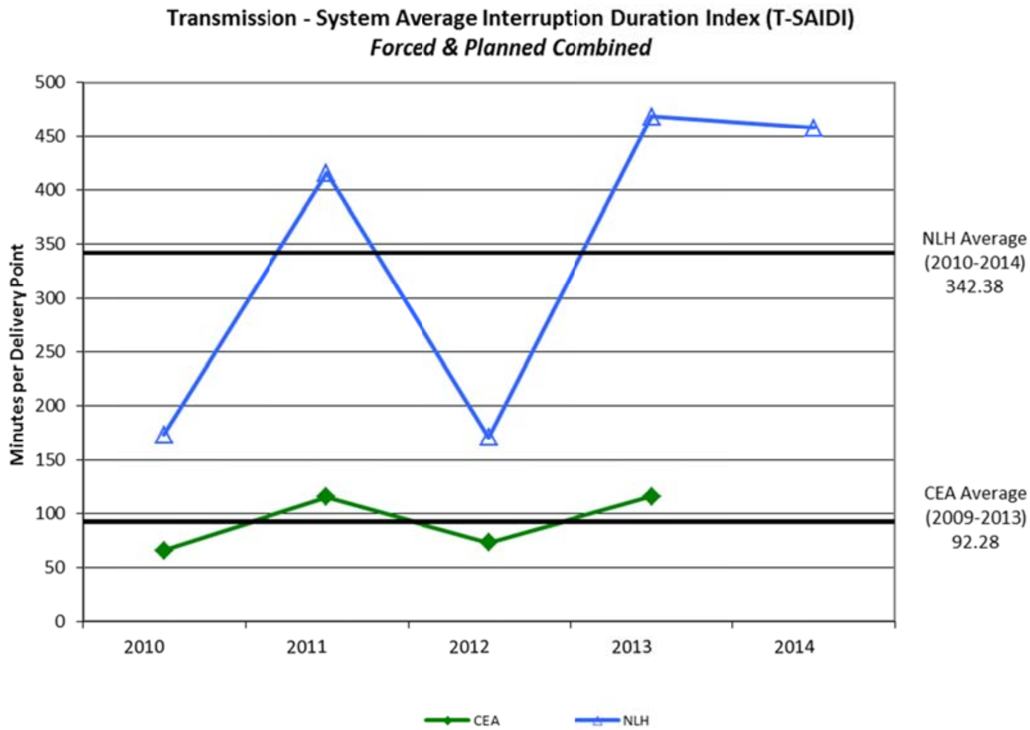
**3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI)** - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 96 minutes per delivery point (forced and planned combined) compared to 120 minutes in 2013.

The total 2014 T-SAIDI was 458 minutes per delivery point compared to a 2013 total of 469 minutes per delivery point and a target of 180 minutes per delivery point. The forced outage duration in 2014 was 214 minutes, compared to 277 minutes in 2013 and a 2014 target of 53 minutes per delivery point. The planned outage duration was 244 minutes, compared to 192 minutes in 2013 and a target of 128 minutes per delivery point.

The significant outages which occurred on January 4 and 5, originating on the Avalon Peninsula, contributed 120 minutes per delivery point to the forced outage T-SAIDI for 2014 (approximately 56% of the total forced T-SAIDI). The increase in the T-SAIDI for planned outages was the result of increased maintenance on terminal station equipment.

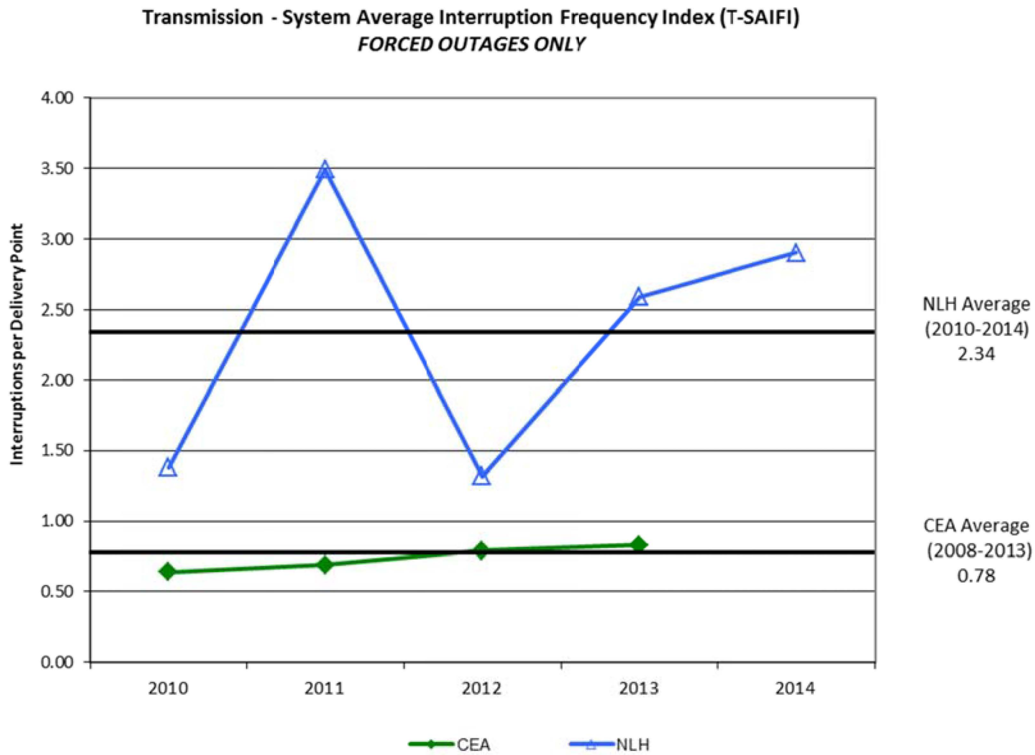


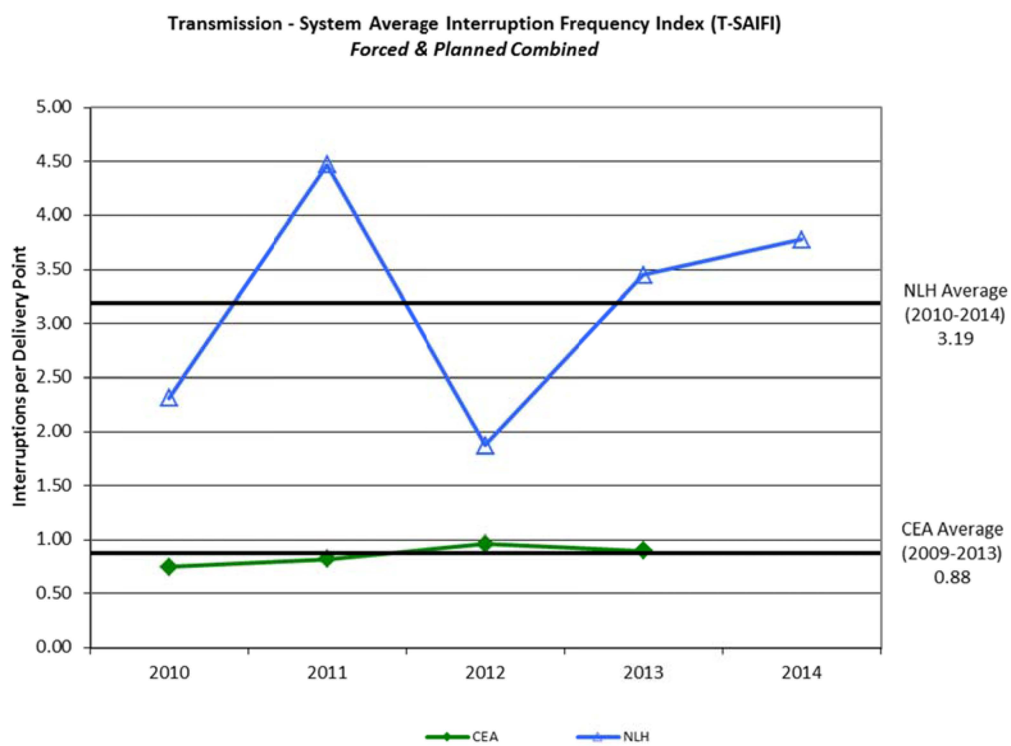



**3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI)** - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 0.48 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.17 and 0.31, respectively. The 2013 fourth quarter T-SAIFI was 0.91 outages per bulk delivery point.

The 2014 T-SAIFI was 3.78 outages per bulk delivery point, compared to 2013 T-SAIFI of 3.45 outages per delivery point and the 2014 target of 1.58. The number of forced outages per delivery point in 2014 was 2.90 compared to 2.59 in 2013. The number of planned outages per delivery point in 2014 was 0.88 compared to 0.86 in 2013.


Transmission - System Average Interruption Frequency Index (T-SAIFI)
*FORCED OUTAGES ONLY*
Interruptions per Delivery Point
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
2014
NLH Average
(2010-2014)
2.34
CEA Average
(2008-2013)
0.78
CEA
NLH

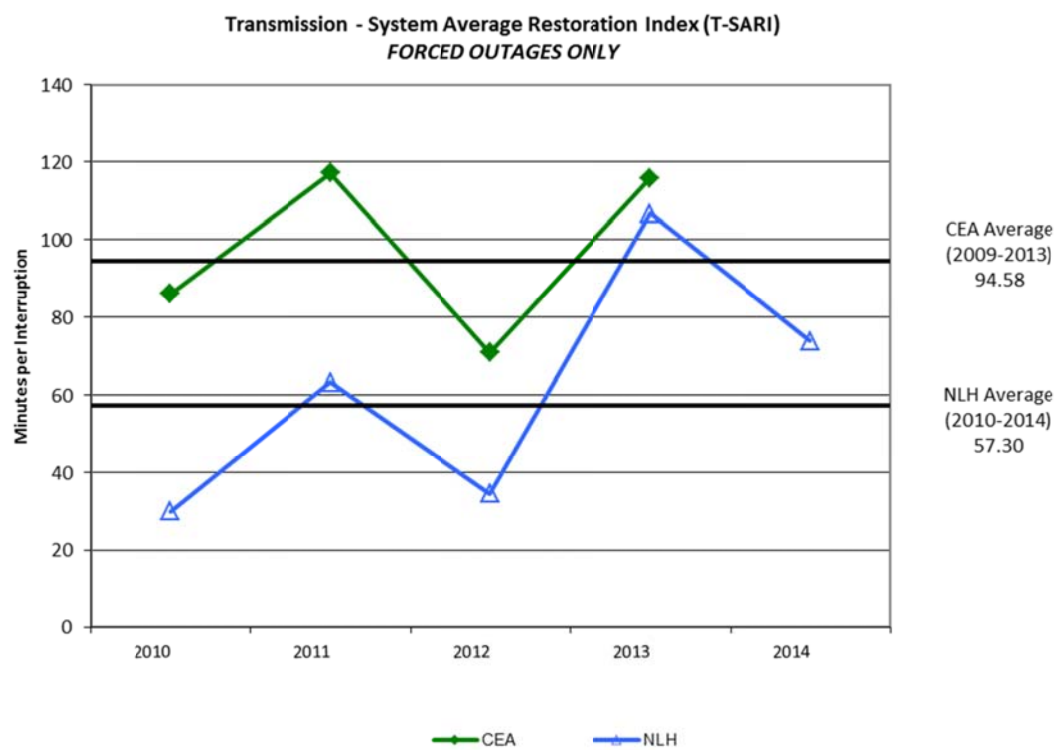

Transmission - System Average Interruption Frequency Index (T-SAIFI)
*Forced & Planned Combined*
Interruptions per Delivery Point
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2010
2011
2012
2013
2014
NLH Average
(2010-2014)
3.19
CEA Average
(2009-2013)
0.88
CEA
NLH

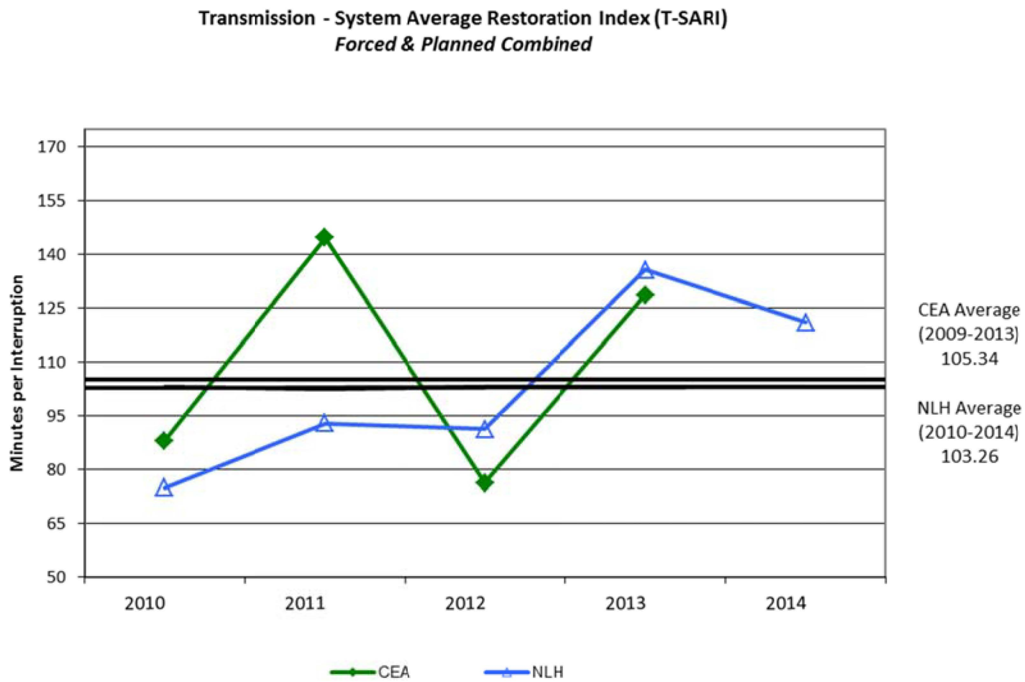
**3.1.2 c) Transmission System Average Restoration Index (T-SARI)** - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

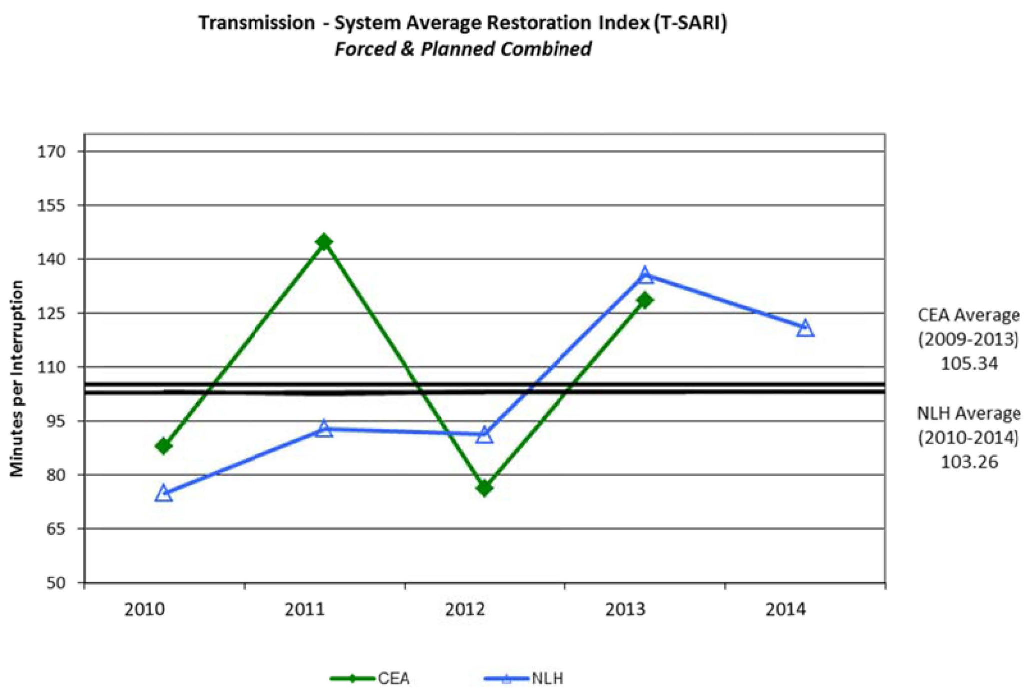
Hydro's total transmission T-SARI was 199 minutes per interruption for the fourth quarter of 2014, compared to 131 minutes per interruption during the same quarter in 2013. The forced outage component of T-SARI was 42 minutes per interruption, compared to 91 minutes per interruption in 2013. The planned outage component of T-SARI was 286 minutes per interruption compared to 192 minutes in 2013.

Hydro's 2014 total transmission T-SARI on an annual basis was 121 minutes per interruption, compared to 136 minutes in 2013 and a 2014 target of 114 minutes. The forced outage component of T-SARI was 74 minutes per interruption, compared to 107 minutes in 2013. The planned outage component of T-SARI was 277 minutes per interruption, compared to 223 minutes in 2013. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase results from the increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance improved in 2014 compared to 2013 and is better than the latest CEA five year average.






There were four forced transmission outages and 11 planned transmission outages in the fourth quarter. A summary of these outages follows:

**Forced**

On October 4, customers supplied by the Main Brook and Roddickton Terminal Stations experienced an unplanned power outage of ten minutes. The outage occurred at the commencement of a planned outage to perform preventative maintenance on breakers at the St. Anthony Airport Terminal Station. During the switching to prepare for the planned outage, there was a protection trip of TL261 on opening L56T1. Customers in St. Anthony continued to be supplied via the St. Anthony Diesel Plant.

On October 29, all customers on the Great Northern Peninsula, north of and including Plum Point, experienced an unplanned power outage of up to one hour and 32 minutes. The outages were caused by the misoperation of the neutral overcurrent protection on Plum Point transformer T1 resulting in a transformer lockout which tripped transmission Lines TL241 and TL244. The protection was activated by issues on feeder L2 in the Plum Point distribution area. Customers north of Plum Point were subjected to an extended outage due to the failure of a micro switch on the high side disconnect switch B1T1 on T1 at Plum Point. The failure of this micro switch required that personnel travel to Plum Point to reset the transformer lockout before TL241 and TL244 could be restored. The St. Anthony Diesel Plant was started to restore St. Anthony customers.

On November 9, customers supplied by the Main Brook and Roddickton Terminal Stations experienced an unplanned power outage of 25 minutes. The outage occurred during switching for a planned outage at the St. Anthony Airport Terminal Station. The customers in Main Brook, Roddickton and St. Anthony distribution systems were planned to be supplied by the St. Anthony diesel plant. The outage occurred when TL261 tripped when disconnect switch L56T1 was opened. The trip is related to an issue with the line distance protection on TL261 operating when the St. Anthony Airport Terminal Station is disconnected from the grid, while the St. Anthony Diesel Plant is on-line supplying customers in the St Anthony, Roddickton and Main Brook areas. A similar trip occurred on October 4. The problem with the line protection has been addressed to prevent further misoperations.

On December 17, customers supplied by the Hawke's Bay Terminal Station experienced an unplanned power outage of 16 minutes. The outage occurred after a fault occurred during the energization of the Mobile Substation P235 at Hawke's Bay during planned work. A set of temporary transportation grounds were not removed from P235 prior to its energization.

**Planned**

On October 4, customers supplied by the Bear Cove Terminal Station experienced a planned power outage of 13 minutes. The outage was required to isolate transmission line TL244 to perform preventative maintenance on breaker B1L44 at Plum Point Terminal Station.

On October 7, customers supplied by the Parson's Pond Terminal Station experienced a planned power outage of five hours and 16 minutes. The outage was required to perform preventative maintenance on equipment in the terminal station.

On October 18, customers supplied by the Wiltondale and Glenburnie Terminal Stations experienced a planned power outage of five hours. The outage was required to connect mobile substation P235 in Wiltondale in order to perform terminal station improvements.

On November 1, customers supplied by the Jackson's Arm and Hampden Terminal Stations experienced a planned power outage of six hours and 17 minutes. The outage was required to perform preventive maintenance on equipment in the terminal stations.

On November 2, customers supplied by the Jackson's Arm and Hampden Terminal Stations experienced a planned power outage of five hours and 36 minutes. The outage was required to complete preventive maintenance on equipment in the terminal stations.

On November 3, customers supplied by the Cow Head Terminal Station experienced a planned power outage of five hours and 36 minutes. The outage was required to remove the high voltage leads on circuit breaker B1L27 in the terminal station. Working is continuing to replace this breaker.

On November 5, customers supplied by the Rocky Harbour Terminal Station experienced a planned power outage of one hour and 11 minutes (71 minutes). The outage was required to obtain a dissolved gas analysis sample from transformer T1 in the station, in addition to the installation of a new pole on feeder L1 in the Rocky Harbour distribution system.

On November 13, customers supplied by the Cow Head and Parson's Pond Terminal Stations experienced a planned power outage of five minutes. The outage was required to safely close bypass switch B1L27-BP at Cow Head Terminal Station.

On November 16, all customers supplied by the Plum Point and Bear Cove Terminal Stations and customers supplied by feeder L2 in St. Anthony experienced a planned power outage of up to seven hours and 44 minutes. Customers in Main Brook, Roddickton, and St. Anthony feeders L1 and L3 were supplied via the St. Anthony Diesel Plant. The outages were required to perform preventative/corrective maintenance on circuit breaker B1L56, disconnect switch B1L44 and the BC6-R1 recloser structure at the Bear Cove station; and to perform preventative/corrective maintenance on circuit breaker B1L41, bypass switch B1L41-BP and disconnect switch B1T1 at the Plum Point station. In addition, the outage facilitated replacement of a pole on structure 405 on transmission line TL241.

On November 22, NP customers supplied by the Sunnyside Terminal Station experienced a planned power outage of five hours and 45 minutes. The outage was required to complete corrective and preventive maintenance on disconnect switches on bus B3 at the terminal station.

On December 2, customers supplied by the Wiltondale and Glenburnie Terminal Stations experienced a planned power outage of five hours and 51 minutes. The outage was required to disconnect the mobile substation P235 in Wiltondale and to energize the new Wiltondale Terminal Station.

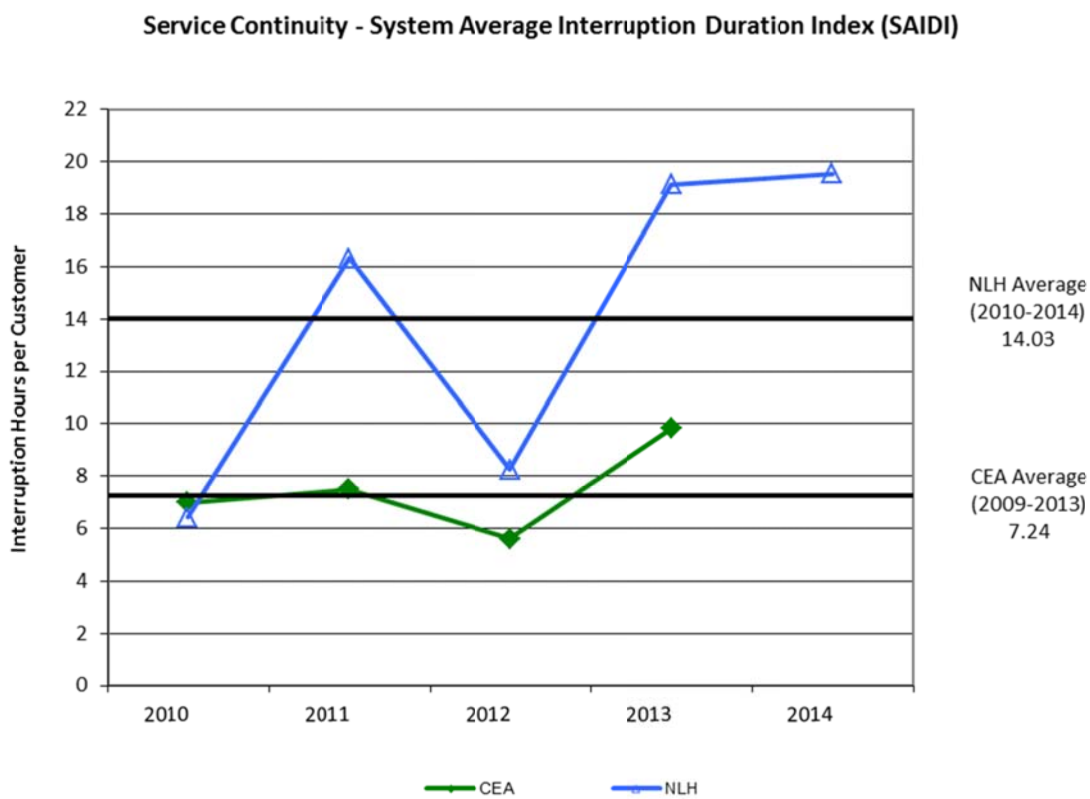
### *3.1.3 Reliability KPI: Distribution*

**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 2014, SAIDI was 2.56 hours per customer, compared to 5.01 hours per customer during the same quarter of 2013.

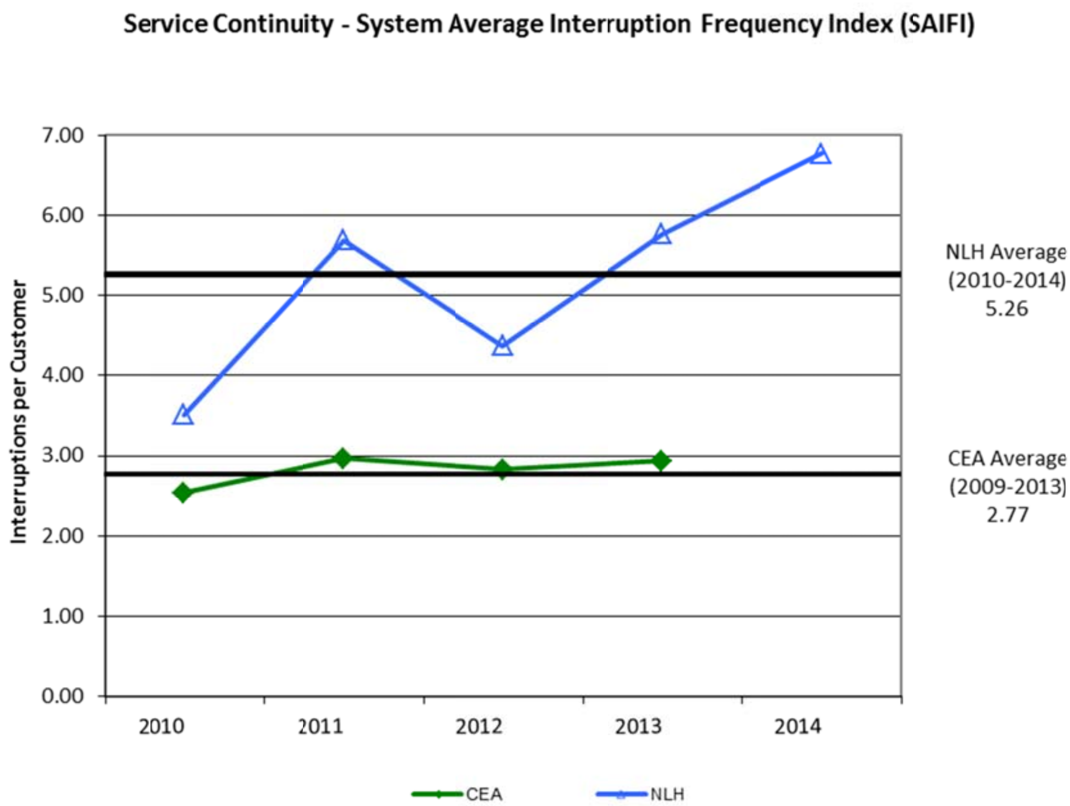
The total 2014 SAIDI was 19.56 hours per customer, compared to 19.22 hours per customer in 2013.

One of the main contributors to SAIDI was a series of planned outages in Labrador City and Wabush in the summer and fall of 2014. The planned outages in Labrador City were required to complete the voltage conversion project, while the Wabush planned outages were to complete upgrades at the Wabush Substation and for various distribution feeders.




**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 of 2014 SAIFI was 1.18, compared to 1.41 during the same quarter of 2013. The total 2014 SAIFI was 6.77, compared to 5.82 in 2013 and a target of 3.65 in 2014.




The outages during the fourth quarter resulted from a variety of causes. The following table presents a summary of the major interruptions.

| Distribution System | Outage Date | Outage Cause | Customers Affected | Outage Duration (Hours) | Notes |
|---|---|---|---|---|---|
| Labrador City | Oct 04, 2014 | Sched Outage-Planned | 593 | 4.00 | Planned outage to safely perform voltage conversion upgrades |
| Labrador City | Oct 19, 2014 | Sched Outage-Planned | 207 | 4.00 | Planned outage to safely perform voltage conversion upgrades |
| L'Anse-Au-Loup | Oct 25, 2014 | Adverse Weather | 984 | 7.47 | High Winds/Line damaged and required repairs |
| Ramea | Oct 31, 2014 | Adverse Weather | 330 | 4.77 | Phase wired burnt off and had to be re-attached |
| Rigolet | Nov 08, 2014 | Loss of Supply | 172 | 50.00 | Problems with diesel generator. Power rotation |
| Black Tickle | Nov 19, 2014 | Defective Equipment | 33 | 22.25 | Broken Conductor on feeder. Outage extended to due weather delay in getting extra crews on site. |
| Black Tickle | Dec 25, 2014 | Loss of Supply | 102 | 24.22 | Severe icing on feeder caused problems on diesel plant. Outage extended to due weather delays In getting extra crews on site. |

A summary of the more significant 2014 interruptions affecting 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 c) Additional Information

As per Hydro's regular quarterly report, this section provides more detailed information on distribution system interruptions with performance broken down by Area, Origin, and Type.

**Rural Systems Service Continuity Performance by Area**

| SAIFI (Number per Period) | | | | | |
|---|---|---|---|---|---|
| **Area** | **Fourth Quarter** | | **12 Mths to Date** | | **5 Year** |
| | **2014** | **2013** | **2014** | **2013** | **Average** |
| **Central** | | | | | |
| Interconnected | 0.27 | 0.71 | 2.48 | 4.02 | 2.78 |
| Isolated | 1.04 | 0.01 | 3.63 | 2.85 | 3.54 |
| **Northern** | | | | | |
| Interconnected | 1.19 | 1.91 | 7.26 | 4.90 | 5.22 |
| Isolated | 3.89 | 1.45 | 13.74 | 4.81 | 7.97 |
| **Labrador** | | | | | |
| Interconnected | 1.01 | 1.75 | 9.76 | 8.74 | 7.22 |
| Isolated | 6.10 | 2.24 | 10.88 | 9.04 | 10.02 |
| Total | 1.18 | 1.41 | 6.77 | 5.82 | 5.26 |

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** | | **12 Mths to Date** | | **5 Year** |
| | **2014** | **2013** | **2014** | **2013** | **Average** |
| **Central** | | | | | |
| Interconnected | 0.64 | 7.46 | 9.18 | 21.37 | 11.90 |
| Isolated | 1.88 | 0.05 | 4.56 | 2.55 | 3.30 |
| **Northern** | | | | | |
| Interconnected | 3.03 | 6.18 | 22.87 | 12.13 | 14.80 |
| Isolated | 10.15 | 0.94 | 43.60 | 6.07 | 13.87 |
| **Labrador** | | | | | |
| Interconnected | 1.72 | 2.67 | 26.48 | 28.56 | 16.79 |
| Isolated | 11.75 | 1.40 | 14.70 | 8.22 | 13.14 |
| Total | 2.56 | 5.01 | 19.56 | 19.22 | 14.03 |

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 2014 | Fourth Quarter 2013 | 12 Mths to Date 2014 | 12 Mths to Date 2013 | 5 Year Average |
|---|---|---|---|---|---|
| Loss of Supply – Transmission | 0.01 | 0.27 | 2.34 | 1.32 | 1.67 |
| Loss of Supply – NF Power | 0.00 | 0.01 | 0.00 | 0.01 | 0.01 |
| Loss of Supply – Isolated | 0.19 | 0.11 | 0.46 | 0.48 | 0.50 |
| Loss of Supply – L'Anse au Loup | 0.03 | 0.00 | 0.24 | 0.05 | 0.09 |
| Distribution | 0.96 | 1.02 | 3.73 | 3.95 | 2.99 |
| Total | 1.18 | 1.41 | 6.77 | 5.82 | 5.26 |

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 2014 | Fourth Quarter 2013 | 12 Mths to Date 2014 | 12 Mths to Date 2013 | 5 Year Average |
|---|---|---|---|---|---|
| Loss of Supply – Transmission | 0.04 | 0.56 | 4.22 | 4.36 | 3.51 |
| Loss of Supply – NF Power | 0.00 | 0.04 | 0.00 | 0.05 | 0.14 |
| Loss of Supply – Isolated | 0.15 | 0.04 | 0.26 | 0.21 | 0.23 |
| Loss of Supply – L'Anse au Loup | 0.01 | 0.00 | 0.20 | 0.05 | 0.07 |
| Distribution | 2.36 | 4.37 | 14.88 | 14.55 | 10.02 |
| Total | 2.56 | 5.01 | 19.56 | 19.22 | 14.03 |

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 – 2014 Fourth Quarter Only

| Area | Scheduled | | Unscheduled | | Total | |
|---|---|---|---|---|---|---|
| | SAIFI | SAIDI | SAIFI | SAIDI | SAIFI | SAIDI |
| **Central** | | | | | | |
| Interconnected | 0.00 | 0.00 | 0.27 | 0.64 | 0.27 | 0.64 |
| Isolated | 0.16 | 0.04 | 0.88 | 1.84 | 1.04 | 1.88 |
| **Northern** | | | | | | |
| Interconnected | 0.54 | 1.38 | 0.65 | 1.65 | 1.19 | 3.03 |
| Isolated | 0.89 | 6.51 | 3.00 | 3.64 | 3.89 | 10.15 |
| **Labrador** | | | | | | |
| Interconnected | 0.61 | 1.44 | 0.40 | 0.29 | 1.01 | 1.72 |
| Isolated | 2.35 | 7.10 | 3.74 | 4.66 | 6.10 | 11.76 |
| Total | 0.47 | 1.41 | 0.71 | 1.15 | 1.18 | 2.56 |

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 four underfrequency events during the fourth quarter of 2014, summarized as follows:

- On October 13, Holyrood Unit 2 tripped. Hydro's investigation has concluded that the Holyrood Terminal Station (HRD TS) Unit #2 unit breakers (B2L42 & B2B11) tripped forcing Unit 2 offline. Hydro was conducting commissioning testing on the HRD TS Unit #1 unit breakers (B1L17 & B1B11) when the incident occurred. As part of the commissioning testing, a protection relay trip check was being performed on the Unit 1 unit breakers. The incorrect protection relay, the protection relay associated with Unit 2 unit breakers, was triggered. The incident and commissioning procedures have been reviewed to ensure a repeat of similar incidents is prevented.

  With the removal of generation (approximately 70 MW) the system frequency dropped to 58.66 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 730 MW. All Newfoundland Power customers were reported to be restored within four minutes after the event occurred. Load Shed: Newfoundland Power: 16 MW. (Unsupplied Energy: 65 MW-Mins)

- On November 15, at 1621 hours, Holyrood Unit 2 tripped. Hydro's investigation has determined that part of the commissioning activities ongoing on Holyrood Unit 1 included control valve programming and testing. Completing this work required working on the Mark V Distributed Control System (DCS) which is common to both Units 1 and 2. Comparisons between Unit 1 and Unit 2 control valve programming were being checked when a test was initiated to stroke the valve on Unit 1. This test was accidentally initiated on Unit 2 causing the trip. The Unit 1 and Unit 2 distributed control system programming parameters are not distinguishable from each other at the programming level. The technologists mistakenly thought they were testing the Unit #1 parameters. Both the Hydro and the OEM contractor technologists are very familiar with this control system. Hydro has identified a failure to check/identify the task as the root cause. The outcomes of the investigation were reviewed with employees who may work inside the DCS to highlight the system limitations on naming convention.

  With the removal of generation (approximately 70 MW) the system frequency dropped to 58.68 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 964 MW. All Newfoundland Power customers were reported to be restored within 2 minutes after the event occurred. Newfoundland Power load loss: 15 MW (Unsupplied Energy: 30 MW-Mins)

- On December 19, at 0849 hours, Holyrood Unit 2 tripped. Hydro's investigation determined the trip was the result of loss of power to all eight of the unit's 4160V motors. The motors tripped due to the failure of a motor lug resulting in a fault which was detected by the overcurrent protection. This subsequently tripped the unit.

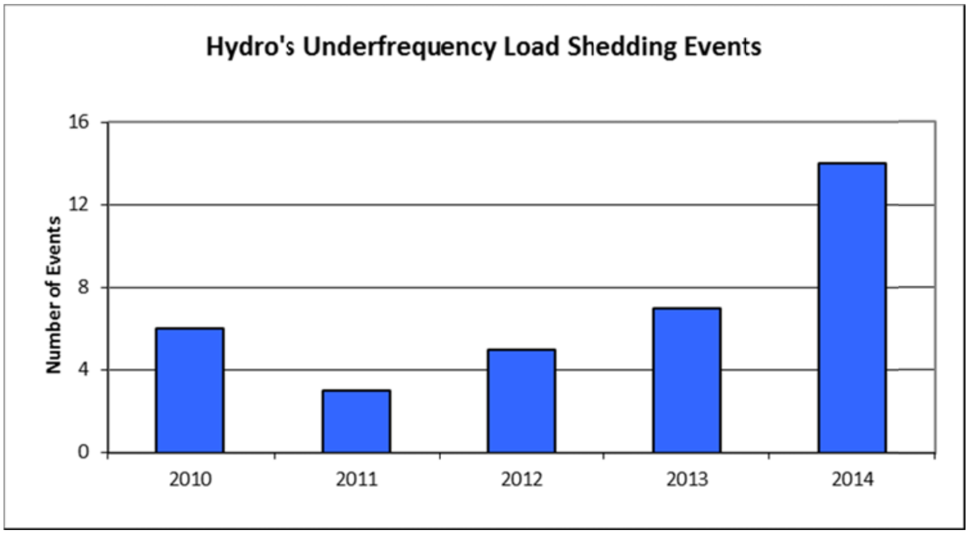
  With the removal of generation (approximately 72 MW) the system frequency dropped to 58.77 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total Island load at the time of the incident was 1125 MW. All Newfoundland Power customers were reported to be restored within 2 minutes after the event occurred. Newfoundland Power load loss: 23 MW (Unsupplied Energy: 46 MW-Mins)

- On December 30, at 2334 hours, Holyrood Unit 3 tripped. Hydro's investigation determined that the unit tripped because of a loss of atomizing steam going to the burner. Operations found two manual valves in the incorrect position (one 90% closed and one 100% closed). The unit controls operated correctly to adjust for a low aux steam pressure but the position of these valves resulted in the cut off of all atomizing steam.

  With the removal of generation (approximately 130 MW) the system frequency dropped to 58.36 Hz resulting in the activation of the under frequency protection at Newfoundland Power, Hydro, and Corner Brook Pulp & Paper Limited. Total Island load at the time of the incident was 1370 MW. Hydro advised Newfoundland Power to begin customer restoration within 4 minutes of the incident. Relative to the time of the incident: all (919) Hydro customers were restored within 4 minutes; Corner Brook Pulp & Paper Limited was restored within 5 minutes; the majority (15,683) of Newfoundland Power customers were reported to be restored within 22 minutes; and the remaining (1299) Newfoundland Power customers were reported to be restored within 69 minutes.

| | | |
|---|---|---|
| Load Shed: | Newfoundland Power: | 95 MW |
| | Hydro: | 3 MW |
| | Corner Brook Pulp & Paper: | 14 MW |
| | Total Load Shed: | 112 MW |
| | *(Unsupplied Energy: 1,664 MW-Mins)* | |

In total, there were 14 UFLS events in 2014, compared to 7 in 2013 and the five-year average (2009-2013) of 5.6 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 2014 to the same quarter in 2013 in addition to annual performance.

**Underfrequency Load Shedding Number of Events**

| Customers | Fourth Quarter 2014 | Fourth Quarter 2013 | Year to Date 2014 | Year to Date 2013 | 5 Year Average (2010–2014) |
|---|---|---|---|---|---|
| NF Power | 4 | 1 | 14 | 7 | 7 |
| Industrials | 1 | 0 | 3 | 0 | 1.2 |
| Hydro Rural* | 1 | 1 | 2 | 3 | 1.6 |
| Total Events | 4 | 1 | 14 | 7 | 7 |

**Underfrequency Load Shedding Unsupplied Energy (MW-min)**

| Customers | Fourth Quarter 2014 | Fourth Quarter 2013 | Year to Date 2014 | Year to Date 2013 | 5 Year Average (2010–2014) |
|---|---|---|---|---|---|
| NF Power | 1,722 | 175 | 5,798 | 13,917 | 4,713 |
| Industrials | 70 | 0 | 200 | 0 | 92 |
| Hydro Rural* | 12 | 0 | 48 | 324 | 96 |
| Total Events | 1,804 | 175 | 6,046 | 14,241 | 4,901 |

* 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 10 UFLS events in 2014 are summarized in Appendix C3.

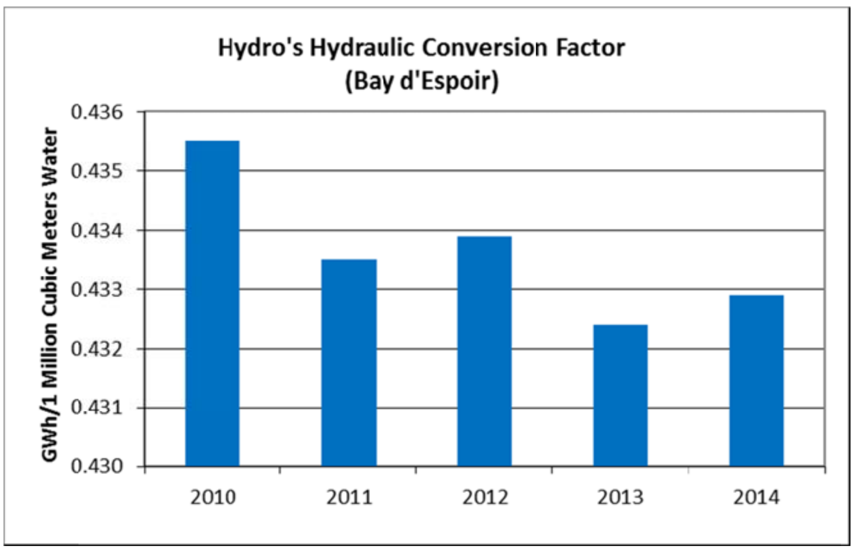
## *3.2 Operating Performance Indicators*

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 2014, the hydraulic conversion factor for Bay d'Espoir was 0.4329 GWh/MCM, compared to 0.4324 GWh/MCM compared to a 2014 target of 0.433 GWh/MCM.




In 2014, the water levels were lower in the reservoirs allowing for improved water utilization at the Bay d'Espoir plant, as there were fewer hours where plant production was higher at less efficient output levels.

**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 proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. The output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production on the Island, quantity of power purchases, customer energy requirements and system security requirements. The thermal conversion factor is also impacted by the heating content in the No. 6 fuel consumed at the plant, measured in BTUs/bbl.

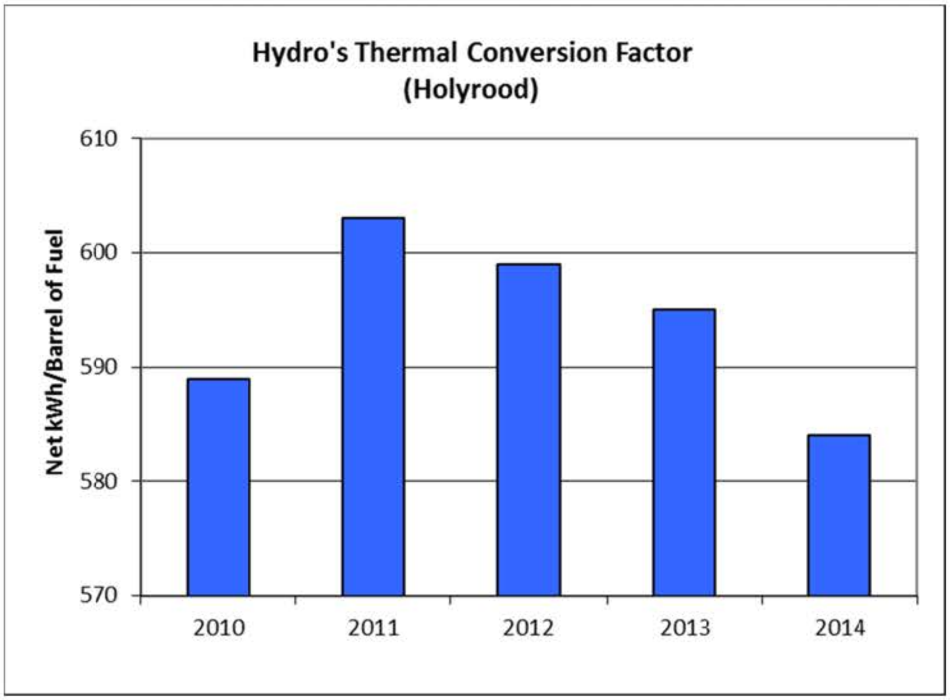
In 2014, Hydro's net thermal conversion factor was 584 kWh per barrel compared to a 2014 target of 615 kWh per barrel. The lower energy conversion rate in 2014, relative to the target, is resulting from two primary factors:

- operating the units at a lower average output level due to the high volume of water resources on the Island and energy receipts relative to the system load requirements; and
- a low heating content in the No. 6 fuel consumed at the Holyrood generating station.

The efficiency at the Holyrood plant has remained relatively consistent with a gross heat rate performance of 10,124 BTU/kWh in 2014 compared to 10,127 BTU/kWh in 2013.

In 2014, the units were dispatched as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 83.2 MW, down from 87.6 MW in 2013 and a forecast of 92.3 MW for 2014.

Overall, net production from Holyrood for 2014 was 1,315 GWh, a 37% increase from 2013 production levels and a decrease of 8% from the 2014 forecast. The production increase in 2014 relative to 2013 was related to operating one unit throughout the summer months in 2014 in order to support the transmission into the Avalon Peninsula, in addition to higher customer demand requirements during the winter and early spring period.


Hydro's Thermal Conversion Factor
(Holyrood)
Net kWh/Barrel of Fuel
610
600
590
580
570
2010
2011
2012
2013
2014

## *3.3 Financial Performance Indicators*

***2014 Financial results are not available at this time.***

## *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*[4].

*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.*

The 2014 residential customer satisfaction survey shows that 84% of customers are either very satisfied or somewhat satisfied with Hydro.


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

# *Appendices*

# Appendix A: Rationale for Hydro's 2014 KPI Targets

| KPI | Comment on KPI 2014 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 2014 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history. |
| Weighted DAFOR | The 2014 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 2014 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 2014 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 | The 2014 target is based on November 2013 budget for 2014 Holyrood plant operation. |
| **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:

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

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 – 2014

There were 12 significant events in 2014. The details follow:

## Event 1

On January 4 at 0905 hours, transformer T1 at the Sunnyside Terminal Station faulted resulting in a fire. Circuit breaker B1L03 failed to isolate T1, and resulted in a trip of transmission lines TL203 and TL237, isolating the Avalon Peninsula from the remainder of the power system. This resulted in the interruption of the following generation: Holyrood Plant, Cat Arm Plant, Hinds Lake Plant, Granite Canal Plant, Upper Salmon Plant, Stephenville Gas Turbine, St. Anthony Diesel Plant, and Hawke's Bay Diesel Plant. **(Unsupplied Energy: 158,954 MW-Mins)**

The following table outlines the delivery point customer interruptions.

| Events on January 4, 2014 (09:05 hrs) | | | | | |
|---|---|---|---|---|---|
| **Delivery Point Affected** | **Start Time** | **Finish Time** | **Duration of Interruptions (mins)** | **MW Load** | **MW-Mins** |
| | | | | | |
| Hardwoods | 1/4/2014 9:05 | 1/4/2014 9:52 | 47 | 268 | 12,596 |
| Oxen Pond | 1/4/2014 9:05 | 1/4/2014 10:43 | 98 | 286 | 28,067 |
| Holyrood - 39L | 1/4/2014 9:05 | 1/4/2014 14:01 | 296 | 29 | 9,320 |
| Holyrood - 38L | 1/4/2014 9:05 | 1/4/2014 14:07 | 302 | 46 | 13,771 |
| Western Avalon - 64L | 1/4/2014 9:05 | 1/4/2014 14:44 | 339 | 94 | 27,735 |
| Western Avalon - Bus B2 | 1/4/2014 9:05 | 1/4/2014 14:01 | 296 | 46 | 16,780 |
| Vale (Long Harbour) | 1/4/2014 9:05 | 1/4/2014 12:22 | 197 | 6 | 1,143 |
| Sunnyside - rural (T5) | 1/4/2014 9:05 | 1/4/2014 20:07 | 662 | 9 | 6,091 |
| Sunnyside - TL219 | 1/4/2014 9:05 | 1/4/2014 20:07 | 662 | 29 | 20,445 |
| Linton Lake | 1/4/2014 9:05 | 1/4/2014 20:07 | 662 | 17 | 11,985 |
| Bay L'Argent | 1/4/2014 9:05 | 1/4/2014 20:07 | 662 | 17 | 4,653 |
| Monkstown | 1/4/2014 9:05 | 1/4/2014 20:07 | 662 | 17 | 2,397 |
| Duck Pond Mine | 1/4/2014 9:05 | 1/4/2014 12:46 | 221 | 9 | 1,923 |
| Wiltondale | 1/4/2014 9:05 | 1/4/2014 9:33 | 28 | 0.1 | 4 |
| Glenburine | 1/4/2014 9:05 | 1/4/2014 9:33 | 28 | 3 | 78 |
| Rocky Harbour | 1/4/2014 9:05 | 1/4/2014 9:33 | 28 | 4 | 118 |
| Grandy Brook | 1/4/2014 9:05 | 1/4/2014 9:33 | 28 | 5 | 132 |
| St Alban's | 1/4/2014 9:05 | 1/4/2014 10:19 | 74 | 5 | 548 |
| Conne River | 1/4/2014 9:05 | 1/4/2014 10:37 | 92 | 2 | 187 |
| English Harbour West | 1/4/2014 9:05 | 1/4/2014 10:37 | 92 | 4 | 362 |
| Barachoix | 1/4/2014 9:05 | 1/4/2014 10:37 | 92 | 7 | 619 |
| | | | | | |
| Come By Chance T2 | 1/4/2014 9:05 | 1/4/2014 13:18 | N/A (BES: 253 mins) | N/A | N/A |
| | | | | | |
| | | **Totals** | | | 158,954 |

# Appendix C1: Significant Transmission Events – 2014 (Cont'd)

## Event 2

On January 4 at 1533 hours, personnel were in the process of re-energizing SSD T4. The transformer had tripped after transformer T1 locked out earlier in the day. During the re-energization there was a breaker failure protection operation associated with the transformer breaker B3T4. Circuit breaker B1L02 at the Sunnyside Terminal Station failed to open due to the breaker failure protection configuration, and resulted in the trip of transmission line TL206 at the Bay d'Espoir Generating Plant. The distance protection was activated on transmission line TL202 but failed to trip this line at the Bay d'Espoir Generating Plant, resulting in a bus lockout on BDE Bus B3 and the loss of the Bay d'Espoir Units 5 and 6. Circuit breaker B5B6 falsely tripped at Bay d'Espoir resulting in the loss of transmission line TL204. Transmission lines TL202, TL203, TL206 and TL207 tripped at the Sunnyside Terminal Station, resulting in the isolation of the Avalon Peninsula from the remainder of the power system. The Come by Chance Oil Refinery was also interrupted. This disturbance resulted in the interruption of the following generation: Cat Arm Plant, Granite Canal Plant, Stephenville Gas Turbine, and Hawke's Bay Diesel Plant. The Holyrood units had not been restored following the events earlier in the morning.
(**Unsupplied Energy: 13,836 MW-Mins)**

The following table outlines the delivery point customer interruptions.

Events on January 4, 2014 (15:33 hrs)

| Delivery Point Affected | Start Time | Finish Time | Duration of Interruptions (mins) | MW Load | MW-Mins |
|---|---|---|---|---|---|
| | | | | | |
| Hardwoods | 1/4/2014 15:33 | 1/4/2014 15:55 | 22 | 164 | 3,608 |
| Oxen Pond | 1/4/2014 15:33 | 1/4/2014 16:06 | 33 | 166 | 5,478 |
| Holyrood - 38L | 1/4/2014 15:33 | 1/4/2014 16:10 | 37 | 24 | 870 |
| Western Avalon - 64L | 1/4/2014 15:33 | 1/4/2014 16:18 | 45 | 61 | 2,750 |
| Come By Chance T1 | 1/4/2014 15:33 | 1/4/2014 15:39 | 6 | 15 | 91 |
| Duck Pond Mine | 1/4/2014 15:33 | 1/4/2014 17:47 | 134 | 5 | 724 |
| Wiltondale | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 0.1 | 1 |
| Glenburine | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 3 | 29 |
| Rocky Harbour | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 4 | 43 |
| Grandy Brook | 1/4/2014 15:33 | 1/4/2014 15:39 | 6 | 5 | 28 |
| St Alban's (1) | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 8 | 75 |
| Conne River | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 2 | 22 |
| English Harbour West | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 4 | 43 |
| Barachoix | 1/4/2014 15:33 | 1/4/2014 15:43 | 10 | 7 | 74 |
| | | | | | |
| Come By Chance T2 | 1/4/2014 15:33 | 1/4/2014 15:39 | N/A (BES: 6 mins) | N/A | N/A |
| Holyrood - 39L | 1/4/2014 15:33 | 1/4/2014 16:39 | N/A (BES: 66 mins) | N/A | N/A |
| | | | | | |
| | | **Totals** | | | 13,836 |

# Appendix C1: Significant Transmission Events – 2014 (Cont'd)

## Event 3

On January 5 at 2127 hours, the Holyrood generating Unit 1 was being prepared to be placed on line. The unit disconnect switch was closed as the first step in this procedure. After this switch was closed the unit connected to the grid, out of synch, single phase through a closed breaker contact. This resulted in a 230 KV disturbance and the tripping of Holyrood units 2 and 3, the Stephenville Gas Turbine, and the Hawke's Bay Diesel Plant.
(**Unsupplied Energy: 34,030 MW-Mins)**

The following table outlines the delivery point customer interruptions.

Events on January 5, 2014 (21:27 hrs)

| Delivery Point Affected | Start Time | Finish Time | Duration of Interruptions (mins) | MW Load | MW-Mins |
|---|---|---|---|---|---|
| | | | | | |
| Holyrood - 38L | 1/5/2014 21:27 | 1/5/2014 21:31 | 4 | 37 | 146 |
| Holyrood - 39L | 1/5/2014 21:27 | 1/6/2014 8:42 | 675 | 17 | 11,610 |
| Western Avalon - 64L | 1/5/2014 21:27 | 1/6/2014 0:22 | 175 | 83 | 14,525 |
| Western Avalon - Bus B2 | 1/5/2014 21:27 | 1/6/2014 0:36 | 189 | 41 | 7,749 |
| | | | | | |
| | | **Totals** | | | 34,030 |

## Event 4

On January 26, customers supplied by the Grandy Brook Terminal Station experienced an unplanned power outage of eight hours and 46 minutes. The outage occurred after a crossarm failed at a structure in transmission line TL250 during an extreme wind storm. There were wind gusts of over 130 km/h recorded on this day. **(Unsupplied Energy: 1,999 MW-Mins)**

## Event 5

On January 28, customers supplied by the Monkstown and Bay L'Argent Terminal Stations experienced an unplanned power outage of three hours and 10 minutes. The outage occurred after a crossarm failed at a structure in transmission line TL212 during an extreme wind storm. There were wind gusts of over 120 km/h recorded on this day. (**Unsupplied Energy: 1,121 MW-Mins)**

# Appendix C1: Significant Transmission Events – 2014 (Cont'd)

## Event 6

On February 19, Vale at Long Harbour experienced an unplanned power outage of two hours and 52 minutes. The outage was caused by transformer T1 tripping due a protection coordination issue with Vale's protection. These protection issues have since been resolved.
(**Unsupplied Energy: 1,032 MW-Mins)**

## Event 7/Event 8/Event 9

On February 23, customers supplied by the Bottom Waters Terminal Station experienced three unplanned power outages of 11 hours and 30 minutes in total. The first outage was caused by a bus lockout operation for a trip of transformer T1. The other two outages occurred during the restoration of T1. The transformer trip was caused by a faulty pressure/vacuum switch. The switch required isolation before T1 could be re-energized.
Event 7: (**Unsupplied Energy: 1,230 MW-Mins)**
Event 8: (**Unsupplied Energy: 2,700 MW-Mins)**
Event 9: (**Unsupplied Energy: 1,238 MW-Mins)**

## Event 10

On April 14, customers supplied by the Bottom Waters Terminal Station experienced an unplanned power outage of 2 hours and 32 minutes. The outage was caused by a squirrel that came into contact with a lightning arrestor on the low voltage side (25 kV) of transformer T1 resulting in the operation of the bus lockout. This, in turn, tripped circuit switcher L60T1 on the high side of T1 (138 kV).
(**Unsupplied Energy: 1,170 MW-Mins)**

## Event 11

On August 5, 7,345 customers on the Great North Peninsula experienced an unplanned power outage. The outage occurred due to a failure of an SF6 Breaker, B1L41 at the Peter's Barren Terminal Station, tripping transmission line TL241 and causing a bus lockout at the terminal station.
(**Unsupplied Energy: 2,530 MW-Mins)**

The following table outlines the delivery point customer interruptions.

# Appendix C1: Significant Transmission Events – 2014 (Cont'd)

**Event -TL241 Trip/PBN B1 Lockout**

| Delivery Point Affected | Start Time | Time of Restoration | Outage Duration (mins) | Load Loss (MW) | MW-Mins |
|---|---|---|---|---|---|
| Parson's Pond | 15:16 | 15:28 | 12 | 0.31 | 3.72 |
| Daniel's Harbour | 15:16 | 15:28 | 12 | 0.37 | 4.44 |
| Hawkes's Bay | 15:16 | 15:28 | 12 | 3.75 | 45 |
| Plum Point | 15:16 | 23:26 | 490 | 2.1 | 1029 |
| Bear Cove | 15:16 | 23:26 | 490 | 2.54 | 1244.6 |
| Main Brook | 15:16 | 15:43 | 27 | 1.7 | 45.9 |
| Roddickton | 15:16 | 15:49 | 33 | 1.4 | 46.2 |
| St Anthony | 15:16 | 15:49 | 33 | 5.3 | 111.3 |

## Event 12

On August 10, customers supplied by the Happy Valley and Muskrat Falls Construction Power Terminal Stations experienced an unplanned power outage of two hours and 40 minutes. The outage occurred when a tertiary lead on the 230/138 kV transformer T71 failed at the Churchill Falls Switchyard, resulting in a fault and a trip of the 138 kV transmission line (L1301/L1302) at the Churchill Falls switchyard.
(**Unsupplied Energy: 2,512 MW-Mins)**

## Appendix C2: Significant Distribution Events – 2014 (Excluding Fourth Quarter)

- On January 1, customers in Happy Valley - Goose Bay, Labrador serviced by feeder L16 experienced two unplanned and one emergency planned power outage. The outages occurred due to unbalanced loading on the feeder. See the following for outages details:

  Outage 1: 1745-1817 hours (32 minutes) 3,984 customers
  Outage 2: 1757 – 1811 hours (14 minutes) 1,019 customers
  (Emergency planned outage for switching operations)
  Outage 3: 1815 – 2344 hours (five hours 29 minutes) 1,019 customers

- On January 22, at 2000 hours (Labrador time), 391 customers in Labrador City, Labrador supplied by Line 13 experienced an unplanned power outage. The outage occurred when a piece of jumper conductor burned off a pole. All customers were restored at 2200 hours.

- On January 26, at 0955 hours, all customers (1369) serviced by the Barachoix Terminal Station, including the communities of Gaultois, Harbour Breton, Hermitage, and Seal Cove experienced an unplanned power outage. The outage occurred due to line damage caused by extreme weather and high winds. Hydro crews safely made the necessary repairs and all customers were restored by 1855 hours. Delays in restoration were due to distance and travel time in extreme weather, the investigation into the cause of the outage, and the repair time.

- On January 26, at 0848 hours, all customers (921) serviced by the Grandy Brook Terminal Station, including the communities of Burgeo, Grand Bruit, and La Poile, experienced an unplanned power outage. The outage occurred when the 138 kV Transmission Line TL250 tripped out of service due to a failed cross arm. There were extreme high winds at the time. Hydro crews safely made the necessary repairs and all customers were restored by 1735 hours. Delays in restoration were due to distance and travel time in extreme weather, the investigation into the cause of the outage, and the repair time.

- On January 26, at 0933 hours, all customers (813) serviced by the English Harbour West Terminal Station, including the communities of Boxey, Belleoram, Coombs Cove, English Harbour West, Mose Ambrose, Pools Cove, Rencontre East, St. Jacques, and Wreck Cove experienced an unplanned power outage. The exact cause of the outage is unknown, however it was most likely due to the extreme weather and high winds experienced at the time. All customers were restored by 1323 hours.

- On April 10, at 1400 hours (Labrador time), 330 customers in Happy Valley - Goose Bay, Labrador serviced by Line 7 experienced a planned power outage. The outage was required to safely replace a utility pole. All customers were restored at 1650 hours.

- On April 14, at 0825 hours, 1774 customers serviced by the Bottom Waters Terminal Station experienced an unplanned power outage. The outage occurred when the 138 kV circuit breaker L60T1 tripped open. This circuit breaker is located on the high voltage side (138 kV) of the transformer - T1. Hydro investigated and discovered that a squirrel had come in contact with a lightning arrestor on the low voltage side (25 kV) of the transformer and the protection systems for transformer T1 commanded circuit breaker L60T1 to trip. All customers were restored by 1057 hours.

- On April 16, at 1906 hours, all customers (990) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred due to a loss of supply from Hydro Québec. Communities affected include L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse au Clair, L'Anse au Loup, West St. Modeste, Capstan Island, L'Anse au Diable, Pinware, Red Bay, and Organ's Island.

  The L'Anse au Loup Diesel Plant was used to restore customers.

  Customer Outage details are as follows:

  Outage 1: 1906 – 1927 hours (21 minutes), 467 customers between L'Anse au Loup to Pinware
  Outage 2: 1906 – 1935 hours (29 minutes), 262 customers in L'Anse Amour and Forteau
  Outage 3: 1906 – 1942 hours (36 minutes), 124 customers in L'Anse au Clair
  Outage 4: 1906 – 1950 hours (44 minutes), 137 customers in Red Bay

  Supply was restored from Hydro Québec at 2330 hours, April 17.

- On May 07, at 0130 hours (Labrador time), 140 customers in Cartwright, Labrador experienced an unplanned power outage. The outage occurred when one phase in a distribution line faulted. Hydro investigated and made the necessary repairs to the line. All customers were restored at 0400 hours.

- On May 22, at 1225 hours, all customers (990) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred due to a loss of supply from Hydro Québec. Hydro Québec reported a pole down. Communities affected include L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse au Clair, L'Anse au Loup, West St. Modeste, Capstan Island, L'Anse au Diable, Pinware, Red Bay, and Organ's Island.

  The L'Anse au Loup Diesel Plant was used to restore customers.

  Customer Outage details are as follows:

  Outage 1: 1225 – 1236 hours (11 minutes), 467 customers between L'Anse au Loup to Pinware
  Outage 2: 1225 – 1241 hours (16 minutes), 262 customers in L'Anse Amour and Forteau
  Outage 3: 1225 – 1245 hours (20 minutes), 124 customers in L'Anse au Clair
  Outage 4: 1225 – 1251 hours (26 minutes), 137 customers in Red Bay

  Supply from Hydro Québec was restored at 1312 hours.

- On May 23, at 2344 hours, all customers (990) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred due to a loss of supply from Hydro Québec. Hydro Québec reported a problem at their Blanc-Sablon Station. Communities affected include L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse au Clair, L'Anse au Loup, West St. Modeste, Capstan Island, L'Anse au Diable, Pinware, Red Bay, and Organ's Island.

The L'Anse au Loup Diesel Plant was used to restore customers. All customers were restored by 0034 hours May 24.
Supply from Hydro Québec was restored at 1038 hours May 24.

- On June 08, at 0600 hours (Labrador time), all customers (5813), including Industrial Customers IOCC and Wabush Mines, in Labrador City and Wabush experienced a planned power outage. The outage was required so that CF(L)Co could safely perform maintenance on the Wabush Terminal Station.

  See the following for the number of affected customers and restoration times:

  Wabush: 2006 hours (1466 customers – 14 hours six minutes)
  Labrador City: 2020 hours (4347 customers – 14 hour 20 minutes)

- On June 25, at 1025 hours (Labrador time), all customers (226) in Port Hope Simpson, Labrador experienced a planned power outage. The outage was required to safely disconnect Mobile Unit 2044. All customers were restored at 1150 hours.

- On July 01, 175 customers in Labrador City, Labrador serviced by Lines 18 and 21 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was four hours.

- On July 02, at 0645 hours (Labrador time), 5677 customers in Labrador City and Wabush, Labrador experienced an unplanned power outage. The outage occurred when a fault at the IOCC mine site activated relay protection at the Wabush Terminal Station, tripping breakers 46-32 (Labrador City) and 46-36 (Wabush). See the following for customer restoration details:

  Outage 1: 1467 Wabush customers, 35 minutes
  Outage 2: 4210 Labrador City customers, one hour

- On July 05, 400 customers in Sheshatshui, Labrador serviced by Happy Valley Terminal Station Line 7, experienced a planned power outage. The outage was required to install new equipment on the distribution system. Outage duration was three hours and 40 minutes.

- On July 12, 350 customers in Labrador City, Labrador serviced by Lines 6 and 15 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was five hours.

- On July 13, 350 customers in Labrador City, Labrador serviced by Lines 6 and 15 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was five hours.

- On July 16, all customers (170) on Long Island including the communities of Beaumont and Lushes Bight experienced an unplanned power outage of seven hours and 30 minutes. Hydro's preliminary investigation indicated a subsea cable failure was the cause of the outage. Hydro attempted to energize the primary and all backup cables without success. Hydro involved additional technical and support staff to assist with the restoration efforts. Hydro had also begun to mobilizing a portable diesel generator to site. Power was restored to Long Island via one of the submarine cables. Preliminary investigation indicates three of the four cables have been damaged and remain out of service. Hydro is arranging for inspection of the cables to determine the cause of the outage and why the other cables could not be energized. Preparations are being made to execute repairs, pending the findings from the inspection. In the interim, standby backup generation has been installed on Long Island should the existing energized cable fail.

- On August 21, all customers (1,466) in Wabush, Labrador experienced a planned power outage of nearly two and a half hours in duration. The outage was required to tie in transformers T3 and T5 at the Wabush Substation. This work was required to energize T5 for condition assessment and monitoring.

- On August 26, 451 customers serviced by Bottom Waters Terminal Station Line 4 are experienced an unplanned power outage of approximately 19 hours in duration. The communities affected included Burlington, Smith's Harbour, and Middle Arm. The outage was caused by a failure of a step-down transformer located in the Burlington Substation. Hydro expedited a replacement transformer from the Bishop's Falls warehouse. Hydro crews worked late into the evening of August 26 and resumed work during the morning of August 27, during which time the replacement of the transformer was completed and all customers were restored.

- On September 07, 723 customers in Labrador City, Labrador, serviced by Line 8, experienced a planned power outage. The outage was required to connect new feeders into the Quartzite Substation. Outage duration was three hours.

- On September 11, all customers (874) in Little Bay and King's Point, serviced by the Springdale Terminal Station, experienced an unplanned power outage. The outage occurred when Newfoundland Power's mobile substation, located in the Springdale Terminal Station, failed causing Hydro's breakers to trip. Newfoundland Power made the necessary repairs to mobile substation, Hydro then proceeded to restore supply to customers. Outage duration was seven hours and 43 minutes.

- On September 14, all customers (1466) in Wabush, Labrador experienced a planned power outage. The outage was required to make modifications to the steel structure within the Wabush Substation yard in preparation for the connection of an additional power transformer. Outage duration was five hours and 45 minutes.

- On September 21, all customers (1459) in Wabush, Labrador experienced an extended planned power outage. The outage was required for the installation of a new power transformer (T6) at the Wabush Substation. All customers were planned to be restored by 1000 hours, however due to an issue with breaker WA36-CB1 at the Wabush Substation, the outage was extended beyond this time. Hydro crews resolved the issue with the breaker. Outage duration was eight hours and 15 minutes.

- On September 22, 1765 customers serviced by the Bottom Waters Terminal Station Lines 1 and 3 experienced an unplanned power outage. The communities affected include Brent's Cove, Burlington, Harbour Round, La Scie, Middle Arm, Ming's Bight, Nipper's Harbour, Pacquet, Round Harbour, Snook's Arm, Shoe Cove, Smith's Harbour, Tilt Cove and Woodstock. This outage also affected Rambler Mines. The outage was caused by rain and high winds in the area blowing trees into the distribution lines. Hydro crews responded, patrolled the lines, and safely removed any trees prior to restoring customers. Outage duration was five hours and 10 minutes.

- On September 26, 446 customers in Labrador City, Labrador serviced by Quartzite Substation Line 13 and Bartlett Substation Line 4 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was three hours.

- On September 27, 311 customers in Labrador City, Labrador serviced by Quartzite Substation Line 13 and Bartlett Substation Line 4 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was two hours and 30 minutes.

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

- On January 10, Holyrood Generating Unit No. 2 tripped. The trip of Unit 2 occurred when a compressor failure resulted in an outage to a 600V power center. This power center supplies auxiliary equipment associated with Unit 2 turbine/boiler. Unit 2 was restored to service at 0123 hours January 11. With the removal of generation (approximately 155 MW) the system frequency dropped to 58.25 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 1,306 MW. Hydro customers (2,210) were restored within three minutes. Newfoundland Power customers (21,067) were restored in twenty-two load blocks. The first customers were restored in seven minutes and all customers were reported to be restored within 28 minutes after the event occurred. **(Unsupplied Energy: 1,568 MW-Mins)**

- On January 12, Holyrood Generating Unit No. 3 tripped. The under frequency trip occurred when a main feed water isolator did not electrically open. As a result Unit 3 tripped on low drum level. Hydro determined that the problem was with a control power signal from the local control system. Repairs were made and the Unit was restored to service at 1830 hours, January 12. With the removal of generation (approximately 66 MW) the system frequency dropped to 58.78 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,030 MW. All Newfoundland Power customers (5,750) were restored within 10 minutes after the event occurred. **(Unsupplied Energy: 220 MW-Mins)**

- On January 15, transmission line TL-201 (from the Western Avalon to Hardwoods terminal stations) tripped and remained open. The fault created a system disturbance which activated the rate of change (df/dt) underfrequency load shedding protection at Newfoundland Power. The decline in system frequency achieved a maximum value of 0.56 Hz/Sec. All Newfoundland Power customers (3,307) were restored within 1 minute after the event occurred. Total NLH system load at the time of the incident was 998 MW. Upon investigation through line patrol, it was determined that two phases on structure 157 had fallen to the ground after the insulators had separated. The immediate cause is suspected to be a mechanical insulator failure due to high winds and adverse weather. The insulators were replaced and the line was restored to service at 2229 hours on January 15. **(Unsupplied Energy: 15 MW-Mins)**

- On January 27, at 1650 hours, Holyrood Generating Unit No. 1 tripped. Hydro's investigation into the cause of the trip on Unit 1 determined that a circuit breaker supplying the burner management system was inadvertently tripped as corrective maintenance was carried out on another piece of equipment located in the same electrical cabinet. With the removal of generation (approximately 120 MW) the system frequency dropped to 58.56 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,248 MW. All Newfoundland Power customers (11,061) were reported to be restored within 18 minutes after the event occurred. **(Unsupplied Energy: 904 MW-Mins)**

# Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter) (cont'd)

- On January 30, at 0509 hours, Bay d'Espoir Generating Unit No. 6 tripped. The unit trip was caused by the failure of the rectifying transformer associated with the unit excitation system. The spare transformer was installed. With the removal of generation (approximately 64 MW) the system frequency dropped to 58.71 Hz resulting in the activation of the under frequency protection at Newfoundland Power and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,060 MW. All Newfoundland Power customers (6,087) were reported to be restored within four minutes after the event occurred. **(Unsupplied Energy: 107 MW-Mins)**

- On February 17, at 0422 hours, Bay d'Espoir Generating Unit No. 6 tripped. The unit trip was caused by the failure of the rectifying transformer (this time the spare unit which was installed following the failure on January 30). With the removal of generation (approximately 67 MW) the system frequency dropped to 58.58 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,053 MW. 15,108 Newfoundland Power customers were reported to be restored within five minutes after the event occurred. Unit No. 6 remains out of service. **(Unsupplied Energy: 240 MW-Mins)**

- On March 18, at 2203 hours, while taking Bay d'Espoir Unit 4 offline, the unit breaker mis-operated, causing a bus lockout of Bus 2 at Bay d'Espoir, and tripping Unit 3 offline. With the removal of generation (approximately 59 MW) the system frequency dropped to 58.72 Hz resulting in the activation of the under frequency protection at Newfoundland Power and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,184 MW. There were 7,225 Newfoundland Power customers reported to be restored within five minutes after the event occurred. **(Unsupplied Energy: 190 MW-Mins)**

- On July 14, at 1414 hours, while Holyrood Unit 3 was undergoing a load test, a problem with the forced draft fans caused the unit to trip offline. With the removal of generation (approximately 113 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 598 MW. All Newfoundland Power customers were reported to be restored within 16 minutes after the event occurred. Load Shed: Newfoundland Power: 13 MW **(Unsupplied Energy: 208 MW-Mins)**

## Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter) (cont'd)

- On July 28, at 0728 hours, Holyrood Unit 3 tripped offline. Hydro's investigation into this incident indicated that the root cause stemmed from an issue that occurred during switching, related to an abnormal configuration of the plant's electrical distribution system which was required for planned maintenance at the Holyrood Thermal Generating Station (HTGS). With the removal of generation (approximately 71 MW) the system frequency dropped to 58.41 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 491 MW. All Newfoundland Power customers were reported to be restored within 18 minutes after the event occurred. Load Shed: Newfoundland Power: 19.5 MW **(Unsupplied Energy: 351 MW-Mins)**

- On July 29, at 0943 hours, Holyrood Unit 3 tripped offline. Analysis concluded the root cause of the incident was a lack of clear communication during switching for a planned equipment maintenance outage in the Holyrood Terminal Station (HRD TS). The investigation also found that this specific outage type had not been executed by all control room operators in the past, highlighting the need for a better understanding of this outage type. Hydro has and continues to communicate this incident internally via lessons learned and training programs. With the removal of generation (approximately 70 MW) the system frequency dropped to 58.50 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 588 MW. All Newfoundland Power customers were reported to be restored within 11 minutes after the event occurred. Load Shed: Newfoundland Power: 40 MW **(Unsupplied Energy: 440 MW-Mins)**

# 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.