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Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System

NEWFOUNDLAND AND LABRADOR HYDRO

A Review of Supply Disruptions and Rotating Outages: January 2-8, 2014 Volume II

March 24, 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

VOLUME I

1	A REVIEW OF SUPPLY ISSUES AND ROTATING OUTAGES: JANUARY 2-8, 2014
2	GLOSSARY OF TERMS
3	TABLE OF CONCORDANCE
SCHEDULE 1	SEQUENCE OF EVENTS LEADING UP TO SUNNYSIDE TRANSFORMER FAULT ON JANUARY 4, 2014
SCHEDULE 2	SEQUENCE OF EVENTS FOLLOWING SUNNYSIDE TRANSFORMER FAULT ON JANUARY 4, 2014

VOLUME II

SCHEDULE 3	LOAD FORECASTING
SCHEDULE 4	GENERATION AND RESERVE PLANNING
SCHEDULE 5	ASSET MANAGEMENT STRATEGY AND PRACTICES
SCHEDULE 6	GENERATION AVAILABILITY
SCHEDULE 7	TRANSMISSION AVAILABILITY
SCHEDULE 8	ROOT CAUSE INVESTIGATION REPORT
SCHEDULE 9	PROTECTION AND CONTROL SYSTEMS REPORT
SCHEDULE 10	EMERGENCY RESPONSE AND RESTORATION
SCHEDULE 11	COORDINATION AND COMMUNICATIONS WITH CUSTOMERS
SCHEDULE 12	TECHNOLOGY AND COMMUNICATIONS INFRASTRUCTURE



NEWFOUNDLAND AND LABRADOR HYDRO

Load Forecasting

March 2014



Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 3
2 REVIEW PROCESS 4
3 BACKGROUND 5
4 INTERNAL REVIEW 11
5 VENTYX REVIEW 18
6 KEY FINDINGS AND RECOMMENDATIONS 21
ACRONYMS 24

Appendices:

Appendix 1 Ventyx, Inc. Report, 2014 Newfoundland and Labrador Hydro Planning Process Review

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included investigation of the rotating outages that occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014. Though some minor improvements are recommended to Hydro's forecasting processes, the review found that forecasting was not a contributing factor to supply disruptions or rolling outages.

This report focuses on the findings of both internal and independent reviews of Hydro's load forecasting processes. The purpose of these reviews was to determine what role the forecasting processes may have played during the January disruptions. Hydro completed its own internal review on its load forecasting methodology. It also engaged Ventyx Inc., a leading supplier of industrial software solutions, to provide independent insight and analyses.

Hydro's long- and medium-term forecasting techniques are accurate and suitable for their intended use. Short-term (seven-day) forecasts vary in accuracy depending on weather and weather forecast accuracy.

While Hydro's forecasting processes were not found to be a contributing factor in the supply disruptions, the reviews did provide some recommendations for improvement. Hydro has accepted these recommendations and will incorporate them during the next medium-term operating forecast cycle in May 2014.

LF1: The load forecasting process should include sensitivity analysis, including sensitivity to extreme weather conditions, particularly in making near term investment decisions. The sensitivity analysis should be used to provide more detailed information on the variability of the forecast to the stakeholders. Newfoundland Power should be asked to provide sensitivity analysis on forecast

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

information it provides to Hydro.

LF2: Hydro's short-term forecasting program does not perform well in unusually low temperatures and improvements are required

LF3: Refinements in the equations for the major end-use on the system, electric heat, should continue and be enhanced through continued surveying of the customer base in terms of both average energy use, and saturation of electric heating.

1 INTRODUCTION

On January 10, 2014, Hydro initiated an internal review of the January supply disruptions on the Island Interconnected[2] System (System[3]). Hydro's view, throughout this process, has been to improve its performance in meeting its mandate to provide least-cost reliable power for Newfoundland and Labrador.

This report focuses on the suitability of Hydro's load forecasts and whether they played any role in the events of the 2014 outages.

On December 14, 2013 Hydro supplied a record-high System demand of 1,501 megawatts (MW) (the Island peak supplied by both Hydro and non-Hydro generation was 1,663 MW). Prior to that date, the System peak was 1,405 MW met in February 2004.

Persistent low temperatures and System operating factors meant demand remained high for the next several weeks. In addition, several major generating plants were unavailable or de-rated. These factors required Hydro to implement its Generation Loading Generation Shortage Protocol (System Operating Instruction T-001) several times.

On January 2, 2014, the System load exceeded the available supply and all steps of the Generation Loading Generation Shortage Protocol were implemented – the last step was to request Newfoundland Power to shed load by rotating feeders, at the same time Hydro shed load by rotating feeders in its service areas.

Further outages occurred as a result of equipment failures on January 4 and 5, 2014.

[2] In this context Interconnected means those parts of the island serviced from the grid (i.e. excluding the isolated communities using diesel power), not interconnection to North America.
[3] 'System' refers to Hydro's system only. System load refers to that met by Hydro, i.e. it does not include load met by Newfoundland Power and Kruger.

2 REVIEW PROCESS

2.1 Internal

During, and immediately following, the supply disruptions in January 2014, Hydro personnel responsible for load forecasting reviewed the forecasts and the forecasting methodology to determine what lessons could be learned for the future.

2.2 Prior Reviews

In recent years, Hydro's load forecasting processes have been analysed as part of several comprehensive reviews of the Muskrat Falls Project.

- In 2011, Navigant Consulting Ltd. completed a document review of Nalcor's decision process studies.
- In 2011, the Public Utilities Board (PUB) commissioned Manitoba Hydro International Ltd. (MHI) to review the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects.
- In 2012, the Government of Newfoundland and Labrador retained MHI to provide an independent assessment of the two generation supply options as prepared by Nalcor Energy.

2.3 Independent Review

Hydro contracted Ventyx, an ABB company and leading supplier of enterprise software and services for asset intensive industries, to perform an independent assessment on Hydro's generation planning and load forecasting processes.

The focus of this work was to provide a review of both the generation planning processes that form the basis of Hydro's strategic plans and forecasts and a review of Hydro's long-term (planning) and medium-term (operating) load forecasting. The work was broken into four main tasks:

- Task 1: Planning and Forecast Process Review - examination of prior independent

reviews of Hydro's practices and comparison to standard practices in planning and forecasting.

- Task 2: Generation Planning Criteria - review of the overall planning process and assumptions used by Hydro to develop its current long-range, and strategic forward-looking plans and commentary on the processes and criteria including recommendations for improvements.
- Task 3: Load Forecasting Process - review of the process used by Hydro to develop its long-range load forecast and medium-term operational forecasts, as well as commentary on the processes, including recommendations for improvements.
- Task 4: Strategist Model Review[4] - review of the Strategist Model assumptions used by Hydro to develop its long-range and strategic forward-looking plans and commentary on the processes and criteria including recommendations for improvements. Ventyx reviewed the current database and commented on its appropriateness and how it is being used.

3 BACKGROUND

3.1 Hydro Forecasting Process

Hydro maintains load forecasts with three different time horizons. The forecasts are summarized in Table 1.

[4] Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. More detail is available in the Ventyx report, included in Appendix A.

Table 1: Comparison of Newfoundland and Labrador Hydro Load Forecasts

	Long-Term Planning Forecast (PLF)	**Medium-Term Operating Load Forecast (OPLF)**	**Short-Term Forecast**
Time Horizon	20 years[5]	5 years	7 days
Time Step	Annual	Monthly	Hourly
Schedule	Q3/Q4	May and December	Five times per day
System	Island Interconnected - Includes NP and Kruger total load generation	Hydro System	Three forecasts: Avalon, System and Island
Primary Purpose	-Reliability Assessment -Planning Resource Developments	-Budgeting -Outage Planning -Hydro-thermal optimization	-Unit Scheduling -Outage Approvals
Responsibility	System Planning	System Planning	System Operations
Primary Source of NP Forecast	Hydro	Newfoundland Power	--
Primary Source of Industrial Forecast	Customers	Customers	--

[5]Extended to 50 years for Muskrat Falls studies

- **Long-Term Planning Forecast (PLF)** - The PLF is the forecast used for assessing the long-term reliability of the Island Interconnected system and for planning resource requirements to meet reliability criteria and typically has a time horizon of 20 years. For long-term requirements, both Newfoundland Power and Hydro Rural Island Systems are simulated by Hydro, while industrial requirements are guided by information directly from the individual industrial customers. The time step for the long-term planning forecast is one year and the forecast is prepared annually. Planning studies for Muskrat Falls have required the forecast to be extended to a 50-

year horizon to cover the full financing period.

- **Medium-Term Operating Load Forecast** (**OPLF)** - The OPLF is used for budgeting and medium-term operational planning, such as outage planning and hydro-thermal optimization and has a time horizon of five years. The time step is monthly and the forecast is prepared one to two times per year, usually in May and November\December. The OPLF includes a forecast of energy and peak demand requirements for Hydro's System with the forecast of requirements being customer driven. All loads (except Hydro's rural load) are supplied by the customers (including Newfoundland Power). Newfoundland Power's peak demand forecast methodology was developed in consultation with Hydro.

- **The System Operations Short-Term Forecast (Short-term Forecast)** - The Short-term Forecast is used for unit scheduling and outage approvals and has a time frame of seven days. The time step is hourly and the forecast is prepared five times a day. Three forecasts are created, one for the Avalon Peninsula, one for the Hydro System, and one for the Interconnected Island System. Newfoundland Power generation is estimated by using the previous day's generation.

3.1.1 Responsibilities

Both the PLF and OPLF are the responsibility of the System Planning group of Hydro's System Operations and Planning Division. The Short-Term Forecast is the responsibility of the System Operations Engineering group, also in the System Operations and Planning Division.

3.1.2 Long-Term Planning Forecasts

There is one PLF cycle completed each year, with the analysis being typically initiated in the last quarter of each year. A primary input to the PLF is the provincial economic forecast which is provided by the provincial Department of Finance. The annual development of long-term load

forecasts ensures, to the best extent possible, that the constantly shifting set of parameters affecting electricity demand in the province are incorporated into current utility operating plans and investment intentions. Figure 1 (below) shows a Hydro flow chart of the load forecast cycle, which develops the demand, capital, operating cost, and rate analysis. It gives a prevailing economic forecast for the province.

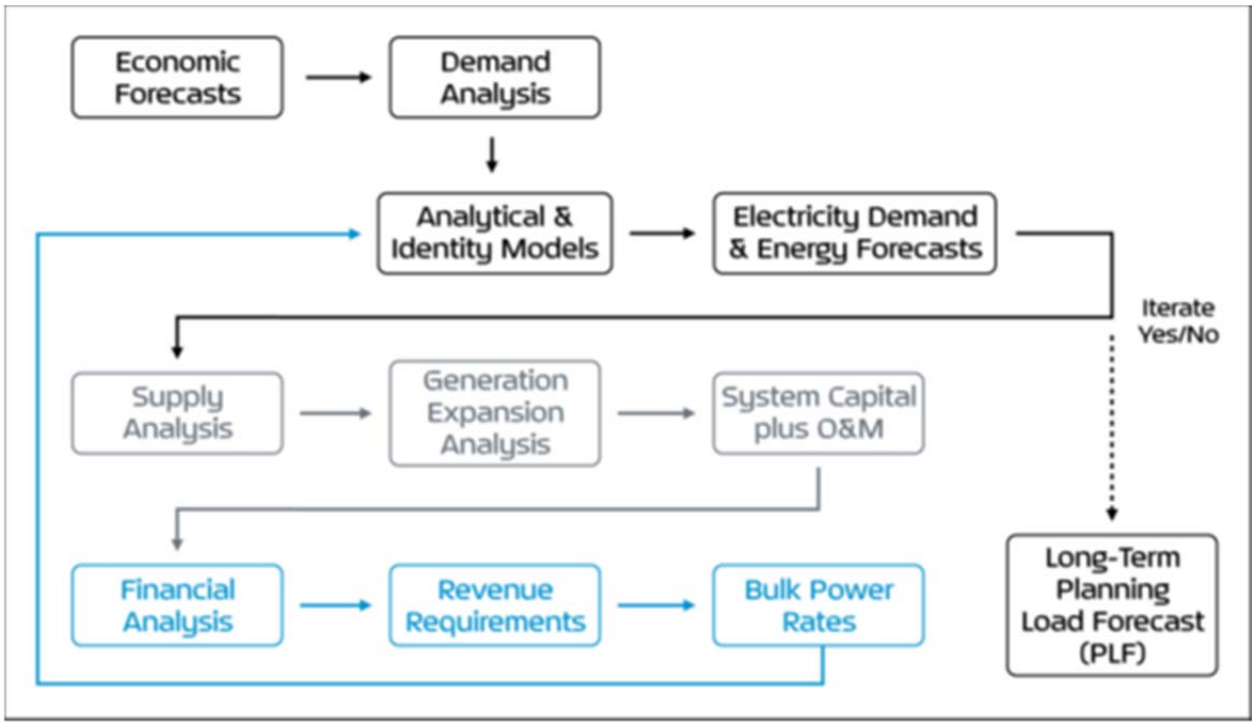


Figure 1: Long-Term Planning Load Forecast Process

The load forecasting model used by Hydro is an econometric model used to project the island's energy and peak demand requirements 20 years into the future. Across the historical period, typically from the late 1960s, the relationships between electricity use and various economic measures are quantified using econometric techniques. The derived relationships can then predict demand levels in future periods, given a certain set of economic conditions. The statistical effort behind the load forecast is primarily directed at long-term forecasting for the utility component of the island's total requirements, i.e., the load forecasts for Newfoundland Power and Hydro's Rural Customers. Data sets and econometric equations, along with all other

modeling parameters, are reviewed and updated annually. Once updated, the load forecast model builds up to a forecast of utility load by aggregating forecasts of domestic and general service retail rate classes.

The PLF assumes normalized weather conditions at the time of peak and assumes that any additional load, due to extremes of weather, will be met with System reserve. Based on Hydro's historical record, a weighted island wind chill of -27 C is used as the weather condition for long-term forecasting models. This is the average wind chill which has occurred during historic winter peaks, and is referred to as the normal peak weather condition. While lower wind chills can and will occur, current planning practice relies on system reserve capacity to meet these extreme weather conditions.

Hydro's forecast of total industrial electric power requirements for large Industrial Customers directly served by Hydro is based on direct input from those customers. Given the small Industrial Customer base, Hydro seeks information directly from the customers. Once updated, the load forecast model combines the residential and commercial components of utility load with direct industrial loads, in order to derive the total Island Interconnected load. The total Island Interconnected load is the load Hydro uses for assessing the long-term reliability of the System and planning resource requirements to meet reliability criteria.

3.1.3 Medium-Term Operating Load Forecast

Hydro's OPLF is necessary for the planning and management of the Island Interconnected System. System Operations requires monthly, customer specific, energy and power requirements covering a 39-month reservoir planning horizon.

The OPLF is generally prepared in the May to June time period after Hydro receives forecast demand and energy requirements from Newfoundland Power and Hydro's Industrial Customers. At that time, forecast requirements for Hydro's Rural Customers are typically updated. The aggregation of these monthly power and energy demand forecasts, together with

Hydro's historical based assumptions with respect to customer coincidence and system loss factors, results in a forecast of expected total production for Hydro. An update to the OPLF is often, but not always, prepared in late fall to adjust for Industrial Customers' declared power requirements for the upcoming calendar year.

The most variable aspect of Hydro's load is the Newfoundland Power load. Each spring Hydro requests that Newfoundland Power provide its current five-year load forecast, including annual and monthly energy and peak demand requirements. In the ensuing period, and prior to the receipt of Newfoundland Power's load forecast by Hydro, there is regular communication between Newfoundland Power and Hydro about load forecast related topics, including recent energy and peak demand experience of the Newfoundland Power system, forecast methodology, provincial economic outlook, and weather normalization of energy and peak.

Subsequent to the receipt of Newfoundland Power's five-year forecast and completion of Hydro's long-term planning forecast, which includes Hydro's forecast of Newfoundland Power's energy and peak demand requirements, Hydro and Newfoundland Power will meet to review the overall results. The intent of such discussion is to understand the drivers which results in forecast differences between the two forecast models. This interaction enables both utilities to flag significant forecast differences that might be unexplained by the input drivers, and to make adjustments, if necessary.

3.1.4 Short-Term System Operation Forecasting

Hydro uses a computer program from Ventyx called Nostradamus, for short-term (one-to seven-day) load forecasting. Nostradamus is a neural network, short-term demand forecasting system, which allows users to track forecasts with actual values, as well as update forecasts when new information becomes available. The neural network algorithm learns the pattern of load changes from numerous weather variables, as well as day of week, time of day, and holidays, by learning from historical data. Other input data includes historical load, weather, and generation data.

Guidance from Ventyx suggests that the period of history to use in training the model is between one and five years, ideally since the last major change in load. Generally, Hydro has been using the period from April 2009 for training, the period since the Grand Falls paper mill was shut down. At times, shorter or longer historic periods of data are used to try to improve the forecast.

4 INTERNAL REVIEW

4.1 Operating Load Forecasts

The internal review of the load forecasts focused on why the System experienced several days of peaks in December 2013 and January 2014, which were higher than the winter peak from the Operating Load Forecast for the winter of 2013/14. Several issues were identified, which are considered to be contributing factors to the higher peaks:

- Colder than normal weather conditions in December;
- Higher than expected system demand losses; and
- Higher end-use customer loads, associated with rotating outages in January.

On December 14, 2013 Hydro met record-high System load of 1,501 MW. The operating load forecast's for Hydro's System for the winter of 2013/2014 was 1,478 MW and it was anticipated that the peak would occur in January 2014. The forecast peak for December 2013 was 1,401 MW.

Though the load of 1,501 MW was record breaking, and not forecast for December 2013, it was met without the need for voltage reductions or curtailment because more than sufficient reserve was available. On January 3, 2014 the recorded System peak load was 1,535 MW. The true peak for January 2014 cannot be accurately determined because of the rolling outages that were implemented during the time of the peak and cold load pickup influencing the magnitude of the peaks being recorded.

Historically, the winter peak on Hydro's System usually occurs between December and March. The winter peak is largely dependent on weather conditions and patterns because of the high proportion of homes and businesses with electric heat. Typically, Newfoundland experiences its coldest weather in January and February.

Temperatures in mid- and late-December 2013 were persistently lower than average, and below 0 C. The low temperatures coincided with high wind speeds, which resulted in low wind chill temperatures. Weather conditions on the Northeast Avalon on December 14, as measured by wind chill, were -20 C, in line with historically recorded weather conditions which resulted in winter peaks occurring in December 2013. These cold weather conditions persisted for multiple days. It has generally been observed that the longer a cold spell, the higher the System load, as customers gradually use more electric heat to maintain comfort levels in their homes and businesses. December peak demands are also positively influenced by end-use loads typically associated with the Christmas season. On average, given similar weather conditions, load over the Christmas period is approximately 30 MW higher than it would be later in the winter.

Figure 2 shows the historic variation of Heating Degree Days[5] in December. December 2013 recorded the second highest degree days in this period, and confirms that the weather was persistently cold and would have positively influenced customers' heating/energy requirements.

[5] **Heating Degree Day** (**HDD**) is a measurement designed to reflect the demand for energy needed to heat a building. It is derived from measurements of outside air temperature. The heating requirements for a home or building at a specific location are considered to be directly proportional to the number of HDD at that location.

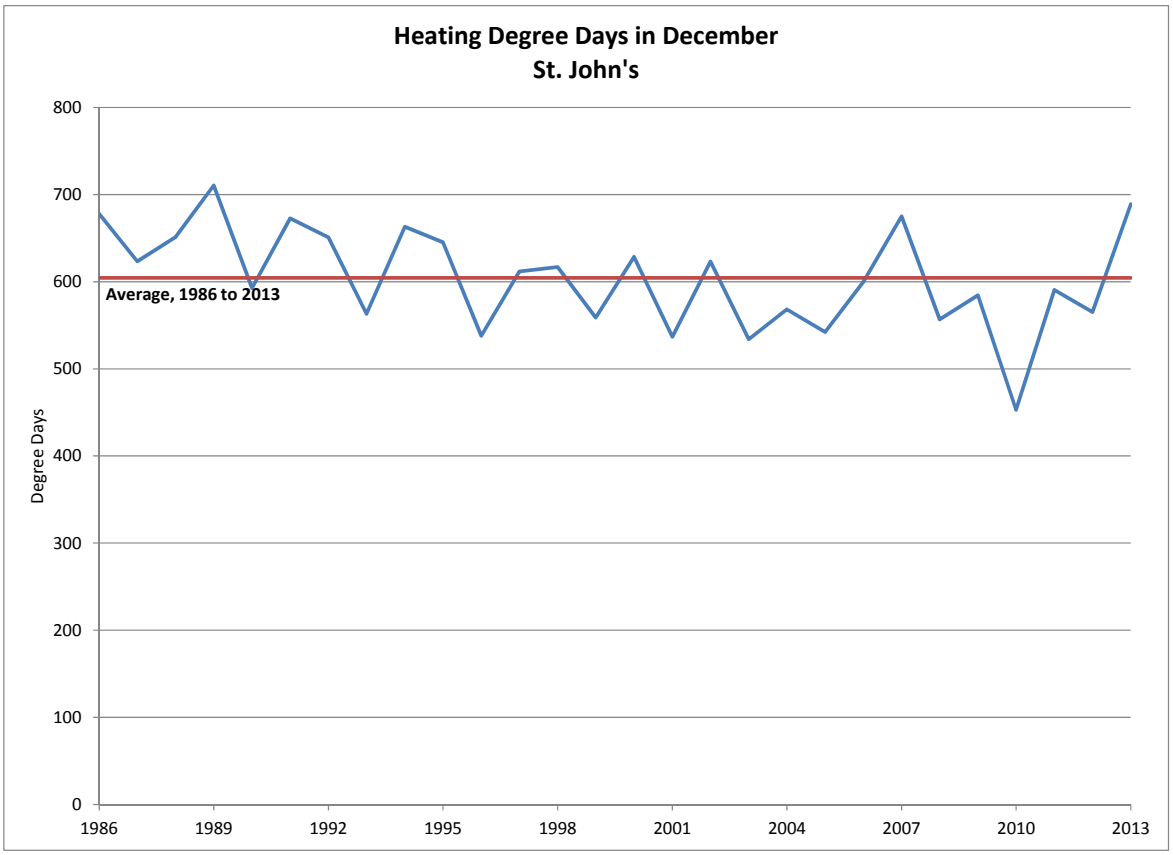


Figure 2: Heating Degree Days in December, St. John's

The Operating Load Forecast is 'weather normalized.' The method used for forecasting winter peak results in a forecast, which reflects average weather conditions (measured as wind chill) coinciding with historical peaks. Historical peaks do not necessarily reflect past weather extremes; meaning, at times of extreme low temperatures, the load could exceed the forecast and system reserve would be used to meet the additional demand (as occurred on December 14, 2013). At times of abnormally mild weather conditions the load would be lower than forecast.

In December 2013 and January 2014 equipment problems meant that, at times, there were several thermal plants that were unavailable or de-rated. The unavailability of the Hardwoods gas turbine and the later supply limitations associated with Holyrood resulted in an increase in power supply to the Avalon Peninsula from Bay d'Espoir through Hydro's transmission system.

This higher load on the transmission lines resulted in increased demand losses on Hydro's System. Demand losses are the electrical losses on the transmission lines and transformers, which are measured as the differences between generation and customer load. Hydro subsequently conducted a load-flow analysis of the conditions experienced in December 2013 and January 2014 and determined the losses to have been 30 to 40 MW higher (approximately double) than what they would have been had all generation been available. The load forecast allowance for losses assumes that the thermal plants are operable in synchronous condenser mode even if they are not on line for generation, which would keep losses at expected values.

In early January 2014 when rotating outages were required because of equipment unavailability, the demands were further increased by the additional demand requirements associated with cold-load pickup on distribution feeders. When customers were returned to service following their rotating outages, they used more energy than they would have in normal circumstances, because of the period of outage. This cold-load pickup requirement was exceptional as broad-based, cold-load pickup is not part of normal day-to-day operations.

An understanding of past forecasting accuracy is important in evaluating the peak in December 2013 and the shortages of January 2014. Table 2 shows the forecast and actual peaks for the winter months from 2004 through 2014. In eight of the 11 years, the forecast was overestimated by between two and nine percent. In three of the 11 years, the actual value was greater than the forecast value, but in two of those years the error was negligible (less than one half percent). Only in 2013/2014 was the discrepancy significantly negative. In the four years prior to this one, the winter peak was overestimated by between two and eight percent. With no marked change in environmental/economic conditions or in forecasting methodology, it could not be predicted that the forecast would be exceeded in 2013/14.

Table 2: Hydro System Peak Demand (MW)

Year	Forecast Winter Peak	Actual Winter Peak	Error
03/04	1399	1405	0%
04/05	1429	1402	2%
05/06	1385	1276	9%
06/07	1358	1323	3%
07/08	1367	1289	6%
08/09	1388	1390	0%
09/10	1372	1305	5%
10/11	1401	1292	8%
11/12	1433	1399	2%
12/13	1461	1378	6%
13/14	1478	1501	-2%

The main finding of this review is that forecasting was not a contributing factor to the supply disruptions and rolling outages in January 2014. One suggestion for improvement is that the load-forecasting process should include sensitivity analysis, including sensitivity to extreme weather conditions, and that analysis should be used to provide more detailed information on the variability of the forecast to the stakeholders. Newfoundland Power should be asked to provide sensitivity analysis on the forecast information they provide to Hydro.

4.2 Short-Term Forecasts

Temperature is by far the most significant variable in short-term load forecasting. The relationship between temperature and peak is demonstrated in Figure 3. In Hydro's opinion, the non-typical, low-temperature conditions, with exacerbating wind chills prevented Hydro's Nostradamus model from accurately forecasting the peak loads in December 2013 and January 2014.

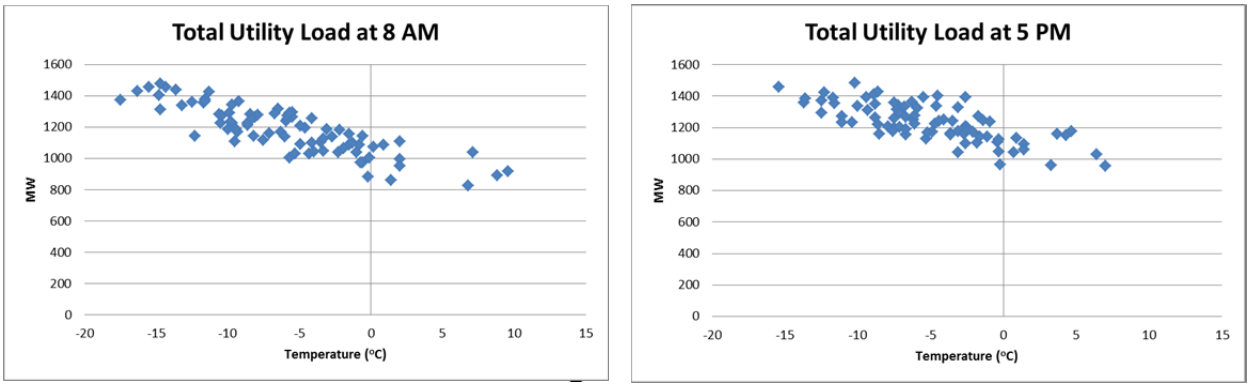


Figure 3: Relationship between Utility Load and Temperature

While the Nostradamus forecast is generally fairly reliable, it has been observed that during periods of unusually cold temperatures and high winds the load forecasts are not accurate. During these times, System Operations staff adjusts the forecasts based on experience and judgment.

A review of hourly temperatures at Badger from 2010 through 2013 showed that less than 0.5% of hourly temperatures were at or below -25 C. Only 2.8% were at or below -15 C. Nostradamus, therefore, had very little data upon which to forecast load at temperatures in the -20 C to -30 C range. Furthermore, most of the historic occurrences of the lowest temperatures were during the night when loads would have been lower than during peak times. The analysis shown in Figure 4 demonstrates that the data used to create the Nostradamus forecast shows almost no correlation between load and temperature at temperatures below -15 C. This is not to say that there is no correlation, or that Hydro does not take it into account in planning, just that the limited data input to Nostradamus does not reflect it.

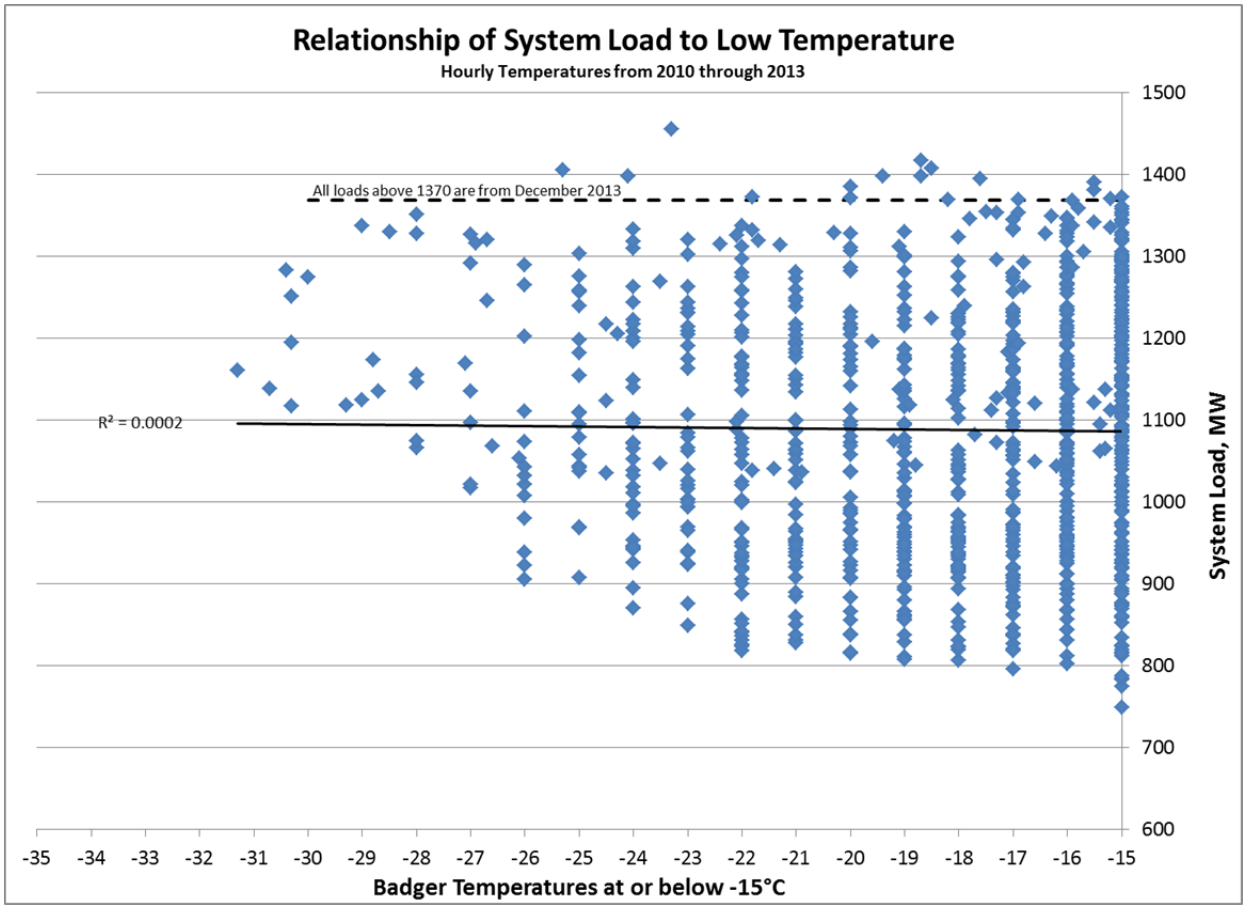


Figure 4: Relationship of System Load to Low Temperatures

System Operations is evaluating an upgrade to the version of the Nostradamus software that it uses for load forecasting, but there have been ongoing difficulties, especially with intraday forecasts. If these issues cannot be resolved with the existing software, new software should be considered.

A more accurate seven-day forecast would not have prevented the supply disruptions in January 2014 as there would not be time within a seven-day period to consider the implications of a higher than anticipated short-term forecast and to add capacity on the System. More reliable forecasts, however, may have been beneficial in managing the rolling outages by giving operators more accurate and advanced knowledge of the expected peaks.

5 VENTYX REVIEW

Hydro retained the services of Ventyx to provide an independent analysis of both the generation planning processes that form the basis of Hydro's strategic plans and forecast, and Hydro's long-term and short-term load forecasting. The results of the Ventyx review regarding Hydro's load forecast is included as Appendix 1 of this report. Ventyx's review of the generation planning process is summarized in the report "Generation Reserve Planning". Specifically, with respect to the load forecast, Ventyx was asked to:

- Review the process used by Hydro in developing its current long-range load forecast and medium-term operational forecasts; and
- Provide commentary on the load-forecasting processes and make recommendations as to specific improvements as required.

5.1 Review Findings

Ventyx's review of the load forecasting process included an examination of Nalcor Energy's documentation relating to the Muskrat Falls project, including the filings with the PUB and the various external reviews, review of the responses to the PUB questions concerning the events of 2014, and one-on-one interviews with both Hydro and Newfoundland Power forecasting staff. Since the independent review of the load forecast conducted by MHI performed a detailed review of the assumptions, Ventyx concentrated its review on the methodology and an assessment of the validity and accuracy of the forecast. Ventyx made no attempt to verify or validate the actual data used since MHI had previously completed the work.

Ventyx reviewed the overall load forecast used in the resource planning process, including Hydro's methodologies for forecasting domestic, general service, street and area lighting classes, and industrial classes. The forecasts for Newfoundland Power and Hydro's Rural Customers are a combination of econometric and regression analyses to determine the energy and demand for each group. The energy by sector is developed using econometric analyses in which the assumptions vary, depending on the various customer classes.

Ventyx concluded that the forecasting methodology used by Hydro is consistent with accepted utility practices. Although the previous review by MHI suggested that the forecasting could be improved by changing to an end-use forecast, it is Ventyx's opinion, based on experience, that the complexity and time needed to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

Ventyx considers that the econometric methods being used are prudent and well validated. The equations all have high statistical coefficients of determination (R^2). The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 3 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided.

Table 3: Coefficients of Determination

Equation	R^2
NP Domestic Class	
Customer Additions	93.4%
Penetration of Electric Heat	88.5%
Conversion of Non-Electric Heat	78.9%
NP General Services Class	
Electric Heat Customer Load	99.9%
Hydro Rural Domestic Class	
Average Use	98.1%
Hydro General Services Class	
Energy	99.6%
NP Peak	99.7%

Ventyx concluded that the analysis should include an evaluation of the impacts that extreme weather conditions would have on the forecast. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 5 shows Ventyx's comparison of the forecasted winter months peaks to the actual peaks for the Hydro System for the years 2004 to December 2013. Since 2004, the forecasted winter peak has consistently been above the actual peaks with the exception of three years. There have been a total of seven months out of 40 winter months that the actual was higher than the forecast. However, since those seven times do not occur in the same month it is likely weather impacting the actual. If a variable, such as the number for customers was off target, it would be impacting the forecast for all winter months in that period.

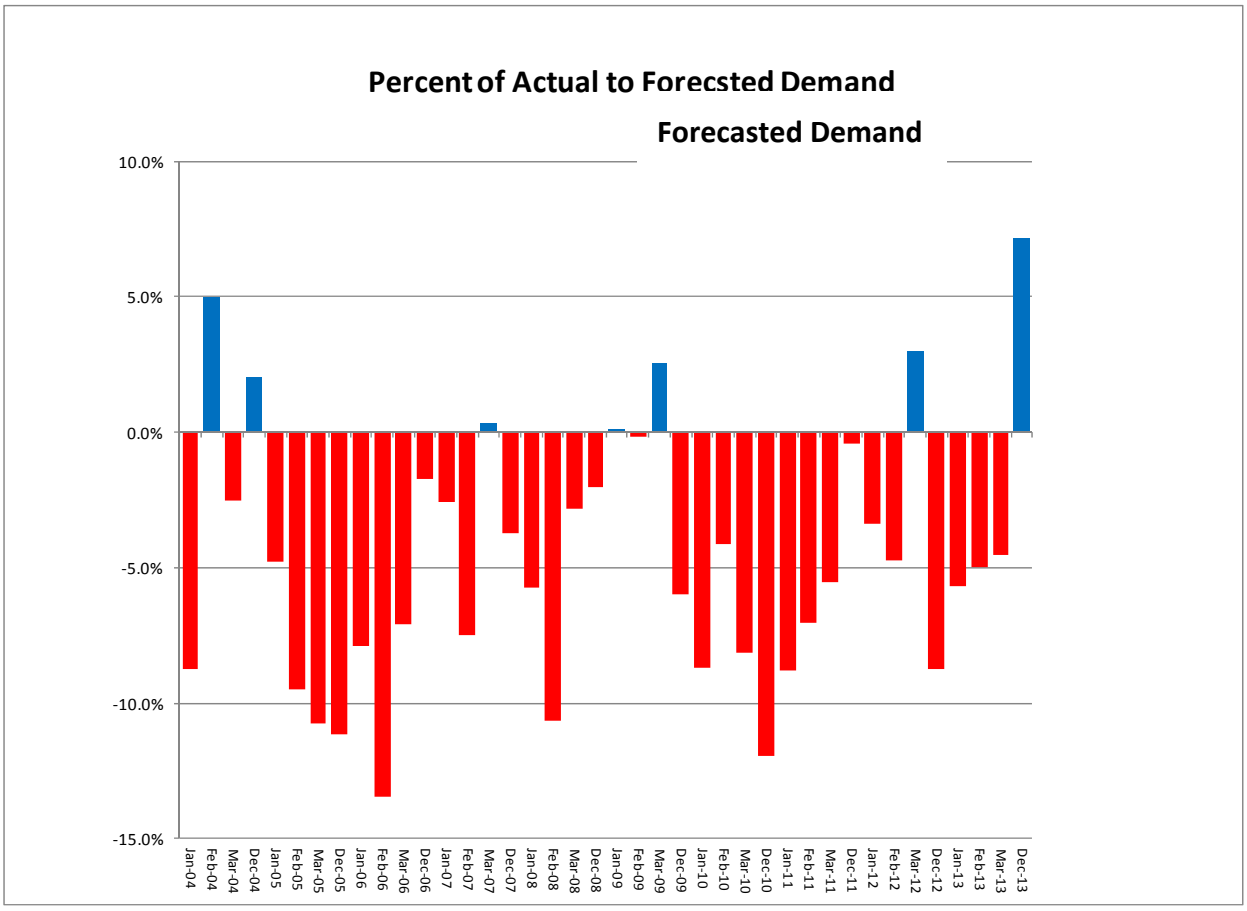


Figure 5: Comparison of Actual and Forecasted Demand

5.2 Recommendations

Ventyx does not consider it necessary to change the forecast methodology to an end-use model because of the increased complexity and cost. The forecast methodology already accounts for

the influence of the major end-use on the system: electric heat. Since the R^2 for the two equations involving heating penetrations were 79% and 89%, it would be advisable to continue to refine the models with respect to these variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturations of electric heat.

Ventyx recommends that Hydro begin to use formal risk assessment in its planning processes. Alternative load forecasts under extreme weather conditions would be required in both the scenario development and the sensitivity analysis phases.

6 KEY FINDINGS AND RECOMMENDATIONS

6.1 Internal Review

Hydro's internal review of the system disruptions identified several underlying causes of the high System peaks in December 2013 and January 2014: weather conditions, increased line losses, and cold-load pickup demand.

It was determined that forecasting was not a contributing factor to the supply disruptions and rolling outages in January 2014. The review recommends that Hydro's load forecasting processes include sensitivity analysis including sensitivity to extreme weather conditions. The sensitivity analysis could be used to provide more information to the stakeholders on the potential variability of the forecast.

The model that System Operations uses for short-term load forecasting did not perform well during the December 2013 and January 2014 cold temperatures. Hydro is continuing to test a new version of the software and if that does not resolve the issue, it will investigate alternate models.

6.2 Prior Reviews

In 2011 Navigant Consulting Ltd. undertook a review of Hydro's load forecasting methodology and concluded that; "Nalcor's forecast methodology is consistent with generally accepted utility practice and the base forecast for demand and energy growth is reasonable."

MHI's (January 2012) review of Hydro's load forecasting concluded the domestic forecast methodology is acceptable, but that best utility practice would incorporate end-use modelling techniques rather than relying solely on econometric techniques. With respect to the general service sector forecast, MHI concluded that the Hydro model had produced remarkably good results and that end-use forecasting was not recommended because the current models are performing very well.

MHI (October 2012) concluded that the load forecast for the Interconnected Island option is well-founded and appropriate as an input into the Muskrat Falls decision process.

6.3 Ventyx Review

Ventyx does not consider it necessary to use end-use modelling for Hydro's forecasting, however, refinements in the equations for the major end-use on the system, electric heat, through continued surveying of the customer base – in terms of both average use and saturations – may be warranted.

Ventyx recommends that Hydro begin to use formal risk assessment in its planning processes. Alternative load forecasts would be required in both the scenario development and the sensitivity analysis phases.

6.4 Recommendations

Recommendation		Status
LF1	The load forecasting process should include sensitivity analysis, including sensitivity to extreme weather conditions, particularly in making near term investment decisions. The sensitivity analysis should be used to provide more detailed information on the variability of the forecast to the stakeholders. Newfoundland Power should be asked to provide sensitivity analysis on forecast information it provides to Hydro.	Will be incorporated into Hydro's next forecasting cycle, May 2014.
LF2	Hydro's short-term forecasting program does not perform well in unusually low temperatures and improvements are required	In Progress
LF3	Refinements in the equations for the major end-use on the system, electric heat, should continue and be enhanced through continued surveying of the customer base in terms of both average energy use, and saturation of electric heating.	2015 or 2016

ACRONYMS

MHI	-	Manitoba Hydro International Ltd
MW	-	Megawatts
OPLF	-	Medium-Term Operating Load Forecast
PLF	-	Long-Term Planning Load Forecast
PUB	-	Board of Commissioners of Public Utilities

Appendices

2014 Newfoundland and Labrador Hydro Planning Process Review

March 21, 2014

Prepared for:

Newfoundland and Labrador Hydro

Prepared by:

Ventyx, An ABB Company
400 Perimeter Center Terrace, Suite 500
Atlanta, GA 30346
www.ventyx.com

Contact:

Charles Adkins, Vice President
(912) 228-4278

VENTYX
AN ABB COMPANY

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Contents

Executive Summary 3
Study Objective 6
VENTYX 7
Strategist® 8
Incident Description 8
Issues within Scope 9
Load Forecasting 9
Generation Planning Criteria 9
Scenario/Sensitivity Planning 10
Load Forecasting 10
Background 10
Conclusions 12
Recommendations 16
Generation Planning Reserve Criterion 17
Background 17
Conclusion 22
Recommendation 22
Generation Forced Outage Rates 23
Background 23
Conclusion 25
Recommendation 25
Scenario Planning 26
Background 26
Conclusions 28
Recommendations 29
Generation Outlook 2014 to 2017 29
Summary of Recommendations 31
Appendices 34

Executive Summary

Over the weekend of January 3rd, 2014, Newfoundland and Labrador Hydro ("NLH") experienced a series of largely unrelated events that led to four days of rolling blackouts. On January 17th, The Board of Commissioners of Public Utilities ("the Board") initiated a process to gather information from NLH and Newfoundland Power ("NP") with a focus on whether load requirements on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecasts, and NLH's long term (20 year) and medium-term (5 year) load forecasting. Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

In the near term, NLH's current resource expansion plan is within the reliability criteria in all calendar years except 2015.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date or an equivalent resource is not implemented the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[1] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 50 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, in addition to the nominal combustion turbine assumed, NLH would need to secure approximately 40 MW of either interruptible contracts with existing

[1] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

customers or conservation and demand management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[2] and 0.91%[3], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets, this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well, there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The current projected plan is based upon a normalized weather forecast. Weather normalization is an industry standard process that adjusts actual peak outcomes to what would have happened under normal weather conditions. Beyond the next seven days weather forecasting is complex and not always accurate. Therefore, NLH should look at a severe

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[2] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[3] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

weather sensitivity to gauge how the system might respond to greater than expected demand particularly in making near term investment decisions.

Specific process recommendations:

- Load Forecasting
    - Continued surveying of the customer base in terms of both average energy use and saturations of heating.
    - Develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.
- Generation Planning
    - NLH should continue forward with its generation planning reserve criterion.
    - After NLH's interconnections are established in 2017, NLH should revisit both their generation planning reserve criterion and their modeling of external markets.
    - NLH should continue forward with its practice of maintaining a more conservative estimate of EFOR for the units.
    - Compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the LOLH criteria of 2.8 hours/year
- Develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.

Study Objective

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts. On January 17th, The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecast and NLH's long term (20 year) and medium term load (5 year) forecasting. Specifically, Ventyx was asked to review:

- The overall planning process and assumptions used by NLH in developing their current long range and strategic forward looking plans;
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required;
- Review of the process and assumptions used by NLH in developing their current long range load forecast and shorter term operational forecasts;
- Provide commentary on the load forecasting processes, criteria and assumptions and make recommendations as to specific improvements as required;
- Review of the Strategist model assumptions used by NLH in developing their current long range and strategic forward looking plans; and
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required.

VENTYX

Ventyx brings a dedicated team of expert consultants that combines experience, industry knowledge, market knowledge, and software expertise to support consulting engagements. Ventyx provides professional consulting services to energy companies in the areas of integrated resource planning, market price forecasting, resource evaluation and planning, trading and settlement, and electric transmission economic analysis. Ventyx has worked with NLH both in support of Ventyx's Strategist software and .with analytical modeling to evaluate the economic and system impacts of the Muskrat Falls hydro project as well as the Maritime Link project with Nova Scotia. Ventyx conducted multiple analytical modeling studies of this pair of projects over a three year period that also included analytical modeling covering the provinces of New Brunswick, Prince Edward Island, Nova Scotia and Newfoundland Labrador as well as surrounding market areas in Quebec, New York and New England for the Atlantic Energy Gateway project

Strategist®

Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. Strategist is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities, economic energy interchange, and direct load control programs are then economically dispatched based on the marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices. The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. The PROVIEW module works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system, or modifying the load through demand-side management (DSM) or marketing programs.

Incident Description

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts.

Issues within Scope

The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts. The scope of this report is focused on the load forecasting and planning criteria and assumptions. With the NLH system setting record peaks during this unfortunate event, the question of load forecast accuracy is raised. The primary planning criteria that are related to an event of this nature are planning reserves and generation forced outage rates. Finally, the issue of load forecasting and planning criteria is enveloped in the overall process of sensitivity analysis to address the inherent risk of the NLH portfolio.

Load Forecasting

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. As the load forecasting process passes from the short term to longer term, the reliability of forecasted weather drops dramatically. Longer term forecasts are typically represented as annual peaks and energies, with monthly detail, to support budgeting planning. Longer term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

Generation Planning Criteria

The generation planning criteria for planning reserves and generation forced outage rates combine to form a prediction of the expected LOLH reliability index. This reliability index forms the foundation of a minimum reliability threshold of 2.8 hours/year. For each year of the NLH planning horizon, the system is designed to maintain sufficient generation planning reserves to ensure the minimum reliability threshold is met. Generation planning reserves are the MW

difference between available capacity and normalized peak demand that are available to meet unforeseen increases in demand, such as extreme load, and unexpected outages of existing capacity. Forecasted trends in LOLH identify whether generation capacity additions are keeping pace with load growth.

Scenario/Sensitivity Planning

Scenario planning is a strategic planning methodology used to identify and assess the inherent risks and benefits of a flexible long term plan. Scenario planning recognizes that many factors may combine in complex ways to create sometimes surprising futures. Scenario planning seeks to identify the causal relationship between factors and demonstrate a plans flexibility to adapt. Scenario planning develops an internally consistent story about the conditions in which the system might be operating in the future that differs from baseline assumptions in sometimes significant ways and usually involves alterations to all of the assumptions at one time. Sensitivity planning varies each of the assumptions either one at a time or in correlated groups to determine how sensitive the results are to changes in the assumptions. These planning techniques are important when there are variables such as weather that can potentially impact the reliability of the system.

Load Forecasting

Background

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. The short term forecasts prepared by NLH use a neural network forecasting approach using the Nostradamus modelling software.

A medium term forecast that covers a time horizon of five years is used for budgeting and near-term supply adequacy. The medium term forecasts are a combination of the NP forecast for

their service territory and NLH economic and regression processes for their rural customers and customer input for the industrial loads.

Longer term forecasts cover the time horizons of 20 years and are typically represented as annual peaks and energies, with monthly detail, to support long term generation planning. The long term forecast is performed by NLH using economic and regression techniques to forecast NP, NLH rural loads, and Industrial customer forecasts of their loads. The long term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

The review of the load forecasting process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent, detailed reviews of the project, a review of the responses to the Board of questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP forecasting staff. Since the independent review of the load forecast conducted by Manitoba Hydro International ("MHI") was a detailed review of the assumptions, the review described in this report focused on the methodology and a look at the validity and accuracy of the forecast. Personal interviews were held with the staffs of NLH and NP to ascertain the sequencing and procedures of each company and the interfacing and integration of the individual component forecasts into a single product. Of particular interest was the accuracy of the winter peak as it applies to the incidents described above.

- The interviews with the NP load forecasting staff revealed the medium term forecast of NP service territory energy was performed for Domestic, General Services and Area and street light classes. Although the process was different for each class, the basic process is an average use methodology that applied econometric forecasting techniques to determine average use per consumer that was then applied to a customer growth forecast.
- The medium term peak demand for NP was developed using an average load factor methodology that calculates a 15 year average load factor that is then applied to the medium term energy forecast to determine the NP service territory Winter Peak demand. This is a standard utility practice.
- The NLH long term load forecasting process is a combination of econometric and regression analyses to determine the energy and peak demand for NP and the NLH rural

groups with industrial energy and demand requirements conditioned by individual customer input .

- The long term peak for NP is forecast by NLH using regression analyses that link NP peak demand to weather, domestic electric heat customer growth, general service sales growth and other economic factors. The peak for the NLH rural group is calculated using a long term historical load factor method that is applied to the forecasted energy. The industrial peak is developed through direct input of existing industrial customers. No forecast is made of potential new industries unless it is fairly certain that a change is going to be made either through government action or a committed industrial customer.

NLH uses historical hourly shapes to develop typical 168 hourly week shapes for each month of the year. These typical shapes are applied to each year of the study and are adjusted by the Strategist Load Forecast Adjustment ("LFA") module to meet the data entered for peak and energy from the forecast. NLH has not updated the historical data since 2002 and is scheduled to perform the update in the next 12 months as part of the next generation expansion planning exercise. Since the system has had a fairly stable load factor and since the LFA continuously modifies the shape to meet the forecast this should not impact the results of the studies. This would only be a problem if NLH was evaluating new Conservation and Demand Management ("CDM") or time dependent programs such as time-of-day rates.

NLH has elected to set the study period to 50 years so that it would cover the financing period of the Muskrat Falls project. This is typically performed using either Economic Carrying Charge calculations or infinite end-effects with a shorter study period of twenty years. However, after discussion with NLH planning staff Ventyx determined that the manner in which they performed the extension of the load forecast and other model data was consistent with the Strategist end-effects methodology.

Conclusions

The methodology used by both NP and NLH are consistent with accepted utility practices. It has been noted by another independent review, by MHI, that the process could be improved by

changing to an end-use forecast. It is Ventyx's opinion, based on experience, the complexity and time to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

The econometric methods being used by NLH are prudent and well validated. The regression equations all have statistical coefficients of determination (R^2) that are in the very high range. The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 1 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided. The R^2 for the regression equations that directly impact the forecast of system peak demand in the long term are included below.

Equation	R^2
NP Domestic Class	
Customer Additions	93.4%
Penetration of Elect. Heating	88.5%
Conversion of Non-Elect Heat	78.9%
NP General Service Class	
Electric Heat Customer Load	99.9%
NLH Rural Domestic Class	
Average Use	98.1%
NLH Rural General Service Class	
Energy	99.6%
NP Peak	99.7%

Table 1 Coefficients of Determination[4]

No attempt was made in this review to verify or validate the actual data used since a previous report was issued by MHI showing a detailed discussion of the data. It is obvious weather has a significant impact on the resulting energy and peak demand forecasts. NLH's forecasting models include weather variables to account for the impacts due to changing weather conditions through the historical period. However, what is missing is an evaluation of the energy and demand impacts due to extreme weather conditions. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 1, shows a comparison of the forecasted winter months peaks to the actual peaks for the system for the years 2004 to December 2013. Since 2004 the actual winter peaks have consistently been below the forecasted peaks with the exception of seven months out of forty winter months that the actual has been higher than the forecast. However, since those seven times do not occur in the same month it would suggest that there was some random pattern

[4] Manitoba Hydro International, *MHI-Report-Volume II-Load Forecast* (February 2012)

such as weather that is impacting the actual. A review of the deviations shows that it is largely weather that impacts all the discrepancies As indicated by the red bars, the actuals are consistently less than the forecast because NLH has experienced a period of warmer than normal peak weather conditions over this period. The December 2013 discrepancy was impacted additionally by the "exceptional" loads resulting from unavailable Avalon generation that resulted in higher system demand loads than expected. If a variable such as the number of customers was off it would be impacting the forecast for all winter months in that period.

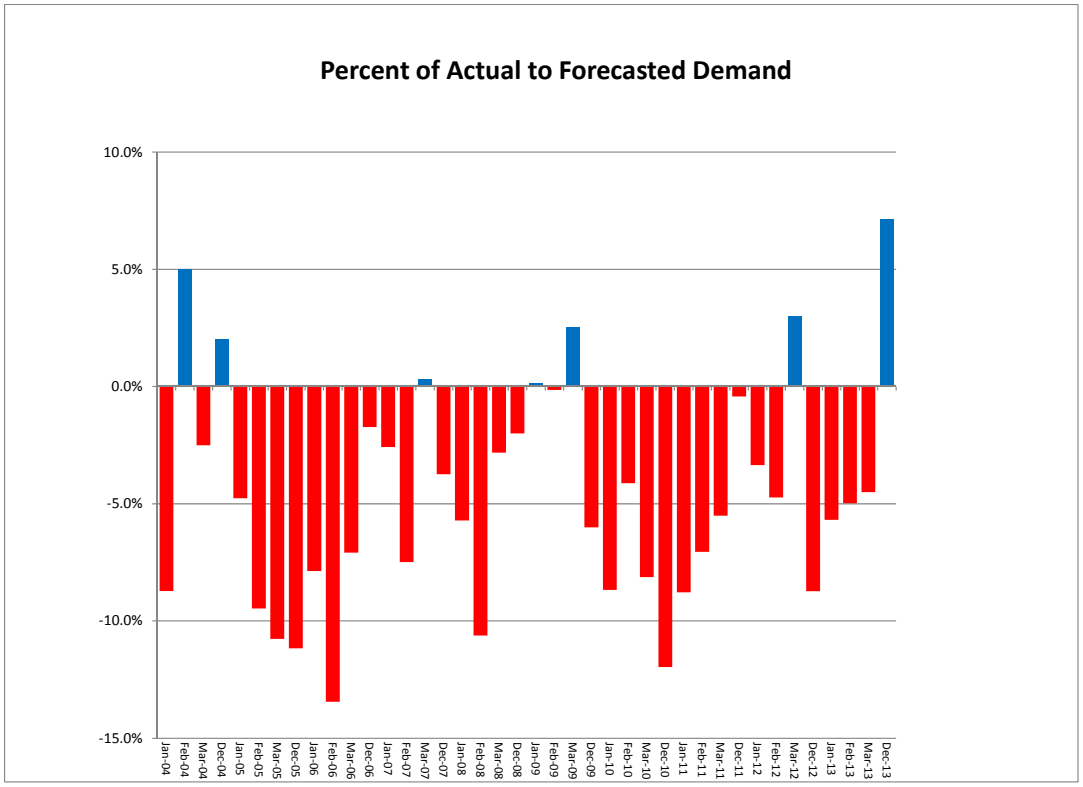


Figure 1[5]

Recommendations

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy

[5] Newfoundland and Labrador Hydro, *PUB-NLH-011* (Newfoundland and Labrador Hydro: Board Response, February 2014)

benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine their models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. Later in the report, Ventyx will discuss using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.

Generation Planning Reserve Criterion

Background

The purpose of a Generation Planning Reserve Criterion is to establish the minimum reliability threshold for a power system. The reliability of a power system is defined as the probability of providing customers with continuous service of a satisfactory nature. Reliability is one of the primary factors that drive the planning, design, operation, and maintenance of a power system. The most common index for reliability is the Loss of Load Probability ("LOLP") which is "the probability of the system load exceeding the available generating capacity under the assumption that the peak load of each day lasts all day."[6] Through a series of analytical processes the reliability index, LOLP, is translated to a reserve criterion stated in terms of Loss of Load Hours ("LOLH") or a defined reserve margin percentage. In Strategist, Loss of Load Hours is the expected total number of hours a year during which the utility will not be able to serve all of its customers. The percent reserve margin is based on the reserve margin at the time of the annual peak and defined as the amount of installed reserves, in MW, divided by the

[6] J. Endrenyi, *Reliability Modeling in Electric Power Systems* (Ontario Hydro: John Wiley & Sons, 1978), 4

system peak demand, in MW. This reserve criterion serves as an input to capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

NLH's capacity planning reserve criterion for capacity planning is "The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours ("LOLH") expectation target of not more than 2.8 hours per year."[7] The LOLH target is based upon a Loss of Load Probability of 1 day in five years or, more commonly denoted as, 0.2 days per year. In 1977, the NLH System Planning department determined that "The LOLP index to be adopted depends upon the availability of capital. System Planning feels that a .1 days/year is not realistic and would suggest .2 days/year as an optimum value to aim for".[8] The results of NLH's recent 2012 capital planning study, 2012 DCL–PLF IT1–A-0801-_R-105 FE-1 Strategist 4.4.1, are enumerated in Table 2.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

Table 2 Expected Loss of Load Hours

[77] PUB-NLH-008

[8] System Planning Department, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions* (Newfoundland Labrador Hydro: internal memo, May 16, 1977), 19

Previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[9] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[9] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[10] and 0.91%[11], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The standard industry practice is to apply a LOLP of 0.1 days/year, or "one day in ten years". However, it should be noted that the 0.1 days/year standard applies to ***interconnected*** utilities. For true "stand alone" utilities, the cost to achieve a 0.1 days/year standard is often cost prohibitive. In 1977, NLH conducted a thorough analysis of system reserves and concluded with the recommendation of 0.2 days/year, or "one day in five years". NLH justified the 0.2

[10] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[11] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

days/year over 0.1 days/year based on the economics of meeting the more stringent requirement. The incremental present value revenue requirements necessary to move from a reliability index of 1.0 days/year to 0.2 days/year was approximately $24 Billion[12]. The incremental present value revenue requirements necessary to move from a reliability index of 0.2 days/year to 0.1 days/year was approximately $17 Billion[13]. Simply stated, the cost to serve the last tenth of the reliability index was 71% of the cost to serve the total of the first eight tenths of the reliability index. NLH was justified in its decision to adopt a reliability index of 0.2 days/year.

From a generation mix perspective, the NLH system is "roughly" the same as it was in 1977; there is no reason to reassess its reliability standard of 0.2 days/year. The primary drivers that would prompt a utility to reassess its reliability standard include: resource mix, plant reliability and maintenance, and interconnections. In 1977, the NLH system was 63% hydro and 37% thermal. Today, the NLH system is 67% hydro and 33% thermal. In terms of plant reliability, the capacity weighted average effective forced outage rate in 1977 was 3.74% versus 4.05% today. From a system reliability standpoint, the NLH system is virtually equivalent to the system in 1977. However, NLH expects to complete the Maritime Link to Nova Scotia in 2017. When NLH interconnects with the North American grid, NLH should reassess its reliability standards in light of their access to new markets.

Loss of Load Probability is a characterization of the adequacy of the generation within a system to serve the load of the system. It is important to note that LOLP does not represent the reliability of the bulk transmission or distribution systems. For the purposes of NLH's planning criteria, it was necessary to translate the LOLP, which is a based on the peak load of each of the 365 days, to an hourly equivalent, LOLH. "When Hydro switched from SYPCO generation

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[12] Ibid, Table V. Grand Total (0.2) 2,896,178 (1977 K$) minus Grand Total (1) 2,872,516 (1977 K$) equals 23,662 (1977 K$).

[13] Ibid. Table V. Grand Total (0.2) 2,912,924 (1977 K$) minus Grand Total (1) 2,896,178 (1977 K$) equals 16,746 (1977 K$). 16,746 is 70.07% of 23,622.

planning software to PROSCREEN II [now called Strategist], it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system."[14]

In 2017, the Maritime Link to Nova Scotia will be completed. Post 2017, NLH will be interconnected with the rest of the North American grid. In addition, there will be a long term sales agreement with Nova Scotia that will provide scheduling flexibility. NLH's current long term planning system does not reflect the reliability benefits of these incremental additions to the NLH portfolio.

Conclusion

NLH's generation planning reserve criterion of a LOLH of 2.8 hours per year is prudent and consistent with standard industry practices. NLH has consistently used the generation planning reserve criterion as an input to their capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

Recommendation

NLH should continue forward with its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. It may be possible that this approach to reserve criterion, if still appropriate may be improved at minimum cost. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to

[14] Newfoundland and Labrador Hydro, *PUB-NLH-056* (Newfoundland and Labrador Hydro: Board Response, February 2014),1

allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Generation Forced Outage Rates

Background

The purpose of generation forced outage rates in generation planning is to represent the probability that a specific unit will not be available for service when required. Generation Planning periodically confirms the resource adequacy of a system through detailed reliability simulations that compare the expected load profiles with specific generating unit forced outage rates and maintenance schedule to determine LOLH values. A typical unit's contribution to resource adequacy is typically a function of the unit's capacity and its equivalent forced outage rate ("EFOR"). NLH uses the convention Derated Adjusted Forced Outage Rate ("DAFOR") which is known as EFOR as used by the North American Electric Reliability Council[15]. For the purposes of this report EFOR and DAFOR have the same meaning. A unit's equivalent forced outage rate is defined according to the following formula:

[15] Roy Billinton, *Reliability Data Requirements, Practices and Recommendations* (Department of Electrical Engineering University of Saskatchewan) page 55.

$$EFOR = \frac{FOH + EFDH}{FOH + SH + Synchronous\ Hrs + Pumping\ Hrs + EFDHRS} \times 100\%$$

Where:

FOH	– Forced Outage Hours
$EFDH$	– Equivalent Forced Derated Hours
SH	– Service Hours
$Synchronous\ Hrs$	– Synchronous Condensing Mode Hours
Pumping Hrs	– All hours pumped storage unit in pumping mode
$EFDHRS$	– Equivalent Forced Derated Hours during Reserve Shutdowns

For the purposes of this discussion, Ventyx focused on NLH's largest aggregate resources that drive overall system reliability, Holyrood, 465.5 MW; and Bay D'Espoir, 592 MW. These two plants comprise 1057.5 MW and represent 54.3% of NLH's installed capacity. The EFOR used in NLH's generation planning and serving as an input to Strategist is derived from the Canadian Electrical Association's ("CEA") 2004 Report and is based on the period from January 1, 2000 through December 31, 2004. Ventyx compared these rates to the current CEA data covering the period from January 1, 2008 through December 31, 2012. NLH's other smaller CT's and Hydro units have less impact upon reliability.

Table 3 lists the five year CEA capacity weighted average EFOR based on the most recent CEA data and the EFOR assumptions in NLH's Strategist database.

Unit Name	NLH Strategist Assumptions	NLH Average 2008 - 2012
Holyrood	9.64%	10.69%
Bay D'Espoir	0.91%	0.41%

Table 3

Conclusion

NLH's overall assumptions are consistent with industry standards. While there might be some rationalization that a significant increased investment might improve Holyrood performance further, given the time until the infeed is realized, the age of the units and outage availability it appears that the time required to gain results will be longer than the relatively short timeframe to interconnection with the North American Grid.

Recommendation

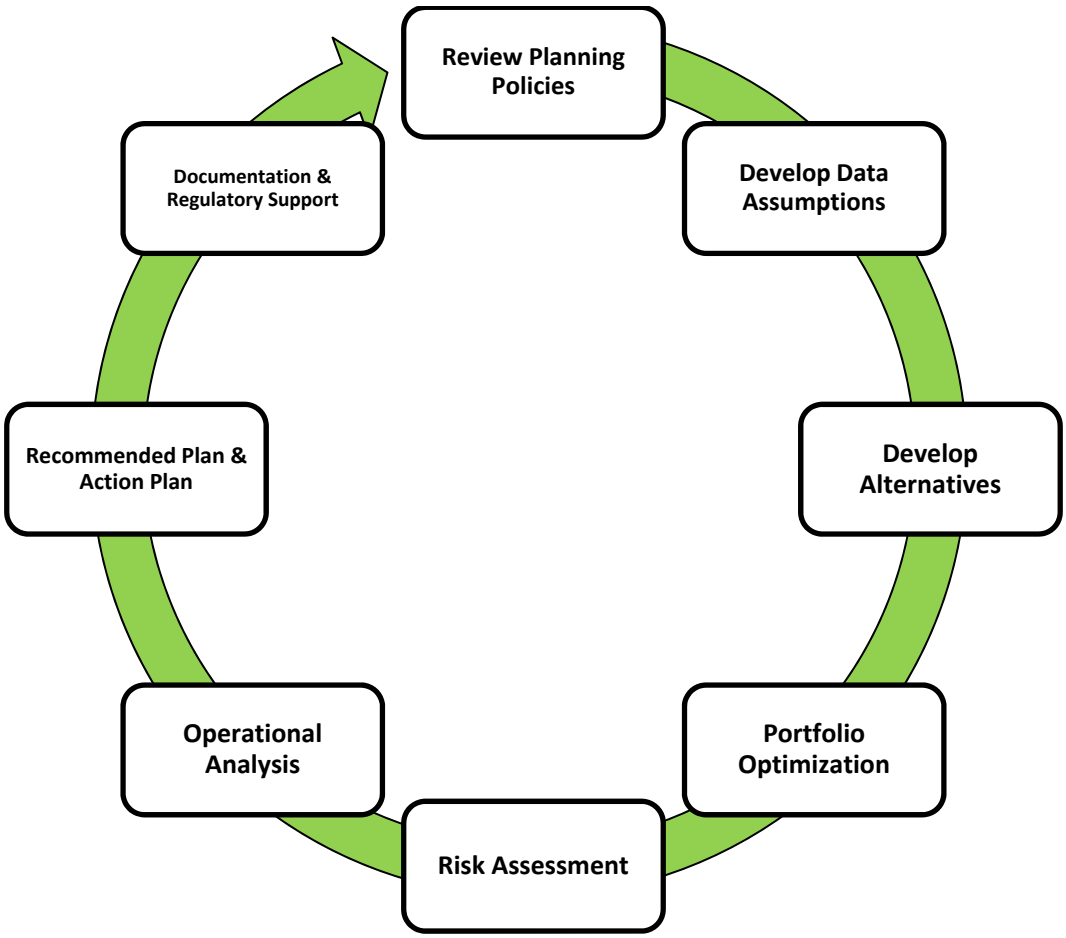
Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model its EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, for which the maximum EFOR would be between 9.7% and 9.8%. At this point, the units' contribution to LOLH would exceed 2.8 hours/year.

Scenario Planning

Background

The purpose of this part of the review is to examine the NLH planning process with respect to accepted utility practices and procedures. The standard that the NLH planning process was compared is the Ventyx Integrated Resource Planning ("IRP") process. This process was developed and used by Ventyx n its worldwide consulting practice.



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Figure 2 IRP Planning Process

Description of each step:

- **Planning Policies Review** – This is the initial IRP project planning step in which the objectives of the IRP are set up. This includes the review of all of the rules and constraints that must be met in performing the planning process
- **Data Assumptions** – In this step all of the data assumptions are gathered and vetted. This includes the operating assumptions of all existing and proposed future alternatives, commodity prices, environmental and market prices, and transmission limits.
- **Develop Alternatives** – The simulation models for the various alternative Demand-side, Supply-side and market/transmission options are developed.
- **Portfolio Optimization** - In this step the potential resource alternatives are pre-screened using economic and operational methods. Through the use of optimization software, such as Strategist, one or more optimal plans are developed that meet a set of defined attributes and constraints.
- **Risk Assessment** - This step takes optimized plans from alternative scenarios and subjects them to sensitivity analysis to determine the impact of changes in assumptions to results. This step also determines the robustness of optimal plans to statistical distributions of sensitive variables. Then using multi-criteria decision making analysis techniques determines the trade-off between competing attributes such as risk and least cost.
- **Operation Analysis** – Selected plans are then further analyzed in terms of financial viability and operational constraints such as hydrological studies.
- **Recommended Plan and Action Plan** - The results of all the above steps is a recommended plan that the utility wished to present as its integrated resource Plan. In conjunction with this overall long –term plan an Action Plan is developed that focuses on the decision period in which actions must be decided on today. With-in the Action Plan a set of signposts are developed from the sensitivities that determine which variables should be monitored, at what value an action should be triggered, and what the contingent actions should be.

- **Documentation and Regulatory Support** –The heart of the IRP is the final documentation. These are the documents that will be filed with regulators and all other parties. It should be thorough, accurate and defendable. Note that this step is best performed as the overall IRP process is being performed.

The review of the resource planning process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent detailed reviews of the project, a review of the responses to the Board's questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP planning staff.

Conclusions

The resource planning process being performed by NLH conforms to the basic structure laid out in the Ventyx IRP process. All areas in the IRP process were deemed as being acceptable. However, two areas, Alternative development, and Risk Assessment were found to be acceptable but in need of improvements.

In the development of alternatives it was found that although existing demand-side programs were included in the development of the resource plan there was a lack of additional demand-side alternatives. The report only mentions the presentation of CDM alternatives to the Board, no mention of the use of demand-side as alternatives to supply resources is made. Due to slow growth requirements of demand programs the use of demand-side alternative will not be effective to solve short-term issues. It will also not change the need for the capacity and energy from the Muskrat Falls project long term. However, it is Ventyx's recommendation that the use of demand-side alternatives be further explored in the period post 2017 while there is ample capacity to cover requirements. In reviewing the documents it was noted that there is no formal risk assessment being performed.

Sensitivities were performed and included in the original documentation but focused mostly on commodity and costing assumptions. Future scenario and sensitivity processes should be expanded to include the impacts of extreme loads. These expanded sensitivity analysis can then be formally included into a risk analyses process to determine the robustness and impacts

of resulting plans. The additional load sensitivities are discussed above in the section on load forecast.

Recommendations

It is noted that while NLH's Resource Planning processes meets the overall IRP process requirements, there are two areas that could be incrementally improved.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternatives to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Generation Outlook 2014 to 2017

On January 17th, the Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. In the near term, NLH's current resource expansion plan is within the reliability criteria.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57.

NLH is currently considering six options[16] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[16] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[17] and 0.91%[18], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if Holyrood unit could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

Summary of Recommendations

Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

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[17] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[18] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine its models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. It has been recommended above that NL begin using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecast in both the scenario development and the sensitivity analysis phases.

NLH should continue to use its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model it's EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the

EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, the maximum EFOR would be between 9.7% and 9.8%. At this point, the unit's contribution to LOLH would exceed 2.8 hours/year.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternative to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Appendices

PUB-NLH-008

PUB-NLH-011

PUB-NLH-056

PUB-NLH-062

Q. How does Hydro determine the appropriate reserve to have available to meet the Island Interconnected system load?

A. From a long-term planning perspective, Hydro has established criteria related to the appropriate reliability for the system, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the system to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year[19].

[19] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[20].

From an operational perspective, Hydro manages generation resource availability on the Island Interconnected System and schedules generating units out of service for planned maintenance in order to meet a (n-1) system contingency reserve criterion. In this manner, sufficient reserves are planned to be available to meet the Island Interconnected System load under a contingency of the largest (MW rating) available generating unit. Hydro does not rely on capacity from wind and other non-dispatchable[21] resources to provide reserve. However, if these resources are in production they can further increase the reserves available. Following the (n-1) criterion results in no extended planned maintenance scheduled during the winter period. However, if the short-term load forecast permits, Hydro may take the opportunity to schedule a short duration generating unit outage to address running or corrective maintenance issues.

[20] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Generation) is based on energy capability adjusted for maintenance and forced outages.

[21] Please refer to PUB-NLH-044 for a definition of "non-dispatchable".

Q. Provide the forecast and actual peak demand for each month in the winter period in each year from 2004 to 2013 and the forecast each year for 2014 to 2017 for each month in the winter period.

A. Please see below for the forecast and actual peak demand supplied by Hydro for the Island Interconnected System. Please note that Hydro interprets the winter period to be from December through March and that the forecasts provided are Hydro's Operating Load Forecasts. Please refer to Hydro's response to PUB-NLH-014 on timing of preparation.

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-04	1399	1277
Feb-04	1338	1405
Mar-04	1237	1206
Dec-04	1374	1402
Jan-05	1429	1361
Feb-05	1405	1272
Mar-05	1301	1161
Dec-05	1353	1202
Jan-06	1385	1276
Feb-06	1369	1185
Mar-06	1256	1167
Dec-06	1333	1310
Jan-07	1358	1323
Feb-07	1350	1249
Mar-07	1238	1242
Dec-07	1336	1286
Jan-08	1367	1289
Feb-08	1356	1212
Mar-08	1242	1207
Dec-08	1350	1323
Jan-09	1388	1390
Feb-09	1377	1375
Mar-09	1262	1294
Dec-09	1349	1268

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-10	1372	1253
Feb-10	1361	1305
Mar-10	1243	1142
Dec-10	1371	1207
Jan-11	1401	1278
Feb-11	1390	1292
Mar-11	1270	1200
Dec-11	1405	1399
Jan-12	1433	1385
Feb-12	1417	1350
Mar-12	1302	1341
Dec-12	1432	1307
Jan-13	1461	1378
Feb-13	1446	1374
Mar-13	1332	1272
Dec-13	1401	1501
Jan-14	1478	-
Feb-14	1429	-
Mar-14	1322	-
Dec-14	1425	-
Jan-15	1523	-
Feb-15	1470	-
Mar-15	1361	-
Dec-15	1447	-
Jan-16	1543	-
Feb-16	1498	-
Mar-16	1383	-
Dec-16	1466	-
Jan-17	1567	-
Feb-17	1515	-
Mar-17	1395	-
Dec-17	1473	-

Note: Forecast and actual peaks reflect gross requirements.

Q. Further to the response to PUB-NLH-008, state the date(s) the criteria used for generation source additions was last reviewed by Hydro. In the response state whether Hydro is of the opinion it should be reviewed in light of Hydro's aging infrastructure and when is the appropriate time to review this criteria.

A. Hydro's generation source additions criteria have been in use for over 35 years and in that period they have been reviewed on a number of different occasions and found to provide a good balance of reliability versus cost.

Before 1977, there were no approved long-term reliability criteria for generation planning in Hydro. The basis of the current criteria is a report, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions*, System Planning Department, May 16, 1977. In that report, a LOLP of 0.2 days per year, or 1 day in 5 years was established. In 1997, when Hydro replaced the SYPCO generation planning software with ProScreen II (now renamed Strategist) generation planning software, it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system. From that point onward, Hydro established the capacity criteria that the Island Interconnected System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.

In 1991, at the direction of the Board, George C. Baker, a consultant working for Hiltz and Seamone Company Limited carried out a study and produced a report -*Report on the Technical Performance of Newfoundland & Labrador Hydro* - October 2, 1991. On page 9 of the report, in Section *7 System Planning,* it states:

Hydro uses two criteria for generation planning in its interconnected system.

(a) Sufficient production capacity to meet all needs under firm water conditions (lowest recorded flows), and

(b) A loss of load expectancy of one day in five years.

The first criterion is usual for utilities with significant dependence on hydraulic generation. The second differs from the one-day-in-ten-years LOLE[22] adopted by many utilities.

The main reason for permitting a higher LOLE is economic. Hydro, unlike almost every other major utility, is an isolated system. Other utilities can, and do, rely on capacity support from interconnected utilities in meeting the one-day-in-ten-years criterion. Hydro cannot do this, and would have to maintain a much higher generation reserve.

[22] Loss of Load Expectation. LOLE is another way of stating LOLP and the two are equivalent.

Hydro believes the costs of doing so would not be justified by the difference in reliability. The Consultant agrees.

In 1999, at the direction of the Board, Quetta Inc. and Associates carried out a study and produced a report *Technical Review of Newfoundland and Labrador Hydro Final Report* March 17, 1999. On page 23 of the report, in Section *2.1.3.2 Capacity*, it states:

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) target of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in five years. It results in a capacity reserve requirement of 18%.

The LOLE capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America (one day in 10 years or 0.1 days/year). Considering the non-interconnected status of the Island's electric utility system, (reserve sharing is not an option) the cost of providing higher reliability level is probably in excess of the benefits to be derived.

Quetta is of the opinion that the capacity and energy criteria are reasonable in the circumstance.

Most recently, the criteria were reviewed in the *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volume 2: Studies January 2012*. This report was prepared for the Board by Manitoba Hydro International. In the report, *Section 3 – Reliability Studies* runs from page 57 to page 71. *Section 3.11 – Conclusions and Findings*, page 70, states the following:

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities.

As part of its internal review of recent events, Hydro has engaged an outside consultant (Ventyx) to review its generation planning practices. One of the areas to be reviewed is the criteria used for generation source additions. As well, in light of Hydro's aging infrastructure, it is also appropriate to review the inputs to the generation expansion model, such as the current and expected forced outage rates of Hydro's generating units. These will also be reviewed.

Q. Further to the response to PUB-NLH-018, which states that there is a capacity deficit identified for 2015, explain in detail each of the "*several generating options potentially available to meet winter peak demand*" that Hydro stated it was pursuing, including the status of the review of each option and the time required to construct or install each option.

A. The options under consideration for meeting the deficit currently expected in 2015 include the following and may be a combination of two or more to meet the potential deficit:

1. **Retain the 16 MW diesel facility at Holyrood (presently under a lease-to-own arrangement).** Once installed, 10 MW can immediately be supplied to the system on a sustained basis. This facility is currently being prepared for commissioning in early March 2014.
2. **Review what is needed to make the remaining diesel power available to the system.** Please refer to Hydro's response to PUB-NLH-064.
3. **Enter into interruptible contracts with large Industrial Customers.** Discussions with Industrial Customers (CBPP, Vale and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored. Please refer to Hydro's response to PUB-NLH-050.
4. **Seek already built combustion turbines in the 50 to 85 MW range**. Preliminary discussions indicate that these options can provide in-service to meet the 2015 requirement. However, discussions with manufacturers, brokers and owners are

ongoing to determine the delivery times, operating experiences, the extent of modifications required, and the facilities required to connect to the Island Interconnected System.

5. **Initiate the supply of a new 60MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart functionality.** All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by 2015.
6. **Conservation and demand management initiatives, with the focus on demand management**. Work is being conducted to assess customer end use options with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.

NEWFOUNDLAND AND LABRADOR HYDRO

Generation and Reserve Planning

March 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 3
2 REVIEW PROCESS 4
3 BACKGROUND 6
4 VENTYX REVIEW 14
5 KEY FINDINGS AND RECOMMENDATIONS 20
ACRONYMS 22

Appendices:

Appendix 1 Ventyx, Inc. Report, 2014 Newfoundland and Labrador Hydro Planning Process Review

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included investigation of the rotating outages that occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014.

This report details the findings of both internal and independent reviews of Hydro's generation and reserve planning processes. Hydro completed its own review and also commissioned Ventyx, an ABB company and leading supplier of enterprise software and services for asset intensive industries, to provide independent feedback and insight.

Both reviews found that generation and reserve planning processes were not contributing factors to the supply disruptions and rotating outages of January 2-8, 2014. Ventyx concluded that it had; "not found any evidence that either the generation-planning process or the load-forecasting process have contributed to the events of January." However, the reviews do recommend minor improvement.

Hydro's capacity and energy criterion are comparable with those of other utilities, differing only where appropriate, as Hydro's grid is not interconnected to North America at this time. Moving to a more stringent reliability criterion would require significantly more investment and therefore higher electricity rates. The generation planning modelling, the computer software system Strategist, as well as the values selected for the variables and the assumptions made in the modelling, are reasonable and appropriate.

Recommendations from the reviews are as follows:

GRP 1: Hydro should continue with its generation planning reserve criterion.

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

GRP 2: After interconnection in 2017, Hydro should revisit both its generation planning reserve criterion and its modeling of external markets.

GRP 3: Since Holyrood is scheduled to be retired in the next 4 to 5 years, Hydro should model its Equivalent Forced Outage Rate (EFOR) close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) Hydro should continue its practice of modeling with a more conservative estimate of EFOR for the units.

GRP 4: Hydro should compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the Loss of Load Hours (LOLH) criteria of 2.8 hours per year.

GRP 5: Hydro should develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.

Hydro has accepted these recommendations and they will be considered in the preparation of the Capital Budget Application currently being prepared to address the forecasted 2015 capacity deficit described below.

1 INTRODUCTION

Hydro has completed an internal review of the supply disruptions on the Island Interconnected[2] System (System) during January 2014, with a view to improving its performance in meeting its mandate to provide least-cost, reliable power for Newfoundland and Labrador.

This report focuses on whether decisions made in Hydro's generation and reserve planning played a role in the capacity shortfalls experienced in January 2014. Included in the review are all generation and reserve planning criteria and processes used to predict when there will be a shortfall in energy on the System and, consequently, what generation sources should be added and when.

On December 14, 2013, Hydro supplied a record-high System demand of 1,501 megawatts (MW) (the Island peak served by both Hydro and non-Hydro generation was 1,663 MW). Prior to that date, the record was 1,405 MW, met in 2004. Due to persistently low temperatures and system operating factors, demand remained high for the next several weeks. As several major generating plants were unavailable or de-rated, Hydro implemented its Generation Loading Generation Shortage Protocol (System Operating Instruction T-001) several times.

On January 2, 2014, the system forecast exceeded the available supply, and all steps of the Generation Loading Generation Shortage protocol were implemented – the last of which was to request Newfoundland Power to shed load by feeder interruptions, at the same time as Hydro shed load by feeder interruptions in its service area. Further outages occurred as a result of equipment failures on January 4 and 5, 2014.

[2] In this context Interconnected means those parts of the island serviced from the grid (i.e. excluding the isolated communities using diesel power), not interconnection to North America.
The Interconnected Island System includes generation by Newfoundland Power and Kruger.

2 REVIEW PROCESS

2.1 Internal Review

During, and immediately following the supply disruptions, Hydro personnel responsible for generation and reserve planning reviewed Hydro's processes and their inputs. From a planning perspective, the main issue for consideration was whether there was adequate capacity and reserve available on the System in December 2013 and January 2014. Hydro's review focused on three areas: the planning criteria; the planning processes; and the inputs to the processes to ensure they accurately represent Hydro's system.

Hydro uses the Strategist Model for generation planning. Strategist is a computer software system, developed by Ventyx, Inc., (Ventyx), which supports electric utility decision analysis and corporate strategic planning. More detail is available in the Ventyx report, included in Appendix 1. One of the main variables that influence the timing of new generation is the forced outage rates or availability of the existing generation. Selection of these rates for older equipment and significantly refurbished equipment is complex. The review considered the assumptions made in the current planning process, and also how those assumptions should change once planned changes are made to the system, including the refurbishments of Hydro's gas turbines, and interconnections to Labrador and Nova Scotia.

2.2 Prior Reviews

In recent years, Hydro's planning processes have been reviewed as part of several comprehensive reviews of the Muskrat Falls Project:

- In 2011, Navigant Consulting Ltd undertook a document review of Nalcor's planning studies;
- In 2011, the Public Utilities Board (PUB) commissioned Manitoba Hydro International Ltd. (MHI) to review the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects; and

- In 2012, the Government of Newfoundland and Labrador retained MHI to provide an independent assessment of the two generation supply options as prepared by Nalcor Energy.

2.3 Independent Review

The internal review process highlighted several areas where Hydro staff felt the opinions of outside expertise would be valuable. Hydro determined that an independent, external, review was the best way to evaluate its generation and reserve planning processes.

Hydro commissioned Ventyx, an ABB company and leading supplier of enterprise software and services for asset intensive industries, to perform an independent assessment on Hydro's generation planning and load forecasting processes.

The focus of this work was to provide a review of both the generation planning processes that form the basis of Hydro's strategic plans and forecasts and a review of Hydro's long-term (planning) and medium-term (operating) load forecasting. The work was broken into four tasks:

- Task 1: Planning and Forecast Process Review - examination of prior independent reviews of Hydro's practices and comparison to standard practices in planning and forecasting.
- Task 2: Generation Planning Criteria - review of the overall planning process and assumptions used by Hydro to develop its current long-range, and strategic forward-looking plans and commentary on the processes and criteria including recommendations for improvements.
- Task 3: Load Forecasting Process - review of the process used by Hydro to develop its long-range load forecast and medium-term operational forecasts, as well as commentary on the processes, including recommendations for improvements.

- Task 4: Strategist Model Review[3] - review of the Strategist Model assumptions used by Hydro to develop its long-range and strategic forward-looking plans and commentary on the processes and criteria including recommendations for improvements. Ventyx reviewed the current database and commented on its appropriateness and how it is being used.

3 BACKGROUND

3.1 Responsibilities

Generation and reserve planning are the responsibility of the System Planning department within Hydro's System Operation and Planning Division.

3.2 Planning Criteria

Hydro's System Planning group has established criteria related to the appropriate reliability for the System at the generation level, which sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the System to ensure an adequate supply for firm demand. However, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities, the following have been adopted:

- Capacity: The System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year. LOLH is a probabilistic assessment of the level of un-served load at time of peak, due to insufficient generation.
- Energy: The System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability. Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows, occurring within the historical record. Firm capability for the thermal resources (Holyrood Generation) is based on energy capability adjusted for maintenance and forced outages.

[3] Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. More detail is available in the Ventyx report, included in Appendix A.

These criteria have been in use by Hydro for many years and represent a balance between cost and reliability. They are consistent with established industry standards and practices.

It is predominantly the criteria for capacity which requires review at this time, because the conditions in January 2014 were affected by constraints on capacity, not energy, i.e. there was plenty of energy in storage on the system, but insufficient equipment available to generate power and meet the peak loads. The sources of firm and non-firm generation currently on the System are listed in Table 1.

Table 1: Island Interconnected System Capacity.

Island Interconnected System Capacity (MW)

		Firm (Dependable)	Additional	Total
Newfoundland and Labrador Hydro				
Owned	Hydroelectric	927.3	-	927.3
Owned	Holyrood	465.5	-	465.5
Owned	Gas Turbine	100.0	-	100.0
Owned	Diesel	14.7	-	14.7
	Total Owned	1,507.5	-	1,507.5
Purchased	Hydroelectric	78.0	31.8	109.8
Purchased	Co-Generation	8.0	7.0	15.0
Purchased	Wind	-	54.0	54.0
	Total Purchased	86.0	92.8	178.8
Total NLH System		1,593.5	92.8	1,686.3
Customer Owned				
Corner Brook Pulp and Paper	Hydroelectric	99.1	22.3	121.4
Newfoundland Power	Hydroelectric	78.7	18.2	96.9
Newfoundland Power	Gas Turbine	36.5	-	36.5
Newfoundland Power	Diesel	5.0	-	5.0
	Total Customer Owned	219.3	40.5	259.8
Total Island Interconnected System		**1,812.8**	**133.3**	**1,946.1**

Hydro's generation source additions criteria have been in use for more than 35 years and in that period have been reviewed several times and found to provide a good balance of reliability and cost. It is not possible to design a 100% reliable system. All equipment has some possibility

of failure. In a regulated energy environment, the level of investment into reliability is limited – moving to a more stringent reliability criterion would require significantly more investment and therefore higher electricity rates.

Initially, Hydro used a Loss of Load Probability (LOLP) criteria established at 0.2 days per year, or one day in five years, however, when Hydro replaced its original generation planning software in 1997, it was necessary to switch to a LOLH criterion. Benchmarking established that a LOLH of 2.8 hours per year was approximately equivalent to a LOLP of 0.2 days per year, for Hydro's system. From that point, Hydro established the capacity criterion that the System should have sufficient generating capacity to satisfy an LOLH target of not more than 2.8 hours per year. This does not mean customers can expect to lose generation for 2.8 hours each year, rather than over the long-term, system conditions may lead to an average loss of 2.8 hours per year in the period leading up to the next capacity addition. The capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America because of the non-interconnected status of the island's electric utility system. In the isolated island system there is no ready market for acquiring additional capacity should a shortage occur; reserve can only be increased by the installation of additional and expensive generating equipment. Hydro's criterion is based on the premise that the cost of providing a higher reliability level is in excess of the benefits to be derived.

When Hydro connects to the North American grid there will be a step change in reliability, as the interconnection will provide access to markets for reserve and reliability. At that time, Hydro will reconsider its criteria and bring them into alignment with other North American utilities.

3.3 Operating Reserves

From an operational perspective, Hydro manages generation resource availability on the System and schedules generating units out of service for planned maintenance in order to meet a (n-1) system contingency reserve criterion. In this manner, sufficient reserves are planned to

be available to meet the System load under a contingency of the largest (MW rating) available generating unit becoming unavailable. Hydro does not rely on capacity from wind and other non-dispatchable resources to provide reserve. The current level of non-dispatchable generation has not affected Hydro's ability to meet its peak load. Hydro's generation planning assessments take into account this non-dispatchable nature, and under most operating conditions, there is more than enough firm dispatchable generation available to meet peak loads. The non-dispatchable generation, when available, increases the level of generation potentially available as reserve.

Following the (n-1) criterion requires that Hydro not allow any extended planned maintenance to be scheduled during the winter period. However, if the short-term load forecast permits, Hydro may take the opportunity to schedule a short-duration generating unit outage to address running or corrective maintenance issues.

3.4 Hydro's Generation and Reserve Planning Process

Hydro uses Ventyx's Strategist Model software to analyse and plan the generation requirements of the System. Strategist Model is an integrated strategic planning computer program that allows modeling of the current and future electric power system and which performs, among other functions, generation system reliability analysis, production costing simulation, and generation expansion planning analysis. It is the industry standard for generation planning and Hydro has been using the Strategist Model (or the versions of the software that preceded it) for many years. Inputs to the model include load-forecast information, information reflecting the characteristics of the hydroelectric and thermal generation on the system, lifecycle information and financial data.

The current expansion plan is based on the 2012 Island Planning Load Forecast (PLF) as prepared by the Market Analysis section of the System Planning department. Hydro's load forecasting and its potential role in the January supply disruptions is the subject of a separate report (Load Forecasting).

In addition to the Muskrat Falls project, the portfolio used in this analysis was:

- Small hydro developments;
- 50 MW Combustion Turbine (CT);
- 170 MW Combined Cycle Combustion Turbine (CCCT);
- Wind farm replacement hydro-constructed; and
- Holyrood environmental improvements.

All generation production units in the model have an associated forced-outage rate, which leads to the unavailability of a generating unit for a set time. The forced outage rates used in this analysis are based on Hydro's operations experience and/or industry norms from the Canadian Electricity Association.

Currently, no cost of carbon atmospheric emissions has been included in the analyses because of uncertainties regarding the timing, scope, and design associated with possible future regulatory initiatives in this regard. Demand management initiatives are not explicitly included in Hydro's Strategist Model. Energy efficiency is integrated into Hydro's load forecast through the use of an efficiency trend variable. The success associated with utility-sponsored energy efficiency remains modest and is taken as a subset of efficiency trends in the load forecast process.

Generation planning is an iterative process. An initial generation expansion analysis is carried out using a load forecast developed from preliminary rates, based on recent load forecasts, and current fuel costs. The output from the least-cost generation expansion plan is fed into the Hydro rates models. The rates that are generated in that model are fed back into the forecast model and the iterative process continues until the timing and choice of generation expansion options remains stable from one iteration to the next. The least-cost generation plan is the one with the lowest Cumulative Present Worth (CPW), which is the present value of all incremental utility capital and operating costs incurred by Hydro to reliably meet a specific load forecast given a prescribed set of reliability criteria. The outcome of the generation planning analysis is

the alternative supply future with the lowest CPW, which will be recommended by Hydro and is consistent with its mandate for least-cost electrical service.

Hydro is confident the selection of the Strategist Model, and the way it represents the island system overall, is reasonable. This has been confirmed by several external reviews over the last several years in connection to the Muskrat Falls project. One aspect, in particular, where Hydro determined that outside advice would be helpful, was forced outage rates/availability of existing thermal equipment used in the model. Ventyx's findings in this regard are discussed in Section 4.2. Strategist Model simulations to date would not have modelled as much of Hydro's generating equipment being forced out of service as occurred in January 2014. A summary of the forced outage rates, used in the current Strategist Model, is provided in Table 2. These values were derived in 2006 and have been reviewed annually to confirm they are still reasonable.

Table 2: Strategist Forced Outage Rates (2012)

Unit/Class of Units	Forced Outage Rate, %
Existing NLH Hydro Units	0.90
New Hydro	0.90
Gas Turbine	10.62
Holyrood	9.64
Standby Diesel	1.18
New CCCT	5.0
Labrador Island Link	0.89
NP Hydro Generation	3.19
DLP Hydro Generation	3.19
Exploits Generation	2.26

3.5 Current Generation and Reserve Plan

The most recent Hydro constructed increase in capacity on the System was the Granite Canal Hydroelectric Project, at 40 MW, in 2003. Since then, capacity has been added to the system by power purchases from the two wind farms at St. Lawrence and Fermeuse (27 MW each). However, energy from wind is non-dispatchable so the full capacity of these projects cannot be relied upon at peak times (the Strategist Models assume approximately 40% of the capacity is available at peak times).

Strategist Model results in 2008 projected an energy deficit to occur in 2012. This deficit moved out further into the future with subsequent Strategist Model analyses because of a reduction of load associated with the decline of paper production in the province. Residential and general service loads continued to grow, but the decline in industrial load meant that no new generation was required to meet the growing load. In addition, the construction date of the Vale processing facility at Long Harbour has been delayed several times, and that industrial load has yet to be added to the system. The most recent analysis in 2012 shows a capacity deficit occurring in 2015 and recommended the addition of a 50 MW combustion turbine by December 2015 as the least-cost solution to mitigate the anticipated deficit. The 2012 recommendation recognized that during early 2015, prior to the installation of the combustion turbine, the LOLH of the system would be greater than the 2.8 hour threshold. The short-term LOLH deficit was not inconsistent with some of Hydro's previous generation expansion decisions.

In the meantime, Hydro has been reconsidering the short-term LOLH deficit. There is a review ongoing to ensure the combustion turbine is still the best option given the system disruptions in January 2014, and to identify means to fully mitigate the 2015 deficit. Other options under consideration include the following (combination of two or more options may be developed to meet the potential deficit):

- Retain the diesel facility being installed at Holyrood for black start capability (presently under a lease-to-own arrangement for commissioning in March 2014).

Once installed, 10 MW can immediately be supplied to the system on a sustained basis. With some modifications, the facility can be made to deliver the full 14.6 MW peaking capacity to the grid;

- Enter into interruptible contracts with large Industrial Customers. Discussions with Industrial Customers (Corner Brook Pulp and Paper, Vale, and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored;
- Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and black start at Holyrood. Preliminary discussions indicate these options may be able to meet the 2015 requirement. However, discussions with manufacturers, brokers, and owners are ongoing to determine the delivery times, operating experiences, the extent of modifications, and facilities required to connect to the Island Interconnected System;
- Initiate the supply of a new combustion turbine for the Holyrood site to supply deficit and black start functionality. All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by 2015/2016; and
- Continue and enhance conservation and demand management initiatives, with the focus on demand management. Work is being conducted to assess customer end-use options, with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.

The project or projects that will be implemented for the winter of 2015 are currently forecasted to be the last new island generation that will be required prior to the commissioning of Muskrat Falls and the Labrador Island Link in late 2017 or early 2018. Muskrat Falls and the interconnection with the North American grid will greatly enhance Hydro's capacity and reserve. It will be many years before Hydro has to again consider adding capacity to the System.

4 VENTYX REVIEW

Hydro retained the services of Ventyx to provide an independent review of both the generation planning processes, which form the basis of Hydro's strategic plans and forecast, and Hydro's long and medium term load forecasting. The Ventyx report is included as Appendix 1 of this report.

In relation to generation planning processes, Ventyx was asked to:

- Review the overall planning process and assumptions used by Hydro in developing its current long-range and strategic forward looking plans;
- Provide commentary on existing planning processes and criteria and make recommendations as to specific improvements as required;
- Review the Strategist Model assumptions used by Hydro in developing its current long-range and strategic forward looking plans; and
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required.

Ventyx's review of the generation planning process included an examination of Nalcor Energy's documentation relating to the Muskrat Falls project, including the filings with the PUB and the various reviews, and Hydro's responses to Requests for Information from the PUB about the events this winter. Ventyx also conducted one-on-one interviews with Hydro staff.

4.1 LOLH Criterion

Ventyx reviewed the results of Hydro's most recent capital planning study (2012) and the Strategist Model results, as shown in Table 3. Hydro currently uses an LOLH criteria of 2.80 hours per year.

Table 3: Strategist Model LOLH Results

Year	Loss of Load Hours	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

Ventyx indicates that the standard industry practice is to apply a LOLP of 0.1 days per year, or "one day in ten years." However, it should be noted that the 0.1 days per year standard applies to interconnected utilities. For true "stand alone" utilities, the cost to achieve a 0.1 days per year standard is often cost prohibitive. In 1977, Hydro conducted a thorough analysis of system reserves and as a result recommended 0.2 days per year, or "one day in five years." Hydro justified the 0.2 days per year over 0.1 days per year, based on the economics of meeting the more stringent requirement. For impact comparison, the incremental present value revenue requirements necessary to move from a reliability index of 1.0 days per year to 0.2 days per year was approximately $24 billion and the incremental present value revenue requirements necessary to move from a reliability index of 0.2 days per year to 0.1 days per year was approximately $17 billion. Simply stated, the cost to move from a reliability index of 0.2 days per year to 0.1 days per year was 71% of the cost to move from a reliability index of 1.0 days per year to 0.2 days per year. Ventyx concluded Hydro was justified in its decision to adopt a reliability index of 0.2 days per year at that time. For the purposes of Hydro's planning criteria, it was necessary to translate the LOLP, which is a based on the peak load of each of the 365 days, to an hourly equivalent LOLH. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system.

Ventyx concluded that, from a generation mix perspective, Hydro's system is "roughly" the same as it was in 1977 and, therefore, there is no reason to reassess its reliability standard of 0.2 days per year. The primary drivers which would prompt a utility to reassess its reliability standard include: resource mix, plant reliability and maintenance, and interconnections. In 1977, Hydro's system was 63% hydro and 37% thermal. Today, Hydro's system is 67% hydro and 33% thermal. In terms of plant reliability, the capacity weighted average effective forced outage rate in 1977 was 3.74% versus 4.05% today. From a system reliability standpoint, Hydro's current system is virtually equivalent to the system as it existed in 1977. However, Hydro expects to complete the Maritime Link to Nova Scotia in 2017. When Hydro interconnects with the North American grid, it should reassess its reliability standards in light of its access to new markets.

Ventyx concluded that Hydro's generation planning reserve criterion of a LOLH of 2.8 hours per year is prudent and consistent with standard industry practices. Hydro has consistently used the generation planning reserve criterion as an input to its capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system. Ventyx recommends that Hydro should continue with its generation planning reserve criterion.

Ventyx recommends that after completion of Hydro's interconnection with Nova Scotia and Muskrat Falls, Hydro should revisit its generation planning reserve criterion of 2.8 hours per year in light of the reliability benefits offered by the access to North American markets.

4.2 Forced Outage Rates

Ventyx reviewed Hydro's assumptions for forced-outage rates and concluded that they are consistent with industry standards.

For the purposes of this discussion, Ventyx focused on Hydro's largest aggregate resources that drive overall system reliability; Holyrood at 465.5 MW; and Bay d'Espoir at 592 MW. These two

plants comprise 1057.5 MW and represent 54.3% of Hydro's installed capacity. Hydro's CTs and other Hydro units have less impact upon reliability. The EFOR used in Hydro's generation planning and serving as an input to the Strategist Model is derived from the Canadian Electricity Association's (CEA) 2004 Report and is based on the period from January 1, 2000 through December 31, 2004. Ventyx compared these rates to current CEA data covering the period from January 1, 2008 through December 31, 2012. Table 4 lists the five year CEA capacity weighted average EFOR based on the most recent CEA data and the EFOR assumptions in Hydro's Strategist database.

Table 4: Hydro EFOR Values

Unit Name	NLH Strategist Assumptions	NLH Average 2008 - 2012
Holyrood	9.64%	10.69%
Bay d'Espoir	0.91%	0.41%

Hydro's overall assumptions are consistent with industry standards. While there might be some rationalization that a significant increased investment might improve Holyrood performance further, given the time until the infeed is realized, the age of the units and outage availability it appears that the time required to gain results will be longer than the relatively short timeframe to interconnection with the North American Grid.

Ventyx recommends that, since Holyrood is scheduled to be retired in the next 4 to 5 years, Hydro should model its EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) Hydro should continue its practice of modeling with a more conservative estimate of EFOR for the units.

Ventyx also suggested that Hydro consider tying outage rates to typical maintenance cycles.

There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower outage rates. However, it should be noted that a five-year rolling average will also account for these cycles. By ramping up the EFOR in the years leading up to a major maintenance cycle, Hydro would have a better picture of the near term, one to five year, view of system reliability. Alternatively, Hydro could also compute a break-even EFOR for each class of its generation. For example for the Holyrood Plant, the maximum EFOR would be between 9.7% and 9.8%. At this point, the unit's contribution to LOLH would exceed 2.80 hours per year.

4.3 Scenario Planning

Ventyx compared Hydro's planning process as a whole to the Ventyx Integrated Resource Planning (IRP) process as a measure of Hydro's conformance to accepted utilities practices and procedures. Ventyx's process is demonstrated in Figure 1.



Figure 1: Ventyx Integrated Resource Planning Process

A description of each step is included in the Ventyx report in Appendix 1.

Ventyx found that Hydro's resource planning processes conform to the basic structure laid out in the Ventyx IRP process. All areas in Hydro's process were deemed as being acceptable, but some suggestions for improvement were offered in the areas of alternative development and risk assessment.

In the development of alternatives, it was found that although existing demand-side programs were included in the development of the resource plan, there was a lack of additional demand-side alternatives. The use of demand-side alternative will not be effective to solve short term issues, but Ventyx recommends that the use of demand-side as alternatives be further explored post 2017, while there is ample capacity to cover requirements.

In reviewing the documents, Ventyx noted that there is no formal risk assessment stage included in the planning process. Sensitivities were performed and included in the original documentation but focused mostly on commodity and costing assumptions. Ventyx recommended that the future scenario and sensitivity processes be expanded to include the impacts of extreme loads.

Ventyx recommended that Hydro:

- Begin to explore the use of demand-side programs as a long-term alternative to future supply side alternatives post 2017; and
- Expand the risk analysis sensitivities to include several levels of load forecast uncertainty.

4.4 Generation Outlook 2014 to 2017

Ventyx reviewed Hydro's current plans with respect to new generation to meet the deficiency in 2015. They consider the combustion turbine under consideration or other combustion options to be key resources for Hydro's near-term reliability. The current plan has the

combustion turbine commissioned in December of 2015. Without this unit, Ventyx calculates that Hydro would face LOLH reliability indices of 4.57 hours per year in 2015, 6.02 hours per year in 2016, and 5.71 hours per year in 2017 if the Labrador In-Feed is in service in December 2017.

Statistically, demand reduction is a slightly better alternative to generation additions, due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 deficiency of 3.98 hours per year to 2.80 hours per year, Hydro would need to secure approximately 40 MW of either interruptible contracts with existing customers, or conservation and demand management initiatives, in addition to the nominal combustion turbine assumed. If that is not practical, then the difference can be made up from the remaining generation capacity options.

5 KEY FINDINGS AND RECOMMENDATIONS

This section describes the findings of Hydro's internal review and the independent reviews of Hydro's generation and reserve planning process.

5.1 Internal Review

The initial Hydro review concluded that the assumptions related to forced-outage rates in the Strategist Model were most likely to influence the results of the generation and reserve planning. Hydro determined that an independent, external review was the best way to evaluate the process.

5.2 Prior Independent Reviews

The 2011 Navigant Consulting Ltd review of Nalcor Energy's Gate 2 decision regarding the Muskrat Falls Project concluded that, "Nalcor's use of the Strategist Model in developing the two generation expansion alternatives is consistent with generally accepted utility practice." Available documentation for reliability assessment performed by Nalcor Energy was reviewed

by MHI in 2012. It concluded that the adequacy criteria of 2.8 hours per year of LOLH for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities.

5.3 Ventyx Review

The following table outlines the recommendations from the independent review by Ventyx.

Table 4: Ventyx Recommendations

Recommendation		Status
GRP1	Hydro should continue with its generation planning reserve criterion	No change required
GRP2	After interconnection in 2017, Hydro should revisit its generation-planning reserve criterion and its modelling of external markets.	In Hydro plans for post 2017
GRP3	Since Holyrood is scheduled to be retired in the next 4 to 5 years, Hydro should model its Equivalent Forced Outage Rate (EFOR) close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) Hydro should continue its practice of modeling with a more conservative estimate of EFOR for the units.	No change required
GRP4	Hydro should compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the LOLH criteria of 2.8 hours per year.	To be incorporated in capital submission addressing 2015 capacity deficit
GRP5	Hydro should develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.	To be incorporated in capital submission addressing 2015 capacity deficit

ACRONYMS

CEA	-	Canadian Electricity Association
CDM	-	Conservation and Demand Management
CT	-	Combustion Turbine
CPW	-	Cumulative Present Worth
CCCT	-	Combined Cycle Combustion Turbines
DAFOR		De-rated Adjusted Forced Outage Rate
EFOR	-	Equivalent Forced Outage Rate
LOLH	-	Loss of Load Hours
LOLP	-	Loss of Load Probability
MW	-	Megawatts
n-1	-	measure of redundancy
O&M	-	Operation and Maintenance
PLF	-	Planning Load Forecast
PPA	-	Power Purchase Agreements
PETS		Project Execution and Technical Services
PUB	-	Board of Commissioners of Public Utilities

Appendices

2014 Newfoundland and Labrador Hydro Planning Process Review

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Prepared for:

Newfoundland and Labrador Hydro

Prepared by:

Ventyx, An ABB Company
400 Perimeter Center Terrace, Suite 500
Atlanta, GA 30346
www.ventyx.com

Contact:

Charles Adkins, Vice President
(912) 228-4278

VENTYX
AN ABB COMPANY

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Contents

Executive Summary 3
Study Objective 6
VENTYX 7
Strategist® 8
Incident Description 8
Issues within Scope 9
Load Forecasting 9
Generation Planning Criteria 9
Scenario/Sensitivity Planning 10
Load Forecasting 10
Background 10
Conclusions 12
Recommendations 16
Generation Planning Reserve Criterion 17
Background 17
Conclusion 22
Recommendation 22
Generation Forced Outage Rates 23
Background 23
Conclusion 25
Recommendation 25
Scenario Planning 26
Background 26
Conclusions 28
Recommendations 29
Generation Outlook 2014 to 2017 29
Summary of Recommendations 31
Appendices 34

Executive Summary

Over the weekend of January 3rd, 2014, Newfoundland and Labrador Hydro ("NLH") experienced a series of largely unrelated events that led to four days of rolling blackouts. On January 17th, The Board of Commissioners of Public Utilities ("the Board") initiated a process to gather information from NLH and Newfoundland Power ("NP") with a focus on whether load requirements on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecasts, and NLH's long term (20 year) and medium-term (5 year) load forecasting. Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

In the near term, NLH's current resource expansion plan is within the reliability criteria in all calendar years except 2015.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date or an equivalent resource is not implemented the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[1] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 50 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, in addition to the nominal combustion turbine assumed, NLH would need to secure approximately 40 MW of either interruptible contracts with existing

[1] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

customers or conservation and demand management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[2] and 0.91%[3], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets, this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well, there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The current projected plan is based upon a normalized weather forecast. Weather normalization is an industry standard process that adjusts actual peak outcomes to what would have happened under normal weather conditions. Beyond the next seven days weather forecasting is complex and not always accurate. Therefore, NLH should look at a severe

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[2] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[3] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

weather sensitivity to gauge how the system might respond to greater than expected demand particularly in making near term investment decisions.

Specific process recommendations:

- Load Forecasting
    - Continued surveying of the customer base in terms of both average energy use and saturations of heating.
    - Develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.
- Generation Planning
    - NLH should continue forward with its generation planning reserve criterion.
    - After NLH's interconnections are established in 2017, NLH should revisit both their generation planning reserve criterion and their modeling of external markets.
    - NLH should continue forward with its practice of maintaining a more conservative estimate of EFOR for the units.
    - Compute a break-even EFOR for each class of its generation to determine the point at which a generator's EFOR will result in the system exceeding the LOLH criteria of 2.8 hours/year
- Develop a formal risk analysis process that utilizes scenarios and sensitivities to test the robustness of resource plans.

Study Objective

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts. On January 17th, The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts.

NLH retained the services of Ventyx, Inc. to provide a review of both the generation planning processes that form the basis of NLH's strategic plans and forecast and NLH's long term (20 year) and medium term load (5 year) forecasting. Specifically, Ventyx was asked to review:

- The overall planning process and assumptions used by NLH in developing their current long range and strategic forward looking plans;
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required;
- Review of the process and assumptions used by NLH in developing their current long range load forecast and shorter term operational forecasts;
- Provide commentary on the load forecasting processes, criteria and assumptions and make recommendations as to specific improvements as required;
- Review of the Strategist model assumptions used by NLH in developing their current long range and strategic forward looking plans; and
- Provide commentary on the existing planning processes and criteria and make recommendations as to specific improvements as required.

VENTYX

Ventyx brings a dedicated team of expert consultants that combines experience, industry knowledge, market knowledge, and software expertise to support consulting engagements. Ventyx provides professional consulting services to energy companies in the areas of integrated resource planning, market price forecasting, resource evaluation and planning, trading and settlement, and electric transmission economic analysis. Ventyx has worked with NLH both in support of Ventyx's Strategist software and .with analytical modeling to evaluate the economic and system impacts of the Muskrat Falls hydro project as well as the Maritime Link project with Nova Scotia. Ventyx conducted multiple analytical modeling studies of this pair of projects over a three year period that also included analytical modeling covering the provinces of New Brunswick, Prince Edward Island, Nova Scotia and Newfoundland Labrador as well as surrounding market areas in Quebec, New York and New England for the Atlantic Energy Gateway project

Strategist®

Strategist is a computer software system, developed by Ventyx, LLC, which supports electric utility decision analysis and corporate strategic planning. Strategist is available as a demand-side management analysis system, as a least cost resource optimization system, as a comprehensive planning tool for quick evaluation of hundreds of alternatives, as a finance and rates planning system and as selected application modules that complement planning capabilities already in place. Strategist's advantage as an integrated planning system is its strength in all functional areas of utility planning. Strategist allows analysts to address all aspects of an integrated planning study at the depth and accuracy level required for informed decisions. Hourly chronological load patterns are recognized. Production cost simulations are comprehensive, yet fast. The production costing procedure consists of two stages. In the first stage, the operation of hydro generation and sale and purchase transactions are simulated. The pumped storage facilities, economic energy interchange, and direct load control programs are then economically dispatched based on the marginal cost curve of the system. The result of this first stage is the remaining annual or seasonal thermal load duration curve. In the second stage, the expected operation of the thermal generating units within the year is simulated by a probabilistic technique. The results are the production costs and system reliability indices. The PROVIEW (PRV) Module is a resource planning model which determines the least-cost balanced demand and supply plan for a utility system under prescribed sets of constraints and assumptions. PROVIEW incorporates a wide variety of expansion planning parameters including alternative technologies, unit conversions, cogenerators, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, emissions trading and environmental compliance options in order to develop a coordinated integrated plan which would be best suited for the utility. The PROVIEW module works in concert with the GAF Module to simulate the operation of a utility system. PROVIEW's optimization logic then determines the cost and reliability effects of adding resources to the system, or modifying the load through demand-side management (DSM) or marketing programs.

Incident Description

Over the weekend of January 3rd, 2014, NLH experienced a series of events that led to four days of rolling blackouts.

Issues within Scope

The Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. Specific issues to be addressed include: asset readiness, maintenance practices, load forecasting, planning criteria and assumptions, equipment performance and reliability, emergency preparedness, system response, and restoration efforts. The scope of this report is focused on the load forecasting and planning criteria and assumptions. With the NLH system setting record peaks during this unfortunate event, the question of load forecast accuracy is raised. The primary planning criteria that are related to an event of this nature are planning reserves and generation forced outage rates. Finally, the issue of load forecasting and planning criteria is enveloped in the overall process of sensitivity analysis to address the inherent risk of the NLH portfolio.

Load Forecasting

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. As the load forecasting process passes from the short term to longer term, the reliability of forecasted weather drops dramatically. Longer term forecasts are typically represented as annual peaks and energies, with monthly detail, to support budgeting planning. Longer term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

Generation Planning Criteria

The generation planning criteria for planning reserves and generation forced outage rates combine to form a prediction of the expected LOLH reliability index. This reliability index forms the foundation of a minimum reliability threshold of 2.8 hours/year. For each year of the NLH planning horizon, the system is designed to maintain sufficient generation planning reserves to ensure the minimum reliability threshold is met. Generation planning reserves are the MW

difference between available capacity and normalized peak demand that are available to meet unforeseen increases in demand, such as extreme load, and unexpected outages of existing capacity. Forecasted trends in LOLH identify whether generation capacity additions are keeping pace with load growth.

Scenario/Sensitivity Planning

Scenario planning is a strategic planning methodology used to identify and assess the inherent risks and benefits of a flexible long term plan. Scenario planning recognizes that many factors may combine in complex ways to create sometimes surprising futures. Scenario planning seeks to identify the causal relationship between factors and demonstrate a plans flexibility to adapt. Scenario planning develops an internally consistent story about the conditions in which the system might be operating in the future that differs from baseline assumptions in sometimes significant ways and usually involves alterations to all of the assumptions at one time. Sensitivity planning varies each of the assumptions either one at a time or in correlated groups to determine how sensitive the results are to changes in the assumptions. These planning techniques are important when there are variables such as weather that can potentially impact the reliability of the system.

Load Forecasting

Background

Load Forecasting is the process of estimating the demand that customers will place on the system. The process for load forecasting is, generally, defined by the time horizon of a specific forecast. Short term forecasts are hourly in nature and cover the time horizon from next hour to seven days to support short term unit commitment and scheduling. Short term forecasts are focused on the most recent historical relationship of weather to load aligned with short term forecasts of weather conditions. The short term forecasts prepared by NLH use a neural network forecasting approach using the Nostradamus modelling software.

A medium term forecast that covers a time horizon of five years is used for budgeting and near-term supply adequacy. The medium term forecasts are a combination of the NP forecast for

their service territory and NLH economic and regression processes for their rural customers and customer input for the industrial loads.

Longer term forecasts cover the time horizons of 20 years and are typically represented as annual peaks and energies, with monthly detail, to support long term generation planning. The long term forecast is performed by NLH using economic and regression techniques to forecast NP, NLH rural loads, and Industrial customer forecasts of their loads. The long term forecasts rely on the historical relationships of weather to load along with seasonal patterns and economic drivers.

The review of the load forecasting process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent, detailed reviews of the project, a review of the responses to the Board of questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP forecasting staff. Since the independent review of the load forecast conducted by Manitoba Hydro International ("MHI") was a detailed review of the assumptions, the review described in this report focused on the methodology and a look at the validity and accuracy of the forecast. Personal interviews were held with the staffs of NLH and NP to ascertain the sequencing and procedures of each company and the interfacing and integration of the individual component forecasts into a single product. Of particular interest was the accuracy of the winter peak as it applies to the incidents described above.

- The interviews with the NP load forecasting staff revealed the medium term forecast of NP service territory energy was performed for Domestic, General Services and Area and street light classes. Although the process was different for each class, the basic process is an average use methodology that applied econometric forecasting techniques to determine average use per consumer that was then applied to a customer growth forecast.
- The medium term peak demand for NP was developed using an average load factor methodology that calculates a 15 year average load factor that is then applied to the medium term energy forecast to determine the NP service territory Winter Peak demand. This is a standard utility practice.
- The NLH long term load forecasting process is a combination of econometric and regression analyses to determine the energy and peak demand for NP and the NLH rural

groups with industrial energy and demand requirements conditioned by individual customer input .

- The long term peak for NP is forecast by NLH using regression analyses that link NP peak demand to weather, domestic electric heat customer growth, general service sales growth and other economic factors. The peak for the NLH rural group is calculated using a long term historical load factor method that is applied to the forecasted energy. The industrial peak is developed through direct input of existing industrial customers. No forecast is made of potential new industries unless it is fairly certain that a change is going to be made either through government action or a committed industrial customer.

NLH uses historical hourly shapes to develop typical 168 hourly week shapes for each month of the year. These typical shapes are applied to each year of the study and are adjusted by the Strategist Load Forecast Adjustment ("LFA") module to meet the data entered for peak and energy from the forecast. NLH has not updated the historical data since 2002 and is scheduled to perform the update in the next 12 months as part of the next generation expansion planning exercise. Since the system has had a fairly stable load factor and since the LFA continuously modifies the shape to meet the forecast this should not impact the results of the studies. This would only be a problem if NLH was evaluating new Conservation and Demand Management ("CDM") or time dependent programs such as time-of-day rates.

NLH has elected to set the study period to 50 years so that it would cover the financing period of the Muskrat Falls project. This is typically performed using either Economic Carrying Charge calculations or infinite end-effects with a shorter study period of twenty years. However, after discussion with NLH planning staff Ventyx determined that the manner in which they performed the extension of the load forecast and other model data was consistent with the Strategist end-effects methodology.

Conclusions

The methodology used by both NP and NLH are consistent with accepted utility practices. It has been noted by another independent review, by MHI, that the process could be improved by

changing to an end-use forecast. It is Ventyx's opinion, based on experience, the complexity and time to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. This is also true since the existing methodology aligns with survey results of the major end-use on the system which is electric space heating.

The econometric methods being used by NLH are prudent and well validated. The regression equations all have statistical coefficients of determination (R^2) that are in the very high range. The R^2 can be interpreted as the percent of variation in the predicted value that is explained by the given variables. Table 1 enumerates the R^2 for each of the equations. The closer an R^2 value is to 100% the better the fit of the equation to the data provided. The R^2 for the regression equations that directly impact the forecast of system peak demand in the long term are included below.

Equation	R^2
NP Domestic Class	
Customer Additions	93.4%
Penetration of Elect. Heating	88.5%
Conversion of Non-Elect Heat	78.9%
NP General Service Class	
Electric Heat Customer Load	99.9%
NLH Rural Domestic Class	
Average Use	98.1%
NLH Rural General Service Class	
Energy	99.6%
NP Peak	99.7%

Table 1 Coefficients of Determination[4]

No attempt was made in this review to verify or validate the actual data used since a previous report was issued by MHI showing a detailed discussion of the data. It is obvious weather has a significant impact on the resulting energy and peak demand forecasts. NLH's forecasting models include weather variables to account for the impacts due to changing weather conditions through the historical period. However, what is missing is an evaluation of the energy and demand impacts due to extreme weather conditions. These extremes should be evaluated using sensitivities and scenario planning techniques.

Figure 1, shows a comparison of the forecasted winter months peaks to the actual peaks for the system for the years 2004 to December 2013. Since 2004 the actual winter peaks have consistently been below the forecasted peaks with the exception of seven months out of forty winter months that the actual has been higher than the forecast. However, since those seven times do not occur in the same month it would suggest that there was some random pattern

[4] Manitoba Hydro International, *MHI-Report-Volume II-Load Forecast* (February 2012)

such as weather that is impacting the actual. A review of the deviations shows that it is largely weather that impacts all the discrepancies As indicated by the red bars, the actuals are consistently less than the forecast because NLH has experienced a period of warmer than normal peak weather conditions over this period. The December 2013 discrepancy was impacted additionally by the "exceptional" loads resulting from unavailable Avalon generation that resulted in higher system demand loads than expected. If a variable such as the number of customers was off it would be impacting the forecast for all winter months in that period.

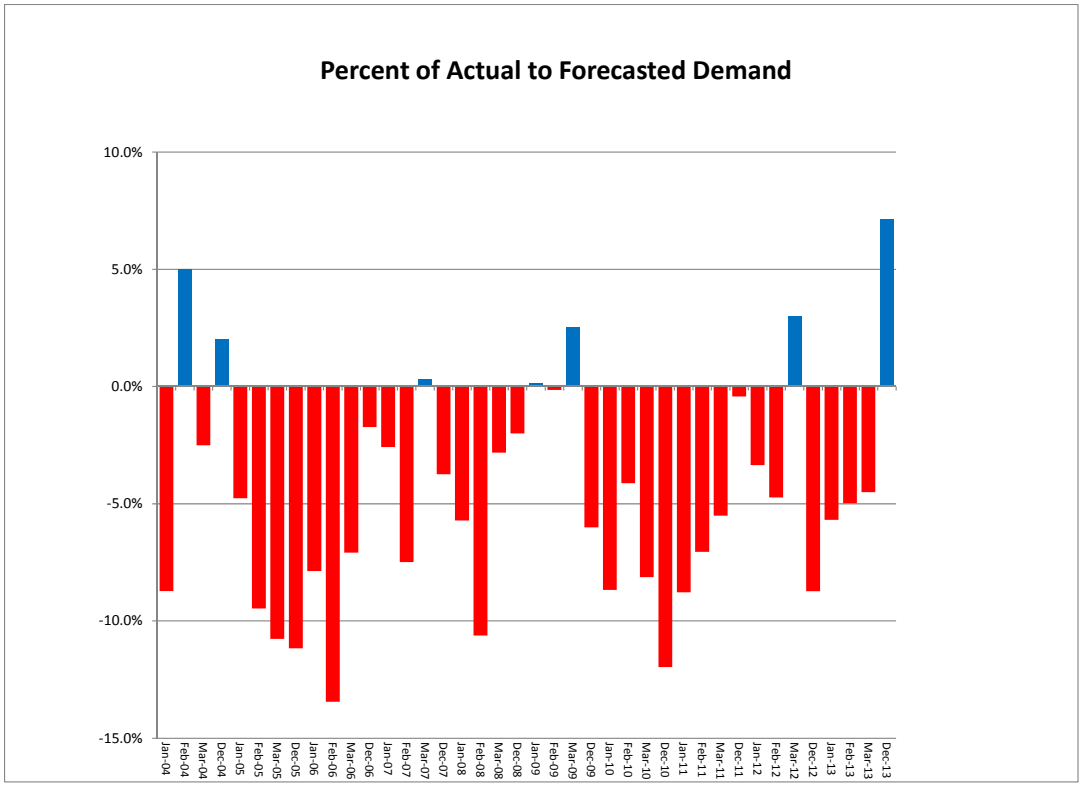


Figure 1[5]

Recommendations

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy

[5] Newfoundland and Labrador Hydro, *PUB-NLH-011* (Newfoundland and Labrador Hydro: Board Response, February 2014)

benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine their models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. Later in the report, Ventyx will discuss using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecasts in both the scenario development and the sensitivity analysis phases.

Generation Planning Reserve Criterion

Background

The purpose of a Generation Planning Reserve Criterion is to establish the minimum reliability threshold for a power system. The reliability of a power system is defined as the probability of providing customers with continuous service of a satisfactory nature. Reliability is one of the primary factors that drive the planning, design, operation, and maintenance of a power system. The most common index for reliability is the Loss of Load Probability ("LOLP") which is "the probability of the system load exceeding the available generating capacity under the assumption that the peak load of each day lasts all day."[6] Through a series of analytical processes the reliability index, LOLP, is translated to a reserve criterion stated in terms of Loss of Load Hours ("LOLH") or a defined reserve margin percentage. In Strategist, Loss of Load Hours is the expected total number of hours a year during which the utility will not be able to serve all of its customers. The percent reserve margin is based on the reserve margin at the time of the annual peak and defined as the amount of installed reserves, in MW, divided by the

[6] J. Endrenyi, *Reliability Modeling in Electric Power Systems* (Ontario Hydro: John Wiley & Sons, 1978), 4

system peak demand, in MW. This reserve criterion serves as an input to capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

NLH's capacity planning reserve criterion for capacity planning is "The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours ("LOLH") expectation target of not more than 2.8 hours per year."[7] The LOLH target is based upon a Loss of Load Probability of 1 day in five years or, more commonly denoted as, 0.2 days per year. In 1977, the NLH System Planning department determined that "The LOLP index to be adopted depends upon the availability of capital. System Planning feels that a .1 days/year is not realistic and would suggest .2 days/year as an optimum value to aim for".[8] The results of NLH's recent 2012 capital planning study, 2012 DCL–PLF IT1–A-0801-_R-105 FE-1 Strategist 4.4.1, are enumerated in Table 2.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

Table 2 Expected Loss of Load Hours

[77] PUB-NLH-008

[8] System Planning Department, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions* (Newfoundland Labrador Hydro: internal memo, May 16, 1977), 19

Previous table is based on the assumption that a new 50 MW CT, is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57 in 2015 and 6.02 in 2016.

NLH is currently considering six options[9] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
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Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[9] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[10] and 0.91%[11], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if the Holyrood units could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

The standard industry practice is to apply a LOLP of 0.1 days/year, or "one day in ten years". However, it should be noted that the 0.1 days/year standard applies to ***interconnected*** utilities. For true "stand alone" utilities, the cost to achieve a 0.1 days/year standard is often cost prohibitive. In 1977, NLH conducted a thorough analysis of system reserves and concluded with the recommendation of 0.2 days/year, or "one day in five years". NLH justified the 0.2

[10] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[11] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

days/year over 0.1 days/year based on the economics of meeting the more stringent requirement. The incremental present value revenue requirements necessary to move from a reliability index of 1.0 days/year to 0.2 days/year was approximately $24 Billion[12]. The incremental present value revenue requirements necessary to move from a reliability index of 0.2 days/year to 0.1 days/year was approximately $17 Billion[13]. Simply stated, the cost to serve the last tenth of the reliability index was 71% of the cost to serve the total of the first eight tenths of the reliability index. NLH was justified in its decision to adopt a reliability index of 0.2 days/year.

From a generation mix perspective, the NLH system is "roughly" the same as it was in 1977; there is no reason to reassess its reliability standard of 0.2 days/year. The primary drivers that would prompt a utility to reassess its reliability standard include: resource mix, plant reliability and maintenance, and interconnections. In 1977, the NLH system was 63% hydro and 37% thermal. Today, the NLH system is 67% hydro and 33% thermal. In terms of plant reliability, the capacity weighted average effective forced outage rate in 1977 was 3.74% versus 4.05% today. From a system reliability standpoint, the NLH system is virtually equivalent to the system in 1977. However, NLH expects to complete the Maritime Link to Nova Scotia in 2017. When NLH interconnects with the North American grid, NLH should reassess its reliability standards in light of their access to new markets.

Loss of Load Probability is a characterization of the adequacy of the generation within a system to serve the load of the system. It is important to note that LOLP does not represent the reliability of the bulk transmission or distribution systems. For the purposes of NLH's planning criteria, it was necessary to translate the LOLP, which is a based on the peak load of each of the 365 days, to an hourly equivalent, LOLH. "When Hydro switched from SYPCO generation

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[12] Ibid, Table V. Grand Total (0.2) 2,896,178 (1977 K$) minus Grand Total (1) 2,872,516 (1977 K$) equals 23,662 (1977 K$).

[13] Ibid. Table V. Grand Total (0.2) 2,912,924 (1977 K$) minus Grand Total (1) 2,896,178 (1977 K$) equals 16,746 (1977 K$). 16,746 is 70.07% of 23,622.

planning software to PROSCREEN II [now called Strategist], it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system."[14]

In 2017, the Maritime Link to Nova Scotia will be completed. Post 2017, NLH will be interconnected with the rest of the North American grid. In addition, there will be a long term sales agreement with Nova Scotia that will provide scheduling flexibility. NLH's current long term planning system does not reflect the reliability benefits of these incremental additions to the NLH portfolio.

Conclusion

NLH's generation planning reserve criterion of a LOLH of 2.8 hours per year is prudent and consistent with standard industry practices. NLH has consistently used the generation planning reserve criterion as an input to their capacity expansion optimization to ensure that all plans selected for comparison meet or exceed the minimum reliability threshold for a power system.

Recommendation

NLH should continue forward with its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. It may be possible that this approach to reserve criterion, if still appropriate may be improved at minimum cost. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to

[14] Newfoundland and Labrador Hydro, *PUB-NLH-056* (Newfoundland and Labrador Hydro: Board Response, February 2014),1

allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Generation Forced Outage Rates

Background

The purpose of generation forced outage rates in generation planning is to represent the probability that a specific unit will not be available for service when required. Generation Planning periodically confirms the resource adequacy of a system through detailed reliability simulations that compare the expected load profiles with specific generating unit forced outage rates and maintenance schedule to determine LOLH values. A typical unit's contribution to resource adequacy is typically a function of the unit's capacity and its equivalent forced outage rate ("EFOR"). NLH uses the convention Derated Adjusted Forced Outage Rate ("DAFOR") which is known as EFOR as used by the North American Electric Reliability Council[15]. For the purposes of this report EFOR and DAFOR have the same meaning. A unit's equivalent forced outage rate is defined according to the following formula:

[15] Roy Billinton, *Reliability Data Requirements, Practices and Recommendations* (Department of Electrical Engineering University of Saskatchewan) page 55.

$$EFOR = \frac{FOH + EFDH}{FOH + SH + Synchronous\ Hrs + Pumping\ Hrs + EFDHRS} \times 100\%$$

Where:

FOH	– Forced Outage Hours
$EFDH$	– Equivalent Forced Derated Hours
SH	– Service Hours
$Synchronous\ Hrs$	– Synchronous Condensing Mode Hours
Pumping Hrs	– All hours pumped storage unit in pumping mode
$EFDHRS$	– Equivalent Forced Derated Hours during Reserve Shutdowns

For the purposes of this discussion, Ventyx focused on NLH's largest aggregate resources that drive overall system reliability, Holyrood, 465.5 MW; and Bay D'Espoir, 592 MW. These two plants comprise 1057.5 MW and represent 54.3% of NLH's installed capacity. The EFOR used in NLH's generation planning and serving as an input to Strategist is derived from the Canadian Electrical Association's ("CEA") 2004 Report and is based on the period from January 1, 2000 through December 31, 2004. Ventyx compared these rates to the current CEA data covering the period from January 1, 2008 through December 31, 2012. NLH's other smaller CT's and Hydro units have less impact upon reliability.

Table 3 lists the five year CEA capacity weighted average EFOR based on the most recent CEA data and the EFOR assumptions in NLH's Strategist database.

Unit Name	NLH Strategist Assumptions	NLH Average 2008 - 2012
Holyrood	9.64%	10.69%
Bay D'Espoir	0.91%	0.41%

Table 3

Conclusion

NLH's overall assumptions are consistent with industry standards. While there might be some rationalization that a significant increased investment might improve Holyrood performance further, given the time until the infeed is realized, the age of the units and outage availability it appears that the time required to gain results will be longer than the relatively short timeframe to interconnection with the North American Grid.

Recommendation

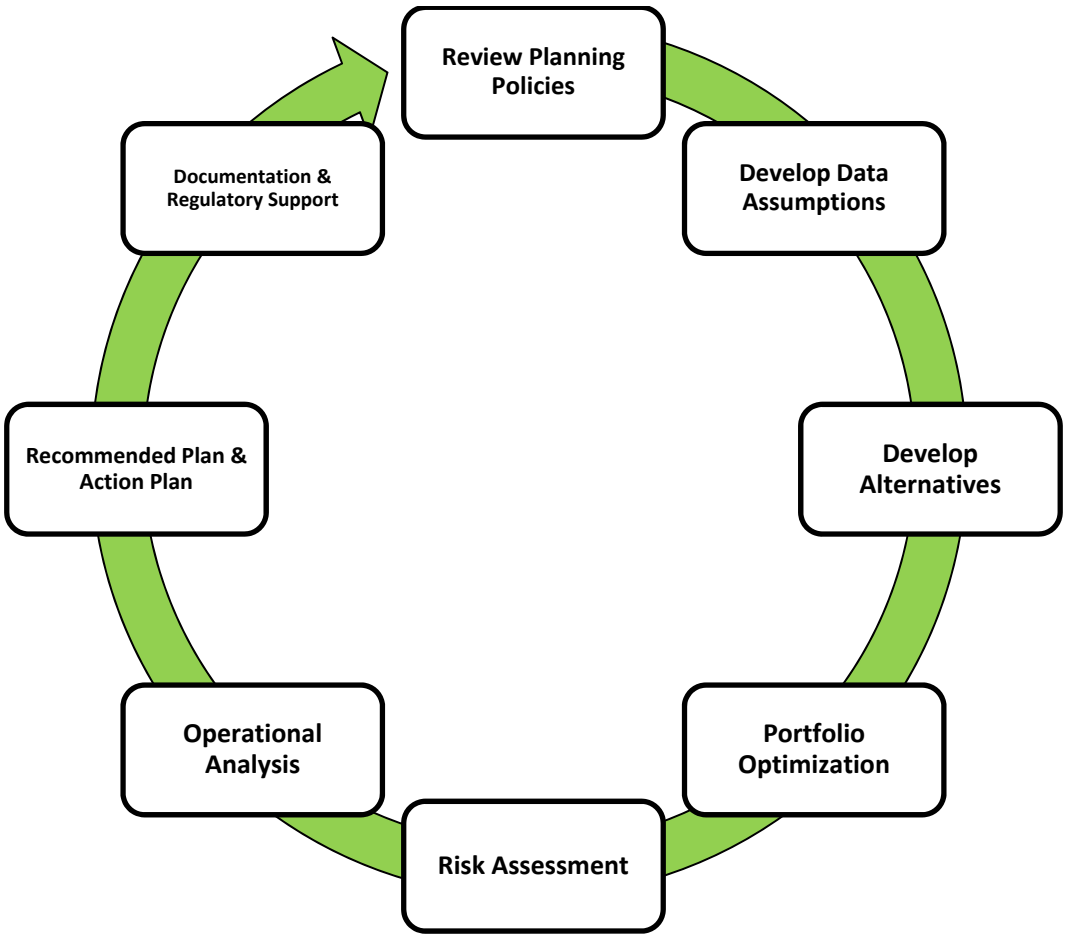
Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model its EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, for which the maximum EFOR would be between 9.7% and 9.8%. At this point, the units' contribution to LOLH would exceed 2.8 hours/year.

Scenario Planning

Background

The purpose of this part of the review is to examine the NLH planning process with respect to accepted utility practices and procedures. The standard that the NLH planning process was compared is the Ventyx Integrated Resource Planning ("IRP") process. This process was developed and used by Ventyx n its worldwide consulting practice.



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Figure 2 IRP Planning Process

Description of each step:

- **Planning Policies Review** – This is the initial IRP project planning step in which the objectives of the IRP are set up. This includes the review of all of the rules and constraints that must be met in performing the planning process
- **Data Assumptions** – In this step all of the data assumptions are gathered and vetted. This includes the operating assumptions of all existing and proposed future alternatives, commodity prices, environmental and market prices, and transmission limits.
- **Develop Alternatives** – The simulation models for the various alternative Demand-side, Supply-side and market/transmission options are developed.
- **Portfolio Optimization** - In this step the potential resource alternatives are pre-screened using economic and operational methods. Through the use of optimization software, such as Strategist, one or more optimal plans are developed that meet a set of defined attributes and constraints.
- **Risk Assessment** - This step takes optimized plans from alternative scenarios and subjects them to sensitivity analysis to determine the impact of changes in assumptions to results. This step also determines the robustness of optimal plans to statistical distributions of sensitive variables. Then using multi-criteria decision making analysis techniques determines the trade-off between competing attributes such as risk and least cost.
- **Operation Analysis** – Selected plans are then further analyzed in terms of financial viability and operational constraints such as hydrological studies.
- **Recommended Plan and Action Plan** - The results of all the above steps is a recommended plan that the utility wished to present as its integrated resource Plan. In conjunction with this overall long –term plan an Action Plan is developed that focuses on the decision period in which actions must be decided on today. With-in the Action Plan a set of signposts are developed from the sensitivities that determine which variables should be monitored, at what value an action should be triggered, and what the contingent actions should be.

- **Documentation and Regulatory Support** –The heart of the IRP is the final documentation. These are the documents that will be filed with regulators and all other parties. It should be thorough, accurate and defendable. Note that this step is best performed as the overall IRP process is being performed.

The review of the resource planning process included a review of the original filings with the Board concerning the Muskrat Falls Project, review of two independent detailed reviews of the project, a review of the responses to the Board's questions concerning the incidents this winter, and one-on-one interviews with both NLH and NP planning staff.

Conclusions

The resource planning process being performed by NLH conforms to the basic structure laid out in the Ventyx IRP process. All areas in the IRP process were deemed as being acceptable. However, two areas, Alternative development, and Risk Assessment were found to be acceptable but in need of improvements.

In the development of alternatives it was found that although existing demand-side programs were included in the development of the resource plan there was a lack of additional demand-side alternatives. The report only mentions the presentation of CDM alternatives to the Board, no mention of the use of demand-side as alternatives to supply resources is made. Due to slow growth requirements of demand programs the use of demand-side alternative will not be effective to solve short-term issues. It will also not change the need for the capacity and energy from the Muskrat Falls project long term. However, it is Ventyx's recommendation that the use of demand-side alternatives be further explored in the period post 2017 while there is ample capacity to cover requirements. In reviewing the documents it was noted that there is no formal risk assessment being performed.

Sensitivities were performed and included in the original documentation but focused mostly on commodity and costing assumptions. Future scenario and sensitivity processes should be expanded to include the impacts of extreme loads. These expanded sensitivity analysis can then be formally included into a risk analyses process to determine the robustness and impacts

of resulting plans. The additional load sensitivities are discussed above in the section on load forecast.

Recommendations

It is noted that while NLH's Resource Planning processes meets the overall IRP process requirements, there are two areas that could be incrementally improved.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternatives to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Generation Outlook 2014 to 2017

On January 17th, the Board initiated a process to gather information from NLH and NP with a focus on whether load requirement on the Island Interconnected system can be met in the near term. In the near term, NLH's current resource expansion plan is within the reliability criteria.

	Loss of Load Hours (Hours)	Reserve Margin (Percent)
2013	0.97	16.32
2014	2.59	12.28
2015	3.98	10.32
2016	2.73	12.21
2017	2.68	11.00

The previous table is based on the assumption that a new 50 MW CT is in service December of 2015. If that unit does not achieve that commission date the LOLH would increase to 4.57.

NLH is currently considering six options[16] for meeting the expected LOLH in 2015. Each of these options offers the possibility to reduce the system LOLH.

1. Retain the 16 MW (10 MW to the system) diesel facility at Holyrood;
2. Review what is needed to make the remaining 4.6 MW of diesel power at Holyrood available to the system by plant modifications to increase equipment ratings to deliver 14.6 MW capacity;
3. Enter into interruptible contracts with large Industrial customers;
4. Seek already built combustion turbines in the 50 to 100 MW range to supply deficit and blackstart;
5. Initiate the supply of a new 60 MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart; and
6. Continue and possibly enhance conservation and demand management initiatives, with the focus on demand management.

The new 60 MW (nominal) combustion turbine or other combustion turbine options are key resources for NLH's near term reliability of supply. The current plan has this unit commissioned in December of 2015. Without this unit, NLH would face LOLH reliability indices of 4.57 hours/year in 2015, 6.02 hours/year in 2016, and 5.71 hours/year in 2017, the Labrador Infeed is in service in December of 2017.

Statistically, demand reduction is a slightly better alternative to generation additions due to inherent uncertainty of generation forced outages. In order to reduce the expected 2015 LOLH of 3.98 hours/year to 2.80 hours/year, NLH would need to secure approximately 40 MW of either interruptible contracts with existing customers or conservation and demand

[16] Newfoundland and Labrador Hydro, *PUB-NLH-062* (Newfoundland and Labrador Hydro: Board Response, February 2014)

management initiatives. If that is not practical, then the difference can be made up from the remaining generation capacity options.

Furthermore, NLH uses reasonable estimates for generation forced outage assumptions as compared to Canadian Electricity Association (CEA) five year averages and the five year averages for its own equipment. The assumptions in Strategist are based upon data collected between 2000 and 2004. The generation forced outage assumption for Holyrood and Bay D'Espoir are 9.64%[17] and 0.91%[18], respectively, and they contributed to the forecast 2015 LOLH of 3.98 hours/year. Recent data from NLH operating data, from 2008 to 2012, indicates that the historical performance for Bay D'Espoir has improved to 0.41% and worsened for Holyrood to 10.69%. These figures are relatively consistent with current performance, however if the generation forced outage assumptions were improved for Bay D'Espoir, the 2015 LOLH would drop to 3.69 hours/year. If the generation forced outage assumptions were changed for Holyrood the contribution to the 2015 LOLH would increase to 4.49 hours/year.

The primary drivers are the Holyrood units. Focusing only on Holyrood, if Holyrood unit could achieve an annual forced outage rate of 8.48% or less then the system would achieve a LOLH of 2.8 hours/year. Recognizing the age of these assets this may not be practical in the short term and continuing the current assumptions is prudent planning, particular for the near term. As well there is merit in assessing some variation of this expected performance to gauge sensitivity on the LOLH result.

Summary of Recommendations

Ventyx has not found any evidence that either the generation planning process or the load forecasting process have contributed to the events of January.

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[17] Source: CEA Typical 2000-2004. Table 6.2.2 100-199 MW Classification for Holyrood.

[18] Source: NLH Operating Experience between 2000-2004. Weighted Average based on Bay D'Espoir units & Hinds Lake, Upper Salmon, Cat Arm and Paradise River

It was noted above that Ventyx does not believe it is desirable to change the forecast methodology to an end-use model. Primarily this is due to the increased complexity and cost, but it is also noted above that the major end-use on the system is electric heat and is already included in the forecast model and thus capturing the majority of any additional detail accuracy benefits that would be expected from an end use model. Since the R^2 for the two regression equations involving heating penetrations were 79% and 89% it would be advisable that NLH continue to refine its models with respect to these two variables. This can be further enhanced through continued surveying of the customer base in terms of both average use and saturation of this end use.

The above discussion has been in terms of the base-case scenario. It has been recommended above that NL begin using a formal risk assessment process that includes the evaluation of plans under extreme weather conditions. As such, it will be important to develop alternative load forecast in both the scenario development and the sensitivity analysis phases.

NLH should continue to use its generation planning reserve criterion.

After completion of NLH's interconnection with Nova Scotia and Muskrat Falls, NLH should revisit their generation planning reserve criterion of 2.8 hours/year in light of the reliability benefits offered by the access to North American markets. In addition, NLH should continue their on-going efforts to include the modeling of external markets in Strategist to capture both the reliability benefits and market value of market interactions. In order to allow for a better understanding of the potentials of economy interchange Ventyx recommends NLH continues to pursue the Network Economy Interchange ("NEI") modeling effort.

Since Holyrood is scheduled to be retired in the next 4 to 5 years NLH should model it's EFOR close to the actuals currently being experienced with sensitivities on either side of the expected value. With respect to all other thermal units in the Strategist model (existing and future) NLH should continue its practice of modeling with a more conservative estimate of EFOR for the units. However, one refinement that NLH could make to its EFOR assumptions would be to tie the level of EFOR to typical maintenance cycles. There is an inherent relationship between higher capital expenditures and maintenance corresponding to lower EFOR. However, it should be noted that a five year rolling average will also account for these cycles. By ramping up the

EFOR, in the years leading up to a major maintenance cycle, NLH would have a better picture of the near-term, one to five year, view of system reliability.

Alternatively, NLH could also compute a break-even EFOR for each class of its generation resources. For example consider the Holyrood Plant, the maximum EFOR would be between 9.7% and 9.8%. At this point, the unit's contribution to LOLH would exceed 2.8 hours/year.

Improve the resource planning process by:

- Beginning to explore the use of demand-side programs as long-term alternative to future supply–side alternatives post 2017 and
- Expand the Risk Analysis sensitivities to include several levels of load forecast uncertainty.

Appendices

PUB-NLH-008

PUB-NLH-011

PUB-NLH-056

PUB-NLH-062

Q. How does Hydro determine the appropriate reserve to have available to meet the Island Interconnected system load?

A. From a long-term planning perspective, Hydro has established criteria related to the appropriate reliability for the system, at the generation level, that sets the timing of generation source additions. These criteria set the minimum level of reserve capacity and energy installed in the system to ensure an adequate supply for firm demand; however, short-term deficiencies can be tolerated if the deficiencies are of minimal incremental risk. As a general rule to guide Hydro's planning activities the following have been adopted:

Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year[19].

[19] LOLH is a statistical assessment of the risk that the System will not be capable of serving the System's firm load for all hours of the year. For Hydro, an LOLH expectation target of not more than 2.8 hours per year represents the inability to serve all firm load for no more than 2.8 hours in a given year.

Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system capability[20].

From an operational perspective, Hydro manages generation resource availability on the Island Interconnected System and schedules generating units out of service for planned maintenance in order to meet a (n-1) system contingency reserve criterion. In this manner, sufficient reserves are planned to be available to meet the Island Interconnected System load under a contingency of the largest (MW rating) available generating unit. Hydro does not rely on capacity from wind and other non-dispatchable[21] resources to provide reserve. However, if these resources are in production they can further increase the reserves available. Following the (n-1) criterion results in no extended planned maintenance scheduled during the winter period. However, if the short-term load forecast permits, Hydro may take the opportunity to schedule a short duration generating unit outage to address running or corrective maintenance issues.

[20] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood Generation) is based on energy capability adjusted for maintenance and forced outages.

[21] Please refer to PUB-NLH-044 for a definition of "non-dispatchable".

Q. Provide the forecast and actual peak demand for each month in the winter period in each year from 2004 to 2013 and the forecast each year for 2014 to 2017 for each month in the winter period.

A. Please see below for the forecast and actual peak demand supplied by Hydro for the Island Interconnected System. Please note that Hydro interprets the winter period to be from December through March and that the forecasts provided are Hydro's Operating Load Forecasts. Please refer to Hydro's response to PUB-NLH-014 on timing of preparation.

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-04	1399	1277
Feb-04	1338	1405
Mar-04	1237	1206
Dec-04	1374	1402
Jan-05	1429	1361
Feb-05	1405	1272
Mar-05	1301	1161
Dec-05	1353	1202
Jan-06	1385	1276
Feb-06	1369	1185
Mar-06	1256	1167
Dec-06	1333	1310
Jan-07	1358	1323
Feb-07	1350	1249
Mar-07	1238	1242
Dec-07	1336	1286
Jan-08	1367	1289
Feb-08	1356	1212
Mar-08	1242	1207
Dec-08	1350	1323
Jan-09	1388	1390
Feb-09	1377	1375
Mar-09	1262	1294
Dec-09	1349	1268

NLH System Peak Demand (MW)

	Forecast	Actual
Jan-10	1372	1253
Feb-10	1361	1305
Mar-10	1243	1142
Dec-10	1371	1207
Jan-11	1401	1278
Feb-11	1390	1292
Mar-11	1270	1200
Dec-11	1405	1399
Jan-12	1433	1385
Feb-12	1417	1350
Mar-12	1302	1341
Dec-12	1432	1307
Jan-13	1461	1378
Feb-13	1446	1374
Mar-13	1332	1272
Dec-13	1401	1501
Jan-14	1478	-
Feb-14	1429	-
Mar-14	1322	-
Dec-14	1425	-
Jan-15	1523	-
Feb-15	1470	-
Mar-15	1361	-
Dec-15	1447	-
Jan-16	1543	-
Feb-16	1498	-
Mar-16	1383	-
Dec-16	1466	-
Jan-17	1567	-
Feb-17	1515	-
Mar-17	1395	-
Dec-17	1473	-

Note: Forecast and actual peaks reflect gross requirements.

Q. Further to the response to PUB-NLH-008, state the date(s) the criteria used for generation source additions was last reviewed by Hydro. In the response state whether Hydro is of the opinion it should be reviewed in light of Hydro's aging infrastructure and when is the appropriate time to review this criteria.

A. Hydro's generation source additions criteria have been in use for over 35 years and in that period they have been reviewed on a number of different occasions and found to provide a good balance of reliability versus cost.

Before 1977, there were no approved long-term reliability criteria for generation planning in Hydro. The basis of the current criteria is a report, *Recommended Loss of Load Probability (LOLP) Index for Establishing Generation Reserve Additions*, System Planning Department, May 16, 1977. In that report, a LOLP of 0.2 days per year, or 1 day in 5 years was established. In 1997, when Hydro replaced the SYPCO generation planning software with ProScreen II (now renamed Strategist) generation planning software, it was necessary to switch to a Loss of Load Hours (LOLH) criterion. Benchmarking established that a LOLH of 2.8 hours per year was equivalent to a LOLP of 0.2 days per year, for Hydro's system. From that point onward, Hydro established the capacity criteria that the Island Interconnected System should have sufficient generating capacity to satisfy an LOLH expectation target of not more than 2.8 hours per year.

In 1991, at the direction of the Board, George C. Baker, a consultant working for Hiltz and Seamone Company Limited carried out a study and produced a report -*Report on the Technical Performance of Newfoundland & Labrador Hydro* - October 2, 1991. On page 9 of the report, in Section *7 System Planning,* it states:

Hydro uses two criteria for generation planning in its interconnected system.

(a) Sufficient production capacity to meet all needs under firm water conditions (lowest recorded flows), and

(b) A loss of load expectancy of one day in five years.

The first criterion is usual for utilities with significant dependence on hydraulic generation. The second differs from the one-day-in-ten-years LOLE[22] adopted by many utilities.

The main reason for permitting a higher LOLE is economic. Hydro, unlike almost every other major utility, is an isolated system. Other utilities can, and do, rely on capacity support from interconnected utilities in meeting the one-day-in-ten-years criterion. Hydro cannot do this, and would have to maintain a much higher generation reserve.

[22] Loss of Load Expectation. LOLE is another way of stating LOLP and the two are equivalent.

Hydro believes the costs of doing so would not be justified by the difference in reliability. The Consultant agrees.

In 1999, at the direction of the Board, Quetta Inc. and Associates carried out a study and produced a report *Technical Review of Newfoundland and Labrador Hydro Final Report* March 17, 1999. On page 23 of the report, in Section *2.1.3.2 Capacity*, it states:

The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) target of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in five years. It results in a capacity reserve requirement of 18%.

The LOLE capacity criterion is somewhat less stringent than that employed by large interconnected systems in the rest of North America (one day in 10 years or 0.1 days/year). Considering the non-interconnected status of the Island's electric utility system, (reserve sharing is not an option) the cost of providing higher reliability level is probably in excess of the benefits to be derived.

Quetta is of the opinion that the capacity and energy criteria are reasonable in the circumstance.

Most recently, the criteria were reviewed in the *Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System – Volume 2: Studies January 2012*. This report was prepared for the Board by Manitoba Hydro International. In the report, *Section 3 – Reliability Studies* runs from page 57 to page 71. *Section 3.11 – Conclusions and Findings*, page 70, states the following:

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities.

As part of its internal review of recent events, Hydro has engaged an outside consultant (Ventyx) to review its generation planning practices. One of the areas to be reviewed is the criteria used for generation source additions. As well, in light of Hydro's aging infrastructure, it is also appropriate to review the inputs to the generation expansion model, such as the current and expected forced outage rates of Hydro's generating units. These will also be reviewed.

Q. Further to the response to PUB-NLH-018, which states that there is a capacity deficit identified for 2015, explain in detail each of the "*several generating options potentially available to meet winter peak demand*" that Hydro stated it was pursuing, including the status of the review of each option and the time required to construct or install each option.

A. The options under consideration for meeting the deficit currently expected in 2015 include the following and may be a combination of two or more to meet the potential deficit:

1. **Retain the 16 MW diesel facility at Holyrood (presently under a lease-to-own arrangement).** Once installed, 10 MW can immediately be supplied to the system on a sustained basis. This facility is currently being prepared for commissioning in early March 2014.
2. **Review what is needed to make the remaining diesel power available to the system.** Please refer to Hydro's response to PUB-NLH-064.
3. **Enter into interruptible contracts with large Industrial Customers.** Discussions with Industrial Customers (CBPP, Vale and North Atlantic Refining) were initiated in fall 2013. These discussions are ongoing and options continue to be explored. Please refer to Hydro's response to PUB-NLH-050.
4. **Seek already built combustion turbines in the 50 to 85 MW range**. Preliminary discussions indicate that these options can provide in-service to meet the 2015 requirement. However, discussions with manufacturers, brokers and owners are

ongoing to determine the delivery times, operating experiences, the extent of modifications required, and the facilities required to connect to the Island Interconnected System.

5. **Initiate the supply of a new 60MW (nominal) combustion turbine for the Holyrood site to supply deficit and blackstart functionality.** All preliminary engineering is complete. With final approval by June 2014, this plant could be in-service by 2015.
6. **Conservation and demand management initiatives, with the focus on demand management**. Work is being conducted to assess customer end use options with a view of providing demand management. This is considered a supplemental means of meeting the deficit and may provide further cost savings opportunities when combined with other options.

NEWFOUNDLAND AND LABRADOR HYDRO

ASSET MANAGEMENT STRATEGY & PRACTICES

Revision 0 March 20, 2014

Prepared/Authored by:

Blair Seckington
Director, Power Consulting, Oakville PPA
AMEC Americas Limited



newfoundland labrador hydro
a nalcor energy company

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Table of Contents

EXECUTIVE SUMMARY

1 INTRODUCTION 1

2 REVIEW PROCESS 2

3 BACKGROUND 3

4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME 23

5 KEY FINDINGS AND RECOMMENDATIONS 25

6 RECOMMENDATIONS STATUS 27

Acronyms

Appendix 1 Asset Management Information Related to Responses to "Other Questions"

Appendix 2 Documents/References Reviewed List

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) is undertaking an internal review of the various aspects of the events and potential contributors to the supply disruptions on the Island Interconnected System during January 2014. The internal review will consider eight sub-sections:

1. Load Forecasting
2. Generation/Reserve Planning
3. Generation Availability
4. Transmission Availability
5. Asset Management Strategy and Practices
6. Coordination and Communication With Customers
7. Emergency Response and Restoration
8. Technology and Communications Infrastructure

The result will be an overall "Summary Report on Supply Disruptions – January 2-8, 2014" which is intended to summarize the results of Hydro's internal review of supply disruptions on the Island Interconnected System during January 2014. Each sub-section will have a supporting report such as this one. The summary document and supporting sub-section reports will be incorporated into the data available to inform those involved in the reviews completed by the Board of Commissioners of Public Utilities (PUB) and the Government of Newfoundland and Labrador.

This sub-section report, "Asset Management Strategies and Practices", outlines the results of the investigation/assessment of Newfoundland & Labrador Hydro's asset management strategy and practices. It is intended to summarize the results of a review of Hydro's Asset Management program, including specifically addressing several aspects:

1) Asset Management Strategy and Practices
2) Long Term Asset Management Plans (1,5, and 20 Year Plans)
3) Asset Criticality and Critical Spares Strategy
4) Maintenance Execution
5) Councils of Experts

Several positive key messages can be taken from the analysis of the information:

Hydro strives to follow a structured approach to Asset Management with Condition Assessment as the foundation for the development, ongoing care, and renewal of its installed asset base.

"Hydro's definition of asset management is the comprehensive management of asset requirements, planning, procurement, operations, maintenance and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations. It is a holistic, cradle-to-grave lifecycle view on how they manage their assets."

Hydro's asset management approach is essentially consistent with best electric industry practices such as the Electric Power Research Institute's (EPRI) condition assessment process for large generation facilities.

Hydro's asset management program is a deliberate, rigorous process. It has an emphasis on self-assessment and measurement to ensure continuous progress and improvement. In essence it provides the basis for ensuring "the management of the right work on the right assets at the right time".

Hydro's asset management program continues, as it has since 2006, to make steady progress in its scope and its application to all aspects of its business.

A key Hydro's asset management program result is the well thought- out, prioritized and integrated portfolio of 20 Year, 5 Years, and 1 Year expenditure plans that can be and are adapted as circumstances change with time. The Execution Work Plan program piloted at Churchill Falls and being extended to other parts of the business in 2014 is very extensive and is considered consistent with best industry practices.

Other key findings/recommendations and their status where applicable include:

1) Hydro's asset replacement/refurbishment activities for older breakers, disconnects, and transformers have been ongoing for several years and extend for many more. Given there were some issues with older breakers during the January 2014 outage incident, the scope and timing of the program should be reviewed in early 2014.
2) Hydro's new Execution Work Plan program has been well demonstrated in 2013 in other business lines. To improve resource utilization and effectiveness and outage management, its planned extension to replace existing Execution Work Plan processes at other Hydro facilities in 2014 is recommended.

3) Hydro critical spares tracking/management until 2011 has been done primarily on a local facility basis reflecting experience, condition assessments, and vendor recommendations, constantly evolving over past years and decades, and continues to do so. After an initial three year development and assessment period beginning in 2011, a comprehensive pilot to the equipment level at Holyrood in 2013 of Hydro's asset criticality and critical spares tracking / management plans provided valuable feedback at an initial "Lessons Learned" assessment that was undertaken January 30, 2014. This should be followed up on, as is Hydro's plan, in early 2014 following the work on the January 2014 incident. This will move the process towards a more comprehensive and cost effective approach consistent with industry practice and addressing critical issues before winter 2014-15 as a part of the overall asset management program for the winter of 2014/15.
4) Hydro has significant technical capability and staff, and has introduced a "Council of Experts" concept to enhance its best technology/technical practices adoption capabilities. It should, as is planned, continue to cost effectively utilize and enhance those groups and look for additional opportunities to enhance its best technology/technical practices capabilities.
5) A more rigorous winter readiness program should be introduced, largely driven by internal self-assessment with appropriate external support/review. An internal winter readiness self-assessment guide has been drafted and 2014 plans include a more rigorous winter readiness program, building on the self-assessment results and 2013 process/facilities review work.
6) Hydro's O&M at Holyrood has not been impacted since the sanction of Muskrat Falls. Condition assessments on critical systems (i.e. re: safety, reliability) have continued. Capital and major operations projects in Holyrood's long term asset management plan are consistent with the station's end of life plans and required to ensure safe, reliable and environmentally sustainable operation have not been impacted. Those not critical for the period to end of generation service in about 2020 have not been approved, and should not impact availability to then.

1 INTRODUCTION

Newfoundland and Labrador Hydro are undertaking an internal review of the various aspects of the events and potential contributors to the supply disruptions on the Island Interconnected System during January 2014. The internal review will consider eight focus area/elements sub-sections:

1. Load Forecasting
2. Generation/Reserve Planning
3. Generation Availability
4. Transmission Availability
5. Asset Management (AM) Strategy and Practices
6. Coordination and Communication With Customers
7. Emergency Response and Restoration
8. Technology and Communications Infrastructure

The result will be an overall "Summary Report on Supply Disruptions – January 2-8, 2014" which is intended to summarize the results of Hydro's internal review of supply disruptions on the Island Interconnected System during January 2014. Each sub-section will have a supporting report such as this one. The summary document and supporting sub-section reports will be incorporated into the data available to inform those involved in the reviews completed by the Board of Commissioners of Public Utilities (PUB) and the Government of Newfoundland and Labrador.

This sub-section report, "Asset Management Strategies and Practices", outlines the results of the investigation/assessment of Newfoundland & Labrador Hydro's asset management strategy and practices. It is intended to summarize the results of a review of Hydro's Asset Management program.

The scope of this focus area/element involves a review of Hydro's:

1) Asset Management Strategy and Practices
2) Long Term Asset Management Plans (1,5, and 20 Year Plans)
3) Asset Criticality and Critical Spares Strategy
4) Maintenance Execution
5) Councils of Experts

It should be noted that some charts and tables presented in this report are from Hydro's asset management process documentation. They are included for the information of the reader to reflect the robustness of analysis, planning and progress undertaken by Hydro on asset

management.

The report includes assessment of how the Asset Management program is related to the sequence of events associated with the January 2014 electrical supply disruptions. Finally it identifies key findings and recommendations and comments on their current status.
The report format is broken down into the following Sections:

EXECUTIVE SUMMARY
1 introduction
2 Review Process
3 Background
4 Sequence of Events: Relevant Time Frame
5 Key Findings and Recommendations
6 Recommendations Status

2 REVIEW PROCESS

The review process involved three basic elements:

i. Review of existing Hydro data relevant to asset management strategy and practices in Hydro AM data room
ii. Discussions/interviews with Hydro AM staff
iii. Experience with Hydro facility practices in previous work (2011-2013 Holyrood Condition Assessments, 2013 Interconnected Island System winter readiness, 2013 Churchill Falls winter readiness, 2012 Capital Program review support, 2012 Holyrood staffing benchmark review)

For the purposes of the assessment, the AMEC staff member's significant experiences with utility practices while with AMEC (6+ years) and Ontario Hydro (OH) /Ontario Power Generation (OPG) (32+ years) were utilized including:

- 32+ years working with OH/OPG fossil and hydroelectric stations, including divisional capital expenditure plan reviews for senior management
- OPG/OH CEA/CEATI fossil generation technical representative
- OPG/OH Electric Power Research Institute (EPRI) fossil and hydro research representative and Generation Council representative
- OH/OPG fossil generation R&D program manager
- OPG/OH/Canada representative to International Energy Agency Greenhouse Gas and Fossil Generation committees

- OH/OPG representative on various joint projects with US and Canadian utilities on advanced generation and environmental controls including Southern Company, AEP, Duke, First Energy, Transalta, EPCOR, NSPower, NB Power, SaskPower, BC Hydro
- AMEC capital/OMA plan and staffing plans for BC Hydro Burrard (6 x 150 MW) natural gas fuelled steam generating station in 2008 through 2013
- AMEC thermal and hydroelectric due diligence expert for three generation and system facilities review in 2011 to 2013

Based on the information, an assessment was made as to the overall Hydro asset management strategy and practices.

3 BACKGROUND

Information relevant to Hydro's Asset Management strategy and practices includes the role it plays, the processes utilized in its execution, and the structure within Hydro by which it is accomplished.

1.1 Asset Management Strategy and Practices

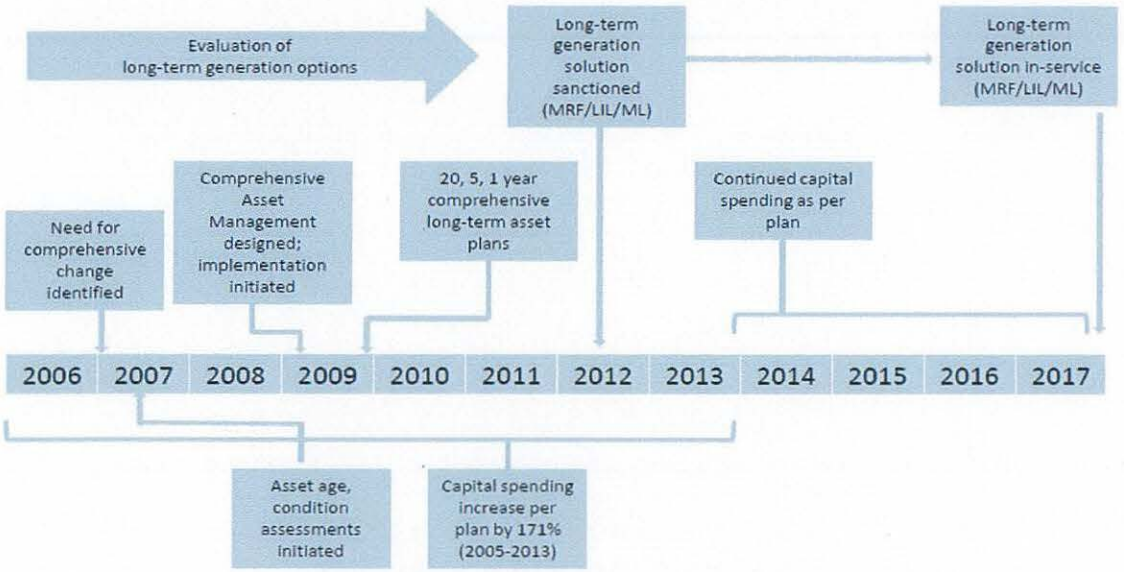
Asset Management Vision within Hydro

Within Hydro, asset management has been defined as follows:

> Asset management is the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations. It is a holistic, cradle-to-grave lifecycle view on how we manage our assets.

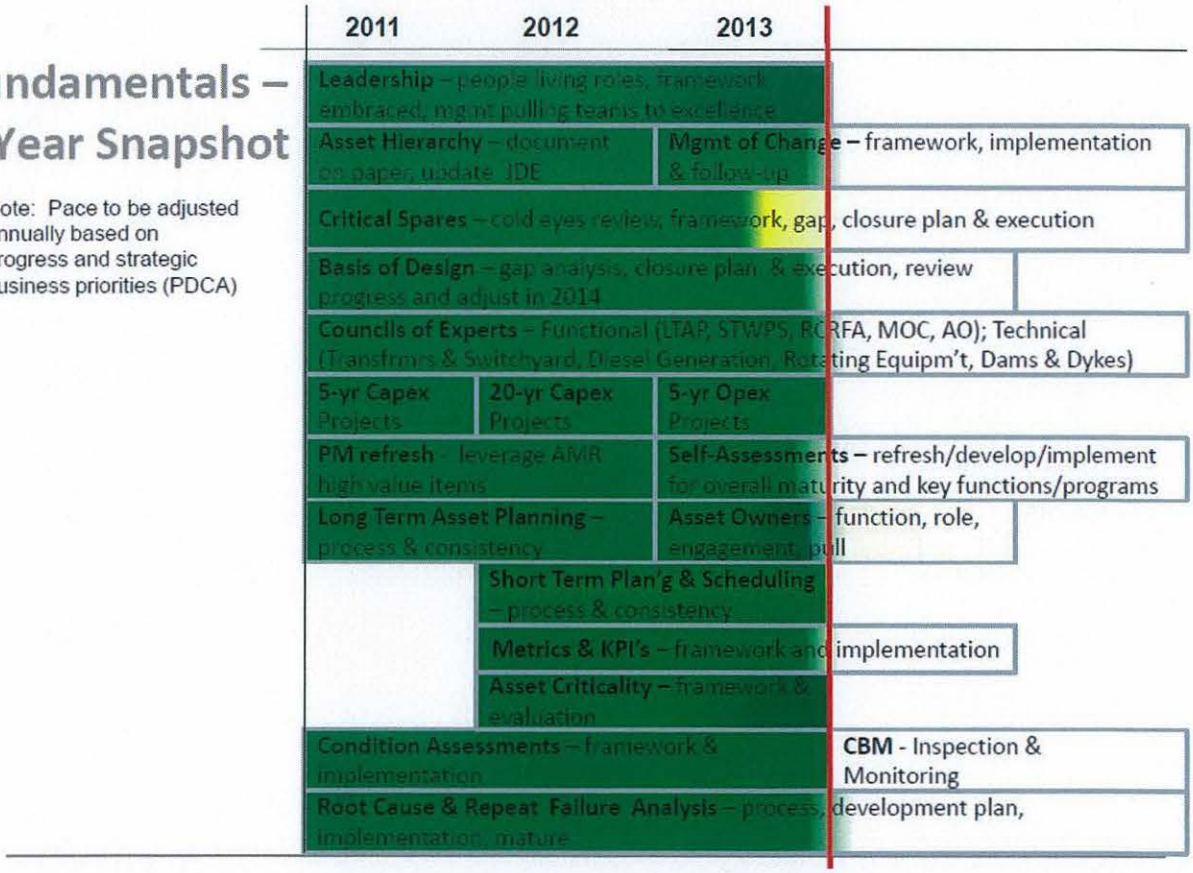
It is clear that while asset management is a backbone to any enterprise, it appears to have been identified as one of Hydro's key issues in 2006. There have been major steps forward, as illustrated in the following Hydro Asset Management charts and confirmed in interviews with Hydro staff. Clear, measurable progress has been made and more is planned by Hydro to be achieved going forward.

Asset Management Progression 2006-



Fundamentals – 3 Year Snapshot

Note: Pace to be adjusted annually based on progress and strategic business priorities (PDCA)



Hydro's broad and aging asset infrastructure requires robust asset management processes. This has been recognized by Hydro and their processes have been founded on best practice. Key changes instituted by Hydro to support this approach have included:

- A comprehensive organizational restructuring to focus on asset management and to support its key functions and outcomes.
- Specifically identified staff, in consistent organizational positions throughout the organization, with assigned accountability for the various aspects of asset management.
- Strengthening of planning and execution processes to align with overall asset management needs.

A key aspect is that Hydro through its strategy and practices and downstream execution has committed itself to having:

> **"The right work being done by the right people on the right assets at right time."**
> **"Knowing the condition of its assets, identifying the right maintenance work, operating the assets properly, managing risk and cost, and robust asset renewal plans."**

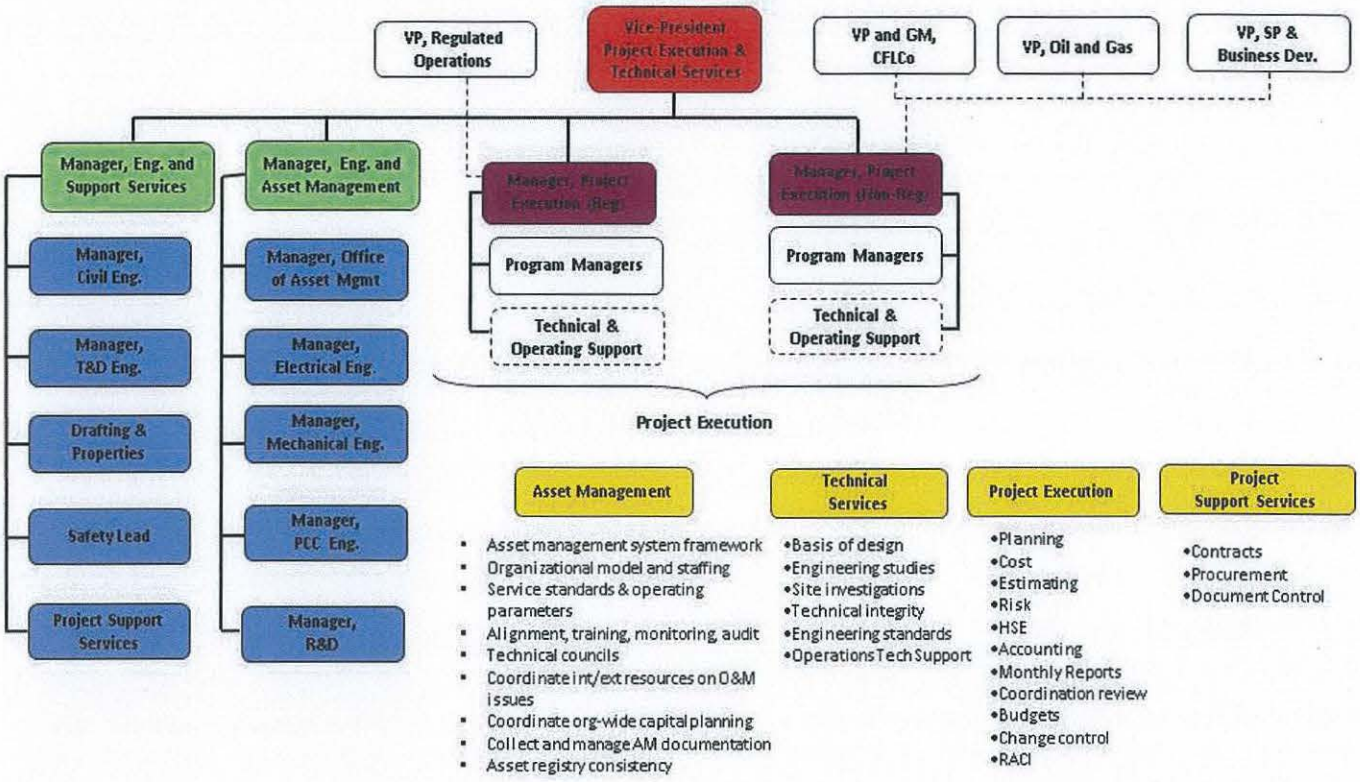
Hydro Structure

Hydro reorganized extensively to bring more accountability and consistency to asset management at all levels of the organization, notable changes include positions supporting the following:

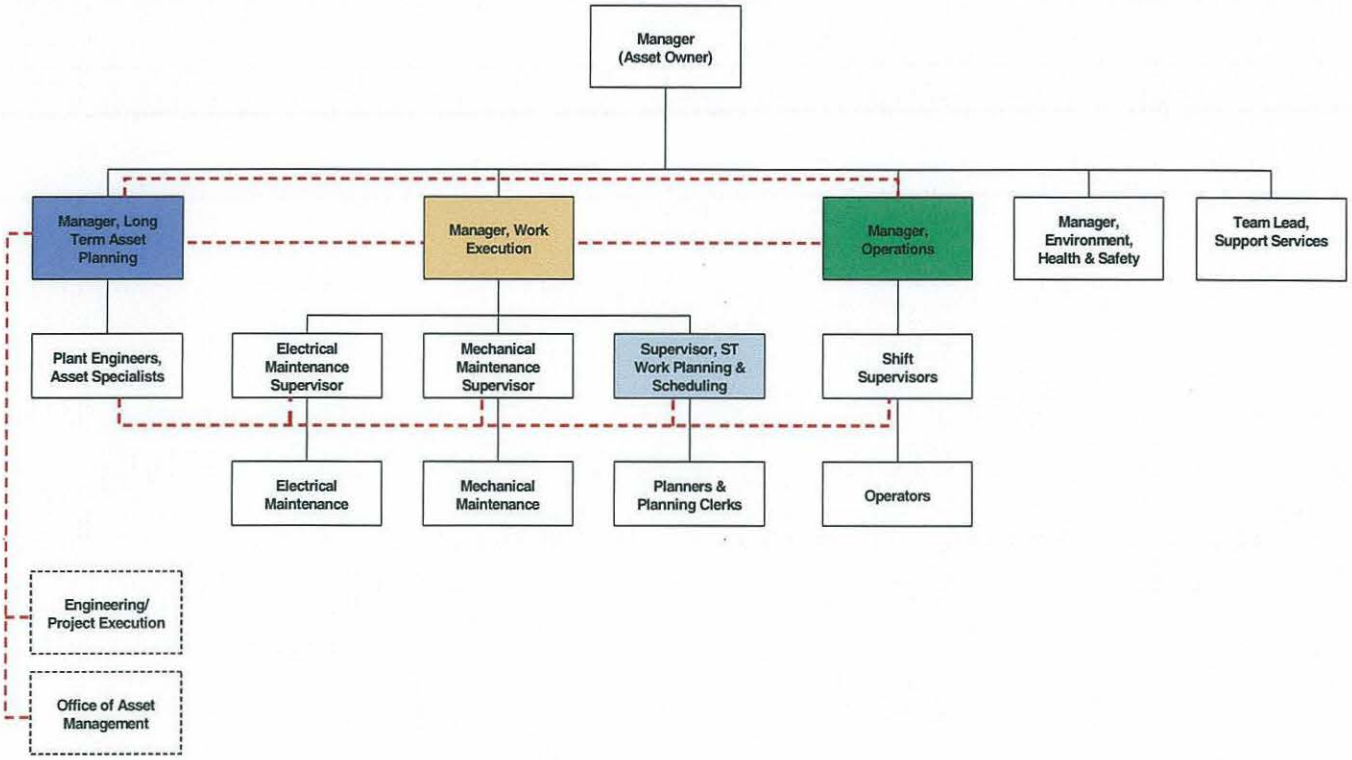
- Office of Asset Management
- Asset Owners
- Long Term Asset Planning
- Work Execution
- Short Term Work Planning and Scheduling
- Project Execution
- Operations
- Support Services

The following Hydro PETS Structure chart illustrates where the Office of Asset Management has been positioned at the corporate level, and the relationship with project execution and technical support for field operations.

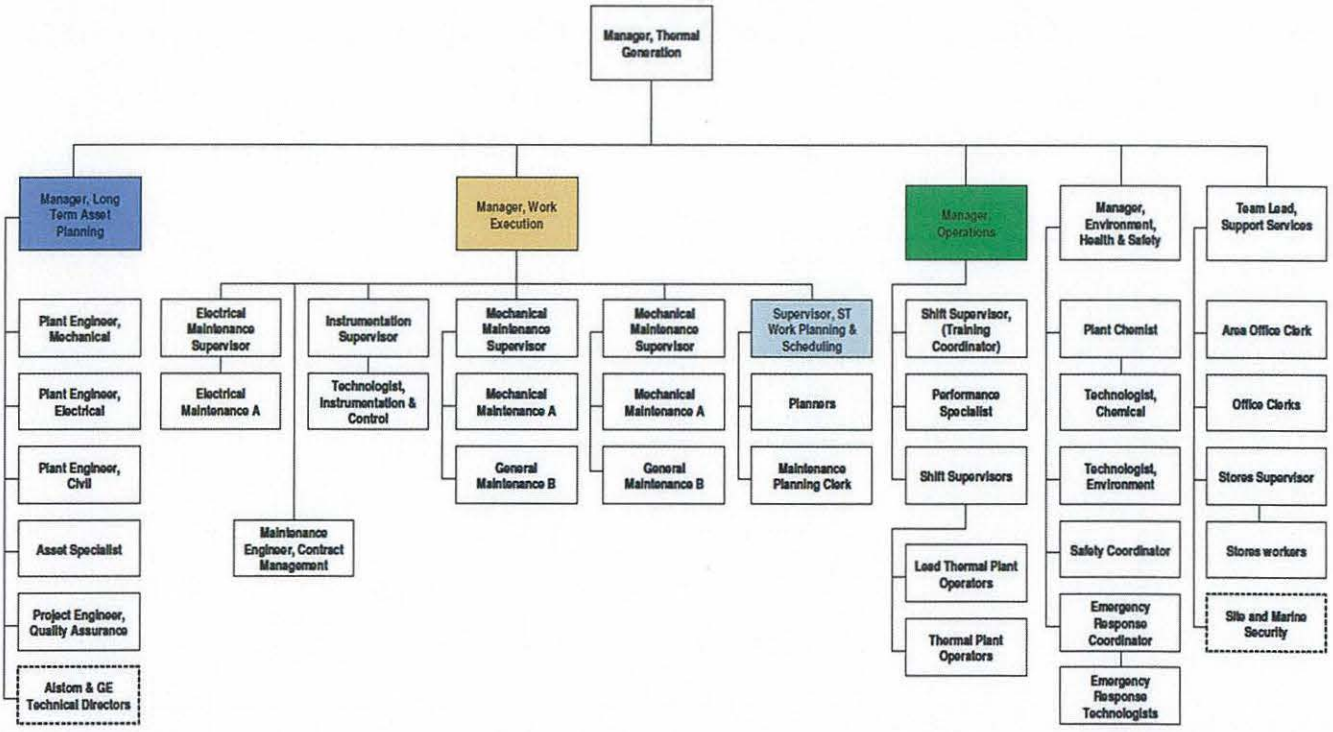
PETS Structure



At the facilities and regional level, the following Hydro organization chart is a representative structure with the asset management roles and relationships shown:



The actual structure for Holyrood GS is shown as an example:



The management and "ownership" of assets and their care at all levels is consistent throughout the organizational structure. This is also consistent with the direction at many utilities where

the importance of ownership/accountability for key assets has been recognized.

Asset Management Processes

Hydro strives to follow a structured approach to Asset Management with Condition Assessment as the foundation for the development, ongoing care, and renewal of its installed asset base.

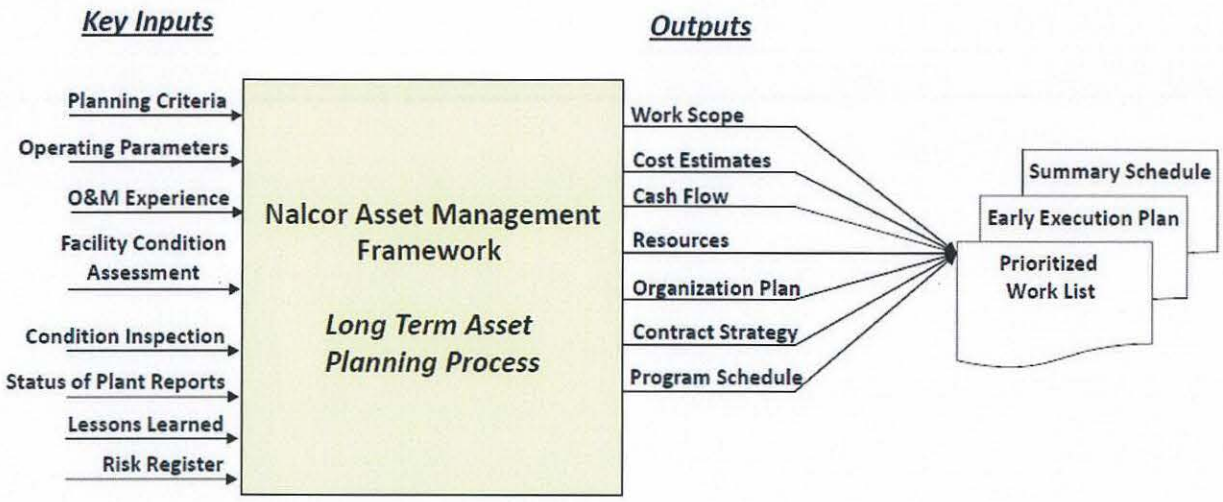
Hydro's asset management program continues, as it has since 2006, to make steady progress in its scope and its application to all aspects of its business. The program is a deliberate, rigorous process. It has an emphasis on self-assessment and measurement to ensure continuous progress and improvement. In essence it provides the basis for ensuring "the management of the right work on the right assets at the right time".

The asset management process involves several different aspects, including:

a) An Asset Management Framework
b) A Staged-Gate Process for Planning and Executing Individual Projects within the Long Term Asset Management Plan
c) A Process for Annual Project Plan Development
d) Condition Assessment and Monitoring
e) Benchmarking/Expert Reviews, including Project Execution/Management

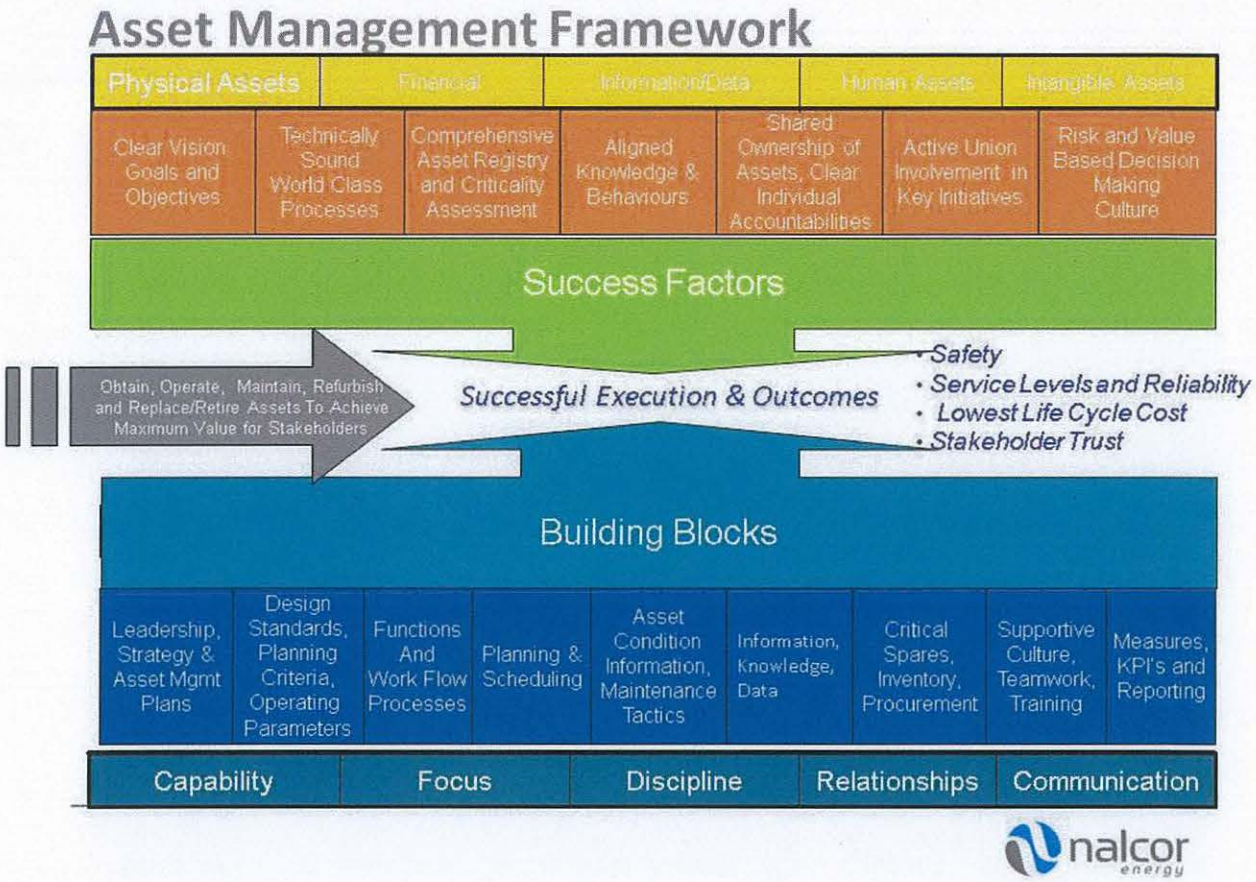
Condition Assessment is a key tool in the development of Hydro's Asset Management plans. Its condition assessment program includes detailed assessments using the principles and stages of power generation facility condition assessment developed by EPRI.

Other key inputs and outputs that form part of Hydro's asset management planning process are illustrated below. These are evident in information from various Hydro facilities and all of these elements work together to make Hydro's asset management approach consistent with good electric industry practices.

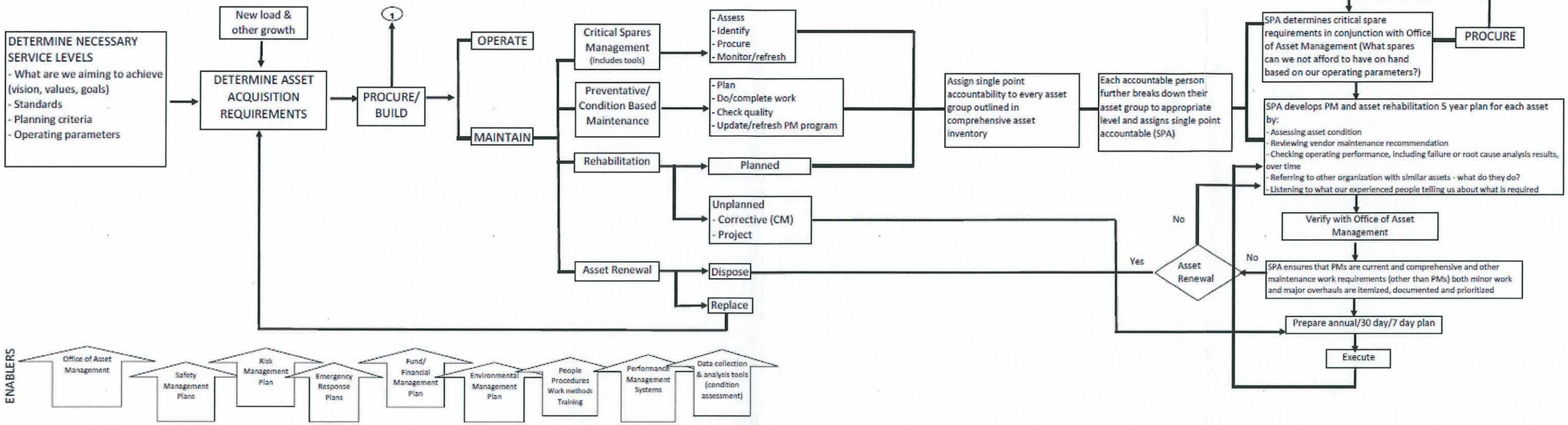


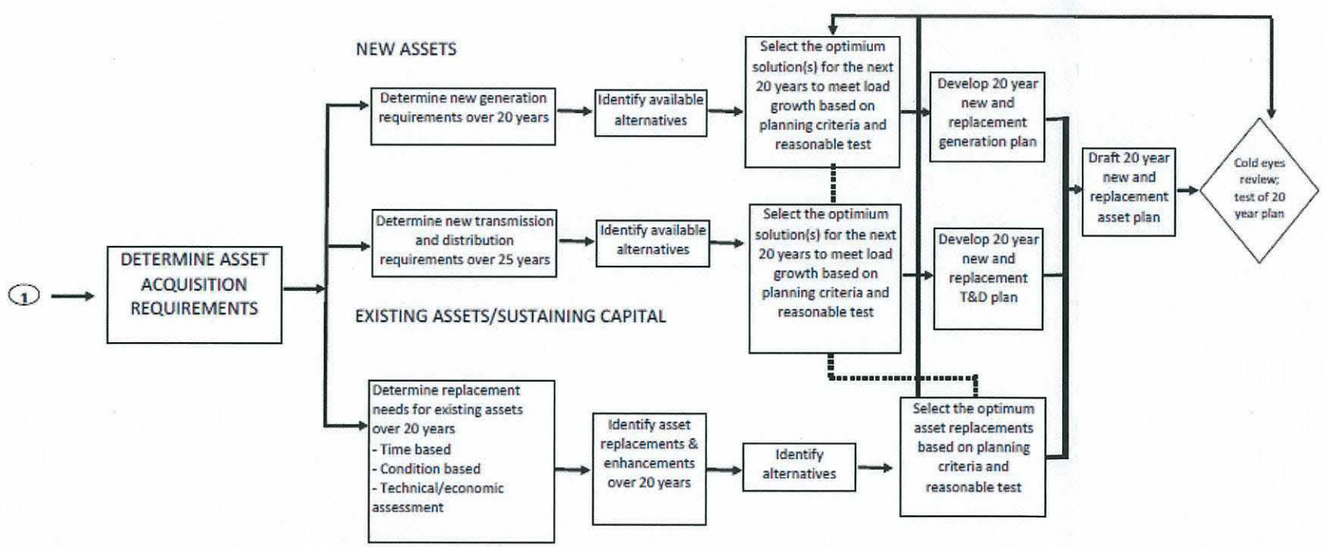
Hydro's Asset Management Framework

The Asset Management Framework used by Hydro is illustrated below. It identifies the steps/stages that Hydro's projects go through in order to become part of the overall Asset Management plan through to execution of both projects and maintenance programs. It is well structured and consistent in principle with practices employed by many utilities in North America.


Asset Management Framework
Physical Assets
Financial
Information/Data
Human Assets
Intangible Assets
Clear Vision Goals and Objectives
Technically Sound World Class Processes
Comprehensive Asset Registry and Criticality Assessment
Aligned Knowledge & Behaviours
Shared Ownership of Assets, Clear Individual Accountabilities
Active Union Involvement in Key Initiatives
Risk and Value Based Decision Making Culture
Success Factors
Obtain, Operate, Maintain, Refurbish and Replace/Retire Assets To Achieve Maximum Value for Stakeholders
Successful Execution & Outcomes
• Safety
• Service Levels and Reliability
• Lowest Life Cycle Cost
• Stakeholder Trust
Building Blocks
Leadership, Strategy & Asset Mgmt Plans
Design Standards, Planning Criteria, Operating Parameters
Functions And Work Flow Processes
Planning & Scheduling
Asset Condition Information, Maintenance Tactics
Information, Knowledge, Data
Critical Spares, Inventory, Procurement
Supportive Culture, Teamwork, Training
Measures, KPI's and Reporting
Capability
Focus
Discipline
Relationships
Communication
nalcor energy

Asset Management Activities: Plant/region





1.2 Long Term Asset Plans (1, 5, and 20 Year Plans)

A key Hydro asset management program result is the well thought out, prioritized and integrated portfolio of 20 Year, 5 Years, and 1 Year expenditure plans that can be and are adapted as priorities change with time.

The 20 year overview with preliminary costs and timelines provides the context/overall picture of how the future may unfold and keeps longer term requirements front and center in planners' minds.

The five year overview provides the context for the nearer term work, particularly highlighting those activities with multi-year activities such as large scale breaker or transformer replacement programs. It focuses some of the prioritization work at a higher level.

The one year view is the budget year, work required and approved, with consideration of the short 3 year term, particularly with respect to multi-year projects. It is developed to a higher level of detail, a higher degree of cost accuracy, and a more detailed implementation schedule. It can often include work that extends over more than one year. It is the culmination of the prioritization process that goes on within the overall corporate program with inputs from all of the businesses and facilities.

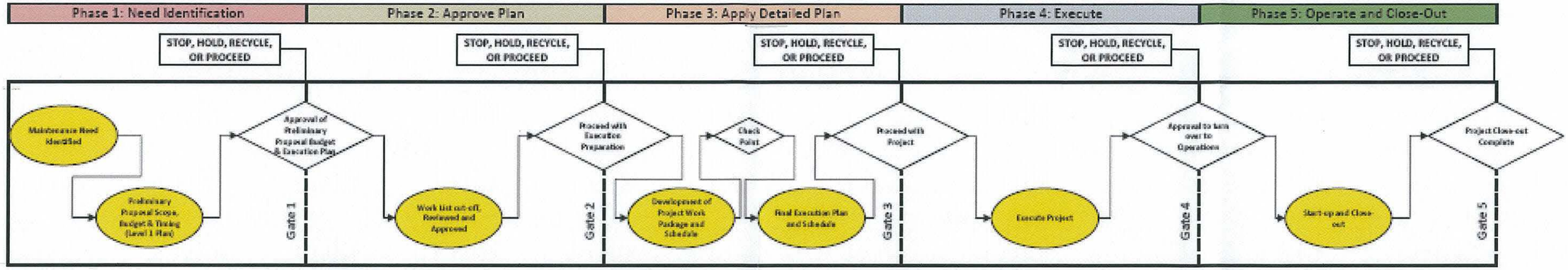
The budget forms the basis for the Execution Annual Work Program for each of the facilities. It includes a range of capital and operating projects, and maintenance programs – predictive, preventive, and corrective.

Staged-Gate Process for Planning and Executing Projects within the Long Term Asset Management Plan

The stage–gate process for planning and executing projects within a Long Term Management Plan is key to ensuring that the right work is done on the right assets at the right time. The Hydro figure below illustrates how Hydro actually uses a stage gate process.

This approach is typical of industry best practice, not only within the electricity industry but in most large process industry (oil, gas, and manufacturing).

Application of Staged-Gate Process for Planning and Executing Individual Projects within the Long Term Asset Management Plan



Phase - Actions	20+ Year Plan	5-Yr Plan	1-2 Yr Plan	Execution Year(s) Plan	
	Anybody **Phase 1:** - Identify need - Create proposal - Forward proposal to Mgr LTAP - Identify multiple alternatives - Categorize project based on Asset Category (BU) - Create Level 1 Plan, including: prelim scope, budget estimate, timing (year) LT Planning	**Phase 2:** - Review wrt Business Objectives - Review work list with Work Execution, Op's Mgr - Assign Project Estimator - field / site inspection req'd - Preliminary BOM[4] Class 3[5] estimates - Review project economics - Narrow alternatives - Initiate Project Plan[6] - Review project estimates with Project Execution - Schedule by duration - Budget for Front End Engineering and Design (FEED) - Revise budget estimate - Training identification - Retirements & disposals identification	**Phase 3:** - Assign project execution team - Execute FEED - Prepare red-line drawings - Conduct risk assessments - Identify contracting strategy - Class 3 estimates / reforecast - Scope Statement (Design Transmittal) prepared - schedule refined, by date for next year - Review outage schedules with Short Term Planning - Mesh with outage schedules - Work Package created - Apply management of change PETS - Tech. Services	**Phase 4:** - Order long lead items - Detailed engineering - Prepare tender documents - Eng'g bi-weekly progress meeting - Engage contractors - Begin construction - Report against schedule, cost - Construction weekly progress meeting - On-site construction management - Initiate completion plan including: - commissioning - performance testing - pre-start review - startup - demobilization - Complete / update drawings / As-builts - Train employees - Identify PM requirements - Identify and order spare parts, add to inventory - Review need for critical spares - Apply management of change - Identify operating parameters	**Phase 5:** - Startup by Operations - Update PM Program - Identify / address deficiencies LOB Operations PETS - Proj. Execution
Gate - point at which	**Gate 1:** - Project begins - More detailed scope & operating history applied - Project added to LTAMP, in future yr. - Decision to hold, abandon, recycle	**Gate 2:** - Single alternative selected - project just'n and scope updated and finalized - Reference point for future MOC - Decision to hold, abandon, recycle	**Gate 3:** - Board of Directors (BOD) / PUB approved - Project starts in next year's Annual Work Plan - Decision to hold, abandon, recycle	**Gate 4:** - Construction & commissioning complete - Prepared for turn over to Operations - Drawings completed / updated - Employees trained	**Gate 5:** - Deficiencies addressed - Project accounts closed-out

Execution Work Plan

The budget that comes out of the staged gate process for the upcoming fiscal/operating year forms the basis for the Execution Work Plan for each of the facilities. It includes a range of capital and operating projects, and maintenance programs – predictive, preventive, and corrective.

The planning process to arrive at the Execution Work Program is extensive. It is also a work in steady progress. Other Nalcor lines of business were first to fully implement/pilot the current planning process program in 2013 to produce a complete deliverable with a further refinement planned for 2014. The following Hydro figure illustrates the path that the process is on and where some elements contributing to the program are currently considered to be at and planned to be. It is considered that Hydro can reasonably be considered to be in level 3 in 2013.

		2012	2013	2014	2015
	Level 1 Initial	Level 2 Structured	Level 3 Organized	Level 4 Managed	Level 5 Optimized
Integration management	No established activity integration practices or standards. All activities are ad hoc.	Activities are documented only in basic format with limited planning and reporting.	Procedures and standards exist to integrate independent projects. Some cross-project integration may exist.	Processes and standards for all projects – integrated with each other and with processes and/or systems.	Project integration efforts are documented and utilized to ensure improvement.
Scope management	Business requirements are stated in very general terms. Scope poorly documented if at all.	Business requirements more formally reported. Items in scope are likely mentioned, items out of scope not mentioned.	Project management processes are established and used. Stakeholders take active role in scoping decisions.	Management processes and methodology used on all projects.	Project scope management is primarily driven by effectiveness and efficiency metrics.
Time management	No scheduling or resource planning performed.	An informal task or activity list is used. No formal scheduling standards or processed exist.	Time management processes documented and used by most projects. Tracking processes begin to emerge.	Time management uses historical data to forecast future performance.	Improvement procedures are utilized for time management processes.
Cost management	No established practices or standards. Costing is performed ad-hoc, if at all.	Basic processes exist for cost estimating, planning and scheduling.	Cost estimating, planning and scheduling are prepared and compared against baselines.	Cost planning and tracking is integrated into the project office, financial and human resource systems.	Lessons learned improve documented cost management processes.

The program includes as inputs:

- Preventive Maintenance Programs and Inspections
- Overhauls
- Capital Projects

- Operating Projects
- Non-Maintenance Activities (e.g. training)
- Corrective Maintenance Packages
- Outage management and constraints (i.e. Winter Availability)

It is agreed that the result for the pilot project going into 2014 is a "Fully Integrated, Resource Levelled, and Ready-for-Use Annual Execution Work Plan". The plan has been vetted by Long Term Asset Planning, Work Execution, Project Execution, Operations, Asset Owners and Finance, having been through iterations to ensure that the activities, resources, outage window availabilities converge to a viable program. The plan has been signed off and the execution team is currently working the plan.

The plan addresses many elements critical to successful execution, including:

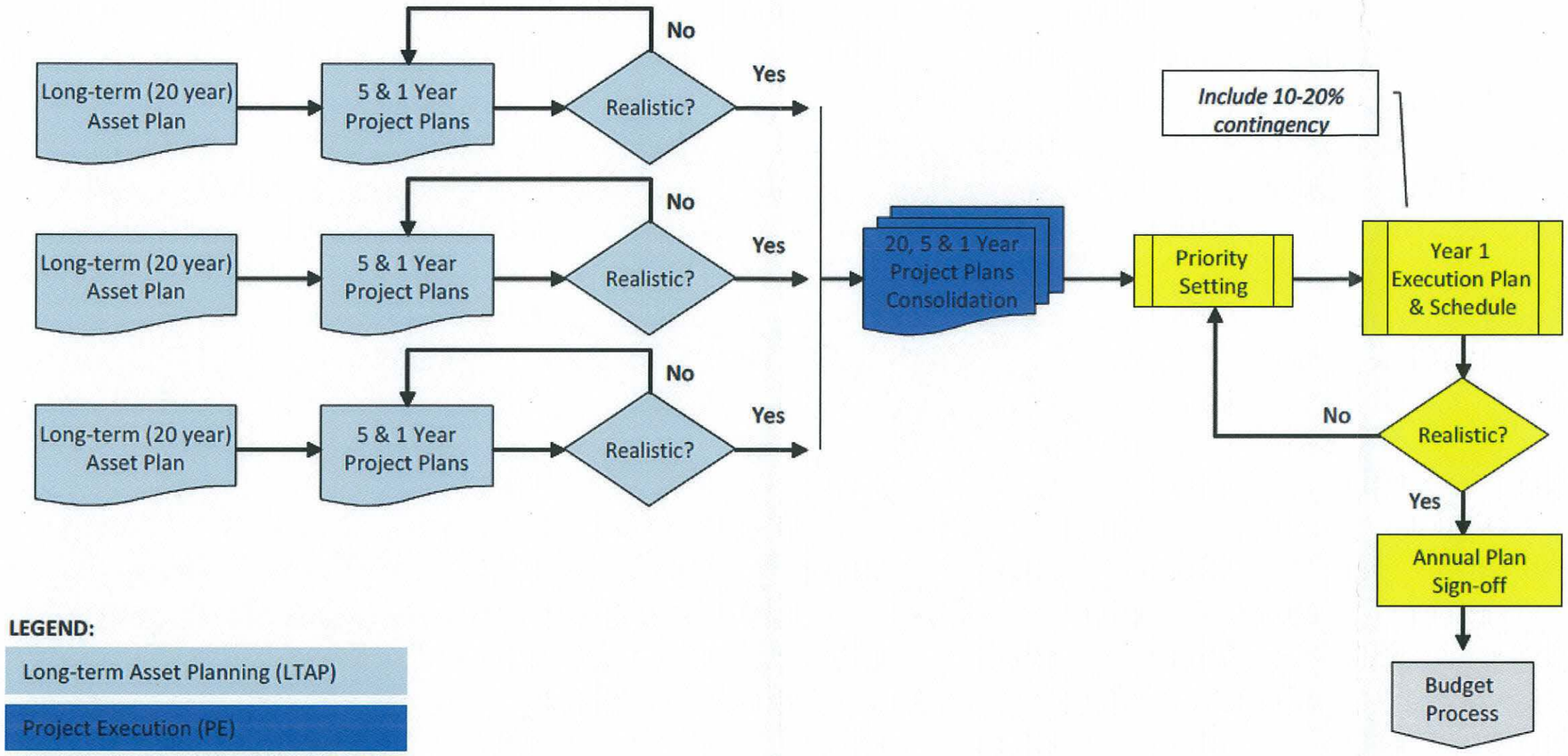
- Work project schedule by week (or more detail if required)
- Overall project resource scheduling
- Overall work plan resource scheduling by skill type
- Equipment outage scheduling
- Overall facility outage schedules/plans
- Overall program requirements and plans
- Monthly red line reviews and active management of change

The annual Execution Work Plan package is very consistent with good utility practice.

This same work is ongoing in the various parts of Hydro to develop their own aligned "Fully Integrated, Resource Levelled, Ready-for-Execution Annual Work Plan" in 2014 and thereafter to work the plans. This represents a continuous improvement/evolution upon current, often local, practices rather than a radical change.

Once fully implemented the process would optimize resource allocation and maximize successful project execution, which in turn will improve overall system reliability. Once fully implemented this would minimize unplanned resource shortages and provide the ability to better adjust to real changes. It would be consistent with very good industry practice.

Process for Annual Project Plan



LEGEND:

- Long-term Asset Planning (LTAP)
- Project Execution (PE)
- Engineering Discipline (Eng. Dis.)
- Joint LTAP/PE/Eng. Dis.

Fully integrated planning is a key requirement given the many demands on existing resources and funds. In the current process, some delays in the timing of scheduled PM work occur in deference to major capital projects and some resource inefficiencies occur due to shifting outage windows.

Condition Assessment and Monitoring

Condition Assessment is a key tool in the development of Hydro's Asset Management plans and can take many forms, including:

- Formal facility condition assessment processes, either directly using or aligned with the principles and stages of assessment developed by EPRI, such as were done for Holyrood Generating Station, for Holyrood's black start gas turbine, and for the Hardwoods and Stephenville gas turbines.
- Condition monitoring/testing of key equipment (i.e. transformers, breakers, generators, large motors) through various preventative maintenance measures (continuous, annual, 3 years, 6 years, 9 years PM's) and tracking (JDEdwards - JDE)
- Major equipment overhauls/refurbishments

Given the age of a significant number of major/critical equipment, the importance of condition assessment and monitoring has increased. Hydro's increased focus in this area is reflected in the increased associated activities and allocation of resources.

Benchmarking/Expert Reviews

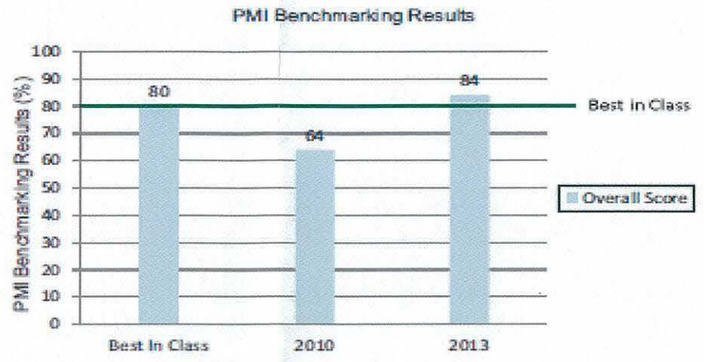
Hydro has undertaken a number of steps since 2006 to assess its performance in asset management and its ability to execute through project management, as well as bring expertise (internal and external) to improve its performance and understanding.

- Participation in CEA and CEATI groups and surveys on various issues, including reliability/availability
- Establishment of Council of Experts to leverage experience, knowledge and best practices, and provide input on plans and project needs
- Integrated use of specific external expertise (i.e. P&C systems analysis; generation condition assessment)
- Integrated use of vendor/OEM support for major equipment (boilers, steam turbines, gas turbines)
- Stantech managed PMI (Project Management Institute) project management benchmarking review in 2011 and 2013 (illustrated below, showing significant improvement between 2011 and 2013)
- Internal self-assessments of Asset Management Maturity by region

Hydro's summary results of the PMI project management benchmarking survey is shown below:

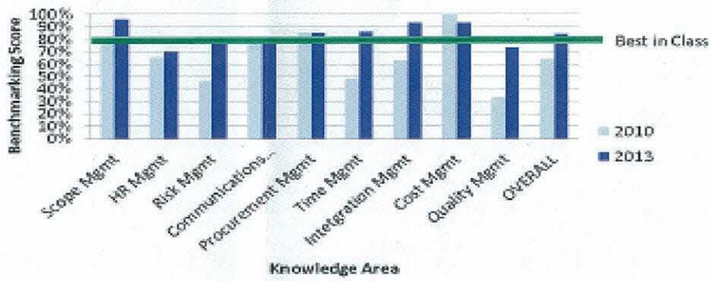
Nalcor Energy _ P.E.T.S. PMI Benchmarking Survey Comparison 20131125

KNOWLEDGE AREA	SURVEY DATE	SURVEY RESULTS	
Project Scope Management	8/16/2011	80%	*More about Knowledge Area* The processes required to ensure that the project includes all the work required, and only the work required, to complete the project successfully. See Ch. 5 of The PMBOK® Guide
	11/25/2013	96%	
Project Human Resource Management	8/16/2011	65%	*More about Knowledge Area* The processes that organize, manage, and lead the project teams comprised of the people with assigned roles and responsibilities for completing the project. See Ch. 9 of The PMBOK® Guide.
	11/25/2013	70%	
Project Risk Management	8/16/2011	46%	*More about Knowledge Area* The processes of conducting risk management planning, identification, analysis, response planning, and monitoring and control on a project. See Ch. 11 of The PMBOK® Guide
	11/25/2013	80%	
Project Communications Management	8/16/2011	80%	*More about Knowledge Area* Processes required to ensure timely and appropriate generation, collection, distribution, storage, retrieval, and ultimate disposition of project information. See Ch. 10 of The PMBOK® Guide
	11/25/2013	88%	
Project Procurement Management	8/16/2011	85%	*More about Knowledge Area* The processes necessary to purchase or acquire products, services, or results needed from outside the project team. See Ch. 12 of The PMBOK® Guide.
	11/25/2013	85%	
Project Time Management	8/16/2011	46%	*More about Knowledge Area* Includes the processes required to manage timely completion of the project. See Ch. 6 of The PMBOK® Guide
	11/25/2013	86%	
Project Integration Management	8/16/2011	63%	*More about Knowledge Area* The processes and activities needed to identify, define, combine, unify, and coordinate the various processes and project management activities. See Ch. 4 of The PMBOK® Guide
	11/25/2013	93%	
Project Cost Management	8/16/2011	100%	*More about Knowledge Area* The processes involved in estimating, budgeting, and controlling costs so that the project can be completed within the approved budget. See Ch. 7 of The PMBOK® Guide
	11/25/2013	93%	
Project Quality Management	8/16/2011	33%	*More about Knowledge Area* The processes and activities that determine quality policies, objectives, and responsibilities so that the project will satisfy the needs for which it was undertaken. See Ch.8 of The PMBOK® Guide
	11/25/2013	73%	

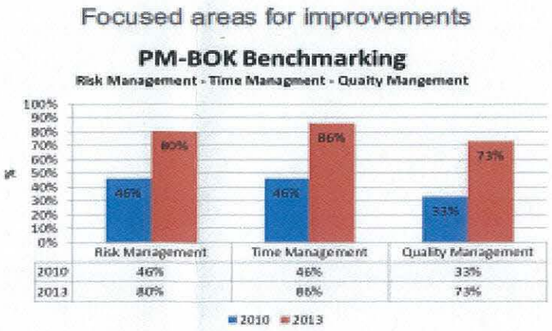


All Areas

External Benchmarking Results



Focused areas for improvements



1.3 Asset Criticality and Critical Spares Strategy

Hydro recognizes the importance of asset criticality and of managing critical spares, as part of the overall asset management plan and to ensure readiness. It has developed a strategy, framework, and process that are consistent with good practice.

Prior to 2011, Hydro generally managed and maintained critical spares based on vendor and OEM recommendations and operational experience, failure history, and equipment condition assessments. Critical spares have been continuously developed over the years. Recent examples of successful sparing strategy are evidenced by the Transmission and Rural Operations group's ability to quickly replace bushings/breakers/disconnect switches which failed and by the ability of generation facilities to respond to incidents like a generator winding failure and a transformer failure with parts from their critical spares.

In 2011 Hydro undertook a three year, three phase asset criticality and critical spares program in recognition that assets were later in their life cycle and that the critical spares program should be refreshed for improved response to equipment failures.

The first phase in 2011 involved a cold eyes review by internal maintenance experts involving both frontline maintainers and technical leads. The process consisted of internal round table reviews of available spares against an area's asset hierarchy and the health of those assets. Perceived gaps were identified, discussed in the context of failure probability and impact, and addressed as appropriate to support least cost reliable service to customers. The process identified some initial augmentations in spares, some potential spares inventory reductions, and some gaps and risks requiring broader discussion. The purpose was to identify obvious risks and address them quickly before the upcoming peak winter season.

The second phase in 2012 involved adding a more structured and detailed approach. External expertise was introduced in the form of an Asset Criticality Workshop facilitated by supply chain experts BDI. The process referenced was a disciplined approach to identifying asset criticality and then strategically stocking critical spares so that negative impacts to corporate goals and objectives are minimized and positive impacts are maximized. An initial framework was identified and sample assets were analyzed.

The third phase in 2013 involved the various divisions undertaking asset criticality reviews. Holyrood piloted a detailed review down to the individual equipment/component level. Other groups undertook an initial review at a higher level in the asset hierarchy.

In 2014 the aim is to refresh the plan for the next 3 years, broadly leveraging the rigor and disciplined process piloted at Holyrood and incorporating knowledge and experience gained to date. An initial "Lessons Learned" workshop was organized and executed with relevant participants through the Long Term Asset Planning Council on January 30, 2014. While higher level assessments have provided some value, the findings had usually been addressed through the qualitative reviews of the past. Detailed equipment/component level assessments were identified by Holyrood as critical to further identify and reduce operational risks relating to spares. This process requires significant work to effectively analyze data and make informed decisions, making prioritization and focus through asset criticality assessments essential.

The Asset Criticality (AC) & Critical Spare (CS) process includes review by qualified personnel and stake holders. It utilizes a two stage approach using an Asset Criticality Risk Matrix and a Critical Spare Decision Diagram to assess asset criticality and identify critical spares. Key elements include the following:

- Identification of critical assets (Consequences and Probability of Failure);
- Spare part lead time;
- Number of potential suppliers;
- Availability of technical specifications and knowledge;
- Type of maintenance whether corrective or preventive;
- Decision diagram for spare part criticality classification.

Hydro's self-assessment "dashboard" chart below illustrates where Hydro believes the status of the work is in 2013. Green is program completed as planned for 2013; yellow is partially completed; red is deferred to 2014). These types of dashboards are used in several Hydro systems to quickly present current status vs plan. Based on available information, Hydro's assessment seems reasonable.

Target	Churchill Falls	Hydro Generation	Thermal/ Holyrood	TRO G&TS	TRO T&D
Asset Criticality assessments				50% Gas Turbines done, Diesel Plants 36% complete, Term Stns 15% done	50% Transmission done, Distribution into 2014
Critical spares rationalizat'n 2013 phase				25% Advanced transformer bushings, priority item	Rescheduled into 2014

The work is continuing in 2014 and is planned to continue beyond that.

1.4 Maintenance Execution

Excellence in maintenance execution is the end result of the successful execution of the "Fully Integrated, Resource Levelled, Ready-for-Use annual Execution Work Plan" – "Plan the Work and Work the Plan". The plan is intended to ensure that the activities, resources, outage window availabilities and other considerations all converge to a viable program, successfully executed. The execution of the plan takes those elements and ensures that they are undertaken so as to achieve the cost, schedule, performance, environmental and regulatory requirements associated with the work.

Hydro has highly competent and well trained staff, including those in maintenance, project management, planning, engineering, operations, and skilled trades. Overall, staff interviews and interactions make it clear that staff commitment to Hydro's success and to performing their work well is very high.

Typically maintenance work priorities start with PM work undertaken on a scheduled basis (typically annual, three year, six year, nine year, or as required by equipment condition/tests), then critical corrective and scheduled outage/overhaul/project work. The scope and schedule for PM work has been updated through a structured Asset Maintenance Review Project completed in 2011. It looked externally at leading practices in the utility industry across North America and compared those to Hydro's own practices, adopting or adjusting as appropriate for Hydro's unique operational and environmental context with evaluation performed by

roundtable panels of internal experts and frontline maintainers and operators. Work execution status is tracked through the JD Edwards maintenance module and reviewed by facility management on a regular basis to ensure critical work is being done.

Testing, inspection and routine ongoing equipment condition assessment is a key element of identifying potential or developing difficulties. Generally Hydro utilizes industry standard testing protocols and frequencies. Decisions are sometimes taken, weighing the benefits and risks, to postpone some more time consuming/complex tests to optimize resource/outage requirements and constraints between tasks.

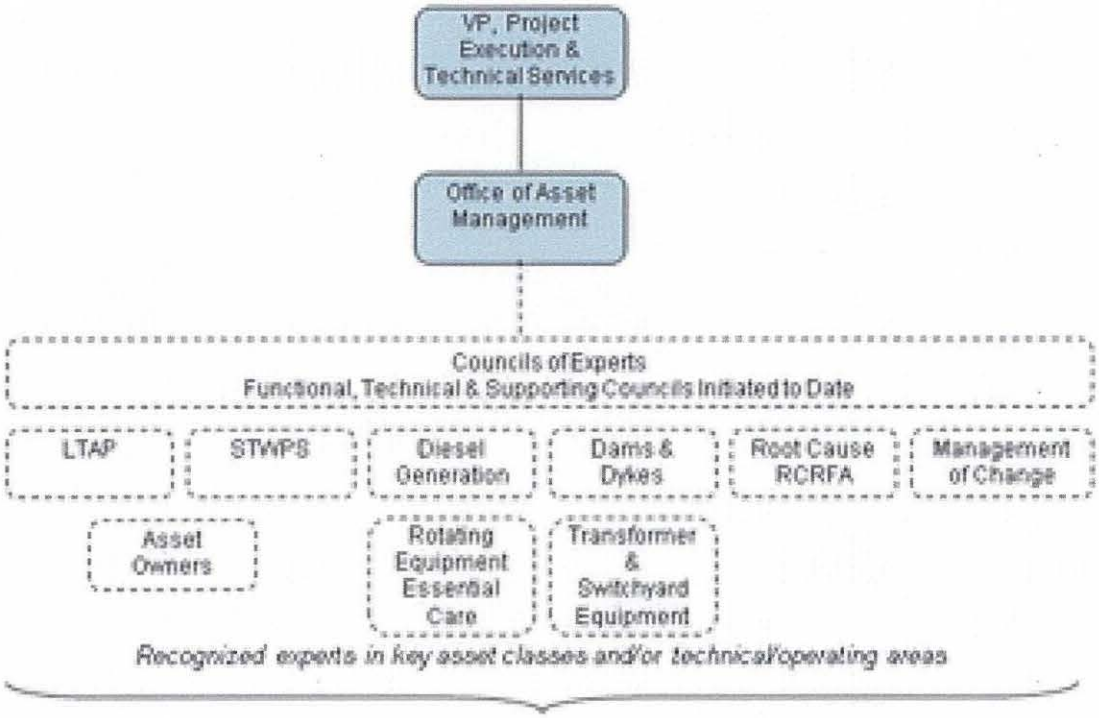
Historically some PM work has been deferred due to shifts in outages for system/economic reasons, or due to trade-offs between work programs. These kinds of decisions on trade-offs are normal practice in any utility, but given the age of much of the Hydro equipment the risks can be higher.

As is evident from the previous PMI benchmarking survey, Hydro is continuing to improve its execution of project work. Similar improvements are expected in preventative maintenance execution and in corrective maintenance as the new annual Execution Work Plan process is fully implemented.

1.5 Council of Experts

Hydro has established Technical Councils / Councils of Experts to assist the Office of Asset Management, through providing input on plans and project needs (for organization see Hydro figure below). These can be either internal Hydro experts or external experts from vendors, consultants or other utilities. These are intended to ensure that the latest and best information is available as input into the asset and project plans for Hydro facilities to enhance its best technology/technical practices capabilities.

In 2011 these "Council of Experts" included Root Cause and Repeat Failure Analysis; Long Term Asset Planning, Short Term Work Planning & Scheduling; and Management of Change. In 2012 the councils added were Transformers & Switchyard Equipment, Diesel Generation, and Rotating Equipment Essential Care. In 2013 councils were added for Asset Owners and Dams & Dykes. In 2014, the plan is to stabilize and mature the councils established to date and examine future needs.



4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME

Asset Management is related to the Sequence of Events associated with the January 2014 System Outage Incident in that it helped Hydro be better prepared to deal effectively and efficiently with unforeseen failures, and it supports continuous improvement and learning from those events. In essence the work of Asset Management has helped to reduce the impacts of unforeseen failures (e.g. through availability of required spares) and reduce the risk to reliable service from aging assets (e.g. through continuously improving asset condition data and asset renewal plans). This works is continuing in 2014 and beyond.

Incident Review Process – Jan 2014

The actual "Sequence of Events Incident Review" process was carried out in a manner consistent with good industry practice in terms of working towards determining a root cause and actionable steps for the future. The methodology used was a robust process, including: a formal "Tap Root" root cause analysis tool and facilitator, OEM/Hydro investigations of failed/suspect equipment, internal and independent external experts reviews and interviews,

field inspections, and system data mining and reviews.

Winter Readiness

In general terms, Asset Management helped ensure that the system was prepared for responding to issues during a high load winter period. Several aspects were evident that much of the work associated with asset management had been done or were underway and that in fact extra effort had been undertaken to ensure winter readiness:

- FM Global Insurance inspections, at Bay d'Espoir and Holyrood in particular, had been undertaken earlier in 2014 and much of the work that could be addressed in 2014 and was relevant to winter readiness had been completed
- 2013 PM's in the Execution Work Plan at generating and TS facilities (including Bay d'Espoir GS and TS, Holyrood GS and TS, Oxen Pond TS, Sunnyside TS, Come-By-Chance TS, Western Avalon TS, Hardwoods TS) had been completed. A trade-off decision had been taken on some TS's to defer some six year PM's due in 2013 and not include them in the 2013 Execution Work Plan due to higher priority capital work programs and other longer backlogged PM's at the various sites.
- Many of the critical PM's at Holyrood GS Unit 2 which were important to winter readiness and had previously been postponed were completed during a shortened 4 day outage and weekend maintenance outages in late November and on weekends into Dec. The Unit 2 outage had been postponed due to even higher priority work on Holyrood Unit 1 steam turbine generator in order to get Holyrood Unit 1 back into service.
- Holyrood Level 2 boiler and high pressure steam/water condition assessment work was undertaken to better assess any operational and safety risk associated with those systems.
- A selective third party winter readiness review was undertaken between November 12 and 26 2014 (weather delays extended the overall duration) which included Holyrood Unit 2 and the fuel system, Bay d'Espoir Unit 7 and auxiliaries, and the major facilities at Bay d'Espoir TS, Holyrood TS, Oxen Pond TS, Sunnyside TS, Come-By-Chance TS, Western Avalon TS, and Hardwoods TS. The review process was based on a visual walkdowns, interviews with management and maintenance/operations staff, reviews of available 2013 Execution Work Plan PM and work records, transformer inspection/oil analysis data, and thermography where practical of major GS switchgear and TS connections.
- A selective third party winter readiness review was undertaken Dec 3 to 6 2014 which included the Churchill Falls GS, the Churchill Falls TS, and the Wabush TS. The review process was based on a visual walkdowns, interviews with management and maintenance/operations staff, reviews of available 2013 Execution Work Plan PM and

work records, transformer inspection/oil analysis data, and thermography where practical of major GS switchgear and TS connections.

- A multi-year program for replacement/refurbishment of older critical equipment (i.e. breakers – OCB, SFA, ACB; disconnect switches, transformers, switchgear, air compressors and piping) that has been ongoing for the last several years and is planned for several years to come. This is evidenced as part of the significant growth in capital program in last five years

Overall the Hydro corporate management and field operations management and staff at the generation, transmission and terminal station facilities are well aware of the importance of Winter Readiness and had undertaken significant efforts to implement projects needed to be ready for the 2014 winter season.

Asset Management Aspects of the Results of the January 2014 Incident Review (Preliminary)

The incident investigation and Tap Root review process related to the January 2014 process has been underway essentially since the system was restored. Several pieces of equipment appear to have failed to operate properly and/or were damaged in the January 2014 outage incident. Details of the causal factors and root cause analysis and recommended actions are part of the formal Tap Root Analysis report.

5 KEY FINDINGS AND RECOMMENDATIONS

Several positive key messages can be taken from the analysis of the information:

Hydro strives to follow a structured approach to Asset Management with Condition Assessment as the foundation for the development ongoing care and renewal of its installed asset base.

"Hydro's definition of Asset Management is the comprehensive management of asset requirements, planning, procurement, operations, maintenance and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service to current and future generations. It is a holistic, cradle-to-grave lifecycle view on how they manage their assets."

Hydro's asset management approach is consistent with best electric industry practices such as the Electric Power Research Institute's (EPRI) condition assessment process for large generation facilities.

Hydro's asset management program is a deliberate, rigorous process. It has an emphasis on self-assessment and measurement to ensure continuous progress and improvement. In essence it provides the basis for ensuring "the management of the right work on the right assets at the right time".

Hydro's asset management program continues, as it has since 2006, to make steady progress in its scope and its application to all aspects of its business.

A key Hydro's asset management program result is the well thought- out, prioritized and integrated portfolio of 20 Year, 5 Years, and 1 Year expenditure plans that can be and are adapted as priorities change with time and data. The Execution Work Plan program piloted within another Nalcor line of business is being leveraged to the various parts of Hydro in 2014. It is very extensive and is considered consistent with best industry practices

Other key findings and their recommended actions where applicable include:

1) Hydro's asset replacement/refurbishment activities for older breakers, disconnects, transformers have been ongoing for several years and extend for many more. Given some issues with older breakers during the January 2014 outage incident, the scope and timing of the program should be reviewed in early 2014.
2) Hydro's new Execution Work Plan program has been well demonstrated in 2013 in other business lines. To improve resource utilization and effectiveness and outage management, its planned extension to replace existing Execution Work Plan processes at other Hydro facilities in 2014 is recommended.
3) Hydro critical spares tracking/management until 2011 has been done primarily on a local facility basis reflecting experience, condition assessments, and vendor recommendations, constantly evolving over past years and decades, and continues to do so. After an initial three year development and assessment period beginning in 2011, a comprehensive pilot to the equipment level at Holyrood in 2013 of Hydro's asset criticality and critical spares tracking / management plans provided valuable feedback at an initial "Lessons Learned" assessment that was undertaken January 30, 2014. This should be followed up on, as is Hydro's plan, in early 2014 following the work on the

January 2014 incident. This will move the process towards a more comprehensive and cost effective approach consistent with industry practice and addressing critical issues before winter 2014-15 as a part of the overall asset management program for the winter of 2014/15.

4) Hydro has significant technical capability and staff, and has introduced a "Council of Experts" concept to enhance its best technology/technical practices adoption capabilities.
5) A more rigorous winter readiness program should be introduced, largely driven by internal self-assessment with appropriate external support/review.
6) Hydro's O&M at Holyrood has not been impacted since the sanction of Muskrat Falls. Condition assessments on critical systems (i.e. re: safety, reliability) have continued. Capital and major operations projects in Holyrood's long term asset management plan consistent with the station's end of life plans and required to ensure safe, reliable and environmentally sustainable operation have not been impacted. Those not critical for the period to end of generation service in about 2020 have not been approved, and won't impact availability to then.

6 RECOMMENDATIONS STATUS

- Recommendation 1): Hydro's asset replacement/refurbishment activities for older equipment (i.e. breakers, disconnects, transformers) have been ongoing for several years and extend for many more. A decision is required in early 2014 in order to begin an assessment in early 2014 of the need for its acceleration.
- Recommendation 2): Hydro's new Execution Work Plan program has been well demonstrated in other business lines. To improve resource utilization and effectiveness and outage management, it is currently planned to extend this to other Hydro facilities in 2014.
- Recommendation 3): Hydro's asset criticality and critical spares tracking/management plans were intended to be broadly expanded beginning in February 2014, but have been deferred modestly due to the January 2014 Outage Incident impacts. An initial "Lessons Learned" assessment was undertaken January 30, 2014. Further detailed work is planned to be initiated in 2014 with critical issues addressed before winter 2014-15.
- Recommendation 4): Hydro has introduced several "Council of Experts" to enhance its best technology/technical practices capabilities. It plans to continue these in 2014 to cost effectively enhance its technical capabilities and to look for additional opportunities to enhance its best technology/technical practices capabilities.

- Recommendation 5): Hydro has drafted an internal winter readiness self-assessment guide and will undertake a more rigorous winter readiness program in 2014, building on the self-assessment and 2013 work.

Acronyms

AC	Asset Criticality
ABC	Air Circuit Breaker
AEP	American Electric Power
AM	Asset Management
BDE	Bay d'Espoir
BOD	Board of Directors
CBC	Come-By-Chance
CEA	Canadian Electricity Association
CEATI	Canadian Electricity Association Technologies Incorporated
CEO	Chief Executive Officer
CM	Corrective Maintenance
CS	Critical Spares
EPRI	Electric Power Research Institute
FD	Forced Draft
FEED	Front End Engineering and Design
GS	Generating Station
GT	Gas Turbine
HRD/HTGS	Holyrood GS/Holyrood Thermal Generating Station
JDE	JD Edwards
kV	kilovolt
LTAM (LTAMP)	Long Term Asset Management (LTAM Plan)
LTAP	Long Term Asset Plan
MOC	Management of Change
MRF/LIL/ML	Muskrat Falls/Labrador Island Link/Maritime Link
OAM	Office of Asset Management
OCB	Oil Circuit Breaker
OEM	Original Equipment Manufacturer
O&M	Operations and Maintenance
O/S	Out of Service
OPG/OH	Ontario Power Generation/Ontario Hydro
NLH	Newfoundland and Labrador Hydro
PETS	Project Execution and Technical Services
PM	Preventive Maintenance
PMI	Project Management Institute
P&C	Protection and Control
PUB	Board of Commissioners of Public Utilities
R&D	Research and Development
SC	Synchronous Condenser
SFA	SF6 Circuit Breaker
SOE	Sequence of Events

SPA	Single Point Accountable
SSD	Sunnyside TS
T&D	Transmission and Distribution
T1	Transformer #1
TRO	Transmission and Rural Operations
TRO G&TS	TRO Generation and Terminal Stations
TS	Terminal Station
WAV	Western Avalon TS

Appendix 1

Asset Management Information Related to Responses to "Other Questions"

Question a) The decision to temporarily remove the jacking oil pump from the Stephenville GT on December 11 and install it at Hardwoods. How and why the decision was made and its implications?

Asset Management Program Response: This would have been an operations decision based on the best information available as to which facility would have benefitted most in terms of in-service and contributed most to supply security. It was not strictly speaking an Asset Management process issue. Had other factors been evident, a different decision might have been made. As far as the January 2014 system incident is concerned, this had no impact.

Question b) The need to replace insulating blankets on end B of the Stephenville GT appears to have been known since the summer of 2013, Why the delay in this issue being addressed? Could it have been addressed sooner, if so would that have entailed additional cost?

Asset Management Program Response: From an asset management process perspective, this is a project management/design issue that likely should have been picked up in a timely fashion. As far as the January 2014 system incident is concerned, this had no impact.

Question c) Was there an alternative that would have allowed the Hardwoods GT alternator repair/replacement to be carried out before the end of the planned outages at Holyrood? Could reasonable efforts have been made to advance the planned Hardwoods GT outage to an end-date before December 19?

Asset Management Program Response: The plan was to have Hardwoods available well before the winter. Delays and the failure of the fuel control valve were not expected. As far as the January 2014 system incident is concerned, the plan had no impact on the January 2014 system incident.

Question d) The new fuel control valve failed at Hardwoods GT on Dec 21 but the required external specialist was not available until Jan 6. Considering the importance of Hardwoods as a "critical generating asset", could extra efforts been made to expedite the availability of the require expertise? How can such matters be planned for more expeditious action going forward?

Asset Management Program Response: Efforts were made to obtain the required expertise more quickly, but were unsuccessful. The failure of the control valve was not expected - a reasonable assumption. The situation will likely be reviewed to see what could be done –

project timing, commissioning spares, etc... As far as the January 2014 system incident is concerned, the failure didn't have a significant impact on the larger system incident, but would have impacted the extent and duration of the rotating power outages. Detailed study would have to be undertaken to make a definitive statement.

Question e) Were any of the required actions to bring the various impacted units, breakers, transformers, etc. which failed during mid-Dec to mid-Jan back into action delayed due to timely access to critical spares or personnel (NLH or external specialists). If so, how is this being addressed?

Asset Management Program Response: Given the analysis to date regarding the January 2014 incident is concerned, it is not believed that any of the required actions to bring the various impacted units, breakers, transformers, etc. which failed during mid-Dec to mid-Jan back into action was delayed due to timely access to critical spares or personnel (NLH or external specialists).

Question f) Were there any prior indications of the issue which caused the Sunnyside transformer fire?

Asset Management Program Response: The transformer PM testing had been completed earlier in the year and did not indicate any significant issue. Thermal imaging of the various Sunnyside switchyard connections and equipment had been completed and showed no issues requiring immediate response. The equipment is being inspected to better define what happened and how it happened, and what could be done to avoid similar occurrences.

Question g) Were there any prior indications of the issue with the Holyrood Unit 3 forced draft fan that could have signalled a concern?

Asset Management Program Response: No PM testing had indicated any concerns earlier in the year. The equipment has been repaired and Hydro have some results on the root cause of the failure. As far as the January 2014 incident is concerned, it is unlikely that the de-rating of Unit 3 due to the FD fan would have had a significant impact on the on the larger system incident, but would have impacted the extent and duration of the rotating power outages. Detailed study would have to be undertaken to make a definitive statement.

Question h) Has the anticipated removal of HTGS from service in any way impacted the capital works considerations which might otherwise have been carried out? Have any of these decisions potentially impacted the availability of the Holyrood generating units?

Asset Management Program Response: Holyrood is planned to remain in generation service until 2020 (as a standby between 2017 and 2020) and Unit 3 will continue as a synchronous

condenser (SC) for the foreseeable future to provide system voltage support. The primary capital impact had to do with converting Units 1 and 2 to synchronous condenser capability which would have required significant expenditures for generator life extension as well as costs for modifying the facility to accommodate the SC service. An alternative approach at Soldier's Pond was selected. No capital was removed that would have significantly affected the availability of Holyrood. As far as the January 2014 incident or similar incident is concerned, there would be no impact on the outcome.

Appendix 2

Documents/References Reviewed List

Asset Management Strategies & Updates

Asset Management and Project Execution at Nalcor Energy
Asset Management Status Update Q1 2013

Asset Management Excellence – December 2013 Progress Report

Project Execution

Project Execution & Technical Services PMI Benchmarking Survey Comparison 2013-11-25

Application of Staged-Gate Process for Planning and Executing Individual Projects within the Long Term Asset Management Plan 2013-05-21

Project Execution Multi-year Plan November 23, 2011 (R3)

Driving Project Execution and Technical Services Excellence December 15, 2013

2011 Project Execution & Technical Services PM Benchmarking Report

2013 Project Execution & Technical Services PM Benchmarking Report

Churchill Falls 2014 Annual Work Plan Integrated Resource Planning

Long Term Asset Management

Holyrood

Hydro Generation

Transmission Rural Operations

- Gas Turbines & Terminal Stations
- Transmission Distribution

Condition Assessments

Holyrood Thermal Generating Station Condition Assessment and Life Extension Study - Phase 2

2012/2013 Level II Condition Assessment Civil Structures and Unit 3 Generator AM141/RP/002 R00 AMEC December 20, 2013

Holyrood Thermal Generating Station Condition Assessment and Life Extension Study - Phase 2 2012/2013 Level II Condition Assessment Boiler and High-Energy Piping AM132/RP/005 R03 AMEC November 13, 2013

Power System Performance Review Report January 11, 2013 - Winter Storm Events Prepared by: Power System Review and Analysis Committee June, 2013

Condition Assessment & Life Extension Study Holyrood Thermal Generating Station Prepared by: AMEC January 28, 2011

Holyrood Gas Turbine Condition Assessment & Options Study Holyrood Thermal Generating Station Prepared by: AMEC December 19, 2011

Diesel Plant Remediation Phase II - Final Report H342925-0000-00-124-0002 Prepared by: Hatch April 12, 2013

Hydraulic Structure Life Expectancy Study Prepared by: Hatch May 22, 2009

Condition Assessment and Life Cycle Cost Analysis Hardwoods and Stephenville Gas Turbine Facilities Prepared by: Stantec December 18, 2007

Circuits TL202, TL203, TL206, TL207 and TL237 Transmission Line Protection Performance and Settings Review Prepared by: Henville Consulting Inc December 31, 2010

Circuits TL201, TL217, TL218, TL236 and TL242 East Coast Transmission Line Protection Performance and Settings Review Prepared by: Henville Consulting Inc December, 2011

Gas Turbines

Maintenance Strategy Manual Hardwoods and Stephenville Gas Turbines April 21, 2008

Final Report - Condition Assessment and Life Cycle Cost Analysis Hardwoods and Stephenville Gas Turbine Facilities December 18, 2007 Stantec Consulting

Hardwoods Gas Turbine Plant Life Extension Upgrades, Year 1 (2009)

Plant Life Extension Upgrades, Hardwoods Gas Turbine, Years 2-4 (2010-2012)

Hardwoods Gas Turbine Alternator Replacement (2013)

Replace Automatic Voltage Regulator on Gas Turbine, Stephenville (2009)

Critical Spares – Plan & Progress

Transmission Rural Operations (Gas Turbine & Terminal Stations)

Transmission Rural Operations (Transmission & Distribution)

Holyrood

Hydro Generation

Capital Plans

Approved 2014 Capital
20 Year Consolidated Plan

Holyrood Binder

Maintenance Strategy Manual Holyrood Thermal Generating Station June 28, 2010

Condition Assessment and Life Extension Study, Holyrood Thermal Generating Station January 28, 2011 AMEC

Holyrood Gas Turbine Condition Assessment and Options Study December 19, 2011 AMEC

Holyrood Thermal Generating Station Condition Assessment and Life Extension Study – Phase 2: Boiler and High Energy Piping November 13, 2013 AMEC

Holyrood Thermal Generating Station Condition Assessment and Life Extension Study – Phase 2: Civil Structures and Unit 3 Generator December 20, 2013 AMEC

Capital Projects 2009, 2010, 2011, 2012, 2013, 2014 - Summary sheets for projects approved by the Public Utilities Board for commencement in 2009

Sample Project Schedule

Sample Project Risk Workshop

Project Management Manual

Project Management Manual
Project Management Manual Updates
Quality Management
Change Management
Time Management
Risk Management
Safety & Health Management

Self-Assessment

Asset Management Maturity - Self-Assessment Surveys 2011 Results, 2012 Results, 2013 Results
Asset Management System Implementation
Planning & Scheduling Function
Lubrication Program - Self-Assessment Template, TRO, BDE, CF(I) Co, Exploits, Menihek, Results Summary
Root Cause Failure Analysis – Self Assessment
LTAP Function
KPI's and Metrics - 2013 Results – Holyrood, Labrador, TRO Northern, TRO Central, Hydro Generation
System Performance - Power System Reliability and Equipment Performance Report – 2011, 2012, 2013

TRO Terminal Stations

Maintenance Strategy Manual, TRO Terminal Stations, April 6, 2011
Capital Projects 2009, 2010, 2011, 2012, 2013 - Summary sheets for projects approved by the Public Utilities Board for commencement

Critical Spares – Plan & Progress

Holyrood
Hydro Generation
Transmission Rural Operations

Asset Criticality & Critical Spares

Asset Criticality and Critical Spares Framework
Asset Criticality Workshop BDI December 05, 2012
Equipment Criticality Assessment Guide

Holyrood Asset Criticality - Lessons Learned January 30, 2014
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Transmission

Wood Pole Line Management Overview
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Wood Pole Line Management Using RCM Principles April 7, 2004
Transmission Internal Standards
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Distribution

Maintenance Strategy Report TRO Distribution System April 20, 2011
Distribution Internal Standards
Canadian Standards Associations C22.3 No. 1-10
Capital Budget Proposals

Other Key Documents

FM Global
Enterprise Risk
Internal Audits
Operations Readiness Check 2013
Business Continuity
Asset Management Councils Status

NEWFOUNDLAND AND LABRADOR HYDRO

Generation Availability

March 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 2
2 REVIEW PROCESS 2
3 BACKGROUND 2
4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME 15
5 KEY FINDINGS AND RECOMMENDATIONS 22
ACRONYMS 28

Appendices:

Appendix 1 Detailed Capability Comparison
Appendix 2 Details – Gas Turbine Availability
Appendix 3 Details – Holyrood Availability
Appendix 4 Details – Hydroelectric Generation Availability
Appendix 5 Details – Wind Generation Availability
Appendix 6 Details – Under-Frequency Event History 2004 to 2013

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed an extensive review of the events surrounding the supply disruptions on the Island Interconnected system during January 2 to 8, 2014. The review included investigation of the rotating outages that occurred between January 2 to 8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014.

This report outlines the results of the investigation/assessment of Hydro's generation assets availability leading up to, and during the January 2 to 8, 2014 system event. It is intended to summarize the results of Hydro's internal review of its generation availability, specifically addressing the following:

- Gas turbine availability
- Holyrood availability
- Hydro generation availability
- Wind generation availability

The Key Findings and Recommendations are provided in Section 5.

The main recommendations from this review are:

- Through the existing Critical Spares Council, follow-up on the critical spares program as is currently in Hydro's plan in early 2014.
- Create a senior position reporting to the Vice-President for Hydro whose accountability includes the oversight of asset management plans, maintenance standards and capital submissions related to gas turbines.

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

1 INTRODUCTION

This report outlines the results of the investigation/assessment of the Island Interconnected System generation assets availability before, leading up to, and during the January 2 to 8, 2014, system event.

The scope of this focus area/element involves an assessment of:

- Factors that contributed to unplanned unavailability.
- Long term asset management plans.
- Maintenance plans and execution thereof.
- Critical spares availability.
- Winter readiness, including availability of fuel.
- Scheduling of gas turbine overhauls/outages.

2 REVIEW PROCESS

The review process involved internal Hydro generation asset experts, as well as generation expertise support from AMEC Americas. The (AMEC) work included:

- Review of existing Hydro data relevant to historical generation asset availability.
- Review of information on generation availability and issues leading up to and during the January 2 to 8, 2014 system event.
- Discussions/interviews with Hydro staff.

3 BACKGROUND

3.1 Overview of Facilities

Planning on the Island Interconnected System is designed to address:

- Capacity planning criteria: The Island Interconnected System should have sufficient capacity to satisfy a Loss of Load Hours (LOLH) expected target of <2.8 hours per year.

- Energy planning criteria: The Island Interconnected System should have sufficient capability to supply all of its firm energy requirements with firm system capability.
- A Transmission Planning Criteria that establishes operating assumptions and the various transmission contingencies for which the system is planned to survive.

Other factors impacting Operational Planning include:

- Dispatch generation to maintain an "n-1" generation reserve.[2]
- Holyrood fuel use minimization is a priority but may be limited by available inflows, reservoir storages and by system security considerations, such as system capacity and voltage constraints.

Figure 1 provides a general overview of Hydro generating facilities and their in-service dates.

In addition, the Island Interconnected System has about 163 MW of non-dispatchable generation sources (the power system operator in the Energy Control Centre (ECC) cannot control and thereby set the level of output), as follows:

- 54 MW of wind generation, varies with wind conditions;
- 90 MW of run-of-river Exploits River generation (63 MW of output can be sustained by varying the flow out of Red Indian Lake; 27 MW is dependent on uncontrolled flows in the river);
- 4 MW of run-of-river generation at Rattle Brook, dependent on river flow; and
- 15 MW Corner Brook Pulp and Paper co-generation, dependent on the paper mill's steam requirements.

[2] "n-1" refers to having generation reserves readily available and able to be started quickly to replace the loss of the largest unit currently in-service in order to avoid a prolonged customer interruption. Operational planning will typically result in extended planned maintenance only occurring during non-winter periods. It is possible that during the winter peak period this criteria could be violated while still adhering to the 2.8 hour criterion.

Island System*

Year	Generating Units	Installed Capacity (MW)	Net Capacity (MW)
1968 -70	Bay d'Espoir Units 1-6	450	438
1971	Holyrood Units 1-2	300	285
1976	Stephenville Gas Turbine	50	50
1977	Hardwoods Gas Turbine	50	50
1977	Bay d'Espoir Unit 7	154	154
1979	Holyrood Unit 3	150	143
1980	Hinds Lake	75	75
1983	Upper Salmon	84	84
1985	Cat Arm	127	127
1988-89	Holyrood Upgrades	40	38
2003	Granite Canal	40	40

*Significant Generation Asset Additions

Figure 1: Overview of Generating Units on the Island System

Note:
1) The difference at Bay d'Espoir is not due to station service, but due to low water conditions.
2) Cat Arm generating units can produce > 63.5 MW each. Installed capacity closer to 67 MW.
3) Diesel units (Hawkes Bay and St. Anthony) provide approximately 15 MW of capacity and were important contributors to the system during rotating outages.

Hydro's generation planning assessments take into account this non-dispatchable nature and under most normal operating conditions, there is more than enough firm dispatchable generation available to meet peak loads. The current level of non-dispatchable generation has not affected Hydro's ability to meet its peak load. The non-dispatchable generation, when available, increases the level of generation potentially available as reserve. Actual dispatch is based on optimizing the generation mix to get the most cost effective power mix while meeting system reliability requirements.

Figure 2 provides a view of the Hydro generating facilities' age distribution.

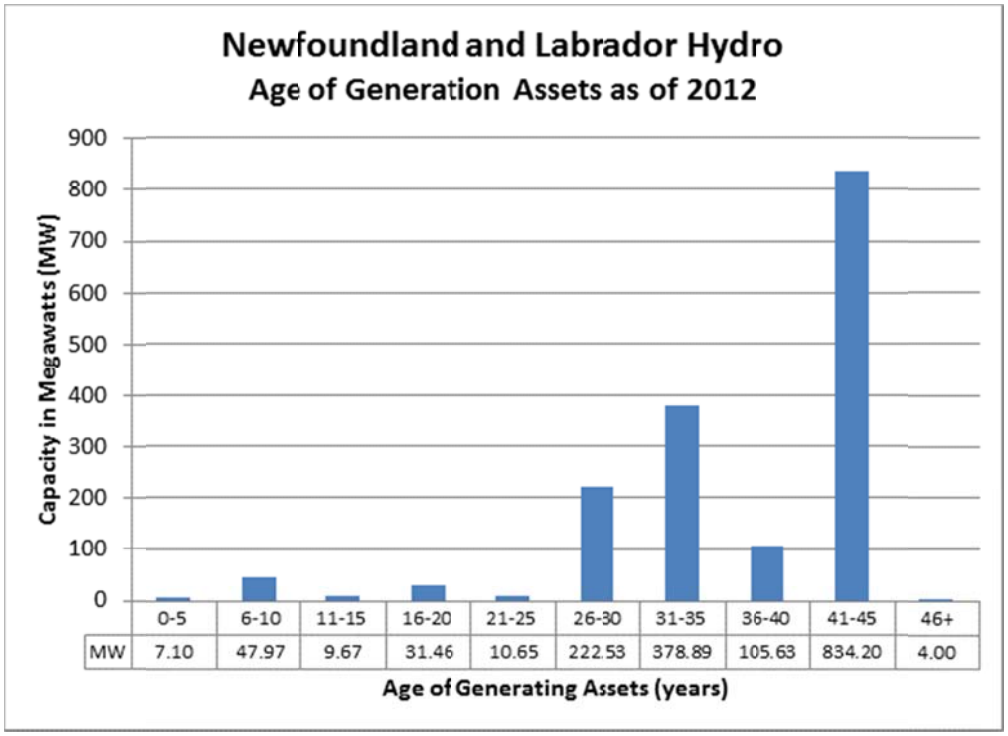


Figure 2: Age of Generation Assets as of 2012

Note: The ages are based on the facilities' original in-service dates. Some key assets within the plants have been renewed. The chart includes the diesel generators.

3.2 Generation Availability Metrics - CEA Benchmarks

Hydro utilizes the Canadian Electricity Association (CEA) membership database as one of its benchmarks for unit performance for equipment reliability – Capability Factor, De-rating Adjusted Forced Outage Rate (DAFOR), Failure Rate, and Utilized Forced Outage Probability (UFOP). Table 1 below highlights the various performance indices for Hydro's generation facilities for 2012 and 2013[3]. The average for the period 2008-2012 for comparison with the latest CEA national average findings for the same period are included as well.

[3] The Hydro data is based on the performance of all of Hydro's generation assets (excluding diesels) and not just those of the Island Interconnected system. The only unit in the data set outside of the Island Interconnected system is the Happy Valley GT. It therefore does provide a reasonable indicator of Island Interconnected facilities.

Table 1: Generation Performance Indices – CEA Benchmarks 2012-2013

Generation Performance Indices – CEA Benchmarks				
Index		**Hydro**	**Thermal**	**Gas Turbine**
Failure Rate (Forced Outages per 8,760 operating hours)	NLH 2013	1.42	8.84	144.46
	NLH 2012	1.78	8.22	231.67
	NLH '08-'12	2.62	6.38	137.89
	CEA '08-'12	2.06	7.11	22.30
Incapability Factor (Percent of Time)	NLH 2013	7.97	53.96	26.73
	NLH 2012	9.26	26.92	31.28
	NLH '08-'12	7.83	30.99	23.12
	CEA '08-'12	9.33	25.62	13.81
De-rating Adjusted Forced Outage Rate (Percent of Time)	NLH 2013	0.55	36.58	
	NLH 2012	0.95	5.98	
	NLH '08-'12	0.76	10.03	
	CEA '08-'12	3.66	9.23	
Utilization Forced Outage Probability (Percent of Time)	NLH 2013			28.07
	NLH 2012			56.33
	NLH '08-'12			22.64
	CEA '08-'12			11.84

Hydro Unit Performance

Hydro unit measures improved in 2013 when compared to 2012 and are better than the latest five year CEA national averages. Hydroelectric unit de-rating adjusted forced outage rate is significantly better than the latest five year CEA national average.

Thermal Unit Performance

Thermal unit performance deteriorated in 2013, particularly the Incapability Factor and De-rating Adjusted Forced Outage Rate measures. Performance in 2013 was worse than the CEA national five year average. The decline is primarily owing to the failure experienced on Holyrood Unit 1 in January 2013 and the lengthy outage that resulted. 2012 Hydro data is

similar to the CEA average, and the 2008- 2012 Hydro average values for its thermal units is consistent with the CEA benchmark. (Note: Hydro's data is comparable despite having less operating time because of its primary winter peak load period role as well as longer summer maintenance outages due to units not being required to meet system load. This is offset by the better availability during operating periods as a result of the additional maintenance and condition assessment activities in the summer months.

Gas Turbine Unit Performance

Hydro's gas turbine performance is much worse than the CEA national average, however it improved in 2013 in all areas. The Hydro Gas Turbine (GT) performance reflects their infrequent peaking role to provide system emergency support. A condition assessment was undertaken by Stantec in 2007-2008 and refurbishment work was carried out between 2010 and 2013. The Stephenville Unit was returned to service in June 2013 after a 20 month forced outage. A decision was made to allow for a longer outage period given planned system needs at the time. The improvements in some of the 2013 performance data were impacted by extended planned outages at Hardwoods for refurbishment and generator alternator replacement. The Utilization Forced Outage Probability is of particular importance to Hydro's use of gas turbines. It describes the degree to which a standby unit can be called upon to supply load when requested.

Table 3 further illustrates the poor gas turbine performance compared to other gas turbines in the CEA database[4]. It should be noted that the Hydro GTs also have a poor start performance. The roles and operating patterns of the gas turbines in the CEA database may include those operating more frequently.

[4] Capability Factor is defined as unit available time, the ratio of a unit's available time to the total number of unit hours. Incapability = 1 minus Capability Factor.
The Utilization Forced Outage Probability is the probability that a generating unit will not be available when required and measures performance of standby units with low operating time such as gas turbines.
Failure Rate is defined as the rate that a generating unit encounters a forced outage = the number of transitions from an operating to a forced outage state divided by the total operating time. It can be greatly influenced by limited operating time for gas turbines.

Table 3: Gas Turbine Performance

Unit	Five Year Average 2008-2012 - All Causes			
	Capability Factor (%)	UFOP (%)	Failure Rate	Number of Unit Starts
Hardwoods GT (2008-2012)	86.53	26.39	116.37	308
Stephenville GT (2008-2012)	37.55	38.68	90.29	97
CEA (2008-2012)	86.19	11.84	22.30	8420

3.3 Historical System Shortfalls Due to Generation Unavailability

In Hydro's operating history, there have been few recorded instances where the unavailability of generation capacity (due to weather conditions and equipment issues) resulted in Hydro being unable to supply the load of the Island Interconnected System. In the last ten years, there have been only two recorded instances of unavailability of generation capacity. The first occurred on January 23, 2006 from 11:25 to 12:30 hours. In that case, the Upper Salmon plant had experienced frazil ice, Holyrood Unit 2 was unavailable due to a boiler tube failure, the Hardwoods and Stephenville gas turbines were de-rated due to control system and fuel nozzle issues respectively, and the Holyrood gas turbine was de-rated due to an oil leak. There was 307 MW of generation capacity unavailable to the system with details as per the following Table 4.

Table 4: Generation Capacity – January 23, 2006

Generation Supply Issues - January 23, 2006			
Plant	Unit Rating (MW)	Unavailable Capacity (MW)	Notes
Holyrood Unit 2	170	170	Boiler tube failure (January 6, 2006)
Upper Salmon Unit	84	84	Frazil Ice blockage at intake
Hardwoods Gas Turbine[1]	54	24	Derated due to control system failures
Stephenville Gas Turbine[1]	54	27	Derated due to fuel nozzle failure on one End
Holyrood Gas Turbine	10	2	Derated due to oil leak and fire (unit ran with fire watch)
Total	372	307	

The second event occurred on January 11, 2013. There was an initial transmission system initiated outage that had a subsequent impact on generation unavailability. Severe weather resulted in failures in the Holyrood Terminal Station and 230 kV line outages that resulted in several generation units tripping, including all three Holyrood units. Unavailable capacity at the time is presented in the following table. Holyrood Unit 1 was damaged and as a result unavailable for much of 2013. This impacted Hydro being able to supply the load of the Island Interconnected System after the terminal station and transmission line repairs were completed.

Table 5: Generation Capacity – January 11, 2013

Generation Supply Issues - January 11, 2013 (as at 0743 hours)			
Plant	Unit Rating (MW)	Unavailable Capacity (MW)	Notes
Stephenville Gas Turbine	50	50	Unit unavailable due to work to rewind alternator
Holyrood Units 1-3	490	490	Units had tripped previously in the morning
Star Lake	18	18	Unit had tripped previously in the morning
Cat Arm Units 1 and 2	127	127	Units tripped due to high system frequency
Upper Salmon Unit	84	84	Unit tripped due to high system frequency
Granite Canal Unit	40	40	Unit tripped due to high system frequency
Other Purchases	83	21	NUGS reduction due to system upset
Total	892	830	

There have also been an average of approximately six under-frequency events per year on the Island Interconnected System from 2004 to 2013. The Island Interconnected System is an isolated system so that when there is a sudden loss imbalance between loads and generation (due to incidents, such as slow clearing transmission faults or sudden large loss of generation) some loads must be interrupted for short periods to bring generation output equal to demand. This automatic action of power system protection, referred to as under-frequency load shedding, is necessary to ensure the integrity and reliability of system equipment. Load interruptions are usually less than 30 minutes for these events because Hydro generally maintains an available reserve to cover off the failure of the largest unit. Details of these under-frequency events in 2004 to 2013 are presented in Appendix 6.

3.4 Generation Asset Readiness

3.4.1 Long Term Asset Management Plans

Hydro's long term asset management planning is comprehensive and consistent with good industry practices. The principles are used for Hydro's thermal, hydroelectric, and gas turbine facilities. Its focus is to achieve maximum value based on the required standard of service to current and future generations. For details of long term asset management plans and planning, the report *Asset Management Strategy and Practices* should be referenced. Condition assessment is a key tool in the development of Hydro's asset management plans, using methods such as those developed by the Electric Power Research Institute (EPRI).

Hydro has actively been undertaking priority condition assessments to better refine maintenance, refurbishment and replacement requirements and reflect those in short and long term work plans. The long term asset management plans are followed, except where unplanned and higher priority work are required or when changes in system production plans may occur. This results in reprioritization of annual plans and may require formal revisions to longer term plans. An example is the impact that the repair work to Holyrood Unit 1 in 2013 had on plans for Unit 2 maintenance work plans.

3.4.2 Maintenance Plans and Execution

Hydro's annual execution work plan is the key to its maintenance plans and their execution. The plan is intended to ensure that the activities, resources and outage window availabilities for all of its facilities converge into a viable overall program. The execution of the plan undertakes those elements to achieve the cost, schedule, performance, and environmental and regulatory goals associated with the work. Hydro has competent and skilled staff, including those in project management, planning, engineering, operations and skilled trades. Details of the maintenance planning and execution process are included in the report entitled *Asset Management Strategy and Practices*.

Hydro's maintenance execution largely reflects the maintenance, refurbishment and replacement activities in its annual execution plans. Plans do change due to reprioritization where unplanned and higher priority work is required. The example in Section 3.4.1 of the impact the repair work to Holyrood Unit 1 in 2013 had on plans for Unit 2 maintenance work applies here as well.

3.4.3 Critical Spares Management

Hydro maintains critical capital and consumable spares for all its facilities based on vendor recommendations, as well as operational experience, failure history and equipment condition assessments. Hydro has developed a strategy, framework and process that are consistent with good industry practice for its facilities.

The availability of generation asset critical spares did not impact the extent or duration of the large January 4 to 5, 2014 transmission/terminal station failure events. Issues at the generation facilities did, however, contribute to some of the rotating outages before the event on January 4, 2014 and during the system restoration activities. Two instances where equipment that might have been considered critical spares may have played a role in the rotating outages were: i) the outage of the Hardwoods GT due to the lack of an available spare fuel control valve; and ii) the de-rating of Holyrood Unit 3 due to lack of a spare 4 kV forced drive (FD) fan motor. The fuel valve was new and it would be a reasonable expectation that it should not fail during initial installation. A spare 4 kV FD fan motor had been suggested for procurement consideration in the 2011 Holyrood condition assessment. It was examined, costed and submitted as part of the 2012 capital approval process, but was not pursued further based on Hydro's capital prioritization process. The subsequent year, it was determined not to be a capital item and did not proceed further. A procurement decision would examine a number of factors, including spare motor cost, potential risk, generation contingency availability, time to repair, remaining generation life and the number of different 4 kV motors that would be required to cover off all of the 4 kV motor applications in the plant. Details of the overall critical

spares management program are presented in the report *Asset Management Strategy and Practices*.

3.4.4 Winter Readiness (including Availability of Fuel)

Winter readiness of generation facilities has been and continues to be a high importance area for Hydro with regular tracking and reporting of performance to bring a higher focus on this period than can be obtained using standard CEA measures. Up until the end of 2012, Hydro used an internal winter availability measure to track winter generation performance from December 1 to March 31 each year. In 2013, Hydro replaced this with a contingency reserve performance measure. The newer contingency reserve measure allows for minor maintenance in the winter period when demand permits while the older measure did not take the level of demand into consideration. This measure will continue to be a key performance indicator with which Hydro will establish targets to focus its efforts on.

In order to meet these targets, planned major project work and high priority corrective and preventive maintenance work on generation assets is planned to be completed so as to be winter ready. In the late fall of 2013, an external review was undertaken by AMEC which included a review of the winter readiness of Holyrood Unit 2 and its fuel systems review as well as Bay d'Espoir Unit 7 and its auxiliary systems. For Holyrood, it was identified that:

- the high priority Unit 2 outage maintenance work had been completed in shorter outages in late November and early December 2013, and
- fuel issues had been mitigated and additional spares procured to address potential fuel related maintenance issues.

Bay d'Espoir Unit 7 was considered to be in good condition for operation in the 2013/14 winter period. The external review did not identify any issues that were causal or contributing factors to the January 2 to 8, 2014 system event.

With the exception of the Stephenville and Hardwoods gas turbines, Hydro's generation assets were considered to be winter ready. The Hardwoods gas turbines would, to a large extent, have been winter ready by mid to late December if no issues had arisen at the end of its generator refurbishment. The failure of the fuel control valve at Hardwoods was unexpected and its extended return to service is the result of the time of year and limited service expertise in the market. The timeliness of the procurement and delivery of the Stephenville insulation blanket is an issue that may have been addressed sooner to minimize its potential impact. However, due to the very cold temperatures at the time of the low generation availability and the steps Hydro took at that time, the insulating blankets did not restrict the turbines output. On January 8, the Stephenville gas turbine experienced an unexpected bearing failure in the recently refurbished B end engine. Its impact could not likely have been prevented by additional inspection prior to the winter (for complete details, refer to Appendix 2).

Liquid fuel availability became an issue throughout the island of Newfoundland during the holiday period and the system event due to the nature of the fuel delivery contracting practices. Typically, fuel delivery in the province is done by contractors many of whom were on holiday in the period before the January 2 to 8, 2014 system event, and then unavailable due to the extreme weather during the rotating outages and system event. It did not, however, have an incremental impact on gas turbine availability. Hydro has a priority delivery contract, but manages its requirements so as not to impact other liquid fuel deliveries. It also undertook special efforts due to the short supply to secure 80,000 litres from the Canadian Coast Guard. The gas turbine fuel storage practice has been to maintain conservative levels of 60% of tank capacity to allow for plenty of room for fuel expansion, to increase the fuel inventory turnover, and to minimize the potential for environmental spills. An 80 to 90% storage volume could have been employed which would have allowed for longer operation without a delivery if necessary. This may have moderately reduced the requirements for some of the rotating outages if the gas turbines had been fully available during this period. It would not have had an impact on the larger January 4 and 5, 2014 transmission/terminal station failure events.

3.5 Winter Generation Capability

The following summarizes the total installed capacity for the Island Interconnected System.

Table 6: Island Interconnected System Supply

Island Interconnected System Supply	
Installed Capacity	
Hydro owned and operated	1,507.5 MW
Purchased	178.8 MW
Customer Owned	259.8 MW
Total Supply	1,946.1 MW

In more detail, it is composed of the following:

Table 6: Island Interconnected System Supply (Detailed)

		Firm (Dependable)						Non-Firm	Total	
Generation		Net Low Head	Low Supply Adjustments		Net High Head	Station Service	Gross High Head After Stn. Service*	Additional	Net Low Supply	Gross High Head After Stn. Service
			Nameplate	High Head						
Newfoundland and Labrador Hydro										
Owned	Hydroelectric	927.3	19.0	12.0	958.3		958.3		927.3	958.3
Owned	Holyrood	465.5			465.5	24.5	490.0		465.5	490.0
Owned	Gas Turbine	100.0			100.0		100.0		100.0	100.0
Owned	Diesel	14.7			14.7		14.7		14.7	14.7
Total Owned		1507.5	19.0	12.0	1538.5	24.5	1563.0	0.0	1507.5	1563.0
Purchased	Hydroelectric	78.0			78.0		78.0	31.8	109.8	109.8
Purchased	Co-Generation	8.0			8.0		8.0	7.0	15.0	15.0
Purchased	Wind				0.0		0.0	54.0	54.0	54.0
Total Purchased		86.0	0.0	0.0	86.0	0.0	86.0	92.8	178.8	178.8
Total NLH System		1593.5	19.0	12.0	1624.5	24.5	1649.0	92.8	1686.3	1741.8
Customer Owned										
Corner Brook Pulp and Paper	Hydroelectric	99.1			99.1		99.1	22.3	121.4	121.4
Newfoundland Power	Hydroelectric	78.7			78.7		78.7	18.2	96.9	96.9
Newfoundland Power	Gas Turbine	36.5			36.5		36.5		36.5	36.5
Newfoundland Power	Diesel	5.0			5.0		5.0		5.0	5.0
Total Customer Owned		219.3	0.0	0.0	219.3	0.0	219.3	40.5	259.8	259.8
Total Island Interconnected System		**1812.8**	**19.0**	**12.0**	**1843.8**	**24.5**	**1868.3**	**133.3**	**1946.1**	**2001.6**

The net capabilities are primarily used for long term generation planning. For long term planning purposes the more conservative Low Head capabilities are assumed. Short term operational planning uses gross capabilities and these can vary between the Low Head and High Head limits depending on actual reservoir conditions.

4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME

4.1 Incident Review Process – January 2014

The review process of the sequence of events was carried out in a manner consistent with good industry practice in terms of working towards determining a root cause and actionable steps for the future. The methodology and detailed results are found in report *Root Cause Investigation of System Disturbances*.

No generation asset was identified as having been a root cause of the January 4 and 5, 2014 transmission/terminal station failure events. The generation assets responded appropriately to the faults occurring within the overall transmission system. The unavailability of some generation assets or de-rating of others did, however, contribute to the extent of some of the rotating outages leading up to the system event and during the restoration efforts.

4.2 Preceding Events Associated with the January 2014 System Incident

Several generation asset issues, which are identified below, arose prior to and early in January 2014 that resulted in the need for rotating outages on January 2 and 3, 2014. They were also present during the January 4 and 5, 2014 transmission/terminal station failure events, but they were not initiating factors. Some of these are discussed in more detail in the Appendices to this report.

DECEMBER 15, 2013		
DATE	**EVENT**	**COMMENT**
December 15, 2013	Exploits River reduced to 38 MW	The Exploits River generation reduced due to frazil ice accumulation in the water channels leading into the Grand Falls generating station Limited success to clear the ice. Resolved on January 15, 2014.

DECEMBER 16, 2013		
DATE	**EVENT**	**COMMENT**
December 16, 2013	Granite Canal reduced 8 MW to 32 MW	Reduced due to turbine axial vibration. No definitive cause identified (associated with extreme cold water and turbine ice accumulation). Further reviews are planned.

DECEMBER 21, 2013		
DATE	**EVENT**	**COMMENT**
December 21, 2013	Hardwoods GT (50 MW) unavailable	Failure of a new fuel control valve. Service provider staff unavailable during holiday period. Restored to service on January 12, 2014

DECEMBER 23, 2013		
DATE	**EVENT**	**COMMENT**
December 23, 2013	Stephenville GT de-rated from 50 to 25 MW	Series of issues (initially asbestos pipe couplings, later B engine bearing failure) result in de-rating through January 2- 8, 2014 period and beyond. Unit in service using vendor loaner engine for engine B at 40 MW.

DECEMBER 25, 2013		
DATE	**EVENT**	**COMMENT**
December 25, 2013	Holyrood Unit 2 de-rated 25 MW to 142 MW	Steam turbine valve issue. Inspections and repairs carried out. Keeping unit on- line (even in a de-rated state was important). On-line solution implemented January 3, 2014.

DECEMBER 26, 2013		
DATE	**EVENT**	**COMMENT**
December 26, 2013	Holyrood Unit 3 de-rate 100 MW to 50 MW	FD fan motor winding failure. Motor removed without outage. Rewound and re-installed. Returned to full capacity January 12, 2014.

4.3 Generation Capability - January 2 to 8, 2014 System Event

Hydro determined that it could not meet the forecast load on January 2, 2014. At that time, it enacted the final steps in its Generation Load Sequence and Generation Shortage protocol and planned for a customer conservation request and probable rotating outages.

The following charts show the generation reserve (the difference between the System Supply and System Demand) that was available. The charts prior to the transmission/terminal station equipment failure events on January 4 and 5, 2014, emphasize that the generation asset outages were an important element of the rotating outages. The issues raised suggest that the need for additional generation capacity may be a consideration, at least in the short term, before major new generating sources are added to the system. These include:

the increased system peak due to severe weather conditions;

- the impact of severe weather conditions on certain generating assets (Granite Canal, Exploits River);
- the availability of spares (Holyrood 4kV motors); and
- the age of some equipment within some of the generating assets (Holyrood Unit 3 FD fan motor).

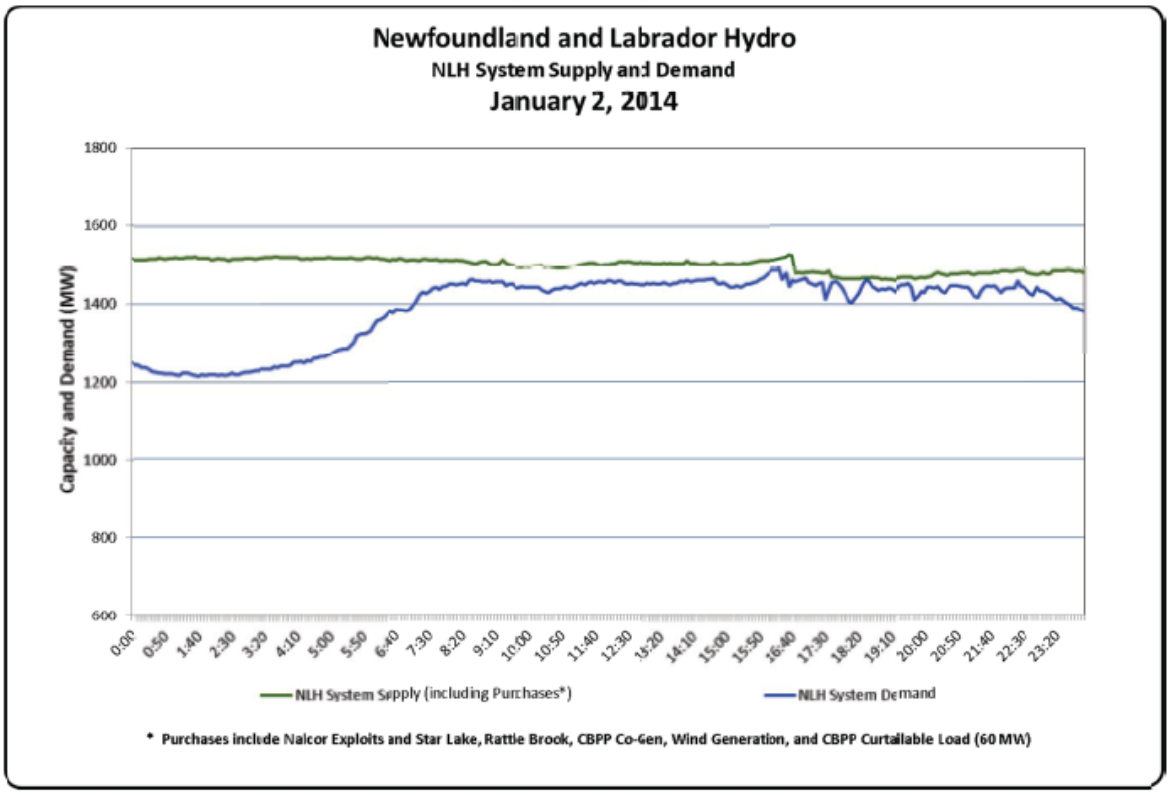


Figure 3: Hydro System Supply & Demand – January 2, 2014

JANUARY 3, 2014		
DATE	**EVENT**	**COMMENT**
January 3, 2014	Wind Turbine Out of Service of 54 MW	Wind turbine generators tripped due to high winds and transmission system conditions. Required manual reset. High winds and site access delayed restart. Returned to service January 6 to 8, 2014.

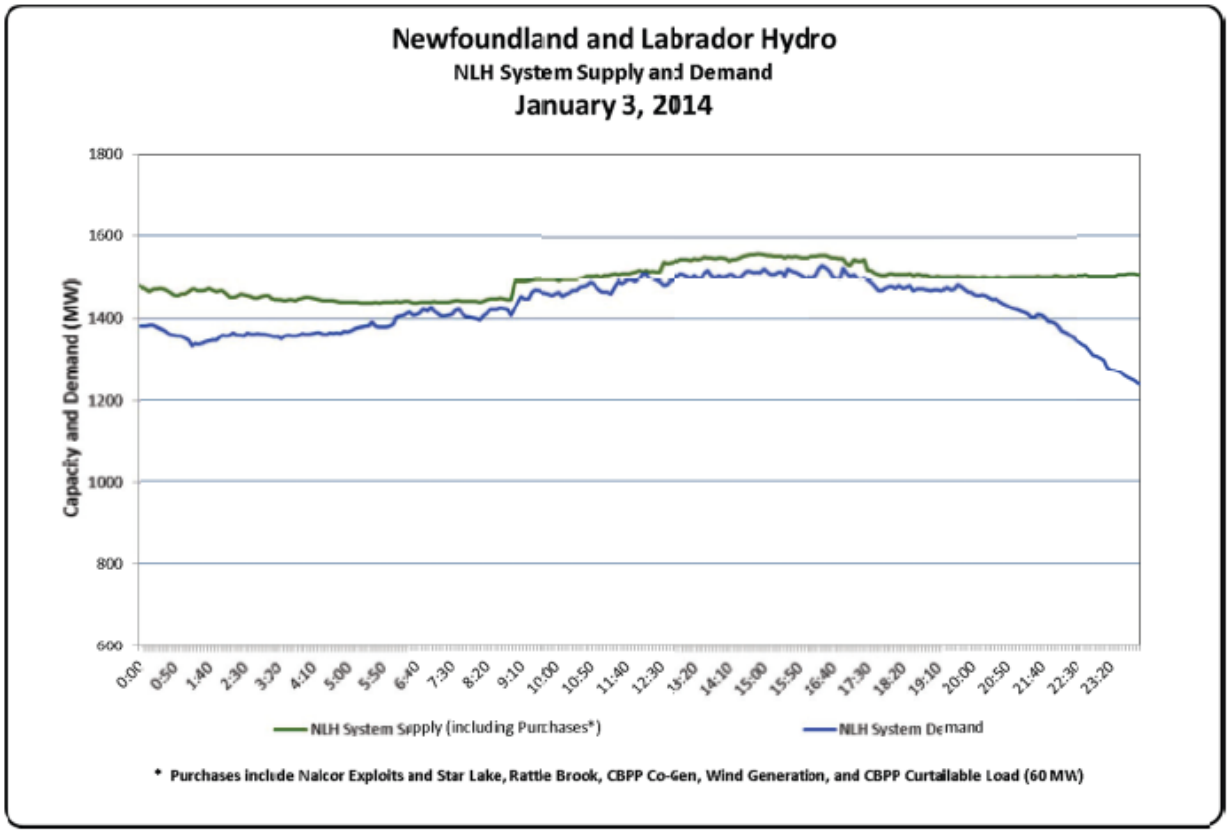


Figure 4: Hydro System Supply & Demand – January 3, 2014

The following charts show the system reserve on January 4 and January 5, 2014 during the system incident. The chart for January 4, 2014 shows the reducing reserve early in the morning up to the first system disruption. The January 5, 2014 chart shows that the reserve varied between a minimum of 30 MW at 0830 hours to a maximum of 438 MW following the separation of the east and west systems at 21:27 hours with the disturbance on the power system that originated at the Holyrood Terminal Station. The increased reserve immediately following the disturbance up to the end of the day was a result of the time required to restore generating equipment, transmission equipment and customer load. In particular, due to the limitations in transmission line power transfer capability serving the Avalon Peninsula, customer load could not be completely restored until generating equipment at Holyrood and transmission lines were restored over the next several hours.

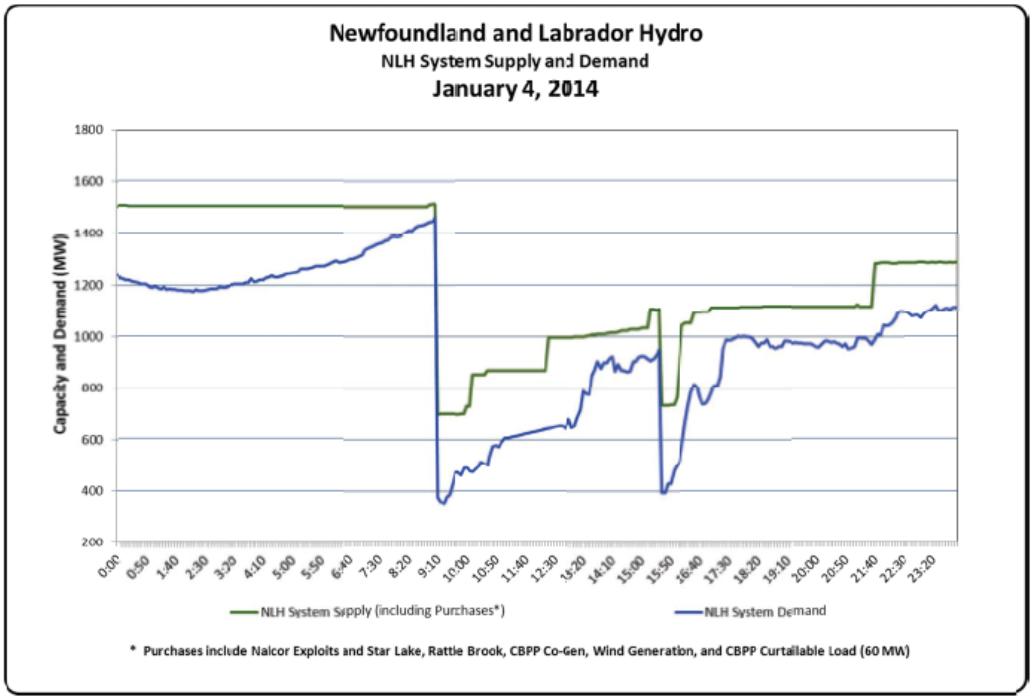


Figure 5: Hydro System Supply & Demand – January 4, 2014

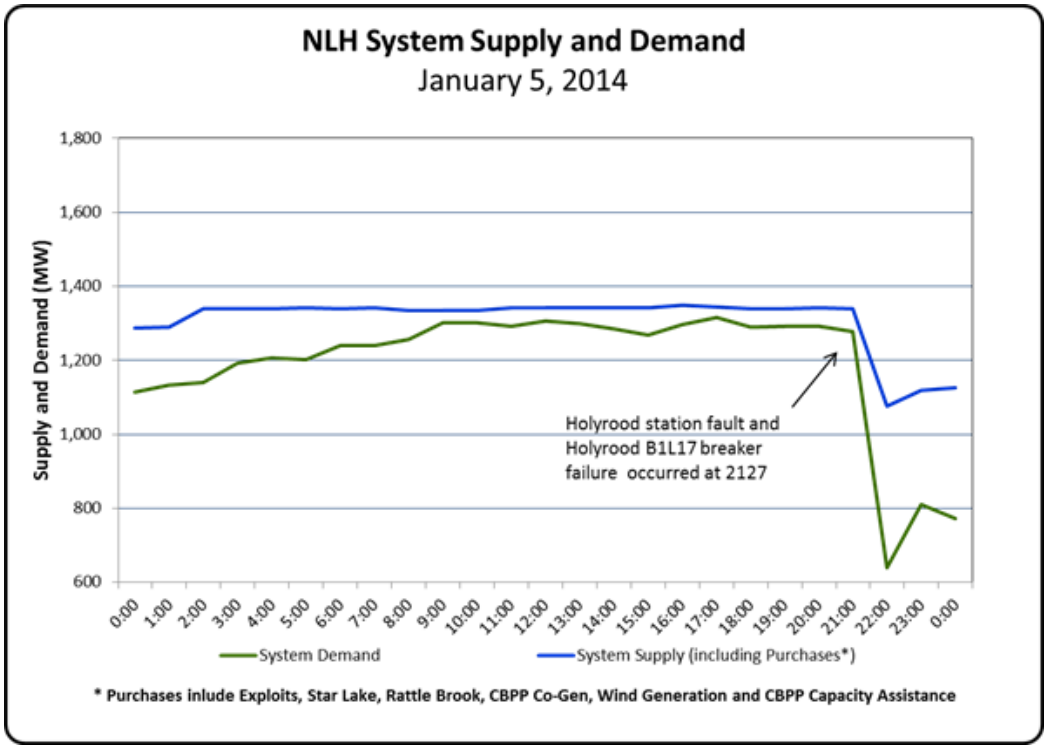


Figure 6: Hydro System Supply & Demand – January 5, 2014

1 The charts show the recovery of both the system supply and loads in the January 6 to 8, 2014
2 period.
3

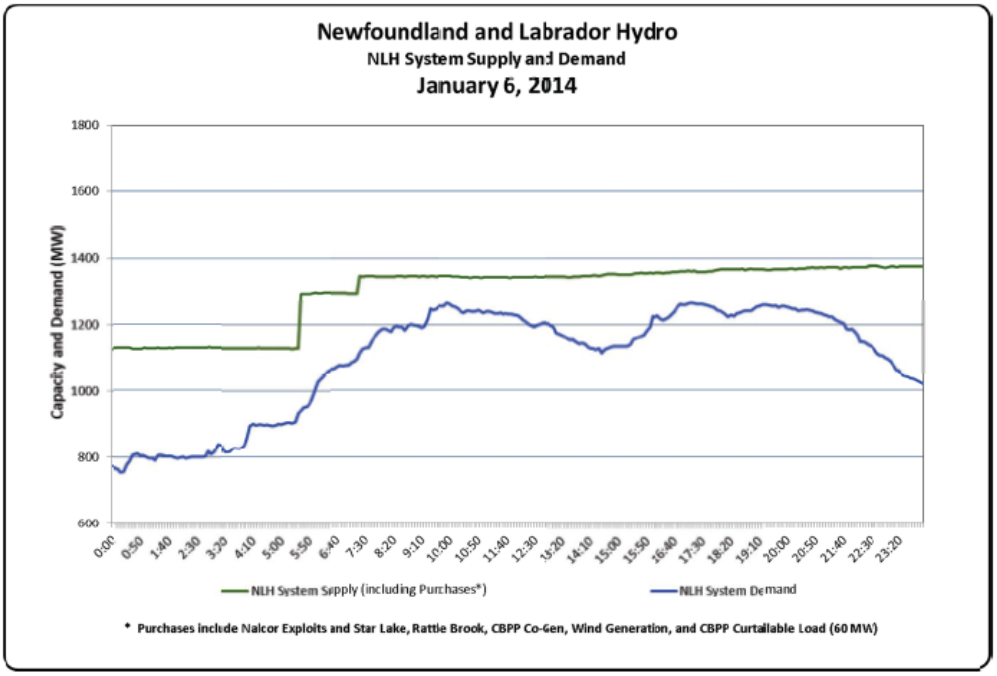


Figure 7: Hydro System and Demand – January 6, 2014

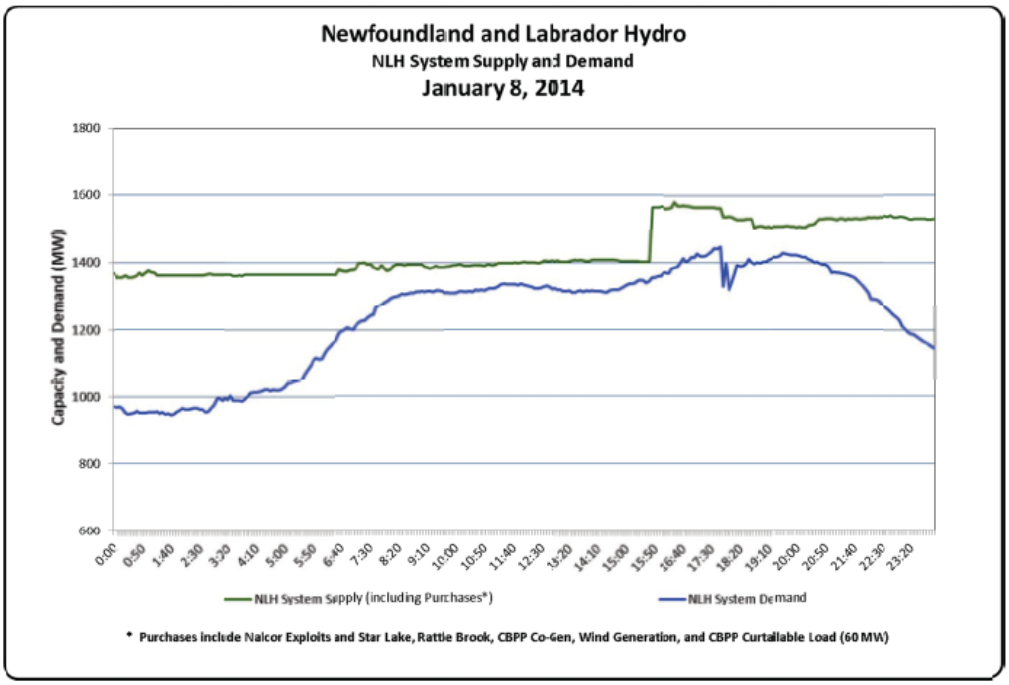


Figure 8: Hydro System Supply and Demand – January 8, 2014

Hydro's focus was to get and keep all generation available. As of noon on January 8, 2014 the status was as follows:

Plant/Unit	Issues	Generation	De-rate
• Holyrood Unit 1	Final checks. Returned to service	170 MW	0 MW
• Holyrood Unit 2	Minor de-rate	165 MW	5 MW
• Holyrood Unit 3	FD fan motor under repair (Jan 12)	50 MW	100 MW
• Hardwoods GT	Undergoing testing (Jan 12)	0 MW	50 MW
• Stephenville GT	Testing of B end (failed Jan 8)	25 MW	25 MW
• Exploits River	Severe frazil ice buildup	50 MW	13 MW
• Wind	System Jan 3 trip, manual reset delayed	50 MW	4 MW

5 KEY FINDINGS AND RECOMMENDATIONS

5.1 Overall Considerations

Many of Hydro's key generation assets were installed in the late 1960's into the 1970's. Over half of the Island Interconnected system generating capacity comes from assets that are more than 40 years old. Several of its hydroelectric assets are in or approaching typical mid-life age and as a consequence some elements would typically require refurbishment or overhaul. As condition monitoring detects issues, refurbishment requirements are integrated into asset plans and work plans and subsequently implemented. Hydro's thermal facilities (Holyrood, Hardwoods GT, Stephenville GT) are closer to their end-of-life major refurbishment or replacement period typical of similar facilities. Condition assessments have been undertaken and refurbishments or partial replacements have been evaluated and have been or are planned to be implemented as appropriate. Some parts are still likely to have a higher risk of failure despite predictive and preventative maintenance due to physical age and may fail without warning (such as the Unit 3 FD fan motor windings).

Hydro's critical spares tracking and management until 2011 has been done primarily on a local facility basis reflecting experience, condition assessments and vendor recommendations, and is constantly evolving over the past years and decades, and continues to do so. After an initial three year development and assessment period beginning in 2011, a comprehensive pilot project to the equipment level at Holyrood in 2013 of Hydro's asset criticality and critical spares tracking and management plans, provided valuable feedback at an initial "Lessons Learned" assessment that was undertaken January 30, 2014 event. This should be followed up on, as is Hydro's plan, in early 2014 following the work on the January 2014 incident. This will move the process towards a more comprehensive and cost effective approach consistent with industry practice and will address critical issues before winter 2014/15 as a part of the overall asset management program for the winter of 2014/15.

Recommendation		Status
GA1	Continue condition assessment and life management activities to identify timely refurbishment and replacement needs.	In Progress – ongoing
GA2	Through the existing Critical Spares Council, follow-up on the critical spares program as is currently in Hydro's plan in early 2014.	Planned - June 30, 2014

5.2 Gas Turbine Availability (For Availability Details – Appendix 2)

Hydro's Hardwoods and Stephenville gas turbine generating assets are in the final phase of a major overhaul period which has been undertaken to address the historic poor availability and performance compared to industry averages. The Hardwoods unit has been substantially refurbished. The Stephenville unit has been partially refurbished and the generator retaining rings replaced. It has two years remaining in its refurbishment plan. The actions to date should result in improved availability and performance going forward. The generator work should also enhance the unit life and safe operation in their synchronous condenser role.

Hardwoods and Stephenville gas turbines were unavailable or de-rated during the January 2 to 8, 2014 system event due to issues identified late in major planned generator refurbishments (Hardwoods fuel valve failure; Stephenville B end replacement of deteriorated asbestos pipe couplings and deteriorated insulating blankets). There was a subsequent Stephenville B engine failure on January 8, 2014. Their unavailability contributed to the size and duration of the rotating outages in the period between January 2 and 4, 2014 and during system restoration attempts between January 4 and January 8, 2014.

The unavailability or de-rating of the Hardwoods and Stephenville gas turbines were not a causal factor in, nor would their operation have mitigated, the January 4 to 5, 2014 transmission/terminal station failure events.

Hydro has a priority contract in place for its gas turbine fuel delivery, but managed its demands to minimize the delivery impacts on other liquid fuel users. Hydro's gas turbine fuel inventory levels were maintained below maximum available storage levels.

Recommendation		Status
GA3	Review the maintenance tactics of the Hardwoods and Stephenville gas turbines.	In Progress - Units refurbished. May 30, 2014
GA4	Assess the impacts of increasing the frequency of starting and running the GT's prior to severe weather to allow time to identify and correct issues.	In Progress – May 30, 2014
GA5	Identify repeat failure events on the GT units and address the root causes.	In Progress – Aug 30, 2014
GA6	Continue to review actual work completed on recent overhauls. Identify and plan for additional GT balance of plant equipment refurbishment not completed.	In Progress – April 30, 2014
GA7	Complete review of GT site fuel storage operating requirements, processes and procedures.	In Progress - April 30, 2014

5.3 Holyrood Availability (For Availability Details – Appendix 3)

Hydro's Holyrood thermal generating station assets availability and performance up to 2013 are consistent with industry averages. Its 2013 availability and performance was significantly poorer due to the time required to repair Unit 1 after it was damaged during tripping in the January 2013 extreme weather event and an extended planned outage on Unit 3 for some equipment replacements.

Hydro's Holyrood generating assets' availability and performance did not contribute to the initiation or duration of the January 4 to 5, 2014 transmission/terminal station failure events. They responded as they should have to the initial transmission system failures when the system separated the large hydroelectric supply in the west from the large load in the east. The Holyrood units could not sustain the load and so they tripped off. They were returned to service as the system was restored.

Holyrood Unit 1's first re-start was delayed due to turbine vibration issues related to the thermal shock of the trip and the pace at which it was re-started, as well as to remaining issues from the January 2013 failure trip and repairs. This was resolved by employing a slower, staged start-up approach.

Hydro's Holyrood generating assets unavailability and/or de-ratings did contribute to the number and/or duration of the rotating outages between January 2 to 4, 2014 and during the system restoration activities between January 4 to 8, 2014. The rotating outage impacts in the period January 6 to 8, 2014, were largely due to Unit 1 which was available to generate but unable to connect to the System due to a terminal station breaker issue. If some or all of the following had been avoided or resolved more quickly, some of the rotating outages might have been avoided or reduced:

- Holyrood Unit 3 was de-rated from 150 MW to about 50 MW from December 26, 2013 to January 12, 2014 due to an FD fan motor winding failure

- Holyrood Unit 2 had a steam turbine valve issue and was de-rated 25 MW to 142 MW from December 25, 2013 to January 2, 2014, when inspections and repairs were made. Keeping the unit on line even in a de-rated state was important and delayed the de-rate recovery until January 2, 2013.

Holyrood's 4 kV motors are subject to physical and operational aging and the station has no spare 4 kV motors. Although the motors were removed, repaired and re-installed expeditiously, the potential impact during repairs on available capacity is significant. The Unit 3 FD fan motor windings failure contributed significantly to the duration and extent of some of the rotating outages.

Recommendation		Status
GA8	Investigate improvements to Holyrood Unit 1 steam turbine generator to prevent future vibration issues and reduce starting times.	In Progress (May 30, 2014)
GA9	Review in early 2014 the cost-benefit analysis of one or more spare 4 kV motors for Holyrood.	In Progress (May 1, 2014)

5.4 Hydro Generation Availability (For Availability Details – Appendix 4)

Hydro's hydroelectric generating assets availability and performance up to 2013 are consistent with or better than industry averages.

Hydro's hydroelectric generating assets availability and performance did not contribute to the initiation or duration of the January 4 to 5, 2014 transmission/terminal station failure events. Hydroelectric generating facility unavailability and/or de-ratings did contribute to the number and/or duration of the rotating outages between January 2 to 4, 2014 and during the system restoration January 4 to 8, 2014.

Granite Canal tripped off on January 2, 2014 and was not available through that evening and was de-rated from 40 MW to 32 MW due to turbine vibrations (suspect water temperature, ice build-up issue) until January 3, 2014. Exploits River was de-rated from 63 MW to approximately 38 MW due to severe frazil ice build-up.

Recommendation		Status
GA11	Investigate further Granite Canal turbine vibration issues as/when they occur and develop mitigation plans.	In Progress (Dec 31, 2014)
GA12	Document Exploits River operational response to severe frazil ice buildup for future use as a best practice.	In Progress (May 30, 2014)

5.5 Wind Generation Availability (For Availability Details – Appendix 5)

Wind generation assets are not usually counted on to provide capacity due to the intermittent nature of wind energy. For example, in periods of very high wind or low/no wind, these units are not available for generation. Wind turbine generators (private power purchases of 54 MW) have been very reliable, with few low/high wind periods or extreme weather (icing) outages. They were, however, tripped out of service January 3, 2014 due to high winds and transmission system conditions. They required inspections up the towers and manual intervention by the private developers to be reconnected. Due to bad weather conditions and access road closures and conditions, this restart was delayed to between January 6 and 8, 2014. At noon on January 8, 2014, St. Lawrence wind was on at full capacity of 27 MW and Fermeuse was at 23 MW.

There are no recommendations related to the wind generators.

ACRONYMS

AC	Asset Criticality
AM	Asset Management
BDE	Bay d'Espoir
BOD	Board of Directors
CBC	Come-By-Chance
CBPP	Corner Brook Pulp & Paper
CEA	Canadian Electricity Association
CEO	Chief Executive Officer
CM	Corrective Maintenance
CS	Critical Spares
EPRI	Electric Power Research Institute
FD	Forced Draft
GS	Generating Station
GT	Gas Turbine
HRD/HTGS	Holyrood Thermal Generating Station
JDE	JD Edwards
OEM	Original Equipment Manufacturer
NLH	Newfoundland and Labrador Hydro
P&P	Pulp and Paper
PM	Preventive Maintenance
PUB	Board of Commissioners of Public Utilities
SOE	Sequence of Events
SSD	Sunnyside Terminal Station
T&D	Transmission and Distribution
TS	Terminal Station
WAV	Western Avalon Terminal Station

Appendices

Detailed Capability Comparison

The following tables indicate which facilities were available to produce generation at peak load on the days indicated.

Available Island Interconnected Generating Capacity (MW)

	Used for Planning Purposes (at Peak)	December 1, 2013 at 1715 hours	December 29, 2013 at 1705 hours
Hydraulic			
Bay d'Espoir	592	617	617
Cat Arm	127	138	138
Upper Salmon	84	88	88
Hinds Lake	75	78	78
Granite Canal	40	41	32
Paradise River & Mini Hydros	9	9	9
Total Hydraulic	**927**	**971**	**962**
Holyrood			
Holyrood Unit 1[3]	170	-	160
Holyrood Unit 2	170	145	140
Holyrood Unit 3	150	145	50
Total Holyrood	**490**	**290**	**350**
Standby GTs and Diesels			
Hardwoods GT	50	-	-
Stephenville GT	50	30	-
St. Anthony & Hawkes Bay Diesels	15	14	14
Total Standbys and Diesels	**115**	**44**	**14**
Purchases			
Exploits River Plants	91	88	48
Star Lake	18	18	18
Rattle Brook	3	4	-
Wind Generation	22	29	34
Corner Brook P & P Co-gen	15	8	8
Corner Brook P & P Interruptible	-	-	60
Total Purchases	**149**	**147**	**168**
Deer Lake Power[2]	**101**	**121**	**61**
Newfoundland Power	**97**	**127**	**120**
Total Island Capacity	**1,879**	**1,700**	**1,675**
Total NLH System Capacity (Including Purchases)	**1,681**	**1,452**	**1,494**
NLH System Peak Load		**1,214 at 1655 hours**	**1,418 at 1725 hours**
CBPP Interruptible actually taken[1]		**0**	**20**
Island Peak Load		**1,387 at 1715 hours**	**1,597 at 1705 hours**

(1) When CBPP Interruptible is used, to determine what the actual Island Peak Load would have been, the amount of Interruptible actually used should be added to the Island Peak Load.
(2) When CBPP Interruptible is available, Deer Lake Power available capacity is reduced to 61 MW.
(3) A unit at Holyrood was out-of-service on Dec 01, as it was not required in service due to system demands being lower.

Available Island Interconnected Generating Capacity (MW)

	January 4, 2014 at 0905 hours	January 4, 2014 at 2355 hours	January 15, 2014 at 1715 hours
Hydraulic			
Bay d'Espoir[3]	617	617	540
Cat Arm	138	138	138
Upper Salmon	88	88	88
Hinds Lake	78	78	78
Granite Canal	32	32	-
Paradise River & Mini Hydros	9	-	9
Total Hydraulic	**962**	**953**	**853**
Holyrood			
Holyrood Unit 1	165	-	165
Holyrood Unit 2	165	165	165
Holyrood Unit 3	50	-	150
Total Holyrood	**380**	**165**	**480**
Standby GTs and Diesels			
Hardwoods GT	-	-	50
Stephenville GT	30	30	25
St. Anthony & Hawkes Bay Diesels	14	14	14
Total Standbys and Diesels	**44**	**44**	**89**
Purchases			
Exploits River Plants	38	38	70
Star Lake	18	18	18
Rattle Brook	-	-	4
Wind Generation	-	-	49
Corner Brook P & P Co-gen	2	-	7
Corner Brook P & P Interruptible	60	60	60
Total Purchases	**118**	**116**	**208**
Deer Lake Power[2]	**61**	**61**	**61**
Newfoundland Power	**128**	**128**	**124**
Total Island Capacity	**1,693**	**1,467**	**1,815**
Total NLH System Capacity (Including Purchases)	**1,504**	**1,278**	**1,630**
NLH System Peak Load	**1,464* at 0905 hours**	**1,122* at 2325 hours**	**1,041 at 1720 hours**
CBPP Interruptible actually taken[1]	**60**	**60**	**0**
Island Peak Load	**1,529* at 0810 hours**	**1,233* at 2355 hours**	**1,243 at 1715 hours**

*Peak occurred prior to the Sunnyside event, when Holyrood Unit 1 was online

(1) When CBPP Interruptible is used, to determine what the actual Island Peak Load would have been, the amount of Interruptible actually used should be added to the Island Peak Load.

(2) When CBPP Interruptible is available, Deer Lake Power available capacity is reduced to 61 MW.

(3) A unit at Bay d'Espoir was out-of-service on Jan 15, as it was not required in service due to system demands being lower.

Events Preceding the January 2014 System Event

- December 11, 2013 The Hardwoods GT jacking oil pump failed. Stephenville GT jacking oil pump was temporarily removed and installed at Hardwoods. Stephenville GT was temporarily unavailable while replacement pump obtained and installed. No resulting customer supply issue.

- December 15-16, 2013 The Exploits River generation was reduced to 38 MW from typical 63 MW in winter due to frazil ice (substantial amounts of ice to accumulate in the water channels leading into the Grand Falls generating station, resulting in a reduction in available capacity of approximately 50 MW from 88 MW at the time). Returned to full service January 14, 2014.

- December 16, 2013 The Granite Canal generating unit was de-rated to 32 MW due to axial vibration (likely caused by extreme cold water or turbine ice accumulation)

- December 19, 2013: Hardwoods Gas Turbine out of service for overhaul and alternator replacement. Scheduled return to service date.

- December 21, 2013: Hardwoods GT (50 MW) unit unavailable until January 12, 2014. Final testing after overhaul revealed failure of newly acquired fuel control valve.

- December 23, 2013: The Stephenville Gas Turbine was restored to 25 MW with the installation of a new jacking oil pump that replaced the part removed on December 11, 2013 for use at Hardwoods. End B was unavailable until January 3, 2014 for the replacement of

deteriorated asbestos pipe couplings. The recovery of the remaining 25 MW capacity was pending the delivery and installation of new insulating blankets, scheduled for early January, but on January 5, 2014, it was determined that colder ambient temperatures would allow for increased output without the blankets. On January 8, 2014, the B end of gas turbine failed and tripped reducing the output of the machine to 25 MW. (See Appendix 2 for more detail.)

- December 25, 2013: Holyrood Unit 2 was de-rated by 25 MW, to 142 MW due to a control valve issues. Careful assessment required to recover lost capacity without removing unit from service and delayed the de-rate recovery until about January 2, 2014.

- December 26, 2013: A Holyrood Unit 3 forced draft fan motor failure resulted in a 100 MW de-rating to approximately 50 MW from 150 M. The motor was removed over the next two days, without requiring Unit 3 to be taken out of service. It was repaired in St. John's and returned to service January 12, 2014.

- December 26, 2013: Minor de-rate of Granite Canal (Corrected Jan 2, 2014).

The following tables provide an account of the events and actions each day related to generation leading up to the rotating outages on January 2, 2014. They also identify where discussions on the Generation Loading Sequence and Shortage Protocol were held.

Date	Event	Actions	Supply and Demand (at Peak)
Thursday, December 26	Holyrood unit 3 de-rated to 50 MW due to FD fan motor failure.	• Implemented Generation Loading Sequence and Generation Shortages protocol up to Step 8 (with the exception of Step 7) • Communications with Newfoundland Power as to the status of generation assets, load forecasts and protocols. • Communications internally to ensure awareness of the situation.	Demand: 1,385 MW Supply: 1,426 MW
Friday, December 27		• Generation Loading Sequence and Generation Shortages not required. • Communications with Newfoundland Power as to the status of generation assets, load forecasts and protocols.	Demand: 1,331 MW Supply: 1,456 MW

Date	Event	Actions	Supply and Demand (at Peak)
Saturday, December 28	Bay d'Espoir Unit 2 removed from service due to air supply issue with breaker B1T2. No customer impact. The unit was restored by 1138.	• Generation Loading Sequence and Generation Shortages not required. • Forecast peak for December 29 of 1410 MW. Communications with Newfoundland Power regarding this. Preparations made between both utilities to prepare as per the Generation shortage protocol. • Customer conservation message was discussed to potentially be required for December 29. Decision to be made early on December 29.	Demand: 1,354 MW Supply: 1,456 MW

Date	Event	Actions	Supply and Demand (at Peak)
Sunday, December 29	Stephenville Gas Turbine failed to start. Crews dispatched and corrected the problem at 2224.	• Implemented Generation Loading Sequence and Generation Shortages protocol up to Step 13. This included asking Corner Brook Pulp and Paper to shed approximately 28 MW of processing load. • Continued to discuss the potential of issuing a public conservation message but determined it was not required. • Forecast peak for December 30 of 1,420 MW. Continued communications with Newfoundland Power regarding the continuing need to implement the Generation Loading Sequence and Generation Shortages protocol.	Demand: 1,425 MW Supply: 1,470 MW (including load reduction from Corner Brook Pulp and Paper).

Date	Event	Actions	Supply and Demand (at Peak)
Monday, December 30	None	• Implemented Generation Loading Sequence and Generation Shortages protocol up to Step 13. This included asking Corner Brook Pulp and Paper to shed approximately 30 MW in the morning and 52 MW in the evening. • Internal meeting to discuss progress on generation and preparations going forward. • Discussions with Corner Brook Pulp and Paper regarding a more formal capacity assistance arrangement. • Forecast peak for December 31 of 1,400 MW. Continued communications with Newfoundland Power regarding the continuing need to implement the Generation Loading Sequence and Generation Shortages protocol.	Demand: 1,417 MW (morning). 1,420 MW (evening) Supply: 1,458 MW (including load reduction from Corner Brook Pulp and Paper).

Date	Event	Actions	Supply and Demand (at Peak)
Tuesday, December 31 (New Years Eve)	None	• Generation Loading Sequence and Generation Shortages protocol not required. • Capacity Assistance agreement reached with Corner Brook Pulp and Paper for 20, 40 or 60 MW blocks of power. • Forecast peak for January 1 of 1,450 MW. Continued communications with Newfoundland Power regarding the continuing need to implement the Generation Loading Sequence and Generation Shortages protocol.	Demand: 1,393 MW Supply: 1,453 MW
Wednesday, January 1, (New Years Day)	None	• Generation Loading Sequence and Generation Shortages protocol implemented up to Step 13. This also includes capacity assistance from Corner Brook Pulp and Paper for 40 MW during peak. • Forecast peak for January 2 of over 1,500 MW. Continued communications with Newfoundland Power regarding the continuing need to implement the Generation Loading Sequence and Generation Shortages protocol.	Demand: 1,440 MW Supply: 1,484 MW (including load reduction from Corner Brook Pulp and Paper).

Generation Availability During the January 2 to January 8 2014 System Event

The following tables summarize the generation unavailability for January 2 to January 8, 2014 during periods when customer interruptions were occurring, either due to the restoration process following the transmission/terminal station failure events on January 4 and 5, or while the rotating outages were occurring to ration the available supply.

Rotating Outages - January 2-8, 2014						
Plant	Unit Rating (MW)	Jan-2 Unavailable Capacity (MW)	Jan-3 Unavailable Capacity (MW)	Jan-5 Unavailable Capacity (MW)	Jan-6 Unavailable Capacity[1] (MW)	Jan-8 Unavailable Capacity[2] (MW)
Hardwoods Gas Turbine	50	50	50	50	50	50
Stephenville Gas Turbine	50	20	20	20	20	25
Holyrood Unit 3	150	100	100	100	150	100
Holyrood Unit 2	170	5	5	5	170	5
Holyrood Unit 1	170	5	5	170	170	170
Granite Canal Unit	40	8	8	-	-	-
Exploits Generation	63	25	24	26	21	14
Total	693	213	212	371	581	364

Notes:

1. On January 6, HRD Unit 2 (165 MW) and HRD Unit 3 (50 MW) were brought on-line during the period of feeder interruptions. The additional generation, as it became re-established, helped to minimize the duration and impact.
2. On January 8, HRD Unit 1 (165 MW) was brought on-line during the period of feeder interruptions. The additional generation, as it became re-established, helped to minimize the duration and impact.

Generation Supply Issues - January 4, 2014 (as at 0906 hours)			
Plant	Unit Rating (MW)	Unavailable Capacity (MW)	Notes
Hardwoods Gas Turbine	50	50	Unit unavailable due to fuel valve issue
Holyrood Units 1-3	490	490	Units tripped during the system disturbance[1]
Stephenville Gas Turbine	50	50	Unit tripped during system disturbance[2]
St. Anthony and Hawkes Bay Diesels	15	15	Units tripped during system disturbance
Cat Arm Units 1 and 2	127	127	Units tripped during system disturbance
Upper Salmon Unit	84	84	Unit tripped during system disturbance
Hinds Lake Unit	75	75	Unit tripped during system disturbance
Granite Canal Unit	40	40	Unit tripped during system disturbance
Purchases	59	59	Units tripped during system disturbance
Total	990	990	

Notes:

1. Unit 3 derated to 50 MW prior to this event due to forced draft fan failure.
2. Unit previously derated to 30 MW prior to this event due to cooling issues.

The following tables for January 1, January 5 and January 8, 2014 present some additional detail of the generation unavailability during the January 2 to 8, 2014 system event.

January 1, 2014

Generation	Location	Equipment	Reason for Unavailability
	Hardwoods	Gas Turbine	Unit unavailable as assessment and work were underway to correct the fuel valve issues discovered during final testing following the unit alternator replacement and overhaul.
	Stephenville	Gas Turbine	End A was available at 25 MW. Turbine End B was unavailable as it was not tested after new pipe couplings were installed on December 31. There was a concern of tripping End A during these tests and making it unavailable. End B was not restored until after the testing on January 3.
	Holyrood	Unit No. 3	Forced derating to 50 MW (100 MW unavailable) due to a forced draft fan motor failure. Awaiting the replacement coils in order to rewind the motor prior to re-installation.
	Granite Canal	Granite Canal Unit	Unit was derated to 32 MW due to vibration issues experienced above this generation level.
	Exploits	Exploits generation	Exploits generation reduced to 40 MW from 63 MW due to frazil ice issues. The ice removal process was ongoing.

January 5, 2014

Generation	Location	Equipment	Reason for Unavailability
	Hardwoods	Gas Turbine	Unit unavailable as assessment and work were underway to correct the fuel valve issues discovered during final testing following the unit alternator replacement and overhaul.
	Stephenville	Gas Turbine	End A available at 25 MW. It was determined that Turbine End B could be run at full capacity (25 MW) due to the cold ambient temperatures. The installation of Insulating blankets was still required for the longer term.
	Holyrood	Unit No. 3	Forced derating to 50 MW (100 MW unavailable) due to a forced draft fan motor failure. Awaiting the replacement coils in order to rewind the motor prior to re-installation.
	Holyrood	Unit No. 1	the trip during the Sunnyside issues on January 4, 2014 at 0905 hours. The unit was ran up several times and ready to re-sync during the evening hours on January 5.
	Granite Canal	Granite Canal Unit	The unit was operated at 40 MW with personnel on site to monitor. No vibration issues were experienced and ice issues (which had since cleared) were suspected.
	Exploits	Exploits generation	Exploits generation reduced to 37 MW from 63 MW due to frazil ice issues. The ice removal process was ongoing.

January 8, 2014

Generation	Location	Equipment	Reason for Unavailability
	Hardwoods	Gas Turbine	Unit unavailable as assessment and work were underway to correct the fuel valve issues discovered during final testing following the unit alternator replacement and overhaul. Available in synchronous condenser mode.
	Stephenville	Gas Turbine	Both ends underwent testing on this day. End B tripped at 0830 hours. After an assessment later that evening, it was determined that both ends were unavailable. End A became available again in the afternoon on January 9. An assessment of End B was underway.
	Holyrood	Unit No. 3	Forced derating to 50 MW (100 MW unavailable) due to a forced draft fan motor failure. Work to re-wind the motor was ongoing.
	Holyrood	Unit No. 1	Unit outaged (165 MW unavailable) due to switchyard equipment issues experienced during the attempted re-start on January 5, 2014 at 2127 hours. Unit No. 1 was restored to service on January 8, 2014.
	Exploits	Exploits generation	Exploits generation reduced to 45 MW from 63 MW due to frazil ice issues. The ice removal process was ongoing.

Generation Availability after the January 2014 System Event

The following table for January 15, 2014 presents a picture of generation availability after the January 2 to January 8, 2014 system event.

January 15, 2014

Generation	Location	Equipment	Status Update
	Hardwoods	Gas Turbine	Both ends returned to service on January 12 at 1800 hours
	Stephenville	Gas Turbine	End A available at 25 MW. End B unavailable since the trip on January 8. Work is ongoing with the OEM to assess the extent of the damage and repairs.
	Holyrood	Unit No. 3	Unit restored to full capacity January 12 at 1615 hours
	Holyrood	Unit No. 1	Unit returned to service January 8 at 1539 hours
	Granite Canal	Granite Canal Unit	Unit had tripped the previous day (January 14) due to problems with a pressure switch on the governor system. Repairs were made and the unit was returned to service at 2107 hours on January 15 at full capacity (40 MW).
	Exploits	Exploits generation	Generation restored on January 14 (70 MW)

Details – Gas Turbine Availability

Hardwoods Gas Turbine

Plant Information

The 50 MW Hardwoods gas turbine installation, located in the St. John's area, is operated as a synchronous condenser for voltage support of the transmission system on the Avalon Peninsula, and to generate power under system peak and Avalon Peninsula emergency/contingency conditions. The unit is also utilized to enable efficient loading and dispatch of the Holyrood Thermal Generating Station by being available to respond to a contingency which would otherwise have to be provided by having an additional unit operating at Holyrood at inefficient loads.[1]

The Hardwoods gas turbine was installed in 1977 and has been in-service for about 37 years. Between 1993 and 2013, the unit operated in generating mode an average of 69 hours per year (1456 hours over the period) and in synchronous condensing mode an average of 3,057 hours per year (64,196 hours over the period).

In 2007-2008, Hydro hired Stantec consulting engineers to undertake a condition assessment of the Hardwoods and Stephenville gas turbines. Given their age, a number of issues were identified and a four- year refurbishment program was identified. Hardwoods refurbishment was initiated in 2010 for completion in 2013. Some balance of plant work may not have been completed due to resources (i.e. junction boxes and wiring termination replacement/upgrade due to possible corrosion issues).

Gas Turbine Incident Availability

In January 2013, it was determined that the Hardwoods unit should be operated in emergency

[1] The Holyrood generating units cannot be quickly turned on and off like gas turbine units to respond to a system problem. Therefore, to provide the same response as a gas turbine, a Holyrood unit must be placed on line and operated at its minimum output level of 70 MW in order to be available to quickly respond to a problem. As problems are unpredictable, this would result in a Holyrood unit being on for many days consuming large amounts of fuel when there would otherwise be no requirement for the unit to operate.

conditions only. This restriction was based on the recommendations from Brush GMS (Brush), the alternator original equipment manufacturer (OEM), due to conditions identified during an inspection of its sister unit in Stephenville in 2012. During this inspection, it was discovered that the rotor retaining rings on the Stephenville unit had cracks that could have led to a catastrophic failure of the unit if it had continued to operate. Based on these findings, and the fact that the Hardwoods and Stephenville alternators were both installed in 1976-77, in service for over 35 years and have never had the rotor retaining rings replaced, Brush recommended that the Hardwoods unit be restricted to run only in emergency conditions until a repair/refurbishment of the unit (including replacement of the retaining rings) could be carried out.

This unforeseen repair caused Hydro to re-evaluate its 2013 planned generation outage schedule. Project planning proceeded with the evaluation of the available options for the repair/refurbishment of the Hardwoods unit. After considering the options, it was decided that the most cost efficient and optimal approach was to replace the alternator. The earliest project implementation start date was October 1, 2013, even with aggressive expedited delivery of the replacement alternator from Brush, and involved a 2.5 month outage to the unit.

Hydro also considered the operating forecast for December 2013 which indicated at the time that there were appropriate reserves on the system to accommodate the outage and still meet forecast demand. Furthermore, once this outage window for Hardwoods was set, Hydro considered the unavailability of this unit in the scheduling and outage planning of the remaining generation to continue to provide for safe and reliable operation of the power system. It has been past practise, if required, to allow a generation outage to extend into December if the operating load forecast can accommodate it.

Hydro submitted an application to the PUB on April 24, 2013 for the approval of the recommended least cost option which was subsequently approved in May 2013.

The scope of work for the alternator replacement was significant including:

- An asphalt crane pad for removal and installation of the alternator assemblies;
- Relocation of the main lube oil cooler to allow crane access;
- Disassembly of the alternator enclosure, air treatment system and stator canopy;
- Disconnection of all auxiliary systems - electrical, mechanical, and fire protection;
- Removal of existing alternator and site assembly of new alternator (rotor and stator);
- Installation and alignment of the new alternator in the enclosure;
- Reassembly of the alternator enclosure;
- Reconnection of auxiliary systems and recertification of the fire protection system; and
- Commissioning.

The outage began on October 3, 2013, once Holyrood Unit 2 was in full operation. Work proceeded on a six day per week, ten hour per day schedule and the unit was placed on- line for testing on December 17, 2013. The unit tested successfully to full load (50 MW) on December 19, 2013. However, during run-up tests for remote operation on December 20, 2013 there was an unexpected failure of a fuel control valve that made the unit unavailable again. Given the holiday period and the unavailability of the required vendor equipment and service expert, repairs on the Hardwoods gas turbine were delayed and the unit was not restored to full service until January 12, 2014.

Hydro exercises their peaking GT units once per month to maintain availability. The Hardwoods GT generally runs well once it is on line. Similar to many vintage gas turbines, reliable start-up can sometimes be an issue, but is usually overcome by one or more restarts. The following table documents 32 start failures of the Hardwoods units between January 2000 and January 2013. This is fairly low average of approximately 2.5 per year.

Gas Turbine Starting Failures from January 1, 2000 to December 31, 2013

Unit	Start_Date	Finish_Date	State Code
HWDT	2000/03/03 11:42	2000/03/03 16:23	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/03/11 9:18	2000/03/11 9:52	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/06/27 11:18	2000/06/27 11:25	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/10/10 11:52	2000/10/10 12:02	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/12/04 16:39	2000/12/04 17:19	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/12/07 22:07	2000/12/07 22:47	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/12/10 9:12	2000/12/10 11:08	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/12/24 17:00	2000/12/25 14:40	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2000/12/24 17:01	2000/12/25 14:40	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2001/06/02 13:09	2001/06/02 17:46	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2001/08/31 8:08	2001/08/31 8:17	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2002/01/24 11:31	2002/01/24 13:45	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2002/01/31 8:28	2002/01/31 8:32	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2002/01/31 8:32	2002/01/31 10:26	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2002/02/13 7:36	2002/02/13 8:42	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2002/05/22 13:26	2002/05/22 14:22	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2004/09/19 22:46	2004/09/19 23:43	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2005/09/02 12:18	2005/09/02 13:35	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2006/01/23 6:58	2006/01/23 7:02	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2007/03/09 4:37	2007/03/09 6:13	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2007/04/03 7:19	2007/04/03 15:37	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2007/04/03 15:48	2007/04/03 15:56	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2007/11/08 12:55	2007/11/08 13:06	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2007/12/21 15:11	2007/12/21 15:44	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2008/07/11 15:18	2008/07/11 15:41	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2009/01/08 8:12	2009/01/08 10:13	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2009/07/20 15:58	2009/07/21 11:38	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2009/09/26 17:56	2009/09/27 10:59	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2011/01/31 11:43	2011/02/01 15:03	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2012/02/15 13:12	2012/02/21 20:53	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2012/02/29 10:56	2012/03/10 13:32	21 (4)-FO-4 : Forced Outage - Starting Failure
HWDT	2013/02/09 11:09	2013/02/09 12:24	21 (4)-FO-4 : Forced Outage - Starting Failure

Stephenville Gas Turbine

Plant Information

The Stephenville gas turbine is operated as a synchronous condenser for voltage support of the transmission system on the west coast, and to generate power under system peak and emergency/contingency conditions. Like Hardwoods, there are two ends to the Stephenville

gas turbine (A and B), both rated at 25 MW each.

The gas turbine was installed in 1976 and has been in-service for approximately 38 years. Between 1993 and 2013, the unit operated in generating mode an average of 29 hours per year (607 hours over the period) and in synchronous condensing mode an average of 2,461 hours per year (51,679 hours over the period).

In 2007- 2008, Stantec undertook a condition assessment. Given the unit's age and operating history a number of issues were identified and a refurbishment program was put in place with two years remaining before completion.

Gas Turbine System Incident Availability

The planned major overhaul at the Stephenville Gas Turbine was completed in the summer of 2013 after completion of an alternator refurbishment (a stator and rotor rewind). In June 2013, the unit was released for service. At this time, it was determined that there was deterioration of the insulation blankets (to prevent excessive heat build-up and a potential trip) on End B, and it was limited to an output of 15 MW, a de-rating of 10 MW from the engine's rated output of 25 MW. It was limited to 30 MW when both ends were operating due to the requirement to keep the output on each end equal. The unit was also released for full synchronous condenser capability.

The blankets on End B required replacement to restore the unit to its original operating condition. These were the original blankets on the unit and specifications had to be developed before a quotation could be obtained. On-site inspections and data collection were required to develop the specification in consultation with the supplier. A quotation for the supply and installation of the insulating blankets on October 18, 2013 would not meet Hydro's date for winter readiness so another supplier quote was received on December 3, 2013 and a purchase order placed. The blankets were received at the end of the first week of January 2014.

End A remained fully available until Dec 11, 2013 when a jacking oil pump was temporarily removed to replace a failed pump at Hardwoods in order to maintain the return to service schedule at Hardwoods. Because of the critical nature of the Hardwoods Gas Turbine, due to its location on the Avalon Peninsula to provide both transmission and system capacity backup during transmission and generation contingencies, there was a very high focus on returning this unit to service. On December 23, a new jacking oil pump was installed on the Stephenville Gas Turbine. Synchronous condenser capability and End A were restored to 25 MW. End B was unavailable pending the replacement of deteriorated asbestos pipe couplings on the unit.

On December 29, 2013, a frozen airline prevented End A from being started. This was repaired that day and the unit was restored by the evening to End A at 25 MW. End B at 0 MW and synchronous condenser capability. On December 31, 2013, the pipe couplings were installed. The repairs were not tested until January 2, 2014, due to the risk of tripping the entire unit during the test. On January 3, 2013, End B was tested and once again became available for generation at 15MW. On January 5, 2014, End A was shut down to check the oil level and look for a leak. Given the cold external temperatures, it was determined that End B could be run up to 25 MW resulting in the unit being restored to its full capacity of 50 MW. On January 8, 2014, End B tripped, making the end unavailable and resulting in a de-rating of the Stephenville Gas Turbine to 25 MW.

A representative from Alba Power, who previously overhauled the unit, travelled to the site on January 9, 2014. The Alba representative along with Hydro carried out an initial visual inspection, including an internal bore scope inspection, and determined that End B suffered a major failure and would require further investigation to determine the root cause.

As of January 27, 2014, the gas turbine was available in generate mode with End A at 25 MW and End B at 0 MW. The unit is also available for synchronous condenser operation. The End B engine is currently with Alba at their facility in the United Kingdom being repaired The B end

engine has been replaced with a vendor engine and the unit is currently operational at up to 40 MW capacity.

Hydro exercises their peaking GT units once per month to maintain availability. The Stephenville GT like Hardwoods generally runs well once it is on line. The following table shows the 17 start failures of the Stephenville unit between January 2000 and December 2013, for a fairly low average of approximately 1.3 per year.

Gas Turbine Starting Failures from January 1, 2000 to December 31, 2013

Unit	Start_Date	Finish_Date	State Code
SVLT	2001/05/28 4:13	2001/05/29 12:02	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2001/05/28 4:16	2001/05/28 16:51	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2001/10/27 9:52	2001/10/27 10:05	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2001/12/04 8:03	2001/12/04 8:14	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2004/09/30 10:57	2004/09/30 11:05	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2004/12/13 17:18	2004/12/14 7:36	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2005/10/21 0:07	2005/10/21 0:51	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2005/10/25 22:05		21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2006/01/23 6:57	2006/01/23 9:01	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2006/08/17 17:22	2006/08/18 0:28	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2007/08/07 13:24	2007/08/07 13:43	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2007/09/26 13:19	2007/09/26 13:35	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2007/11/01 7:12	2007/11/01 7:19	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2008/10/30 6:19	2008/10/30 6:22	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2008/10/30 6:22	2008/10/30 6:30	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2008/10/31 12:12	2008/10/31 15:09	21 (4)-FO-4 : Forced Outage - Starting Failure
SVLT	2010/01/20 9:11	2010/01/20 14:18	21 (4)-FO-4 : Forced Outage - Starting Failure

Factors that contributed to unplanned unavailability

Essentially three factors contributed to the unplanned unavailability of the Hardwoods and Stephenville gas turbines:

- Age and condition of the turbines and generators, particularly the retaining rings in this case (no recent major overhaul/refurbishment/replacement) and the January 8 failure of End B;
- Replacement equipment initial installation failure (fuel valves); and

- Timing of component deliveries, insulation blankets in this case, and expert availability in critical periods.

The only aspect that could have been significantly different would have been the earlier identification and procurement of the Stephenville insulation blankets. Special efforts were made to expedite higher priority work (temporary removal of jacking oil pump from Stephenville to Hardwoods and new alternator procurement for Hardwoods).

Scheduling of GT overhauls/outages

The generator end ring issue was unexpected, and was found during refurbishment of Stephenville in 2012. As indicated, the scheduling of the repairs as originally planned, took into account the extension into the normal winter readiness period, the priority requirements of other outage requirements (Holyrood Units), and the expected generation/load match. The equipment would have been ready for service for winter readiness purposes and the January 2014 system event had other issues not occurred. It is possible that some of the equipment issues, particularly the insulation blanket, could have been recognized and addressed earlier.

Details – Holyrood Availability

Plant Information

Holyrood Thermal Generating station is a three unit 1969-1979 vintage heavy oil fuelled power plant. Units 1 and 2 are rated at 170 MW (originally 150 MW) commissioned in 1970-71 and uprated in 1988-89. Unit 3 is a 150 MW unit that entered service in 1979 and was retrofitted with additional equipment to enable it to run as a synchronous condenser.

The plant typically runs seasonally base loaded in winter with minimal cycling impacts due to the modest band of operation from 70 to 150 MW most of the time. Unit 3 generator runs as a synchronous generator in other parts of year, typically summer.

Factors that contributed to unplanned unavailability

Holyrood's early life availability was strongly influenced by the high sulphur, high vanadium heavy fuel oil that it consumed. Frequent winter shutdowns for boiler cleaning and tube leak repairs were the norm. A switch to a higher quality oil in 2006 through 2009 greatly reduced the winter unavailability due to fuel causes. In 2013, a new fuel contract resulted in a more erosive ash, with a propensity to precipitate out heavier liquids/solids in storage and handling systems. This has resulted in some equipment failures/repairs requiring short outages and significant cost issues with the fuel storage and handling systems, particularly in early to mid-2013. Through additional maintenance and parts and fuel quality adjustments with the supplier, Hydro has reduced the impacts for the 2013-14 winter period.

Given that the plant typically runs winter seasonally base loaded with minimal cycling impacts (due to the modest band of operation from 70 to 150 MW most of the time), the equipment is largely in reasonable to good condition. The equipment that deteriorates with time, as opposed to use, is approaching end of life and being replaced. Some of the major equipment, such as the generators, are reaching a life stage where issues may arise. Advanced and more frequent monitoring will help. Refurbishment may become desirable as condition assessments indicate further deterioration, but the expected generation life of between 2017, and in a standby role to 2021, also makes any significant investment more difficult to justify. This would include

significant investments in large, expensive major spares, such as large 4kV motor spares, that would have a very limited useful life.

Hydro carried out extensive condition assessment on Holyrood in 2011 to 2013, and continues to do so, particularly of the critical at-risk systems. This includes the high pressure, high temperature steam and water boiler components to reduce the risk of major steam system failures that could have major facility and safety impacts. The ongoing assessments have resulted in some in-situ repairs, but generally have found conditions to be consistent with operating to the expected end of generation operation. Major turbine and generator and auxiliary testing and overhauls continue on their regular schedule for reliability and maintainability purposes. Routine preventative maintenance and corrective work also continues.

The unavailability of 100 MW from Holyrood Unit 3 due to the failure of a Unit 3 FD fan motor on December 26, 2013 was the most significant generation capacity de-rating during the period of the rotating outages on January 2 to January 8, 2014. While its unavailability would not have caused the larger transmission/terminal station failure events on January 4 and January 5, 2014, the 100 MW loss was a major factor in the rotating outages prior to and during the restoration from those failure incidents. The motor was removed, shipped to a local supplier and returned and reinstalled on January 12, 2014.

A spare 4 kV FD fan motor had been suggested for procurement consideration in the 2011 condition assessment. It was examined and costed and submitted as part of the 2012 capital approval process, but was not pursued further based on Hydro's capital prioritization process. The subsequent year it was determined not to be a capital item and has not proceeded further as yet. Given the quick turnaround in the significant repair, a prioritization decision to procure a spare is a difficult one. One spare to address all the 4kV motors on Units 1 to 3 would be difficult to implement due to different sizes. Unit 1 and 2 have larger motors than Unit 3 and BFP motors are a different size from FD fan motors. Given the recent failures, the issues of spares versus the timeliness and impacts of repairs should be revisited.

Details – Hydroelectric Generation Availability

Granite Canal – Turbine Generator Vibration

In mid-December, 2013, the Granite Canal unit was de-rated from 40 MW to 32 MW, as axial vibration was being experienced when the unit was run past that limit. The cause of the vibration was unknown. This unit experienced a similar vibration issue in February 2012. Neither Hydro nor the OEM was able to determine a definite cause of the vibration. One theory at the time was related to the cold temperature of the water.

Given the very high system demand through the end of December 2013, it was decided to leave the unit operating on a de-rated basis until the system load came back down and a maintenance outage could be scheduled. At approximately 16:30 on January 2, 2014, the unit tripped due to a suspected vibration issue.

On January 3, 2014, crews arrived on site and returned the unit to service at approximately 30 MW. Vibration issues with the unit remained at over 32 MW. The work crew stayed with the unit through the weekend to ensure a timely response to any further issues given the pending weather and the system generation issues.

On January 4, 2014, the unit tripped again. This time it was due to the system imbalance caused by the issues at Sunnyside and elsewhere. The unit was brought back in service in less than one hour to approximately 32 MW. The crew remained with the unit.

On January 5, 2014, due to system demand, the crew ran the unit to 40 MW, maximum capacity, and the vibration issue was no longer present. It was suspected that there could have been ice formations causing the vibration and that the ice had come off the unit. Crews stayed with the unit through to January 8, 2014, and the system demand was reduced.

Exploits River – Frazil Ice Build-Up

Exploits River generation was initially reduced to 38 MW below the typical 63 MW obtained in winter due to frazil ice [1] buildup. There was a significant shift of a substantial amount of ice that accumulated in the water channels leading into the Grand Falls generating station, ultimately resulting in a reduction in available capacity of approximately 50 MW (from 88 MW at the time). Crews quickly responded to try to clear out the ice to the extent possible. Crews continued to work to remove the ice until January 14, 2014, when, through a combination of milder temperatures and the efforts of ice removal, the plant was restored to normal.

[1] Frazil ice is a collection of loose, randomly oriented needle-shaped ice crystals, sometimes resembling slush that are formed in turbulent water. It sporadically forms in open, turbulent, supercooled water, which means that it usually forms in rivers, lakes and oceans, on clear nights when the weather is colder.

Details – Wind Generation Availability

Wind generation is provided from two sites. St Lawrence Wind Project (ENEL Green Energy Power Canada Inc.) produces about 27 MW from nine Vestas V90 3.0 MW wind turbines. The project has produced on average over the last four years about 104,000 MWh/Year and thus operates at over 43% capacity factor. Fermeuse Wind is also a 27 MW wind project. The average production over the last three years has been about 87,300 MWh/Year and thus operates at about a 37% capacity factor. These are both excellent values and reflective of both good wind sites and good turbine availability.

St Lawrence Wind Project in 2012 was available 8566.4 hours of 8784 hours or an availability of about 97.5%. The facility experienced seven occurrences where it had to be restarted from offline. It had a total of 138 hours due to forced outages from balance of plant (BOP) equipment. There were no full day low wind days or no full day excessive wind days. Extreme wind and icing caused one day off associated with its substation. There were visual observations of thirteen lightning related days, and two freezing air/icing storms. There was 6.7 hours of outage due to extreme weather on one day attributable to Hurricane Leslie. All told, there were six extreme weather days in 2012 affecting the turbines or their associated substations, all in December through February.

Factors that contributed to unplanned unavailability

Extreme weather and system interruptions are the primary causes of unplanned unavailability. Prior to the January 2014 event, extreme weather related specifically to the turbines and auxiliaries was low. For example, it was just six days in 2012 for 50% of the installed capacity.

In the January 2014 system event, the St. Lawrence wind farm came off line at approximately 19:00 on January 3, 2014, due to weather conditions and high winds. On January 4, 2014, the wind farm lost grid power early in the morning due to the system events. The farm was subsequently unavailable until January 6, 2014. This was a result of icing conditions on the

turbines and the requirements to complete inspections on the turbines. The inspections required climbing the towers which could not be done for periods due to high winds. The return to service was also delayed by the inability of crews to get to the site due to road closures and bad road conditions.

The Fermeuse wind farm came off line on January 3, 2014, related primarily to the weather conditions and high winds. These turbines came back in service between January 5 to January 8, 2014, at various levels of production. Issues were similar to those at the St Lawrence wind farm.

A key issue is that the units have to be manually reset on site when tripped. In the January 2014 system event, extreme weather, as well as system issues on January 3, 2013, resulted in the shutdown of the 54 MW of wind generation facilities. The weather and access closures limited access to the facilities by the private developer's staff to inspect and reset the units. This extended the time to get to the units back in service -- between January 6 and January 8, 2014. At noon on January 8, 2014, St. Lawrence wind was on at full capacity of 27 MW and Fermeuse was at 23 MW.

Details – Under Frequency Event History 2004 to 2013

Details of Under-Frequency Events 2004-2013 as per Section 3.3 are presented below.

Year	Event	Date/Time	Generation Loss (MW)	Number of Customers Affected				Initiating Event
				Total	NF Power	Industrial	Hydro	
2004	1	Feb 20, 2004 09:15 AM	115	11,030	8,849	2	2,179	Holyrood Unit 2 - Exciter Problem
	2	Mar 07, 2004 10:03 PM	143	13,181	11,000	2	2,179	Holyrood Unit 2 - Loss of Station Service
	3	Apr 13, 2004 08:37 PM	125	13,996	11,814	3	2,179	Holyrood Unit 3 - Fuel System
	4	Aug 15, 2004 02:42 AM	45	1	0	1	0	Cat Arm Unit 2 - Fire System Failure
	5	Sep 21, 2004 01:43 PM	141	17,920	13,411	3	4,506	Bay d'Espoir Unit 7 - Exciter testing
	6	Oct 07, 2004 12:30 PM	100	12,646	8,138	2	4,506	Holyrood Unit 1 - DCS Testing
	7	Dec 21, 2004 03:53 PM	81	24,218	23,006	2	1,210	Holyrood Unit 1 - Inadvertent Trip
2005	1	Mar 22, 2005 12:54 PM	61	3,527	2,306	1	1,220	Hinds Lake Unit - Trip during testing
	2	May 09, 2005 06:26 PM	N/A	31,243	29,180	3	2,060	Problem with governor on Bay d'Espoir Unit 6 caused a significant drop in system frequency
	3	Jul 20, 2005 03:16 PM	80	2	0	2	0	Cat Arm Units 1 and 2 - Lightning Strike to TL247
	4	Sep 02, 2005 12:00 PM	N/A	71,011	64,566	3	6,442	A significant frequency disturbance resulted after all on-line units responded to a frequency oscillation.
	5	Sep 10, 2005 10:51 AM	80	10,205	8,698	3	1,504	Holyrood Unit 3 - Station Service Issues
2006	1	Jan 06, 2006 09:32 AM	110	10,818	8,763	2	2,053	Holyrood Unit 2 - Boiler Tube Leak
	2	Apr 12, 2006 01:11 PM	70	7,254	6,035	1	1,218	Holyrood Unit 3 - Inadvertent Trip
	3	May 15, 2006 11:44 AM	55	7,253	6,034	1	1,218	Cat Arm Unit 1 - Fire System Failure
	4	May 17, 2006 09:20 AM	67	7,253	6,034	1	1,218	Bay d'Espoir Unit 1 - High Bearing Temp
	5	Dec 15, 2006 12:55 AM	50	6,319	5,482	1	836	Holyrood Unit 3 - Fuel Oil Controls
	6	Dec 20, 2006 06:57 PM	62	2,258	2,257	1	0	Bay d'Espoir Unit 1 - Spherical Calve Closed
2007	1	Feb 10, 2007 01:46 PM	120	24,047	21,987	1	2,059	Cat Arm Units 1 and 2 - TL247 Trip (Icing)
	2	Mar 23, 2007 09:53 AM	75	7,169	6,328	2	839	Upper Salmon Unit - Fault at Intake
	3	Jun 19, 2007 01:28 PM	50	6,007	5,167	2	838	Holyrood Unit 1 - Loss of Station Service
	4	Oct 12, 2007 12:28 PM	77	8,208	7,369	1	838	Holyrood Unit 3 - Fuel Oil Controls
	5	Nov 25, 2007 12:08 PM	133	29,139	27,592	2	1,545	Holyrood Unit 1 - Boiler Trip
	6	Dec 28, 2007 02:21 PM	120	13,592	12,046	1	1,545	Holyrood Unit 1 - Lube Oil Pump Failure
2008	1	Jan 01, 2008 12:28 AM	70	8,465	7,504	1	960	Holyrood Unit 3 - Phase wire down on unit transformer
	2	Feb 14, 2008 04:26 PM	145	19,014	16,941	2	2,071	Holyrood Unit 3 - Station Service Issues
	3	Feb 20, 2008 03:57 AM	69	8,266	7,304	2	960	Bay d'Espoir Unit 3 - Stator Ground Fault
	4	Jul 03, 2008 12:31 PM	62	5,250	4,287	1	962	Cat Arm Units 1 and 2 - Lightning Strike to TL247
	5	Jul 29, 2008 10:26 PM	120	49,787	43,775	2	6,010	Cat Arm Units 1 and 2 - Lightning Strike to TL247
	6	Jul 29, 2008 06:09 PM	57	5,136	4,291	1	844	Hinds Lake Unit - High Bearing temp
2009	1	Mar 05, 2009 05:14 PM	90	10,881	9,633	1	1,247	Holyrood Unit 1 - High Drum Level
	2	Jul 29, 2009 10:26 AM	N/A	11,309	10,061	1	1,247	67 MW of generation was removed from system at Corner Brook Pulp and Paper. An overload occurred on the Deer Lake Power system after TL248 was taken out of service for maintenance, while Deer Lake Power Line 1 was also out of service.
	3	Aug 24, 2009 03:21 AM	N/A	5,425	5,424	1	0	Slow clearing fault on TL202 resulting in a drop in system frequency (tree contact)
	4	Aug 24, 2009 03:33 AM	N/A	18,188	16,941	0	1,247	Another slow clearing fault on TL202 resulting in a drop in system frequency (tree contact)
	5	Nov 06, 2009 07:41 PM	98	16,397	15,149	1	1,247	Holyrood Unit 1 - High Drum Level
	6	Dec 02, 2009 12:33 AM	N/A	15,676	12,537	1	3,138	70 MW of generation was removed from system at Corner Brook Pulp and Paper. Deer Lake Power Lines 1 and 2 tripped and resulted in an overload on transformer T1 at Deer Lake Terminal Station.
	7	Dec 06, 2009 04:27 PM	56	4,879	4,879	0	0	Holyrood Unit 1 - High Drum Level

Year	Event	Date/Time	Generation Loss (MW)	Number of Customers Affected				Initiating Event
				Total	NF Power	Industrial	Hydro	
2010	1	Jul 13, 2010 12:30 PM	N/A	3,560	3,560	0	0	A slow clearing fault on TL233 resulting in the operation of the rate of change under frequency protection.
	2	Jul 18, 2010 07:18 PM	N/A	3,530	3,530	0	0	A slow clearing fault on NP Line 363L resulting in the operation of the rate of change under frequency protection.
	3	Jul 18, 2010 10:54 PM	50	6,488	6,488	0	0	Hinds Lake Unit - Lightning Strike to TL243
	4	Nov 14, 2010 10:33 PM	53	5,057	5,057	0	0	Bay d'Espoir Unit 3 - Inadvertent Trip
	5	Dec 22, 2010 09:19 PM	75	5,273	5,272	1	0	Upper Salmon Unit - Governor trip
	6	Dec 30, 2010 12:57 PM	70	5,273	5,272	1	0	Holyrood Unit 3 - Cooling water flow issues
2011	1	Jan 14, 2011 02:33 PM	70	5,487	5,487	0	0	Holyrood Unit 3 - Trip during testing
	2	May 12, 2011 05:13 PM	73	6,485	6,485	0	0	Holyrood Unit 1 - Low Drum Level
	3	Oct 27, 2011 12:04 AM	66	5,346	5,346	0	0	Upper Salmon Unit - Unit transformer trip
2012	1	Jan 14, 2012 01:15 PM	142	21,141	18,940	1	2,200	Holyrood Units 1 and 2 - Station Service Problems
	2	May 22, 2012 01:12 PM	60	6,046	6,046	0	0	Cat Arm Unit 1 - Fire System Failure
	3	Oct 17, 2012 07:11 PM	71	17,824	16,546	0	1,278	Holyrood Unit 1 -False trip from DCS
	4	Nov 21, 2012 02:38 PM	98	12,872	11,594	0	1,278	Holyrood Unit 2 -Low Drum Level
	5	Nov 25, 2012 11:24 AM	60	6,660	6,660	0	0	Holyrood Unit 2 -Inadvertent Trip
2013	1	Jan 16, 2013 11:35 PM	121	17,498	15,299	0	2,199	Holyrood Unit 3 - False Vacuum Trip Alarm
	2	Jan 18, 2013 09:40 PM	68	4,309	4,309	0	0	Bay d'Espoir Unit 4 - False Protection Signal
	3	Mar 01, 2013 03:06 AM	52	6,256	6,256	0	0	Bay d'Espoir Unit 1 - Exciter Trip
	4	Mar 10, 2013 04:33 PM	69	6,041	6,041	0	0	Holyrood Unit 3 - Fuel Pump failure
	5	Apr 16, 2013 11:35 AM	91	15,711	14,430	0	1,281	Holyrood Unit 2 - Low Bearing oil pressure
	6	Apr 17, 2013 07:00 AM	146	49,164	42,502	0	6,662	Bay d'Espoir Units 3 and 5 - Bus B3 lockout and Breaker failure protection issues
	7	Nov 29, 2013 06:13 PM	119	6,764	6,764	0	0	Holyrood Unit 1 - Inadvertent Trip

NEWFOUNDLAND AND LABRADOR HYDRO

Transmission Availability

March 21, 2014

Prepared/Authored by:

Brian Scott

Brian Scott
Electrical Engineering Specialist
AMEC Americas Limited

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 5
2 REVIEW PROCESS 5
3 BACKGROUND 7
4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME 10
5 KEY FINDINGS AND RECOMMENDATIONS 15
6 RECOMMENDATIONS STATUS 18

APPENDIX 1 DETAILED SEQUENCE OF EVENTS 20
APPENDIX 2 HYDRO RESTORATION PLAN FOR AVALON PENINSULA (INSTRUCTION NO. T-032) 31
APPENDIX 3: PROCEDURE FOR LOSS OF EMS FUNCTION 34
APPENDIX 4: DIGITAL FAULT RECORDER TRACES 38

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) is undertaking an internal review of the various aspects of the events and potential contributors to the supply disruptions on the Island Interconnected system during January 2014. The internal review will consider eight sub-sections:

1. Load Forecasting
2. Generation/Reserve Planning
3. Generation Availability
4. Transmission Availability
5. Asset Management Strategy and Practices
6. Coordination and Communication With Customers
7. Emergency Response and Restoration
8. Technology and Communications Infrastructure

The result will be an overall "Summary Report on Supply Disruptions – January 2-8, 2014" which is intended to summarize the results of Hydro's internal review of supply disruptions on the Island Interconnected system during January 2014. Each sub-section will have a supporting report such as this one. The summary document and supporting sub-section reports will be incorporated into the data available to inform those involved in the reviews completed by the Board of Commissioners of Public Utilities (PUB) and the Government of Newfoundland.

This sub-section of the report, "Transmission Availability", provides a chronological summary of the key events involved in the supply disruptions as they unfolded over the two days of January 4th – 5th, 2014. It includes a review of the performance of the transmission network and its operation. It also includes a description of the internal Hydro process used to investigate the outages. This is one of three reports relating to the transmission system. The others are Protection System Impacts and Root Cause Analysis.

The review of the transmission system and the events of those two days consisted of reviewing the specific information related to the events and assessing the performance against the historical performance of Hydro's transmission system and industry practices. The review of specific information included reviewing the sequence of events logs, diagrams, documents and procedures, interviewing technical and operations staff, and participating with the Hydro

internal review team on the root cause analysis.

Hydro's performance of the bulk transmission system has historically compared very favourably with the national average as reported by the Canadian Electrical Association (CEA). Between 2004 and 2012, the latest year for published results, and based on a 5-year rolling average Hydro considerably outperformed comparable utilities represented in the CEA average for both 230 kV transformers and circuit breakers. For 230 kV transmission lines Hydro posted results that were more variable with some results above and others below the CEA averages.

Although not mandated to follow standards as required elsewhere in the interconnected North American electricity system, Hydro generally follows industry practices in the planning, design, construction and operation of the transmission system.

Hydro utilized a rigorous and formal "TapRoot" root cause analysis process led by an external facilitator to conduct an internal investigation of the event. The investigative team was composed of internal Hydro resources from operations and maintenance and external consultants in generation, asset management, protection and control and transmission that had been dedicated to this effort. Expertise throughout the Hydro organization was made available as required to assist in the effort. External OEM suppliers were consulted and participated in the investigation of equipment failures. All of the equipment investigation has not yet been completed.

The "TapRoot" analysis identified 4 key incidents for which the root cause should be determined. Those four incidents were:

1. Sunnyside transformer T1 fire (9:05 Jan. 4, 2014)
2. Western Avalon transformer T5 tap changer failure (12:22 Jan. 4, 2014)
3. Sunnyside bus 3 restoration failure (15:33 Jan. 4, 2014)
4. Holyrood unit #1 breaker B1L17 failure (21:27 Jan. 5, 2014)

The initial incident started with a fault in T1 transformer at Sunnyside terminal station that was quickly detected by the protection system. However, one of the five breakers failed to open

resulting in a delay in clearing the fault. The event rapidly escalated leading to an islanding of the electrical network and a blackout on the Avalon and Burin Peninsulas. The entire outage would have been limited to the failure of the Sunnyside transformer and Burin Peninsula and local area if the breaker had operated properly and the fault had been cleared quickly. The delayed clearing may have contributed to the severity of the transformer damage since the initial fault was detected very quickly. The failed breaker and the delayed clearing led to a configuration at Sunnyside that was more complex and involved additional equipment. When attempts were made later in the day to restore station service and pick up load at Sunnyside some equipment did not operate correctly leading to a loss of supply from Bay d'Espoir and a second blackout of the Avalon Peninsula. The slow clearing also caused power swings leading to separation of the transmission system east of the Sunnyside terminal. Holyrood generating station immediately tripped off when it could not supply the load and one of the unit breakers failed. The failure of the breaker at Holyrood was not discovered until the unit was being brought back on-line the next day and it caused significant additional power interruptions.

A major factor in this outage event was the performance of 230 kV circuit breakers. At least three failed to operate properly during the key incidents investigated.

The results of the root cause analysis process are dealt with in a separate report. That report will provide an identification of the underlying causes for each of the incidents and the actions that can be taken to eliminate or mitigate future occurrences.

Some key messages can be taken from a review of the events.

- Equipment failures, particularly 230 kV air blast circuit breakers (ACB) and their associated air systems, contributed significantly to the extent of the outages and to delays in restoration. Three similar type air blast circuit breakers built between 1966 and 1973 have been associated with the incidents described in this report and failed to operate properly during the 2-day event. The failure modes are different for each so the failures cannot be traced to a single cause factor. However, a thorough review is recommended to assess the acceleration and modification of the existing ACB refurbishment/replacement program, particularly the continued use of these breakers in critical areas on the bulk power system.
- Hydro's historical performance of the 230 kV transmission system has been very good

demonstrating performance results in transformers and circuit breakers better than CEA averages. This event is an uncommon occurrence and the performance of the circuit breakers represents a departure from previous experience.

- The design of the transmission network follows industry practices and provides a reliable and robust network. The events that occurred during the January 4 – 5th outages involved multiple events that are not typically designed for. A more extensive review of the event is recommended to capture unexpected outcomes and use these as lessons for future improvements.
- Hydro has processes and facilities in place to deal with events of this nature that are reviewed and tested on a regular basis. These include a restoration plan for loss of supply to the Avalon Peninsula, a back up control centre, and regular staff training. Enhancements should be made to ensure that facilities work as designed, personnel training encompasses similar extreme events and plans for resource allocation are focused on key issues. A more extensive review of the event is recommended to determine what enhancements should be made in addition to on-going continuous improvement initiatives.
- In the face of the overwhelming volume of data that occurs in an event of this nature, some Information was available but not acted upon that could have enabled operations staff to potentially reduce the impact of the outages. "Protection" alarms and "fault traces" need to be reviewed as soon as possible on an on-going basis during such an event. It is recommended that staff be readily available prior to anticipated extreme weather or potential system emergency conditions and be dedicated to this task during events of this nature. Other recommendations relating to protection and alarms include:
    a. Identify the key set of priority alarms that must be available and reviewed by the operator even during events of this magnitude.
    b. Provide additional training as necessary to operators on the importance of alarms.
    c. Implement a program to install modern digital relays that are able to store time-synchronized fault data. An installation plan should be developed to gain/increase visibility of all major equipment such as 230 kV transformers.
- Internal technical staff and external consultants involved in the event review as well as operations staff are knowledgeable, experienced and professional. Hydro should consider how it can best transfer the knowledge and experience gained both during the

event and in the investigation to the rest of the organization.

1 INTRODUCTION

Newfoundland and Labrador Hydro are undertaking an internal review of the supply disruptions on the Island Interconnected system for the period January 2-8, 2014. The internal review will focus on a number of areas. The focus for this sub-section report which deals with Transmission Availability is the performance of the transmission system during the Jan 4-5 disturbance events that largely impacted the Avalon Peninsula.

An overall "Summary Report on Supply Disruptions – January 2-8, 2014" will form the basis of the internal Hydro review. This report contains a number of sub-sections, eight in total, covering various aspects of the review. Each sub-section will have a supporting report such as this one. The summary document and supporting sub-section reports will be incorporated into the data available to inform those involved in the reviews completed by the Board of Commissioners of Public Utilities (PUB) and the Government of Newfoundland.

This sub-section of the report, "Transmission Availability", provides a chronological summary of the key events involved in the supply disruptions as they unfolded over the two days of January $4^{th} - 5^{th}$, 2014. It includes a review of the performance of the transmission network and its operation. It also includes a description of the internal Hydro process used to investigate the outages. This is one of three reports relating to the transmission system. The others are Protection System Impacts and Root Cause Analysis.

2 REVIEW PROCESS

Hydro established an internal review team to begin an analysis of the events involved in the supply disruptions in January 2014. Field investigations of damaged equipment were initiated and interviews were conducted with operations and maintenance staff. Hydro utilized a formal "TapRoot" root cause analysis process led by an external facilitator to conduct the internal investigation of the event. The investigative team was composed of internal Hydro resources

from operations and maintenance that had been dedicated to this effort. Expertise throughout the Hydro organization was made available as required to assist in the effort. External OEM suppliers were consulted and participated in the investigation of equipment failures. In addition, external consultants participated in the "TapRoot" process and findings.

The "TapRoot" analysis identified 4 key incidents for which the root cause could be determined. Those four incidents were:

1. Sunnyside transformer T1 fire (9:05 Jan. 4, 2014)
2. Western Avalon T5 tap changer failure (12:22 Jan. 4, 2014)
3. Sunnyside bus 3 restoration failure (15:33 Jan. 4, 2014)
4. Holyrood unit #1 breaker B1L17 failure (21:27 Jan. 5,2014)

Each of the 4 key incidents were thoroughly investigated and all relevant documentation such as the design, maintenance practices, history of equipment, and sequence of events for the incident were reviewed. Any issues were noted and followed-up on. The objective of the process was to determine the causal factors and the appropriate short and long term actions.

The external resources who participated in the "TapRoot" analysis were contracted by Hydro to provide a high level review of the approach used, assist in the analysis, bring knowledge of industry practices and focus on specific areas of expertise. Each of the external resources prepared a report on their focus area. A brief description follows:

1. "Protection Systems Impacts on 4 January 2014 Supply Disruptions" by Charles Henville, Henville Consulting, Inc.

   This report focuses on the protection systems' impact on the disturbances and identifies the protection issues from a high level. A detailed analysis was performed for the incidents at Sunnyside, the failed circuit breaker at Holyrood and the tap changer failure at Western Avalon

2. "Asset Management Strategy and Practice" by Blair Seckington, Director Power Consulting, AMEC Americas Ltd.

   This report contains an investigation and assessment of the Hydro asset management strategy and practices. This includes the strategy and standards, maintenance execution, long term asset plans, critical spares strategy and council of experts. It also looks at the

specific maintenance schedule and execution for the equipment that was involved in the Jan 4 – 5th incidents.

3. "Transmission Availability" by Brian Scott, Electrical Engineering Specialist, AMEC Americas Ltd.

   This report, included here, provides an overview of the transmission system performance during the Jan. 4 – 5th incidents and includes a summary of the sequence of events.

The review of the transmission system performance began with an overview of the transmission system - the location and size of generating units, peak and light load conditions, a general discussion of the loading of the transmission system, an identification of the primary constraints on the system and a summary of operating practices. This was followed by a review of both the detailed list and a summary of the sequence of events, system and terminal station diagrams, documents and procedures. Technical and operations personnel were made available to answer questions. For some of the detailed issues protection traces from Digital Fault Recorders were accessed and analysed. Participation with the Hydro internal review team on the root cause analysis took place early on during the review period and was valuable in focusing the analysis on key areas.

3 BACKGROUND

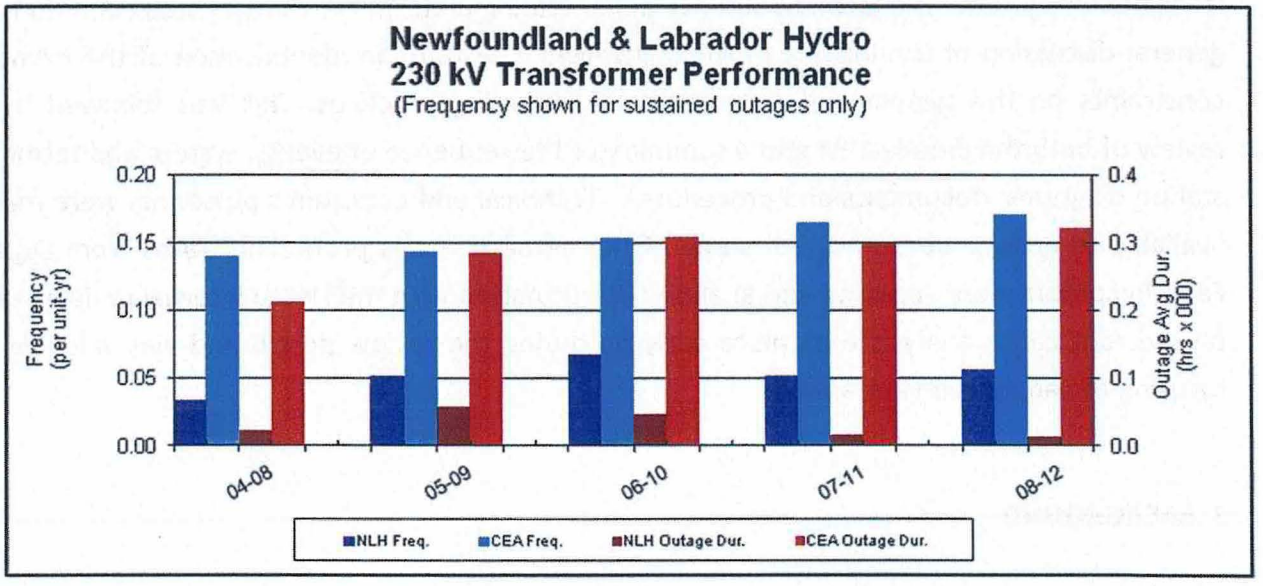
Hydro operates an electrical island that has not been interconnected with the North American electricity grid. As such there is no requirement to adhere to the standards established for the rest of the continent as defined by the North America Electric Reliability Corporation (NERC). Alternately, Hydro must be totally self-sufficient and cannot depend on help from its neighbours when significant supply disruptions occur such as during the events of Jan. 2 - 8, 2014. Hydro has drawn from the experience of others and has planned and constructed its electrical grid largely following the practices including NERC of the electrical industry in North America.

A review of the performance of the transmission system must therefore rely on the established standards and practices of Hydro. Industry practices as well as NERC standards can provide guidance and inform the reasonableness of Hydro's practices.

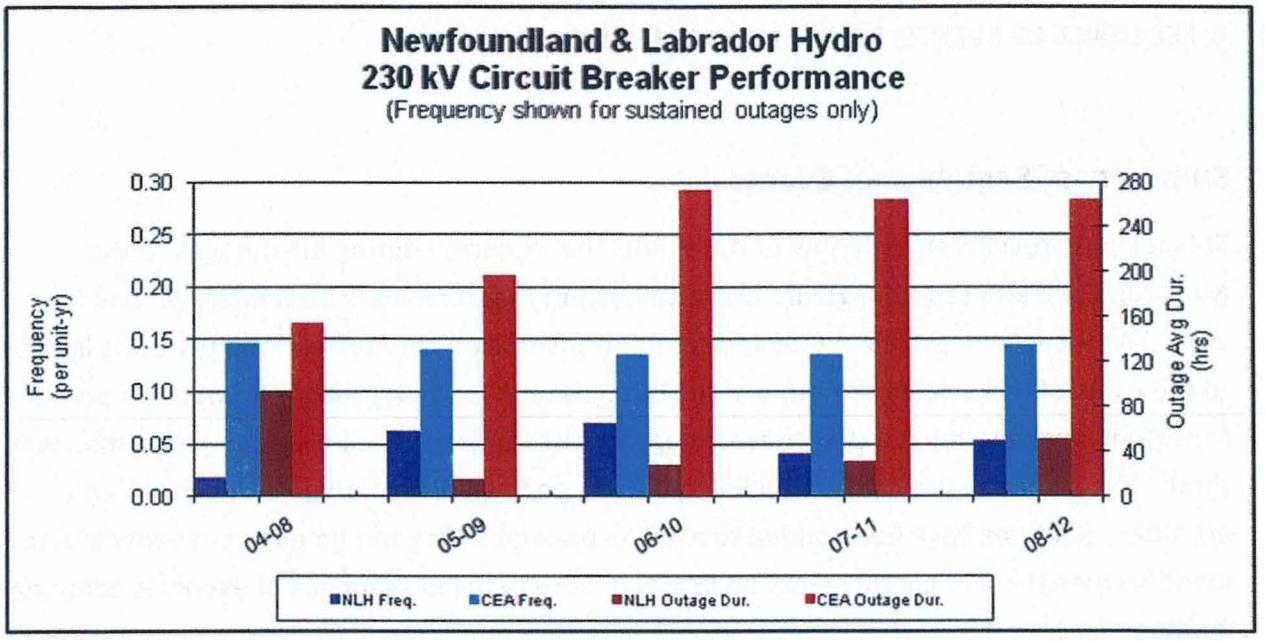
Hydro is a member of CEA and participates in an annual survey of equipment performance.

Hydro compares its results to a rolling 5-year average for similar utilities represented in CEA. Results for 2012, the latest available data published by CEA, demonstrate that the performance for the 230 kV transmission system for Hydro is very good.

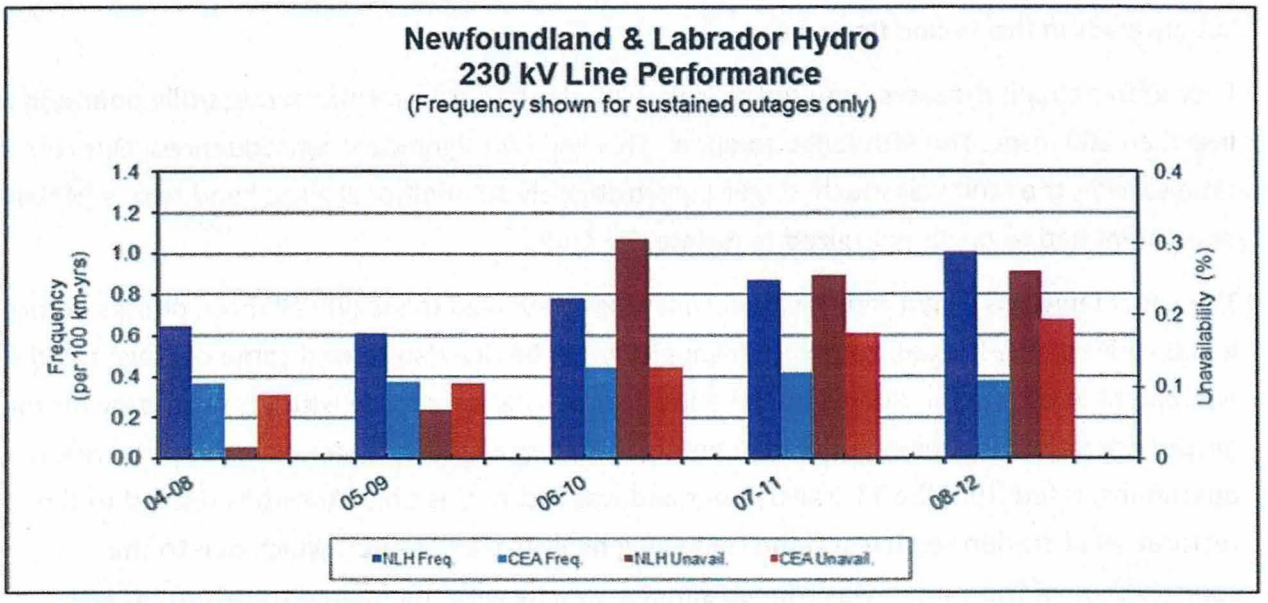
The following graph shows the performance results for 230 kV transformers for the years 2004 – 2012. Each group of bar graphs represents a 5-year period. As can be seen from the graph Hydro (NLH) had significantly fewer outages and the duration of outages was much less than the CEA average.



Hydro (NLH) demonstrated similar performance with 230 kV circuit breakers (see graph below). In this case, Hydro's outage duration for circuit breakers is trending upward but CEA averages show a similar trend and are at a much higher level.



The performance of the Hydro 230 kV transmission system compared to CEA averages is shown in the graph below. Here the frequency or number of outages per 100 km-yrs for Hydro's 230 kV lines is consistently higher. The unavailability of the lines has at times been better than CEA averages but not in the last 3 years of the survey. A review of the details underlying the statistics show that over 80% of Hydro's 230 kV transmission outages in 2012 were due to weather events (45% wind and 37% lightning); an indication that weather variability will have a significant impact on the number and frequency of outages.



4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME

Summary of Sequence of Events

This section provides an overview of the events that occurred during the outages to the Newfoundland and Labrador Hydro electrical system that took place on January 4th and 5th, 2014. The focus is on the 230 kV bulk electrical transmission network and the review is limited to the Avalon Peninsula where most of the outages took place. Although the western part of Newfoundland was impacted by these outage events the transmission system performed well there. The summary provides a timeline of events and highlights the major incidents and activities. Subtitles have been added to assist in understanding the timeline of events and to identify when the 4 major incidents occurred. A more detailed sequence of events is contained in Appendix 1.

T1 transformer failure and fire

On the morning of Saturday, January 4, 2014 at 9:05 am the Newfoundland and Labrador Hydro transmission system experienced a fault on transformer T1 at the Sunnyside terminal station. At the time the 230 kV lines into and out of the station were heavily loaded and the Newfoundland system load was near peak conditions. A total of 554 MW were coming in on the two 230 kV lines from Bay d'Espoir. Of this, 89 MW were flowing through the transformers at Sunnyside to serve area loads and the remaining 445 MW were flowing on two 230 kV lines to supply loads in the Avalon Peninsula.

Four of five circuit breakers required to isolate the faulted transformer successfully operated in less than 200 msec. The fifth failed to open. This had two significant consequences. One, the time to clear the fault was much longer (approximately an additional 2 sec.) and two, additional equipment had to be de-energized to isolate the fault.

The initial fault was a light internal fault that quickly evolved to include all three phases before it was cleared. The faulted transformer caught fire. The fire also caused some damage to other equipment in the station due to smoke and oil spray. Station service which is necessary for the proper operation of equipment in the station, including charging batteries to support critical operations, is fed from the T1 transformer and was lost at this time. Activities related to the restoration of station service and the remaining healthy transformer, which due to the configuration of the station was tripped simultaneously with the faulted transformer, were carried out later in the day.

When the fault was not cleared at Sunnyside, protection circuits at the Western Avalon and Come-by-Chance terminal stations detected the fault. The voltages at these two terminal stations were depressed due to the fault and the power system was beginning to go unstable. As a result, two 230 kV lines were tripped. When the first line between Sunnyside and Western Avalon (TL203) tripped, it cleared the fault. When the second line between Come-by-Chance and Western Avalon (TL237) tripped, it caused a separation of the electrical grid into two islands, Avalon Peninsula and the remainder of Newfoundland. The refinery at Come-by-Chance remained connected to the western island. Although not required to isolate the fault this second line tripped because the fault was seen by the protection for this line, through a combination of low voltage, high current and the power swing. Although it had no impact on this initial event one of the line TL237 circuit breakers that operated to clear the fault indicated a slow clearing time (Western Avalon B1L37). Later during the restoration process this same circuit breaker experienced problems and could not be successfully closed. Post-event analysis has determined that only two of three poles actually closed on this circuit breaker.

Blackout of the Avalon Peninsula

Loss of the two 230 kV lines and the separation of the grid resulted in a deficiency of supply for the Avalon Peninsula of nearly 450 MW. This led to an immediate collapse of the system and all three generators at Holyrood with a total generation of about 380 MW tripped off 3 seconds after the initial fault on the transformer. During the tripping of Unit # 1, one of the unit breakers B1L17 failed to open on all three phases. The protection systems at Oxen Pond and Hardwoods terminal station detected the failed breaker operation and circuit breakers at these locations successfully operated to trip transmission lines TL 218 and TL 242. Due to the blackout of the system it was not obvious that the failure had occurred and the problem was not discovered until the time when Unit #1 was being brought back on late the next day.

Restoration

Immediately following the blackout the ECC operator performed an overall assessment of the situation to determine the initial cause and the extent of the outage. This included discussions with the Bay d'Espoir plant operator and Newfoundland Power (NP). At this time the operator relied primarily on the mapboard and the SCADA one-line diagrams. Due to the flood of alarms and events of all kinds (1800 alarms and events were received in the first 5 minutes) the operator was limited to performing only a quick review of alarms.

At 9:27 am the ECC operator closed the breaker at Come-by-Chance to re-energize the line to Western Avalon (TL237) and effectively begin the restoration of power to the Avalon Peninsula. Hydro has a System Operating Instruction (Inst. T-032. See Appendix 2) to restore power to the Avalon Peninsula for loss of TL202 and TL206, the two 230 kV lines supplying the peninsula from Bay d'Espoir. This instruction generally was applicable with some key differences; in particular the separation point between the two electrical islands was the two lines on the peninsula side of Sunnyside rather than on the Bay d'Espoir side and the transformer failure T1 at Sunnyside introduced a significant complication. It appears as though the operator used this instruction as a guideline and the step-by-step restoration of lines closely follows the steps contained in the instruction. However, it appears that the operator did not use a group breaker open function prior to restoration as per the instruction. This would have ensured a known starting configuration as well as a controlled configuration for each step in the restoration process..

The restoration instruction outlines a step-by-step procedure for energizing each of the terminal stations beginning with those closest to the supply in Bay d'Espoir. As each station is energized voltages are adjusted. Restoring power to Holyrood terminal station is a priority so that the units can be re-started . Once all stations are connected, the remaining 230 kV lines are closed to complete the grid. The operator needs to co-ordinate with Newfoundland Power to bring on loads in conjunction with the restoration of supply.

This process continued over the next few hours. The procedure could not be followed exactly because the initial conditions were not the same as those in the instruction and at times breakers would not close properly. The operator operated some breakers multiple times without success and then attempted to use alternative ways to get the grid restored. This is not unusual given several factors (the reported history of breakers sometimes failing to close on the first try but being successful later; breaker low air system problems; the vast amount of data that was pouring into ECC; and the stress of wanting to restore power quickly).

The Western Avalon terminal station was particularly difficult to energize with one breaker (B1L37) tripping after each close attempt. There was a problem with the breaker. It was later identified that only two phases closed which caused the breaker to immediately re-open. An investigation was undertaken on Feb. 13, 2014 but the breaker operated properly at that time. Therefore, the underlying cause could not be identified with certainty. The operator eventually went on to energize Hardwoods terminal station first. Then, when the attempt was made to re-energize Holyrood from Hardwoods via line TL242 protection operated and tripped the line immediately. It was tripped because it connected to the failed breaker B1L17 and one phase of the Holyrood unit #1 transformer. The operator proceeded to isolate the entire bus at Holyrood

before retrying. Although this operation was successful, an opportunity to identify breaker B1L17 had failed was missed.

These issues undoubtedly led to some delays in the time needed to restore the 230 kV transmission system on the Avalon Peninsula.

Loss of EMS

Grid power had been lost to Hydro Place during the initial blackout. The EMS continued to operate without any interruptions on the Uninterruptible Power Supply (UPS) fed from the battery. Diesel #1 came on line immediately and the UPS was transferred automatically to the diesel. On the previous day both diesels had shut down due to over temperature alarm when the air intake louvers had closed due to loss of air supply. Diesel #1 was successfully re-started. However Diesel #2 was removed from service due to an undiagnosed synchronization problem and therefore was not available on January 4th. At 10:38 Diesel #1 tripped off on high temperature. The air intake louvers for Diesel #1 had closed causing the temperature to rise. An interim measure had been put in place but the air supply was lost again. An on-call person was in the building and responded quickly by manually opening the louvers and re-starting Diesel #1 at 11:03. Simultaneously with the trip, the UPS again switched to its battery source and continued to run without interruption. At 11:15 the EMS shut down due to loss of battery power. Typically a battery is sized only to provide power for a few minutes allowing time for the diesel to be started manually if required (15 - 30 minutes).

Switching of the UPS between various AC sources is done through the use of transfer switches. When the configuration is in its "normal" mode the transfer is automatic. Once all sources of AC supply were lost as was the case here the system was no longer in a normal mode and switching had to be done manually. Diesel #1 was brought back on-line at 11:03 and the grid power was restored by 11:15. However, the UPS had to be manually transferred to an appropriate AC supply by an employee knowledgeable with the operation of the transfer switch. This on-call person was contacted and brought in to restore the supply. Once the supply for the UPS was restored then the computer system was restarted, the various software systems activated and RTUs were polled to get the latest information at all terminal stations. By 11:46 the EMS was fully operational to perform grid control. A separate report contains the details of the loss of the EMS function.

Hydro has a procedure (see Appendix 3) for the loss of the EMS. The procedure was initiated. A full review of the procedure was not done as part of this external review. However, the ECC operator alerted the operator at Bay d'Espoir and transferred responsibility for frequency

control to the plant and also notified Newfoundland Power of the situation. Hydro considered moving resources to the back-up emergency control centre and activating it but with an understanding of the problem and a restoration of grid power to the building chose to remain at ECC. Hydro operators train annually for the loss of the EMS as well the transfer of operations to the backup control centre.

Western Avalon T5 tap changer failure

During the system restoration effort that began around 9:30, one of the first steps taken was to attempt to energize the Western Avalon B1 and B3 busses from Come-by-Chance via line TL237 using breaker B1L37. When this was performed the breaker tripped after 1.2 seconds. During the incident investigation by the external team it was found that only two phases of breaker B1L37 closed. This meant that the transformers connected to the 230 kV bus at Western Avalon, including transformer T5, were energized on two phases only. Although a gas/temperature/oil alarm was generated while the breaker was closed it is not known if the operator actually saw it. This same alarm had also been generated during the initial fault on T1 transformer at Sunnyside. A further 3 unsuccessful attempts were made to close breaker B1L37 that morning. At 12:22 Western Avalon busses B1 and B3 were finally energized when breaker L01L03 was closed connecting the station to Come-by-Chance. The T5 transformer tap changer failed 22 seconds later. There were no records that indicated a problem with the transformer prior to the failure. An Investigation by the tap changer OEM revealed that the failure was caused by a phase to phase flashover inside the tap changer. The investigation is continuing.

Sunnyside 230 kV Bus Lockout

At 12:57 after transformer T1 at Sunnyside terminal station had been electrically isolated; the 230 kV side of transformer T4 was energized successfully restoring station service. Approximately 1 ½ minutes later a 138 kV circuit breaker (B3T4) was closed enabling load current to flow through the undamaged transformer T4. The 230 kV bus was immediately tripped by bus differential protection as T4 isolation switch B1T4 opened automatically under load (something it was not designed to do), caused an arc and flashed over. It was noticed that the CT wiring had been damaged by the fire and was therefore considered to be the cause of the incorrect protection trip.

Emergency modifications were made to the wiring of the bus protection and a second attempt was made to energize the 138 kV bus at Sunnyside terminal station at 15:33. The bus protection

did not operate but the T4 isolation switch (B1T4) again opened automatically under load. This caused an arc and a subsequent flashover. The Sunnyside bus protection which should have operated to clear the fault failed to do so because of the emergency modifications and initiated breaker failure protection. The fault lasted for 0.6 seconds. This resulted in the two transmission lines TL 202 and TL206 tripping at the remote end in Bay d'Espoir to clear the fault. Again the supply to the Avalon Peninsula was cut off. The St. John's load that had already been restored following the 9:05 incident was lost for a second time.

The protection operation at Bay d'Espoir caused the outage to be even greater. TL202 breakers were slow to open and breaker failure was activated. This is covered in more detail in the external report on protection.

Holyrood Unit #1 breaker B1L17 failure

The transmission system had been restored and by the evening of January 5th most customers had their power back on. During the evening peak there were some load curtailments because generation had not been fully restored. At Holyrood, units #2 and #3 were on-line and total plant generation was approximately 210 MW.

At 21:27 on January 5, 2014 Holyrood unit #1 disconnect switch was closed in preparation for bringing the unit on-line. At the time, it was believed by the operator that the unit was isolated with both unit breakers open. Synchronization would then take place by closing one of the breakers. However, it is now known that breaker B1L17 was failed and one phase of the breaker was still closed. Although there was no fault, the unit transformer was energized through one phase. This caused the voltage to drop to approximately 200 kV and unbalanced currents to flow. Protection operated quickly to remove all supply sources. Transmission lines TL217, TL218 and TL242 were tripped. A lockout signal was generated for all three generating units. The three transformers feeding Newfoundland Power load were tripped and the station service transformers were tripped.

Loss of the two units at Holyrood, created a significant loss of supply once again to the Avalon Peninsula and numerous customer outages. However, there were no additional significant transmission incidents during the restoration that followed.

5 KEY FINDINGS AND RECOMMENDATIONS

Findings

1. One of the key findings in this outage event and a major contributing factor to the extent of the outages and to delays in restoration was the performance of 230 kV circuit breakers. At least three 230 kV air blast circuit breakers (ACB) failed to operate properly during the key incidents investigated. The probability of this happening is very low given that the failure modes are different for each. Specifically, the breakers were:

    a. Breaker B1L03 failed to open at Sunnyside during T1 transformer failure. The breaker was closed manually later in the day. Type: Brown Boveri air blast DCVF Built 1966

    b. Breaker B1L17 at Holyrood opened on only 2 phases when unit #1 tripped following the T1 incident. The problem was found and the breaker has subsequently been repaired under the supervision of ABB. This breaker is scheduled to be replaced as part of the program to upgrade breakers to meet fault level/interrupting capacity requirements. Type: Brown Boveri air blast DLF Built 1973

    c. Breaker B1L37 at Western Avalon closed on only 2 phases and after 1.2 seconds re-opened during Jan 5 – 6 outage events (on 7 occasions). This certainly led to delays in restoration. A number of the close operations occurred prior to the transformer T5 tap changer failure and the closure would have energized the all the 230/138 kV transformers at Western Avalon including transformer T5. It is unclear what if any contribution this would have had on the failure of the transformer. A work permit was issued for Hydro maintenance personnel to investigate B1L37 on Feb. 13th. The breaker operated successfully at that time. Type: Brown Boveri air blast DCVF Built 1968

2. Problems were experienced with other circuit breakers as well:

    a. Breaker B1L17 at Western Avalon experienced a number of difficulties. The operator experienced difficulties operating the breaker and there were issues with the breaker open/close state indication.

    b. Breaker B2L42 at Holyrood showed multiple changes of state between open and close.

3. Hydro's historical performance of the 230 kV transmission system has been very good demonstrating performance results in transformers and circuit breakers better than CEA averages. This event is an uncommon occurrence and the performance of the circuit

breakers represents a departure from previous experience.

4. The design of the transmission network follows industry practices and provides a reliable and robust network. The events that occurred during the January 4 – 5th outages involved multiple events that are not typically designed for.
5. Hydro has processes and facilities in place to deal with events of this nature. These include a restoration plan for loss of supply to the Avalon Peninsula, a back up control centre, and regular staff training.
6. In the face of the overwhelming volume of data that occurs in an event of this nature, some Information was available but not acted upon that could have enabled operations staff to potentially reduce the impact of the outages.
7. Internal technical staff and external consultants involved in the event review as well as operations staff are knowledgeable, experienced and professional.

Recommendations:

1. A thorough review is recommended to assess the acceleration and modification of the existing ACB refurbishment/replacement program, particularly the continued use of these breakers in critical areas on the bulk power system.
2. A more extensive review of the outage event as it relates to the performance of equipment and use of resources is recommended to capture unexpected outcomes and use these as lessons for future improvements.
3. Enhancements should be made to ensure that processes and facilities that are in place to deal with events of this nature work as designed, personnel training encompasses similar extreme events and plans for resource allocation are focused on key issues. A more extensive review of the event is recommended to determine what enhancements should be made in addition to on-going continuous improvement initiatives.
4. "Protection" alarms and "fault traces" need to be reviewed as soon as possible on an on-going basis during such an event. It is recommended that staff be readily available prior to anticipated extreme weather or potential system emergency conditions and be dedicated to this task during events of this nature.
5. Other recommendations relating to protection and alarms include:
    a. Identify the key set of priority alarms that must be available and reviewed by the operator even during events of this magnitude.

b. Provide additional training as necessary to operators on the importance of alarms.

c. Implement a program to install modern digital relays that are able to store time-synchronized fault data. An installation plan should be developed to gain/increase visibility of all major equipment such as 230 kV transformers.

6. A major event such as this provides very useful information on facilities, equipment and resources, both in terms of what worked well and what needs improvement. Hydro should consider how it can best transfer the knowledge and experience gained both during the event and in the investigation that followed to the entire organization in a deliberate manner.

6 RECOMMENDATIONS STATUS

All of the recommendations in this report require an evaluation of the circumstances and development of an implementation plan. They should therefore be completed in the mid to long term timeframe. This section provides some general targets for completion.

Recommendation 1: Assessment and modification of the existing ACB refurbishment / replacement program.

This should be evaluated in two parts. The first would be to assess and modify the program for the upcoming maintenance period. This would be constrained by availability of new equipment, outage plans and other factors. The second would be to evaluate the multi-year plan for the remaining breakers which should coincide with the next budget cycle.

Recommendation 2: A more extensive review of the outage event as it relates to the performance of equipment and use of resources.

All equipment that has been identified as experiencing problems during this event should be investigated and actions incorporated into the scheduled maintenance plans.

A review of the utilization of resources, whether they were adequate and if any training is required, can be done as part of the overall event review.

Recommendation 3: A more extensive review of the event to determine what enhancements should be made to ensure that processes and facilities in place for events of this nature work as designed, personnel training encompasses similar extreme events and plans for resource allocation are focused on key issues.

No action is recommended on this until the investigation is complete. It would be helpful to have a plan in place prior to the next winter season.

Recommendation 4: Protection staff be readily available prior to anticipated extreme weather or potential system emergency conditions and be dedicated to this task during events of this nature.

It is recommended to start action on this recommendation immediately to ensure resources are trained and in place before the next severe weather event occurs.

Recommendation 5: Other recommendations relating to protection and alarms.

Work on the alarm prioritizations can start immediately but it is expected that they will take several months to implement. Operator training on alarms can be done as part of the normal training. A plan for installation of digital relays should be completed prior to the budget cycle.

Recommendation 6: How Hydro can best transfer the knowledge and experience gained both during the event and in the investigation to the rest of the organization.

No action is recommended on this until the investigation is complete.

APPENDIX 1 DETAILED SEQUENCE OF EVENTS

Note: This appendix contains a more detailed summary of alarm and events for the outages on January 4th and 5th, 2014. In general, only key alarm/events at the 230 kV level are shown unless more detail is required for clarity purposes. Moreover details are provided only around the timeframes of the actual events and not for the entire period. Time is shown to the nearest minute, second or millisecond.

Jan. 04, 2014

9:05:34.600 Fault detected in transformer T1 at Sunnyside. Lockout 86T1 operates. **Sunnyside T1 failure**

9:05:34.715 138 kV breaker L109T4 at Sunnyside opens (low side of T4 transformer)

9:05:34.753 138 kV breaker B3T4 at Sunnyside opens (low side of T4 transformer)

9:05:34.755 230 kV Breaker B1L02 at Sunnyside opens

9:05:34.786 138 kV breaker B2T1 at Sunnyside opens (low side of T1 transformer). Four of five breakers for T1 Transformer operate. Breaker B1L03 does not open

9:05:35.641 Disconnect switch B1T1 at Sunnyside starts to open. Disconnect switch takes about 5.4 seconds to fully open (9:05:41.036)

When B1L03 does not open and the fault continues to evolve and protection circuits at multiple locations sense the fault after a delay of about 2 seconds and issue a trip signal:

9:05:36.695 TL203 at Sunnyside

9:05:36.704 TL203 at Western Avalon

9:05:36.715 TL237 at Come-by-Chance

The protection operations cause a number of breakers to open:

9:05:36.719 Breaker L03L06 at Sunnyside opens

9:05:36.742 Breaker L01L37 at Western Avalon opens

9:05:36.719 Breaker B1B2 at Come-by-Chance opens. At this point separation between Avalon Peninsula and the rest of the system occurs because TL203 is already open on the Sunnyside end. (See Appendix 4, Figure 1 for trace showing system becoming unstable)

9:05:36.820 Breaker L03L17 at Western Avalon opens which clears the fault on T1 transformer, 2.2 seconds after the fault was initiated.

9:05:36.991 Breaker L01L03 opens at Western Avalon

09:05:36 AC power was lost to the Hydro building

09:05:36 Hydro's EMS switched to battery power

The units at Holyrood cannot supply the load and trip off:

9:05:37.387 Holyrood G1 lockout 86-3/G1

9:05:37.419 Holyrood G2 lockout 86-3/G2

Unit breakers for G1 open:

9:05:37.471 Breaker B1L17 at Holyrood opens. This breaker only opens two phases. C phase remains closed

9:05:37.511 Breaker B1B11 at Holyrood opens. **Holyrood Unit #1 trips**

Unit breakers for G2 open:

9:05:37.517 Breaker B2L42 at Holyrood opens

9:05:37.529 Breaker B2B11 at Holyrood opens. **Holyrood Unit #2 trips**

Unit breakers for G3 open

9:05:37.660 Breaker B3B13 at Holyrood opens

9:05:37.711 Breaker B3L18 at Holyrood opens. **Holyrood Unit #3 trips**

9:06:21.834 Holyrood G3 lockout 86-4/G3. (The lockout indication should occur before the breaker operation so there may have been a delay in indication)

As soon as unit #1 breaker B1L17 at Holyrood opens (2 phases) protection circuits at Hardwoods and Oxen Pond operate to trip the lines feeding Holyrood. This occurs even before

unit #3 has tripped. It appears as though protection also issued a trip to breaker B3L18 at Holyrood. (See Appendix 4, Figure 2 for trace showing neutral current on unit #1 transformer after the unit has tripped)

9:05:37.577 Protection trip initiated for line TL242 Hardwoods

9:05:37:578 Protection trip initiated for line TL218 Oxen Pond

9:05:37.622 Breaker B2L42 at Hardwoods opens

9:05:37.732 Breaker B1L18 at Oxen Pond opens

Breaker B1L37 opens at Western Avalon, then closes and re-opens. The initial opening appears to be a delayed opening to the protection operation initiated at 9:05:36. Operations staff indicated that the close is likely an automatic re-close. The subsequent opening after a delay is consistent with only 2 phases closing as seen later in the morning. A gas/temperature/oil alarm is also seen.

9:05:38.195 Western Avalon T5 gas/temperature/oil alarm

9:05:38.209 Breaker B1L37 at Western Avalon opens

9:05:41.041 Breaker B1L37 at Western Avalon closes

9:05:41.036 Disconnect switch at Sunnyside is fully open providing isolation for the high side of the failed transformer T1

9:05:42.137 Breaker B1L37 at Western Avalon re-opens after 1.2 seconds

09:05:45 Diesel #1 at Hydro Place on-line restoring AC supply

09:05:45 Hydro's EMS switched to diesel supply

09:06:49.649 Disconnect switch B3T3 at Holyrood is opened by plant operator to isolate unit #3

9:09:02 Status of breaker BL42 at Holyrood generating station begins to toggle between open and close, literally dozens of times. The operator would be able to quickly ascertain that the breaker did not actually operate but it would have been difficult to determine the actual state and it would have added confusion to determining the state of the power system.

9:27:44 Operator closes breaker B1B2 at Come-by-Chance to re-energize TL237 to Western Avalon. **Restoration Begins**

9:38:01 Operator opens breaker B1L17 at Western Avalon to prepare to energize bus B1 only.

9:41:00 Operator closes breaker B1L37 at Western Avalon to energize bus B1 from line TL237. Breaker closes but trips again 1.2 seconds later. This is due to only 2 phases closing. Subsequent trip is on phase disagreement (See Appendix 4, Figure 3 for trace showing current in 2 phases only). Since breaker B1B3 is closed (It does not open until the fault on T5 at 12:22) bus B3 is energized which energizes transformer T5. In addition breaker B1L08 is still closed so line TL208 to Voisey's Bay is also energized. A gas/temperature/oil alarm is received for transformer T5 at 9:41:09 during the time when the breaker B1L37 is closed.

9:41:43 Operator opens breaker B1L08 at Western Avalon to isolate TL208 and Voisey's Bay.

9:42:11 Operator attempts to close breaker B1L37 at Western Avalon a second time with the same result as before. Breaker closes but trips after 1.2 seconds and a gas/temperature/oil alarm is received for T5.

9:44:34 Operator opens B1L36 at Hardwoods to prepare to energize Hardwoods terminal station.

9:51:44 Operator closes L01L37 at Western Avalon to energize TL201 and busses B1 and B2 at Hardwoods. No loads have yet been successfully re-energized at Western Avalon. **Hardwoods is restored**

10:14:43 Operator attempts to close B2L42 at Hardwoods to energize line TL242 to Holyrood. This energizes bus B12 at Holyrood. However, since the failed breaker B1L17 at Holyrood has not been isolated (failed state of breaker has not been discovered) and the unit disconnect is still closed, then one phase of unit #1 step-up transformer would be energized. Protection circuits for TL242 operated at both Holyrood and Hardwoods. (See Appendix 4, Figure 4. This contains a trace of the unbalanced current flow as seen from Western Avalon via line TL237) At Holyrood breaker B12L42 tripped open and after 2 minutes an event was generated indicating that the breaker B2L42 failed to close. The protection system operated correctly and the unit transformer was energized through a single phase for about 4 cycles. The unbalanced current flow was probably not high enough to cause significant damage to the generator. About this time breaker B1L17 at Holyrood indicates several open/close operations (4).

10:15:51 Operator opens breaker B13B15 at Holyrood

10:15:56 Operator opens breaker B12B15 at Holyrood

10:16:03 Operator opens breaker B7T5 at Holyrood – low side breaker of transformer T5 connected to 230 kV bus B11

10:16:17 Operator opens breaker B12T10 at Holyrood – high side breaker of transformer T10 connected to 230 kV bus B12. The only 230 kV breakers that remain closed are B12L17 and B12L18.

10:22:31 Operator attempts to close B2L42 at Hardwoods a second time. This time the breaker closes successfully because breaker B12L42 at Holyrood is now open. Transmission line TL242 is re-energized.

10:23:15 Operator opens breaker B12L17 at Holyrood.

10:23:19 Operator opens breaker B12L18 at Holyrood. All 230 kV breakers are now open at Holyrood.

10:23:31 Operator closes breaker B12L42 at Holyrood which energizes bus 12 at Holyrood. **Bus B12 at Holyrood is restored.**

10:24:39 Operator closes breaker B12T10 at Holyrood which energizes the 25 MVA transformer T10 enabling the restoration of station service to the plant. The low side breaker B6T10 is closed about 1 minute later.

10:25:31.281 Disconnect switch B1T1 at Holyrood is opened by plant operator isolating unit #1 and avoiding for the time being any further system issues with unit breaker B1L17.

10:25:50.635 Disconnect switch B2T2 at Holyrood is opened by plant operator to isolate unit #2

10:38:44 Diesel #1 at Hydro Place tripped offline due to high temperature. Air intake louvers had closed due to heavy ice build-up

10:38:44 Hydro's EMS switched to battery power

10:41:13 operator closes breaker B1L36 at Hardwoods to energize line TL236 to Oxen Pond and the Oxen Pond B1 bus. **Oxen Pond is restored.**

10:57:15 Breaker B1L03 at Sunnyside, the one that failed to open during the transformer fault, opens.

11:02 Hydro's EMS shutdown due to loss of UPS Battery Power

11:03 Diesel #1 on-line - UPS does not automatically switch to diesel supply (manual switching required)

11:00 -11:15 AC power is restored to Hydro Place by Newfoundland Power. As noted above, UPS does not automatically switch to AC supply (manual switching required)

11:46:50 Hydro's EMS grid control functions are restored to ECC.

12:00:31 Disconnect switch B2L12-1 at Sunnyside is opened by field personnel, a low-side isolation point for transformer T1. Status is manually set.

12:00:38 Disconnect B2B3 at Sunnyside is opened by field personnel. Status is manually set. This isolates the low side of transformer T1.

12:13:03 Operator attempts to close breaker B1L37 at Western Avalon. Similar to previous attempts the breaker closes but trips after 1.2 seconds and a gas/temperature/oil alarm is received for T5.

12:15:16 Operator attempts to close breaker B1L37 at Western Avalon. This time the breaker fails to close and after 2 minutes an event was generated indicating the status.

12:15:57 In the meantime, operator closes breaker B1L17 at Western Avalon. Since the other end of the line TL217 is open this action has no effect.

12:17:31 After receiving notification that breaker B1L37 at Western Avalon failed to close, the operator attempts another close operation. Again the breaker fails to close and after 2 minutes an event was generated indicating the status.

12:19:47 Operator closes breaker L03L17 at Western Avalon. The breakers for line TL203 had tripped to clear the T1 transformer fault at Sunnyside and were still open. That is, except for the breaker B1L03 at Sunnyside. This breaker had been manually opened at 10:57. Therefore, closing this breaker had no effect.

12:22:07 Operator closes breaker L01L03 at Western Avalon. This energizes busses B1 and B3 at Western Avalon via line TL237 from Come-by-Chance. Due to previous actions, line TL203 to Sunnyside and line TL217 to Holyrood are also energized. Breaker close indication received at 12:22:15.721. The transmission line to Sunnyside appears to be energized prior to opening the

disconnect switches (12:38) to isolate the failed breaker B1L03. Since the status is manually set, this may be just a timing issue and the operator has already been made aware that the breaker has been isolated. **Western Avalon B1 and B3 busses restored**

12:22:39.892 Western Avalon transformer tap changer fails. A phase to phase fault develops. 86T5 lockout protection operates. **Western Avalon T5 tap changer failure**

12:22:39.862 Western Avalon breaker B1B3 opens to clear fault on T5 transformer

12:22:40.486 Western Avalon switch B4T5 opens – low side of transformer T5

12:22:41.294 Western Avalon switch B3T5 opens – high side of transformer T5 to isolate T5 transformer

12:23:12 Operator closes breaker B12L17 at Holyrood enabling power to flow. The other end had been closed at 12:22:07.

12:30:25 Operator closes breaker B1L18 at Oxen Pond energizing line TL218 to Holyrood.

12:30:33 Operator closes breaker B12L18 at Holyrood, the other end of line TL218.

12:38:20 Disconnect switch B1L03-2 at Sunnyside is opened by field personnel. Status is manually set.

12:38:25 Disconnect switch B1L03-1 at Sunnyside is opened by field personnel. Status is manually set. This isolates the breaker B1L03.

12:42:03 Operator closes bus tie breaker B1B3 at Western Avalon. The breaker fails to close and provides indication 2 minutes later at 12:44:04.

12:56:55 Operator initiates close of breaker B1L02 at Sunnyside. At 12:57:07.804 the breaker closes which energizes bus B1 and the healthy transformer T4. Station service is also restored.

12:58:11 Operator opens 138 kV breaker L19L100 at Sunnyside.

12:58:12.030 138 kV breaker L19L100 at Sunnyside opens

12:58:21 Operator initiates close of 138 kV breaker B3T4 at Sunnyside. At 12:58:23.928 the breaker closes. **First attempt to load T4 at Sunnyside**

12:58:24.281 138 kV breaker B3L19 at Sunnyside opens

12:58:24.356 138 kV breaker B2L12 at Sunnyside opens

12:58:25.807 138 kV disconnect switch B1T4 at Sunnyside begins to open.

12:58:30.392 Bus 1 lockout 86B1 at Sunnyside operates due to fault caused by opening of B1T4 under load.

12:58:30.524 Breaker B1L02 at Sunnyside opens

12:58:30.540 138 kV breaker B3T4 at Sunnyside opens

12:58:35.273 138 kV disconnect switch B1T4 at Sunnyside is fully open

13:04:38 Operator attempts to close disconnect switch B1T4 at Sunnyside. Operation fails and open status indicated about 30 seconds later at 13:05:09

14:09:17 Operator attempts again to close disconnect switch B1T4 at Sunnyside. Operation fails and open status indicated about 30 seconds later at 14:09:48

14:36:16.206 138 kV disconnect switch B1T4 at Sunnyside is closed. Since there is no indication of operator action, it is assumed that the switch was closed locally by field personnel. Beginning at 14:16:57 there had been a number of state changes for this switch between Open and In Transit.

14:40:47 Operator closes breaker L03L06 at Sunnyside.

14:41:14 Operator initiates close of breaker B1L02 at Sunnyside. At 14:41:18.339 the breaker closes which similar to the previous attempt energizes bus B1 and the healthy transformer T4. Station service is also restored.

15:33:23 Operator initiates close of 138 kV breaker B3T4 at Sunnyside. At 15:33:26.498 the breaker closes. **Second attempt to load T4 at Sunnyside**

15:33:28.339 Similar to the previous attempt, 138 kV disconnect switch B1T4 at Sunnyside begins to open.

15:33.32.525 Protection signals 77-TL202 PRI and 77-TL202 SEC sent from Bay d'Espoir.

15:33.32.526 Protection signals 77-TL206 PRI and 77-TL206 SEC sent from Bay d'Espoir.

15:33:32.531 Protection signal 85-TL202 PRI received at Sunnyside. Secondary protection signal for TL 202 also received 15 msec. later.

15:33:32.532 Protection signal 85-TL206 PRI received at Sunnyside. Secondary protection signal for TL 206 also received 12 msec. later.

15:33:32.866 Breaker B11L06 at Bay d'Espoir opens and at 15:33:32.889 breaker L06L34 at Bay d'Espoir opens to trip line TL206

15:33:33.122 Lockout 86B3 at Bay d'Espoir operates

15:33:33.150 Breaker B3B4 at Bay d'Espoir opens

15:33:33.215 Breaker B4B5 at Bay d'Espoir opens. B3B4 and B4B5 will trip line TL202 but were slow in opening. **Loss of supply from Bay d'Espoir to Sunnyside and Avalon peninsula including Come-by-Chance initiating a second blackout**

15:33:33.237 Breaker B5B6 at Bay d'Espoir opens. With B4B5 open this trips TL204

15:33:33.247 Breaker L02L07 at Sunnyside opens

15:33:33.258 Breaker B1L02 at Sunnyside opens

15:33:33.353 Breaker B3T6 at Bay d'Espoir opens. Unit #6 is tripped off-line

15:33:33.416 Breaker B3T5 at Bay d'Espoir opens. Unit #5 is tripped off-line

15:33:37.206 – 15:33:37.986 Status indication that breaker B1L02 at Sunnyside opens/closes multiple times (5 close operations followed each time by an open operation).

15:33:37.206 – 15:33:37.986 Status indication that breaker B1L03 at Sunnyside closes opens/closes multiple times (6 close operations followed each time by an open operation).

15:33:37.214 Breaker L02L07 at Sunnyside closes

15:33:37.214 Breaker L02L07 at Sunnyside opens

15:33:37.214 -15:33:37.833 Disconnect switch B1T1 shows In Transit / Open states (4 times)

15:33:39.416 138 kV disconnect switch B1T4 at Sunnyside is fully open

15:37:58 Operator initiates close of breaker B11L06 at Bay d'Espoir. At 15:38:00.875 the breaker closes to energize line TL206 and start the restoration process. **Restoration begins**

The restoration process that began at 15:38 is not included.

21:21:40.348 Disconnect switch B2T2 at Holyrood is closed by plant operator to prepare to bring unit #2 on-line

21:34:07.819 Breaker B2L42 at Holyrood is closed by plant operator to synchronize unit #2. **Holyrood unit #2 on-line**

21:34:42.219 Breaker B2B11 at Holyrood is closed by plant operator

Jan. 5, 2014

01:39:28.029 Disconnect switch B3T3 at Holyrood is closed by plant operator to prepare to bring unit #3 on-line

01:40:42.797 Breaker B3L18 at Holyrood is closed by plant operator to synchronize unit #3. **Holyrood unit #3 on-line**

01:41:05.969 Breaker B3B13 at Holyrood is closed by plant operator

08:10:16 Operator closes B1L08 at Western Avalon to energize line TL208 to Voisey's Bay. **Voisey's Bay is restored**

Holyrood generators trip

21:27:34.420 Unit #1 disconnect switch B1T1 at Holyrood closes. Since breaker B1L17 has failed the unit transformer is energized. This causes the voltage to drop to approximately 200 kV and

protection to operate for lines TL217, TL218 and TL242.

21:27:41.133 Unit #1 disconnect switch at Holyrood opens.

21:27:41.295 Unit #1 lockout operates 86-2/G1

21:27:41.414 Unit #2 lockout operates 86-3/G2

21:27:41.501 Breaker B2L42 at Holyrood opens. This breaker continues to give multiple open/close state changes

21:27:41.575 Breaker B8L39 at Holyrood opens – low-side breaker for transformers T6, T7 and T8 supplying Newfoundland Power Loads

21:27:41.823 Breaker B13B15 at Holyrood opens –one of two high-side breakers for transformers T6, T7 and T8 supplying Newfoundland Power Loads

21:27:41.843 Breaker B7T5 at Holyrood opens – low side of SS transformer

21:27:41.856 Breaker B12L18 at Holyrood opens

21:27:41.996 Unit #3 lockout operates 86-4/G3

21:27:42.010 Breaker B12L17 at Holyrood opens

22:12:31 Operator attempts to open breaker B12B15. Control failure status given after 16 seconds

APPENDIX 2 HYDRO RESTORATION PLAN FOR AVALON PENINSULA (INSTRUCTION NO. T-032)

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SYSTEM OPERATING INSTRUCTION

STATION:	Energy Control Centre	**Inst. No.**	T-032
TITLE:	Restoration Plan for Loss of TL202 and TL206	**Page**	1 **of** 3

This plan is devised to assist in the restoration of the power system should TL202 and TL206 trip simultaneously. Newfoundland and Labrador Hydro's Energy Control Centre Shift Supervisor will direct all actions necessary to restore the power system to its normal operating state. Upon loss of both 230 kV transmission lines from Bay d'Espoir to Sunnyside, Hydro's automatic restoration scheme will activate. The goal of the scheme is to restore power to TL207 from either TL202 or TL206. A number of items can be performed while the auto-restoration program is running. If unsuccessful, the program will timeout after 1½ to 2 minutes. Complete the following items in preparation of restoring the system.

***Note*- Maintain Contact with Newfoundland Power throughout this Restoration Procedure.**

	Newfoundland Hydro (NLH)	Comments
1.	Upon loss of TL 202/TL 206 auto-restoration program will execute.	***Check program status - Come -by-Chance (CBC) display set. (T-023)***
2.	Restore lines and customer load tripped due to underfrequency load shedding (TL 226, TL 220, GBK L1, St. Alban's, etc.)	***Reminder: - AGC has tripped to Monitor.***
3.	Monitor and Control West Coast voltage.	***Follow Guidelines for West Coast Voltage Control.***
4.	Request Bay d'Espoir Plant to take local control.	***Have Bay d'Espoir staff monitor and regulate frequency.***
5.	Notify North Atlantic Refining Ltd and Vale.	***NARL – 463-8811 ext.487*** ***Vale – 758-8778 or 697-1102***
6.	Notify System On-Call and Corporate Relations.	
7.	Execute Group Breaker openings in OPD, HWD, HRD and WAV.	****NLH will verify group breakers open completed.*** ****NP will verify Avalon feeders Open.***
8.	Check CBC, HWD, OPD Cap Banks Open.	****Verify all Avalon Capacitor Banks Open.***

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SYSTEM OPERATING INSTRUCTION

STATION:	Energy Control Centre	**Inst. No.**	T-032
TITLE:	Restoration Plan for Loss of TL202 and TL206	**Page**	2 of 3

	Newfoundland Hydro (NLH)	Comments
9.	If HRD Unit(s) tripped, Request Holyrood's Control Room to open all unit breakers.	***ECC will verify Holyrood unit breakers open.***
10.	Execute SSD Group Breaker opening.	***Separate 138 kV from 230 kV at Sunnyside and verify group breaker open completed.***
11.	Restore TL 202 and/or TL 206 (If not already done by auto-restoration). If TL202 and TL206 remain out, consider HRD Blackstart from either Newfoundland Power's Mobile Generation at HRD or HWD TL242 (refer to Instruction T-007 and T-023).	***TL 202 preferred to avoid energizing TL 203 when restoring SSD 138 kV bus. Adjust SSD LTC's to acceptable voltage levels.***
12.	Restore TL 207 (If not already done by auto-restoration) and restore TL 237 to WAV.	***Notify NARL to restore (30 MW).*** ****May require adjusting all online generating units to achieve acceptable Avalon voltage levels.***
13.	Restore Sunnyside 138 kV bus. Monitor and Control Voltages. *Note:* ****Use of CBC caps will result in excessive Voltage spikes****	***Restore TL212 and TL219. Notify Newfoundland Power to restore Burin and SSD Feeders.*** ****If required the removal TL219 (SSD-SPO) will help lower the Avalon voltage.***
14.	Restore second line from Bay d'Espoir to Sunnyside, if possible.	***Monitor and control voltage to acceptable levels.***
15.	Restore TL237 at WAV, adjust WAV LTC's to acceptable levels (142 kV) and notify Newfoundland Power to restore WAV Loads.	***64L, B2T1, B2T2, and 86L loads.***
16.	Close WAV L01L37 to energize TL201 to HWD via B1L01. Adjust HWD LTC's to acceptable levels (68 kV) and notify Newfoundland Power to restore HWD Loads.	****Use HWD Cap Banks after LTC's usage exhausted.*** ****Start Hardwoods GT, if not already started.***

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SYSTEM OPERATING INSTRUCTION

STATION:	Energy Control Centre	**Inst. No.**	T-032
TITLE:	Restoration Plan for Loss of TL202 and TL206	**Page**	3 of 3

	Newfoundland Hydro (NLH)	Comments
17.	Close HWD B2L42 to energize TL242 to HRD. *If not completed through Black Start T-007* Close HRD B12L42.	***HRD station service restored. Notify NP and restore 39L and 38L (If not already completed).***
18.	Close HRD B12L18 to energize TL218 to OPD. Close OPD B1L18. Adjust OPD LTC's to acceptable levels (68KV) and notify Newfoundland Power to restore OPD Loads.	****Use OPD Cap Banks after LTC's usage exhausted.***
19.	When HRD Unit(s) are Online, restore all remaining loads. Use CBC Cap Banks as required.	
20.	Restore all remaining 230kV Transmission Lines, TL203, TL217, & TL236.	***Monitor and control voltage to acceptable levels.***

Notes:

- To secure the system after load has been restored, place remaining 230 kV transmission lines in-service and start Paradise River plant. Newfoundland Power will restore the remainder of their system, picking up load in consultation with Hydro (ECC).
- The Wind Farms should not be re-connected to the system until the Holyrood plant is in a stable mode of operation and the load is restored. When connected, the output of the wind farm(s) should be limited to the total pick-up capability of the Holyrood plant in the event that the wind generation is suddenly lost or rejected.
- Under extenuating circumstances (HRD offline for extended period), the Wind Farms could possibly supply load to Newfoundland Power's system and help maximize the available Avalon Generation capacity.

REVISION HISTORY

Version Number	Date	Description of Change
0	2013-04-11	Original Issue

PREPARED: Jason Dean	**APPROVED:**

APPENDIX 3: PROCEDURE FOR LOSS OF EMS FUNCTION

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS STANDARD INSTRUCTION

TITLE:	Inst. No. 015
CONTINGENCY PLAN FOR LOSS OF THE ENERGY MANAGEMENT SYSTEM FUNCTION	Rev. No.
	Page 1 of 4

Introduction

The Energy Management System (EMS) is used by the Energy Control Centre (ECC) to operate the power systems on the Island and in Labrador. If the EMS fails and is unable to function, operation of the power system must be carried out by staffing generation and terminal stations normally operated using the EMS. The details of this plan, which are directed by ECC staff, are included in the Contingency Plan for Loss of EMS Function retained as part of several technical and administrative instructions maintained by ECC. This instruction outlines the responsibilities of operating staff who are required to attend stations, the preparation required, and the frequency for testing the contingency plan.

Preparedness

To ensure that individuals are familiar with the procedures and responsibilities associated with this instruction, this contingency plan will be simulated yearly to measure effectiveness.

Responsibilities

Asset Managers – Generation and Terminal Stations	1.	Managers should ensure that personnel are aware of this procedure and the rationale for its creation.

PREPARED BY:	APPROVED/CHECKED BY:	ISSUED DATE: 2003-07-15
C. Kirby		REV. DATE:

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS
STANDARD INSTRUCTION

TITLE:	**Inst. No.** 015
Contingency Plan For Loss of **The Energy Management System Function**	**Rev. No.**
	Page 2 **of** 4

Responsibilities (cont'd)

Asset Managers – Generation and Terminal Stations	2.	Managers should ensure that the detailed contingency plan referred to in the introduction, equipment manuals, paper/pencils, functional communications equipment, PPE for switching, and other equipment/materials needed by staff during an EMS outage, to manually monitor and control a station, are available at each station listed in the detailed plan.
Regional On-call Supervisors	1.	When contacted by ECC, supervisors will be required to staff stations with switching personnel, and plant operators where appropriate. ECC will identify the stations or plants that require manual operation.
	2.	When presented with event logs from switching or plant personnel, the logs should be forwarded to the Superintendent of ECC.
Hydro Generation On-call Supervisors	1.	When contacted by ECC, supervisors will dispatch operators to the plants specified by ECC.
	2.	ECC will indicate if personnel are required at flow control structures.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 2003-07-15
C. Kirby		**REV. DATE:**

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS STANDARD INSTRUCTION

TITLE:	Inst. No. 015
CONTINGENCY PLAN FOR LOSS OF THE ENERGY MANAGEMENT SYSTEM FUNCTION	Rev. No.
	Page 3 of 4

Responsibilities (cont'd.)

Hydro Generation On-call Supervisors	3.	When presented with event logs from plant personnel, the logs should be forwarded to the Superintendent of ECC.
Switching Staff and Plant Operators	1.	When arriving on site contact the Energy Control Centre, identify oneself, location and any unsafe conditions that would require immediate attention. Await instructions from ECC. The priority for communications is Operational Voice, Newfoundland Telephone, then VHF.
	2.	ECC staff will contact station personnel hourly to obtain operating data key to that station, (i.e. generation levels, transmission lines flows, bus voltages, delivery point voltages etc. which ever are appropriate). Station personnel shall maintain an hourly log of information and record the time and nature of any abnormal system event, (i.e. time of alarm/outage and activating device/relay), and contact ECC when such an event occurs.

PREPARED BY:	APPROVED/CHECKED BY:	ISSUED DATE: 2003-07-15
C. Kirby		REV. DATE:

HYDRO
THE POWER OF COMMITMENT

NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS
STANDARD INSTRUCTION

TITLE:	Inst. No. 015
CONTINGENCY PLAN FOR LOSS OF THE ENERGY MANAGEMENT SYSTEM FUNCTION	Rev. No.
	Page 4 of 4

Responsibilities (cont'd.)

Switching Staff and Plant Operators	3.	Staff should retain their event logs and present them to the appropriate on-call supervisor.
ECC Superintendent	1.	Shall arrange for an annual simulation of the plan to ensure its effectiveness.

PREPARED BY:	APPROVED/CHECKED BY:	ISSUED DATE: 2003-07-15
C. Kirby		REV. DATE:

APPENDIX 4: DIGITAL FAULT RECORDER TRACES

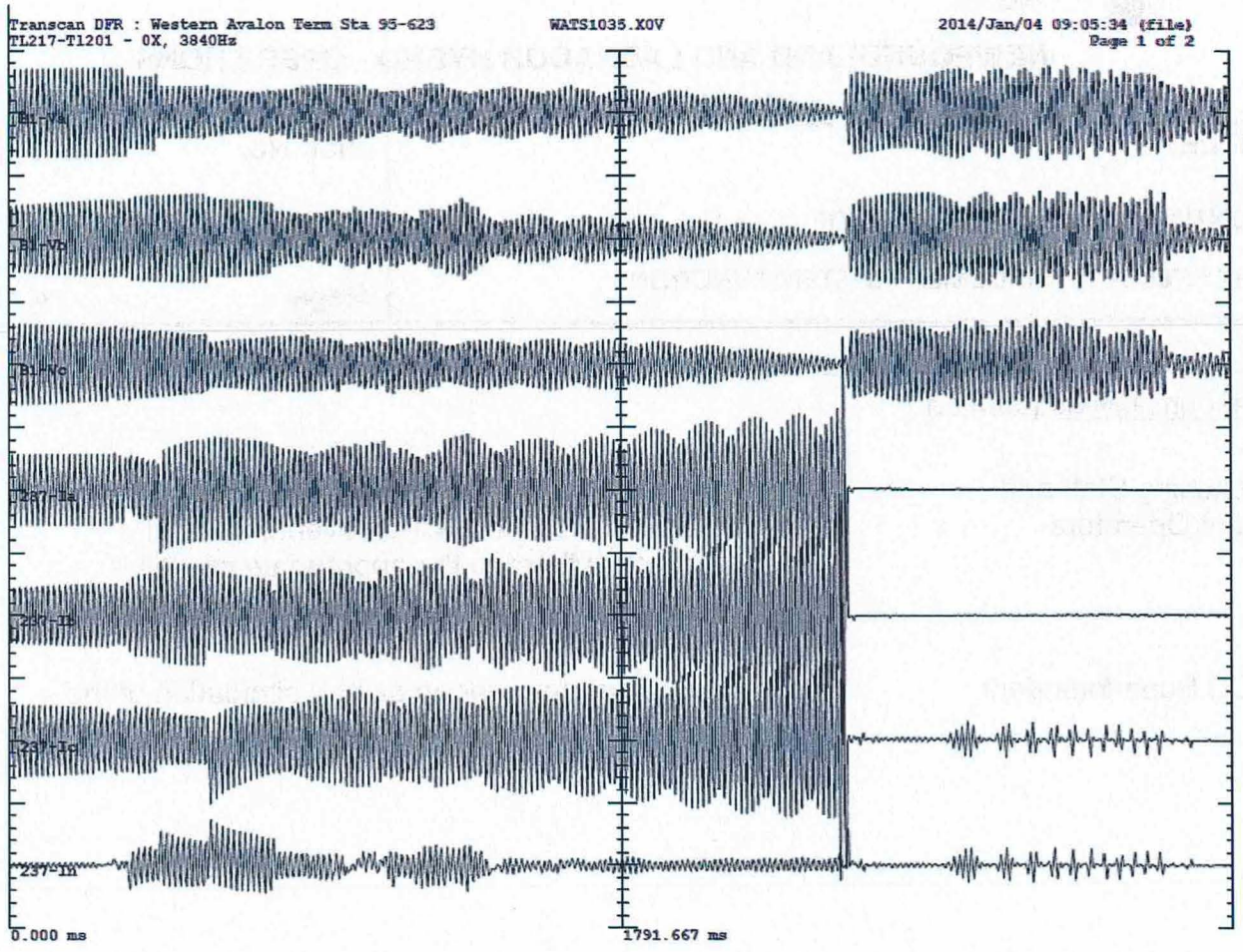


Figure 1: Loss of Stability of Power System following fault on transformer T1 at Sunnyside

Traces from Western Avalon station show bus voltages (top 3 traces) rapidly decline and the currents on line TL237 (second set of 3 traces) oscillate and become unstable.

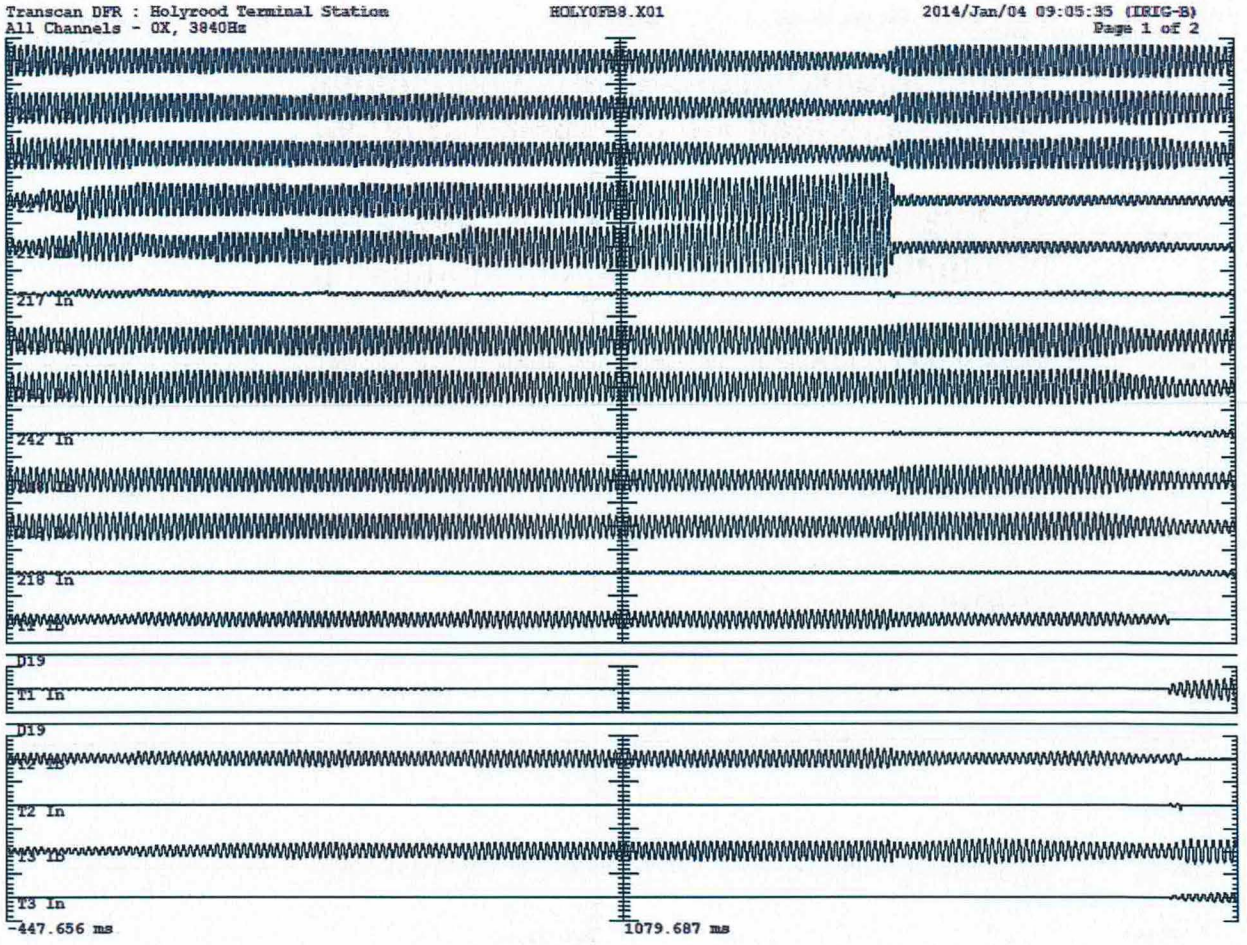


Figure 2: Holyrood Generator #1 Trip at 9:05:37 Jan. 4, 2014

Traces from Holyrood generating station show current in B phase and neutral current for each of the three generating unit transformers (bottom 6 traces). Unit #1 shows neutral current increase when the unit trips off while the current in B phase goes to zero. This is as expected because C phase failed to open. Note that when unit #2 trips off both the B phase current and the neutral current goes to zero; unit #3 trips after trace ends as shown above so there is an increase in the B phase current and the neutral current.

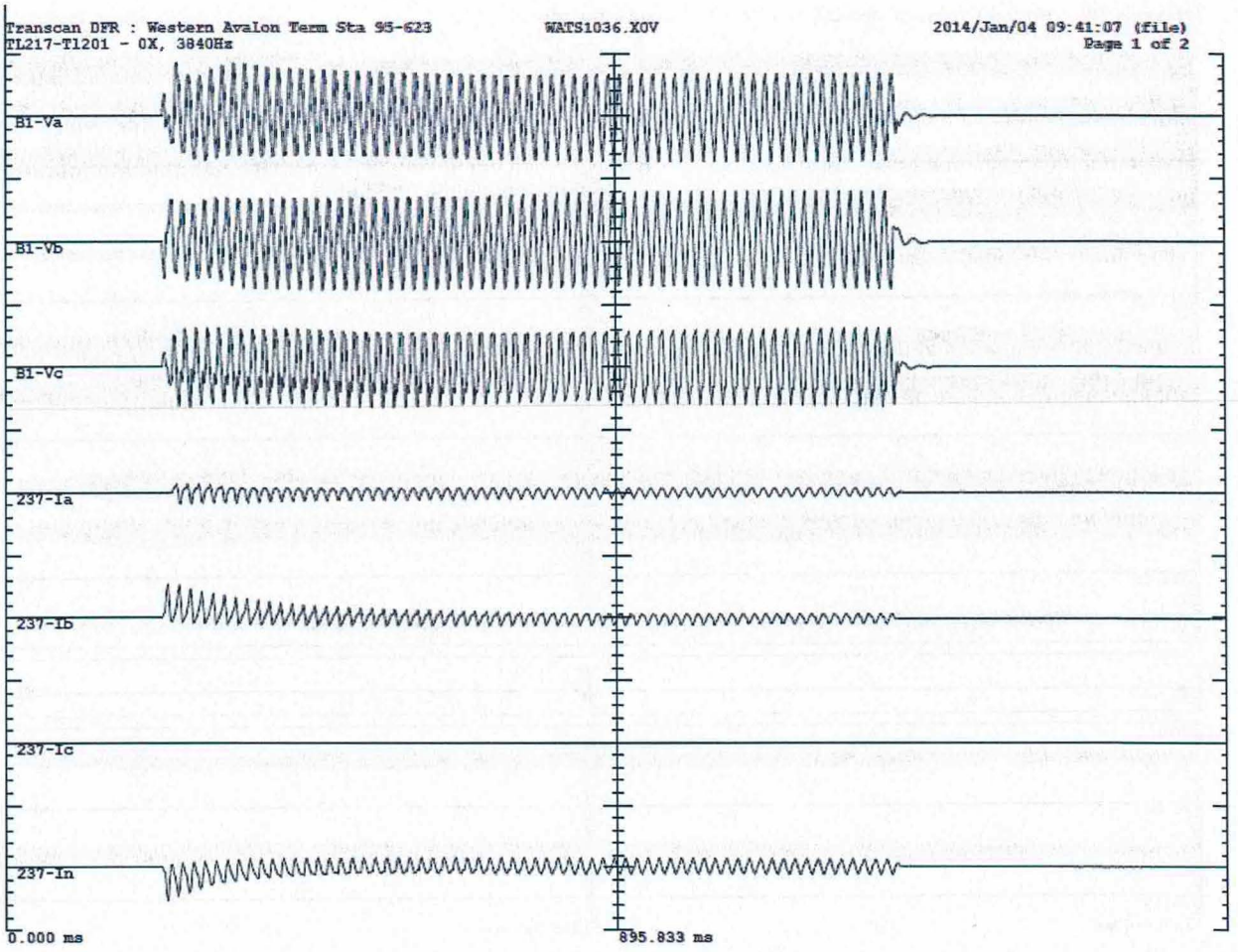


Figure 3: Circuit Breaker B1L37 at Western Avalon closes on two phases only 9:41 Jan. 4, 2014

Traces from Western Avalon for TL237 (bottom 4 traces) show current in 2 phases only plus neutral current when breaker B1L37 is closed. Condition lasts for approximately 1.2 seconds.

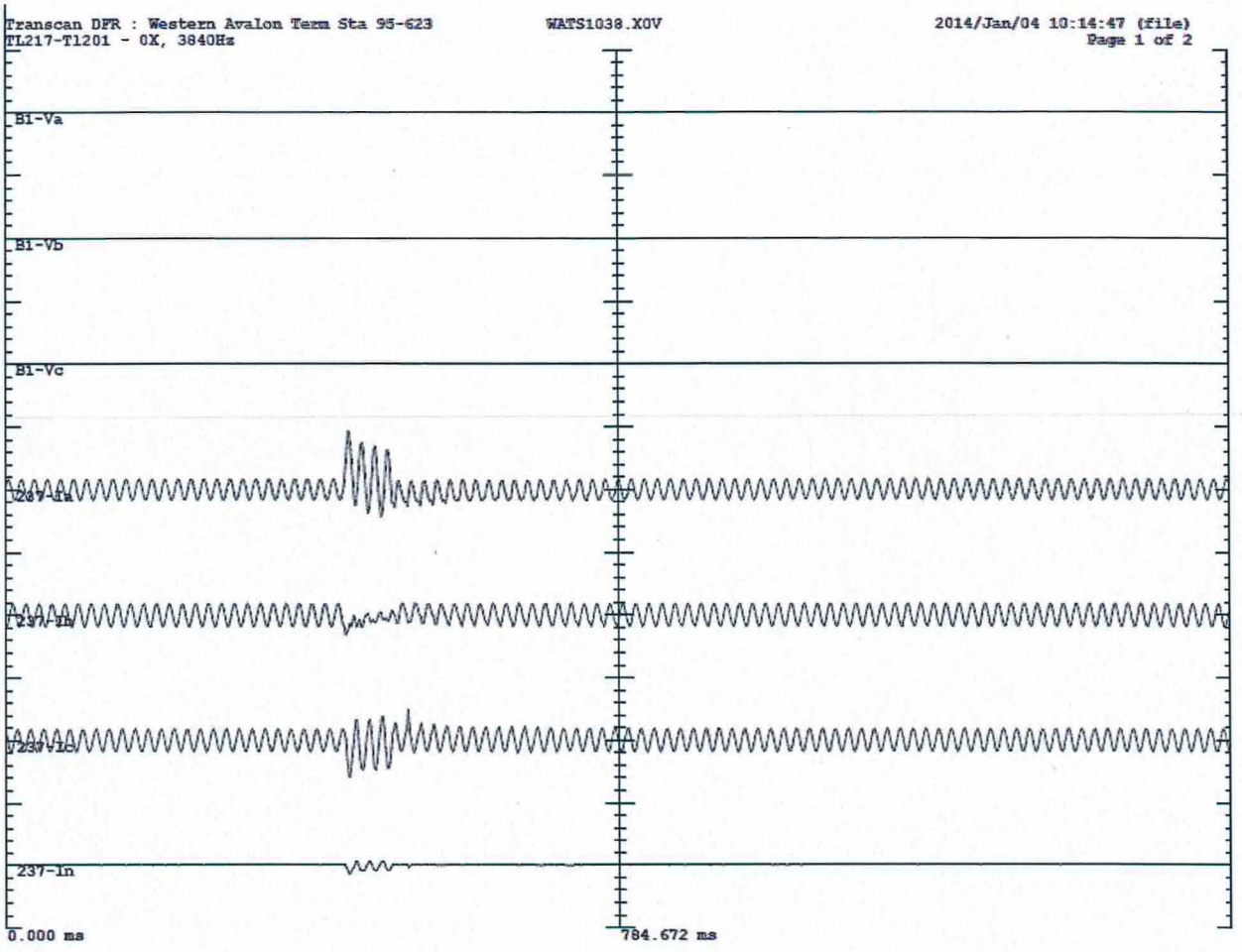


Figure 4: Holyrood generator transformer T1 is energized 10:14:43 Jan. 4, 2014

This trace from Western Avalon shows a disturbance that lasts for about 4 cycles when the generating unit #1 transformer at Holyrood is energized because one phase of the breaker B1L37 at Holyrood is still closed.

NEWFOUNDLAND AND LABRADOR HYDRO

Root Cause Investigation of System Disturbances
On January 4 and 5, 2014
Sunnyside Transformer T1 Fire,
Western Avalon Transformer T5 Tap Changer Failure,
Sunnyside Terminal Station Restoration Failure, and
Holyrood Breaker B1L17 Failure

March 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 5
2 REVIEW PROCESS 7
3 BACKGROUND 13
4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME OF EQUIPMENT FAILURE INCIDENTS 13
5 KEY FINDINGS AND RECOMMENDATIONS 17

Appendices:
Appendix 1 - Pictures
Appendix 2 - Drawings
Appendix 3 – PM's & CM's
Appendix 4 – Fault Traces
Appendix 5 – Sequence of Events
Appendix 6 – Relay Cards
Appendix 7 – External Reports - DRAFT
Appendix 8 – Snap Charts
Appendix 9 – Additional Findings and Areas for Continuous Improvement

EXECUTIVE SUMMARY

TapRooT® is a highly structured investigative process designed to focus on the identification of causal factors and specific problems of clearly specified events. By its nature, the purpose of the TapRooT® analysis is to determine the root cause and identify corrective actions directly related to the problem being investigated. In the course of an investigation, TapRoot® often identifies additional areas for consideration that are not directly related to the cause of the problem. TapRoot® is recognized as industry best practices for investigative processes.

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included investigation of the rotating outages that occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014. The focus for this report documents the root cause investigation into four incidents that contributed to the outages, which occurred on January 4 and 5, 2014. These incidents are the Sunnyside Transformer T1 Fire, Western Avalon Transformer T5 Tap Changer Failure, Sunnyside Terminal Station Restoration Failure, and Holyrood Breaker B1L17 Failure. The purpose of this investigation is to identify recommendations and corrective actions that will reduce the likelihood of a reoccurrence of these incidents, based on root causes or most probable root causes where a clear specific root cause was not attainable.

This portion of the review is prepared by an internal team of Nalcor Energy employees. This report utilizes data collected from field inspections of the four incidents by the investigation team, analysis performed by Nalcor staff, equipment inspections by original equipment manufacturers (OEM) such as ABB, Reinhausen and CG Global; external analysis of protection systems performance by Henville Consulting Inc.; and external validation of the TapRooT® process by consultant Brian Tink.

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

On January 4, 2014 an internal fault occurred on Sunnyside T1 transformer, which due to a breaker failing to open, resulted in a fire on the transformer and wide-spread customer outages. The fault on Sunnyside T1 in combination with other factors such as cold weather conditions, power system loading, equipment failures, and protection modifications contributed to the Sunnyside Bus Restoration Failures and Holyrood Breaker B1L17 Breaker Failure. While the cause has not yet been determined on Western Avalon T5 Transformer, there appears to be a connection between this transformer's tap changer failure, and the system disturbance caused by Sunnyside T1 failure.

The key findings of the TapRooT® investigation with recommendations and corrective actions are presented in this report.

- TA1: Conduct a formal risk/reward review on expanding the current program for the installation of on line continuous gas monitor on generator step up (GSU) transformers to include other transformers installed on the Hydro System.
- TA2: When system conditions allow, conduct an in-depth analysis of the DC system for Breaker B1L03 to determine if any high-impedance paths exist which may affect its operation.
- TA3: Consider conducting a formal risk/reward review of system design to determine whether 230kV transformers require their own 230kV breaker in all terminal stations, as this would reduce complexity and increase reliability.
- TA4: Consider conducting a formal risk/reward review of the 230kV breaker failure protection philosophy for transformers at stations that currently do not have breaker fail protection.
- TA5: Consider implementing transformer protection initiation of breaker fail protection at all stations that have breaker fail protection.
- TA6: Conduct an analysis of the Island Interconnected System to determine if a transient overvoltage, due to system harmonics, was a cause of the Western Avalon T5 Failure.

TA7: Review application of lockout protection on all transformers to ensure that the proper isolation of the transformer automatically blocks the initiation of 138kV breaker failure protection on the associated breakers.

TA8: Consider having additional resources (P&C technologists and engineers) available on site to support the restoration of power in emergency situations.

TA9: Review breaker failure protection applications of all transformer protection designs at stations using the same breaker failure relay (Schweitzer Engineering Laboratories type SEL-501). This review would determine whether the breaker failure protection re-trip function (if applied in the SEL-501) is being used in a similar non-conventional application to that at Sunnyside. If it is, modify the scheme to prevent undesirable or unexpected response from the non-conventional application.

TA10: Revise work method SWM-000318 to include:

- Correct procedure to seal the breaker air receiver tanks to prevent moisture ingress while the interrupters are removed; and
- Visual inspection of the breaker air receiver tanks prior to the reinstallation of the interrupters.

TA11: Conduct a risk/reward review of the current practice for the application of the Room Temperature Vulcanizing (RTV) coating with consideration given to the following alternatives which would reduce the amount of time the interrupters are removed from the main receiver tank:

- Materials that can be applied without having to disassemble the breaker;
- Installing spare interrupters that have the RTV coating applied; and
- Applying RTV in a nearer controlled environment (Holyrood has some facilities).

TA12: Conduct a review of the Transmission and Rural Operations (TRO) Central Annual Work Plan to identify opportunities for improvement as it relates to the prioritization and timely execution of work. The review should include, but not be limited to, factors affecting the priority and execution of work, such as the

availability of resources (staff, tools and equipment) to effectively execute the annual work plan.

1 INTRODUCTION

This focus area report is part of an internal report on the Hydro power disruptions on January 4 and 5, 2014. The main report references this focus area with respect to root causes and corrective actions around four incidents. These incidents are the Sunnyside Transformer T1 Fire, Western Avalon Transformer T5 Tap Changer Failure, Sunnyside Terminal Station Restoration Failure and Holyrood Breaker B1L17 Failure.

Hydro employs several processes for the systematic investigation of the fixable root causes of quality, safety, production, or maintenance problems. For complex events, the TapRooT® System combines both inductive and deductive techniques for investigations, which can be used both reactively – to create corrective actions that prevent a recurrence – or proactively – to improve performance.

TapRooT® is a highly structured investigative process designed to focus on the identification of causal factors and specific problems of clearly specified events. By its nature, the purpose of the TapRooT® analysis is to determine the root cause and identify corrective actions directly related to the problem being investigated. In the course of an investigation, TapRoot® often identifies additional areas for consideration that are not directly related to the cause of the problem. TapRoot® is recognized as industry best practices for investigative processes.

From an investigation and TapRooT® analysis, the system disturbances of January 4 and 5, 2014, can be attributed to a combination of cold weather, power system loading, equipment failures, and protection modifications.

At 09:05 on January 4, 2014 a fault occurred on Sunnyside T1 transformer, which was the initiating event. Subsequent events were the failure of Western Avalon T5 Transformer Tap Changer, Sunnyside Bus Restoration Failure and Holyrood Breaker B1L17 failing, all of which are interrelated incidents which contributed to causing power outages primarily to the Avalon

Peninsula. Figure 1 below is a pictorial representation of the four incidents and their interdependencies.

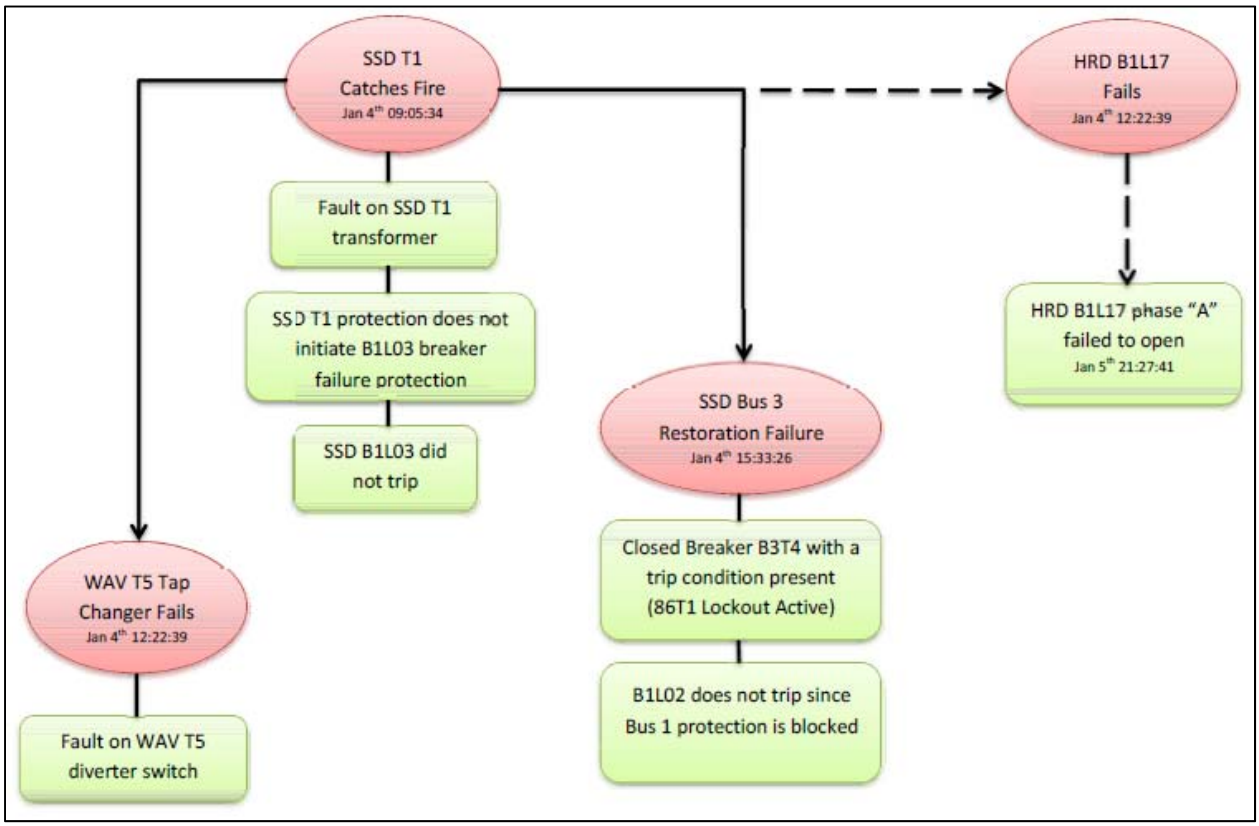


Figure 1 – Incident Interdependences

An internal fault occurred on Sunnyside T1 transformer and if everything operated as the design intended, it would have been taken offline and isolated from the grid for further investigation with a short localized disruption of power. However, breaker B1L03 failed to operate correctly, which caused the fault to remain longer and led to the T1 transformer fire, as well as triggering further system disturbances.

While the investigation has not been completed on Western Avalon T5 Transformer, there appears to be a connection between this transformer's tap changer failure and the system disturbance caused by Sunnyside T1 failure.

In response to the disturbance caused by Sunnyside T1 and breaker B1L03 failure, all three Holyrood generating units tripped offline. An analysis of the fault traces have shown that breaker B1L17, which is one of two breakers connecting generating Unit G1 at Holyrood to the grid, failed at this time.

During the restoration effort of Sunnyside Station, there were difficulties in isolating T1 Transformer, which led to further delays in getting power restored to customers.

Subsequent sections of this report provide a more detailed analysis of the full sequence of events; determining the causal factors, root causes, and provides corrective actions.

2 REVIEW PROCESS

Events within the Hydro system which result in widespread customer outages and/or significant equipment damage are subject to a comprehensive review and investigation. Hydro utilizes its *Standard for Root Cause and Repeat Failure Analysis* (a TapRooT® Investigation) for these comprehensive investigations. As such, the management team selected the four events of January 4 and 5, 2014 to be investigated utilizing the TapRooT® process due to the impact on customers and substantial damage to equipment.

To carry out the investigation it was deemed essential to assemble a qualified team to assist with performing a thorough analysis of the events. The team follows a standard process for conducting root cause investigations. The team utilized both internal and external resources in determining the root causes of the incidents. The team membership had a previous working knowledge of the TapRooT® process itself, as well the support of a TapRooT® Process Matter Expert to help guide the investigation from an external perspective. Independent utility industry experts, with an in-depth knowledge of the operations of power systems, including experience with power system disturbances, were involved in the overall investigation. Subject matter experts were utilized to help with system and data analysis, as well as review protection

system operation and design. OEMs and their field-service technicians assisted with equipment design reviews, as well as disassembly, and forensic field investigations. All external members of the team provided independent reports, which supplement this investigation.

2.1 Team Composition

The team composition consisted of Hydro resources, process experts, subject matter experts and OEM technical experts.

2.2 Hydro Resources

Dave Hicks, Manager of Electrical Engineering for Project Execution and Technical Services (PETS), with 24 years experience with Hydro, mostly with high voltage terminal station equipment specification and design. Dave has past experience with Terminals Station Review Committee and is current chair of Transformers and Switchyard Technical Council.

Perry Taylor, Senior Electrical Engineer, with more than 13 years experience covering system analysis, high voltage equipment specification and design review, as well as experience with operation and maintenance of high voltage switchyard of Churchill Falls and the underground power house. Perry is a member of the Transformers and Switchyard Technical Council; a former member of the TapRooT® Technical Council; has been trained in TapRooT® process and has conducted multiple TapRooT® investigations of equipment failures throughout Nalcor Energy.

Blaine Piercey, Senior Electrical/Mechanical Supervisor of Terminal Stations Maintenance crews for TRO Central with more than 29 years experience with Hydro working primarily with terminal station equipment operations and maintenance, including high voltage transformers, circuit breaker overhauls, and air support systems.

Brad Eddy, Electrical Equipment Engineer, with more than five years experience dealing primarily with Hydro's power transformers refurbishment and replacement programs. Brad has

been trained in TapRooT® process and has conducted multiple TapRooT® investigations of equipment failures throughout Nalcor Energy.

2.3 Process Experts

Brian Tink, TapRooT® Process Matter Expert and former member of Ontario Power Generation, with 30 years working with both generation and transmission assets.

2.4 Subject Matter Experts

Brian Scott of AMEC, subject matter expert with more than 30 years experience with operation and maintenance with New Brunswick Power's system including power system analysis and power system disturbances events. He was director of reliability and operations for New Brunswick Power.

Blair Seckington of AMEC, subject matter expert with more than 30 years experience with operation and maintenance of power systems including power system disturbances, with Ontario Power Generation. He was a condition assessment and reliability expert with Ontario Power Generation.

Charlie Henville, of Henville Consulting Inc., a Senior Protection and Control Design Review Engineer and former BC Hydro protection and control engineer with more than 44 years of professional engineering experience.

2.5 OEM Technical Experts

ABB: Mustaf Lahloub, transformer field service engineer and forensics expert.
ABB: Scott Morris, field service technician for air blast circuit.
CG Power: Chris Sarrasin, field service technician for power transformers.
Reinhaussen: Markus Zwicknagel, field service technician for tap changers.

2.6 Process Followed

The processes followed by the team are shown in Figure 2 – Process Flow Diagram.

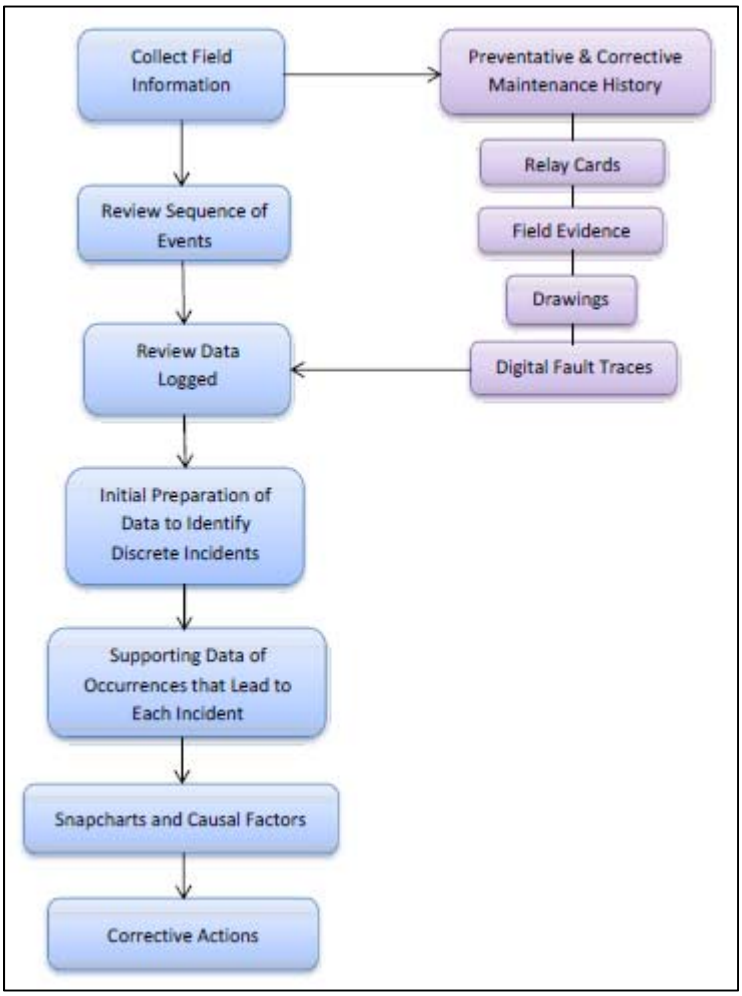


Figure 2 - Process Flow Diagram

In addition to the work performed by external consultants and OEMs, the internal team made an extensive effort, with the help of numerous colleagues throughout the system, to collect all the vital information relevant to the events of January 4 and 5, 2014. Such information included sequence of events records, fault traces, drawings, preventative maintenance and corrective maintenance records, as well as discussions with participants in the incidents. All relevant information was shared with external consultants and OEMs to aid their detailed analysis of failed equipment. Using the collected information, as part of the TapRooT® process, a timeline

of events leading up to the incident was created on a SnapCharT®. Conditions to support these events were added to the SnapCharT® and causal factors were identified. These causal factors were then analyzed to identify root causes for the incident. Recommended corrective actions were then developed based on the root causes.

2.7 Schedule

While the root cause investigation officially started on January 7, 2014, with the establishment of the scope of the investigation and assembling the team, internal members of the team were at the various sites on January 5, 2014 to help ensure the preservation of evidence. Site visits to the Sunnyside, Western Avalon and Holyrood Terminal Stations were completed by various members of the investigation team throughout the subsequent investigation.

Brian Tink was consulted and visited the site for the first time on January 13, 2014 to help facilitate the TapRooT® process.

Consultation began immediately with ABB (OEM for Sunnyside T1) on performing an internal inspection to help determine the cause for the failure of Sunnyside T1, as well to begin the design review. A design review was done of Sunnyside T1 and sister units Sunnyside T4, Stony Brook T1 and T2. Mustafa Lahloub began his investigation into the failure and was onsite in Sunnyside immediately following the incident. He performed an internal inspection on January 21, 2014 as soon as the oil test results were complete and the transformer had been drained of its oil. A preliminary report of their findings has been submitted for review, which provides a detailed synopsis of the cause of failure. Their report supplements this report and is attached in Appendix 7 – External Reports.

ABB (OEM for Holyrood breaker B1L17) was consulted, and on January 16, 2014 Scott Morris, a field service representative, came to site to inspect Holyrood breaker B1L17. Mr. Morris also came back to Holyrood on January 27 to oversee the rebuild of breaker B1L17. On February 3, 2014 he travelled to Bishop's Falls to oversee the teardown inspection of the components

removed from breaker B1L03 at Sunnyside. Mr. Morris provided two separate reports of his findings, one for each investigation. Both reports supplement this report.

Knowing the incidents of January 4 and 5, 2014 would have a significant impact on the overall power system, and for which the fault recorders would have captured essential data, Charlie Henville was immediately engaged to help with the analysis of this data and to conduct a review of the performance and design of the protection systems. This would help with early identification of any issues that may have contributed to the incidents. Mr. Henville's report supplements this report.

On January 11, 2014, a field service representative from Reinhausen (tap changer OEM for Western Avalon T5 tap changer) came to Western Avalon to inspect the diverter switch, associated with the tap changer. While this investigation is not complete, Reinhausen has provided a preliminary report of their findings. On February 21, 2014, Markus Zwicknagel from Reinhausen and Chris Sarrasin from CG Global (OEM for Western Avalon T5 transformer) were on site to conduct an internal inspection of the Western Avalon transformer T5 tap changer and transformer, to access damage and provide a report as to the cause of the failure.

The team has since met with representatives of the Liberty Consulting Group (Liberty) as part of the Public Utilities Board (PUB) review, during which they reviewed our process and the investigation. While the root cause has been clearly determined for some incidents, there are still some unknowns, due in part to insufficient information to complete a thorough analysis. Further comments from Liberty will be explored and will contribute to the final analysis.

In total, the team has been engaged in the process almost full-time, apart from a few exceptions and competing priorities, for a total of eight weeks.

3 BACKGROUND

The TapRooT® root cause analysis method was utilized by the team for the root cause analysis of the above incidents. Hydro has a Root Cause and Repeat Failure Analysis (RCRFA) Technical Council whose mandate is to ensure that major system disturbances and/or equipment failures are thoroughly investigated by an appropriate team to identify root causes and corrective actions. The RCRFA Technical Council has a Standard for Root Cause and Repeat Failure Analysis, and this standard was followed for this investigation.

The TapRooT® method involves the following general steps:

1. Identification of the incident(s);
2. Information collection (documented on a SnapCharT®);
3. Identification of immediate causes (causal factors in TapRooT® terminology);
4. Identification of all root causes associated with each causal factor; and
5. Creation of corrective actions for each root cause.

Provided that the investigation obtains sufficient information, each causal factor results in one or more root causes, and each root cause results in one or more corrective actions. The purpose of the corrective actions is to prevent the incident from reoccurring.

4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME OF EQUIPMENT FAILURE INCIDENTS

4.1 Incident 1: Sunnyside Transformer T1 Catches Fire

At 09:05:34 on January 4, 2014, a fault occurred on the Sunnyside T1 transformer. The T1 protection operated correctly and initiated a trip to five breakers to clear the fault. Only four of the five circuit breakers tripped within 186 milliseconds to clear the fault. The breaker B1L03 failed to open and the fault remained on Sunnyside T1 transformer. Since the fault was not

cleared quickly, it resulted in additional damage and the subsequent fire of the Sunnyside T1 transformer. The fault lasted for two seconds until line protection on TL203 operated and cleared the fault. This resulted in a widespread (187,500 customers) power interruption across the system. Figure 3 below, is a portion of the single line diagram of the Sunnyside Terminal Station showing the equipment involved in the incident. The complete single line for Sunnyside Terminal Station is attached in Appendix 2 – Drawings.

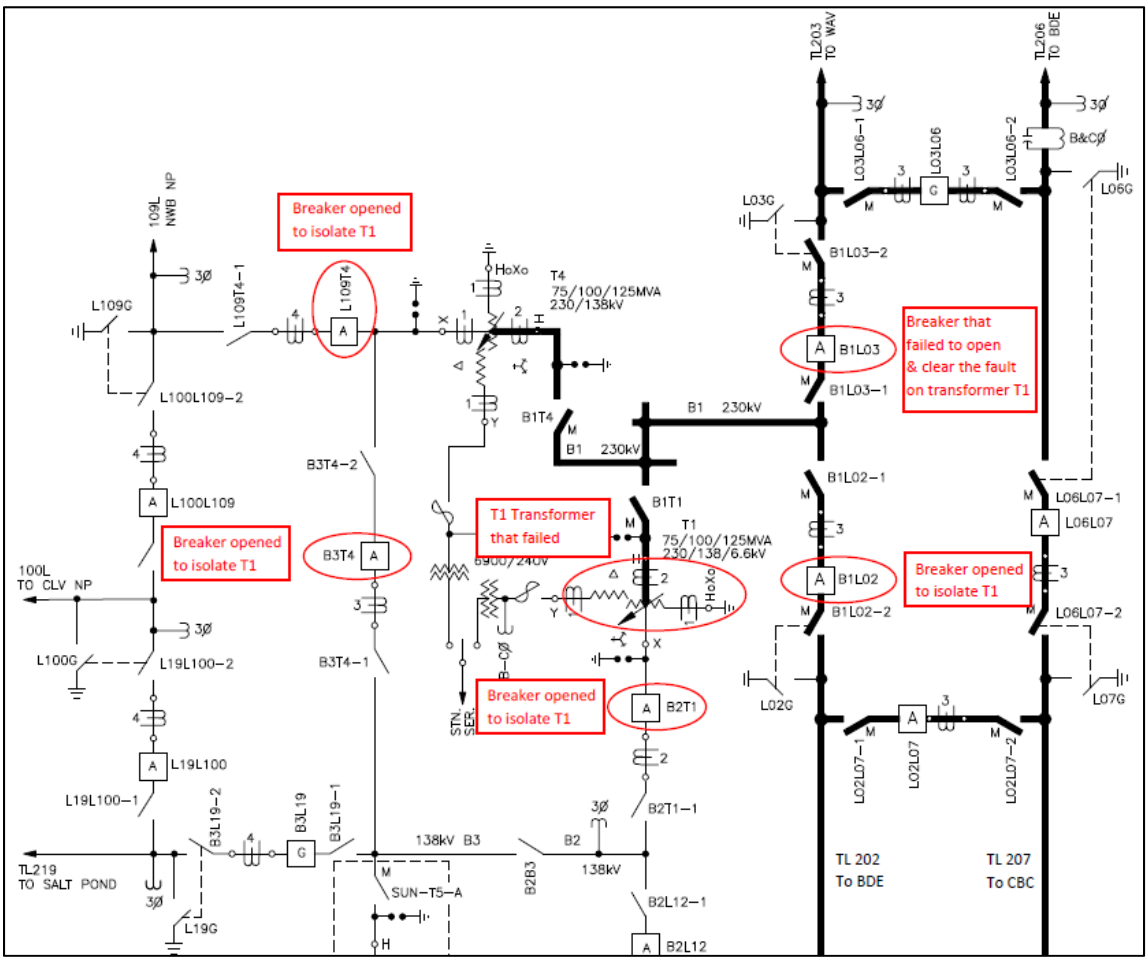


Figure 3 – Sunnyside Terminal Station at 09:05:34

4.2 Incident 2: Western Avalon Transformer T5 Tap Changer Failure

At 12:22:39 on January 4, 2014, Western Avalon T5 tap changer failure resulted in a fault on the transformer. The T5 transformer protection operated correctly and initiated a trip of one breaker and one load break switch, both of which operated correctly and cleared the fault. This

incident resulted in an extended outage for some customers, as the T5 Transformer trip had to be investigated before restoration of the station. Figure 4 below is a portion of the single line for the Western Avalon Terminal Station showing the equipment involved in the incident. The complete single line for Western Avalon Terminal Station is attached in Appendix 2 – Drawings.

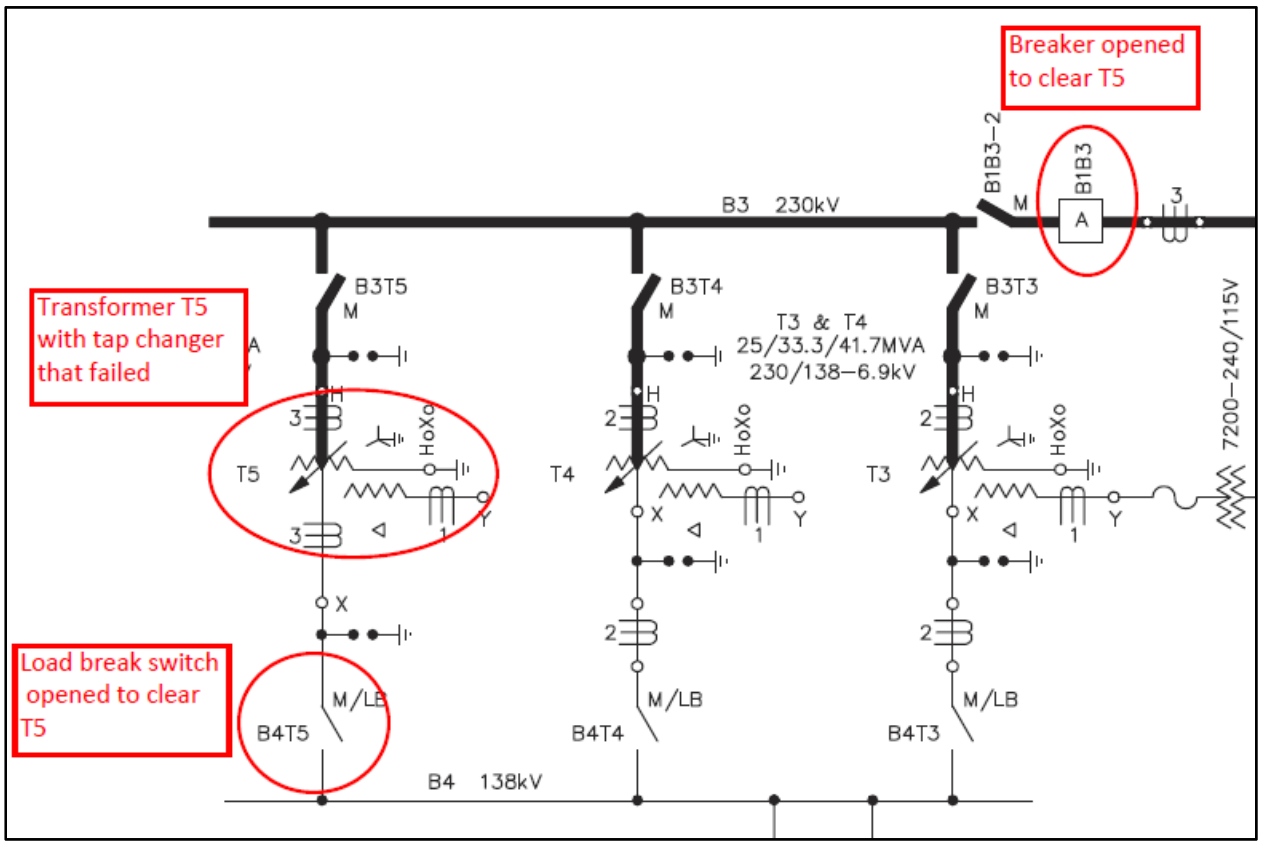


Figure 4 – Western Avalon Terminal Station at 12:22:39

4.3 Incident 3: Sunnyside Terminal Station Restoration Failure

At 12:58:30 on January 4, 2014, an unsuccessful attempt was made to restore power to customers. Temporary protection modifications were made following that unsuccessful attempt to isolate the suspected area of damage due to the fire. At 15:33:26, a second attempt was made to restore power to customers supplied from the Sunnyside Terminal Station. These temporary modifications had an adverse effect on the protection and resulted in a power interruption (165,000 customers) across the system. The details of this event are complex and

involve inherent design issues that are further explained in the "Protection Systems Impacts on 4 January 2014 Supply Disruptions - External Protection Review" by Mr. Henville. Figure 5 below is a portion of the single line of the Sunnyside Terminal Station showing the equipment involved in the incident. The complete single line drawing for Sunnyside Terminal Station is attached in Appendix 2 – Drawings.

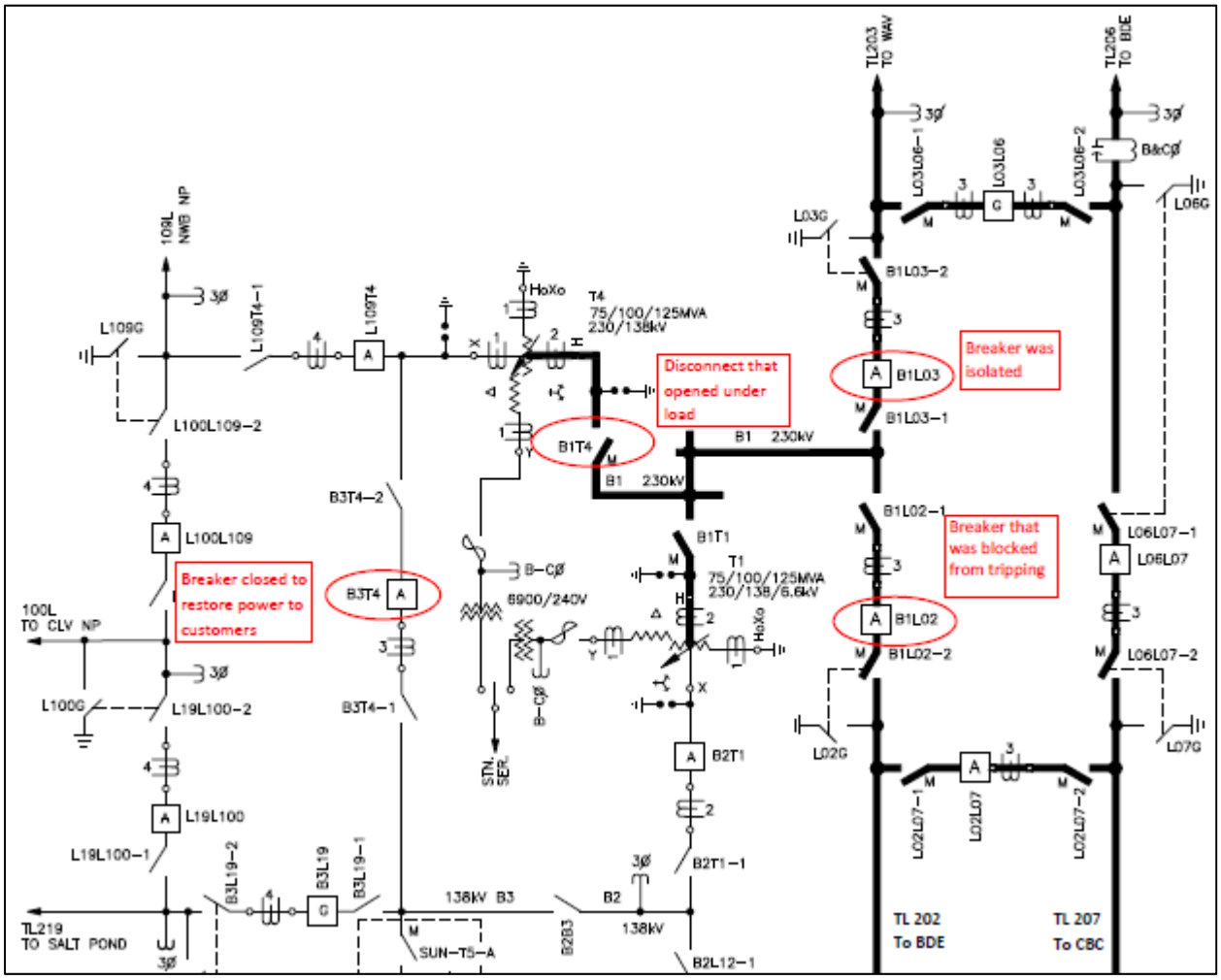


Figure 5 – Sunnyside Terminal Station

4.4 Incident 4: Holyrood Breaker B1L17 failure

At 21:27:34 on January 5, 2014, the Holyrood Terminal Station 230kV disconnect B1T1 was closed in preparation to bring Holyrood Generating Unit G1 online. Closing B1T1 disconnect

caused a significant system imbalance, as one phase of breaker B1L17 had failed to open despite breaker indications showing it as being open on all three phases. The protection for TL217 and Bus B1 operated correctly to clear the imbalance. However, as a result of the neutral overcurrent on the system that resulted from one phase of B1L17 failing to open and the heavy loading on the transmission system at the time, a widespread (110,000) customer interruption was initiated by this event. Figure 6 below is a portion of the single line for Holyrood Terminal Station showing the equipment involved in the incident. The complete single line for Sunnyside Terminal Station is attached in Appendix 2 – Drawings.

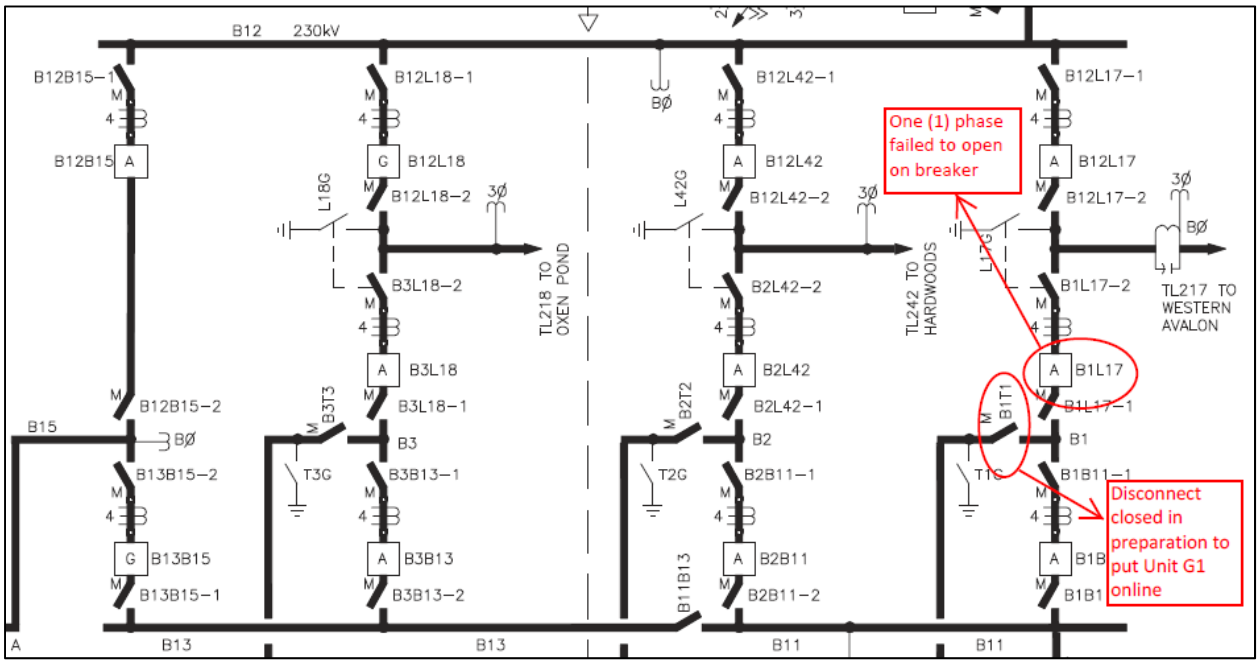


Figure 6 – Holyrood Terminal Station at 21:27:39

5 KEY FINDINGS AND RECOMMENDATIONS

As stated earlier in this report, the TapRooT® method was utilized by the investigation team for the root cause analysis of the four incidents that occurred on January 4 and 5, 2014.

The analysis of the four incidents resulted in a total of eight immediate causes (causal factors in TapRooT® terminology), eight root causes, and 12 recommendations. Below is the breakdown

by incident:

- Sunnyside T1 Fire: three causal factors, two root causes and five recommendations;
- Western Avalon T5 Tap Changer Failure: one causal factor, zero root causes and one recommendation (Investigation not complete);
- Sunnyside Terminal Station Restoration Failure: two causal factors, three root causes and three recommendations; and
- Holyrood Breaker B1L17 Failure: one causal factor, three root causes and three recommendations.

5.1 Incident 1: Sunnyside Transformer T1 Catches Fire

Sunnyside T1 transformer failed due to a bushing failure that initiated inside the transformer. As a result of breaker B1L03 failing to open and no 230kV breaker failure protection associated with T1 transformer fault, the fault was present for an extended period of time and consequently, a fire developed. Figure 7 below is the SnapCharT® of the incident which shows the sequence of events and associated information.

Causal Factor #1: Fault on Transformer T1

The presence of combustible gases in transformer oil is an indication of activity inside the transformer and sudden changes can indicate a problem with the transformer. Early detection of changes in these gases can prevent a catastrophic transformer failure.

Hydro currently performs annual independent laboratory analysis of transformer oil, and plans on installing continuous online gas monitors on existing GSU transformers. In addition, all new transformers being purchased have continuous online gas monitors. Sunnyside T1 had a gas relay, which detects both gas accumulation and gas pressure, but does not have a continuous online gas monitor. Continuous online gas monitors were not available at the time Sunnyside T1 was installed in 1978.

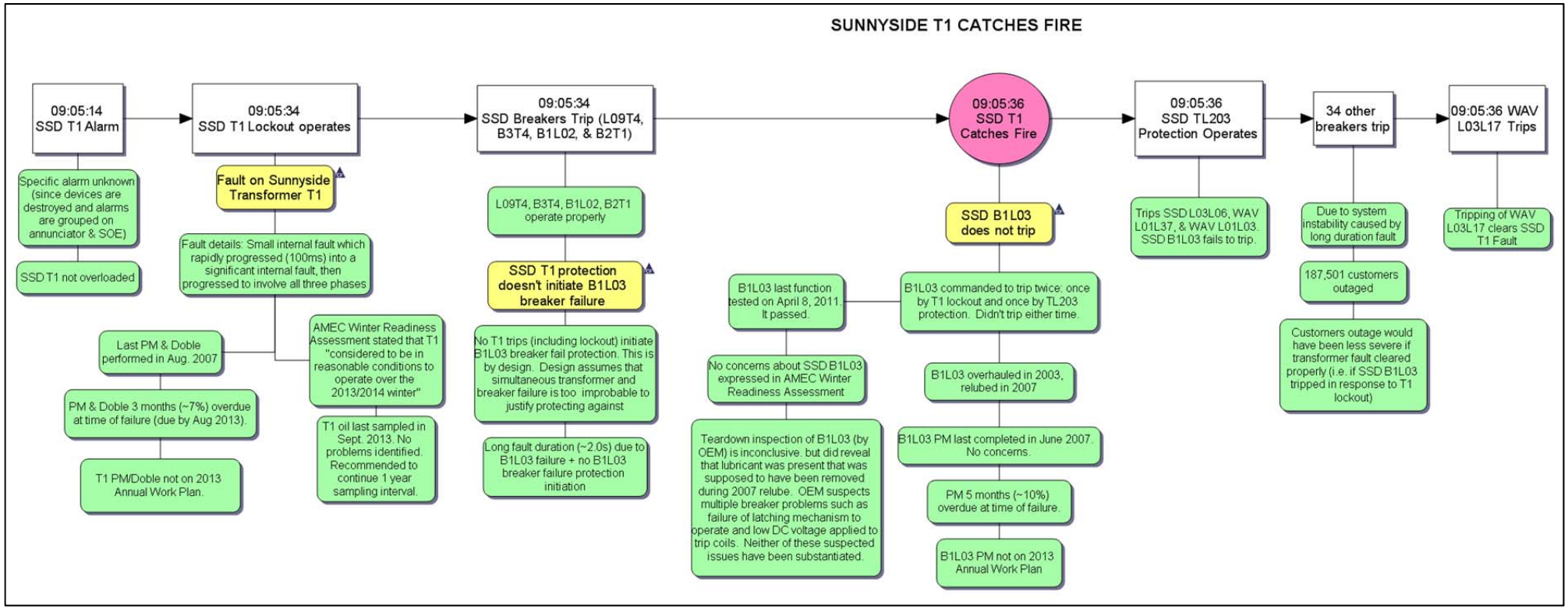


Figure 7 – Sunnyside Transformer T1 Fire SnapCharT®

Root Cause #1: Errors Not Detectable

Errors Not Detectable is a TapRooT® term, which means a problem goes undetected. In this case, it refers to the fact that the generation of combustible gases in the transformer was occurring without being detected by the transformer's gas relay, or any other transformer protection.

Corrective Action #1

Recommendation #	Recommendation
TA1	Conduct a formal risk/reward review on expanding the current program for the installation of online continuous gas monitor on GSU transformers to include other transformers installed on the Hydro system.

Causal Factor #2: SSD B1L03 Does Not Trip

Based on the report by ABB of the inspection of B1L03 the findings are not conclusive and points to issues such as possible high-impedance connections in control circuits, low voltage on DC system, some corrosion of components, low temperatures and/or dirty linkages. In consultation with Hydro's experienced staff and the findings of the ABB report, further testing is required to determine the immediate cause for the B1L03 failure. Breaker B1L03 was overhauled and function tested before it was returned to service. No issues were noted during the standard tests conducted.

Recommendation #	Recommendation
TA2	When system conditions allow, conduct an in-depth analysis of the DC system for breaker B1L03 to determine if any high-impedance paths exist which may affect its operation.

Causal Factor #3: Sunnyside T1 Protection Does Not Initiate B1L03 Breaker Failure Protection

By design, the protection for Sunnyside T1 transformer does not initiate breaker failure protection of the 230kV breakers that protect the transformer. This is also true for Sunnyside T4 transformer. The fault that occurred on T1 on the morning of January 4, 2014 would have cleared faster if the T1 protection initiated breaker B1L03's failure protection and may have cleared it fast enough to prevent the system collapse and transformer from catching fire. The decision not to have this protection initiated was made decades ago during the design of the station. The probability of simultaneous failure of both a transformer and a breaker was considered too low justify this protection.

Root Cause #2: Problem Not Anticipated

During the design of the Sunnyside Terminal Station, the simultaneous failure of a transformer and a 230kV breaker was considered to be too low of a risk to protect against.

Recommendation #	Recommendation
TA3	Consider conducting a formal risk/reward review of system design to determine whether 230kV transformers require their own 230kV breaker in all terminal stations, as this would reduce complexity and increase reliability.
TA4	Consider conducting a formal risk/reward review of the 230kV breaker failure protection philosophy for transformers at stations that currently do not have breaker fail protection.
TA5	Consider implementing transformer protection initiation of breaker fail protection at all stations that have breaker fail protection.

5.2 Incident 2: Western Avalon Transformer T5 Tap Changer Failure

A preliminary analysis of a phase-to-phase fault across the diverter switch of Western Avalon T5 tap changer, suggests a breakdown of insulating materials and/or abnormally high system voltage. Further analysis is required to determine the cause of the fault. Internal inspection of the transformer suggests that it has sustained no damage other than to the tap changer, but further testing is required. Figure 8 below is the SnapCharT® of the incident which shows the sequence of events and associated information.

Causal Factor #4: Fault on Western Avalon T5 Diverter Switch

To date, the root cause for the diverter switch failure has not been determined. From the equipment inspection and subsequent report provided by Reinhausen's field representative, it is their assessment that the failure of the diverter switch was due to a system overvoltage or break down of the insulating oil for the diverter switch. Due to the failure of the hard drive at the Western Avalon Terminal Station, just prior to the incident on January 4, 2014 digital fault traces are not available to determine if a system over-voltage was present. To determine if a system over-voltage or disturbance was the cause of the tap changer failure, further investigation is required.

Recommendation #	Recommendation
TA6	Conduct an analysis of the Island Interconnected System to determine if a transient overvoltage due to system harmonics is a cause of the Western Avalon T5 Failure.

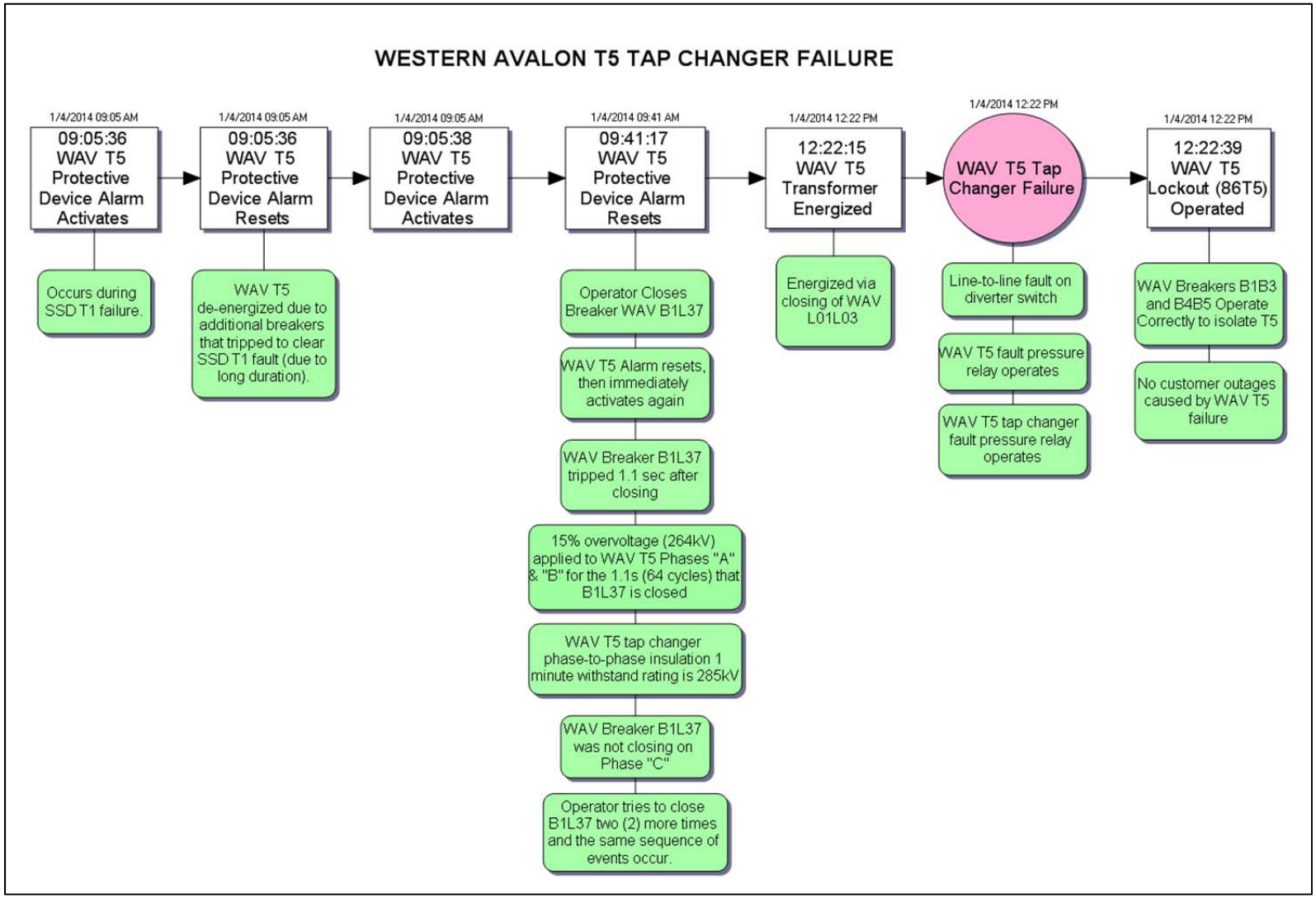


Figure 8 – Western Avalon T5 Tap Changer Failure SnapCharT®

5.3 Incident 3: Sunnyside Terminal Station Restoration Failure

The Sunnyside Terminal Station restoration failure occurred as a result of unnecessary initiation of the breaker failure protection after the fault on T1 had been isolated. The restoration was further impeded by non-conventional application of the B3T4 breaker failure protection and modifications that occurred during the transformer fire event, which protection modification had an adverse effect on the Sunnyside Bus 1 protection. Figure 9 below is the SnapCharT® of the incident which shows the sequence of events and associated information.

Causal Factor #5: Breaker B3T4 Closed with Trip Condition Present

By design, the initiation of B3T4 breaker failure protection was not removed after the isolation of the Sunnyside T1 transformer. When the crews isolated the T1 transformer via the 230kV B1T1 disconnect and 138kV B2T1-1 disconnect, the control circuitry should have automatically blocked the trip commands to any equipment associated with the tripping zone of transformer T1, such as breaker B3T4. However, this is not how the protection scheme is designed and as a result, when B3T4 was closed, its breaker failure protection was initiated and resulted in an extended outage to customers.

Root Cause #3: Problem Not Anticipated

The design of the Sunnyside Terminal Station protection scheme is such that isolation of the T1 transformer would not block the initiation of B3T4 breaker failure.

Recommendation #	Recommendation
TA7	Review application of lockout protection on all transformers to ensure that the proper isolation of the transformer automatically blocks the initiation of 138kV breaker failure protection on the associated breakers.

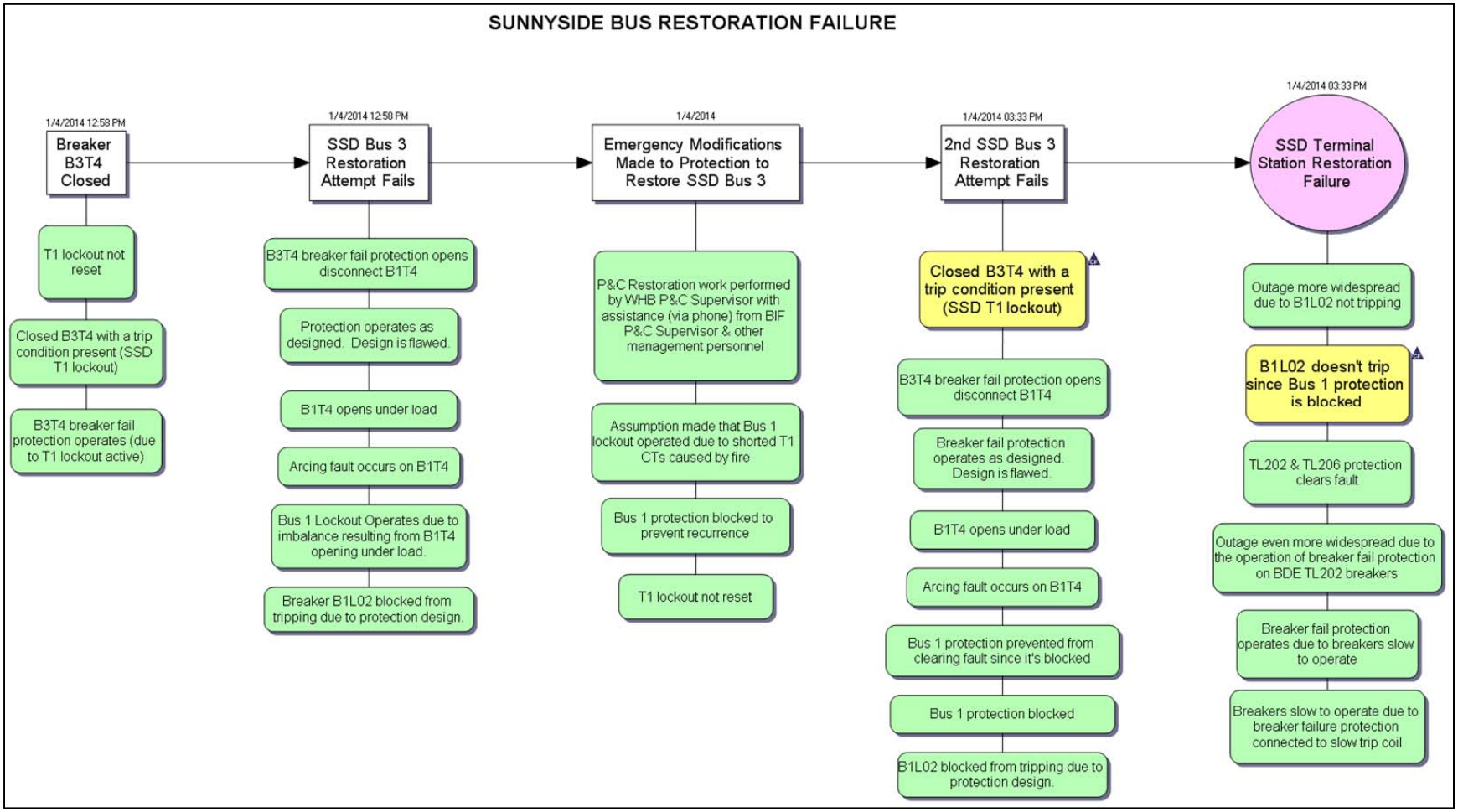


Figure 9 – Sunnyside Terminal Station Restoration Failure SnapCharT®

Causal Factor #6: Sunnyside Breaker B1L02 Does Not Trip Since Bus 1 Protection is Blocked

After the first attempt at 12:58 to restore power to customers supplied from the Sunnyside Terminal Station was unsuccessful, staff reviewed the targets from the protection. They determined that the differential protection operated and initiated the Bus 1 lockout 86B1. In consultation with the Energy Control Center (ECC), it was assumed that the Bus differential protection operated from the Current Transformer (CT) wires on transformer T1, which were likely shorted as a result of the fire. The P&C technician at the site was the supervisor and in consultation with others, emergency modifications were made to the protection to isolate the CT wiring. These emergency modifications had an unforeseeable and undesirable effect on the protection and contributed to a widespread outage at 15:33, when the breaker B3T4 was closed in a second attempt to restore power to customers.

Root Cause #4: Knowledge Based Decision Required

Knowledge Based Decision Required is a TapRooT® term which means that personnel with sufficient knowledge of the work are required to make the decision (or assist with it). In the case of the Sunnyside Terminal Station restoration, the P&C supervisor on site at the time of the fire was relatively unfamiliar with the protection wiring configuration.

Recommendation #	Recommendation
TA8	Consider having additional resources (P&C technologists and engineers) available on site to support the restoration of power in emergency situations.

By design, the non-conventional application of the re-trip function on B3T4 breaker failure protection prevented 230kV breaker B1L02 from opening, when an arcing fault occurred on 230kV disconnect B1T4. When breaker B3T4 was closed, the breaker failure protection was initiated and resulted in the 230kV disconnect B1T4 being opened. Since the re-trip function for breaker B3T4 prevents the tripping of 230kV breaker B1L02, the 230kV disconnect was opening under load and eventually flashed over and resulted in an arcing fault on the B1T4 disconnect.

Additionally, modifications made to Bus 1 protection prevent the breaker B1L02 from opening and clearing the arcing fault. The combination of these two conditions lead to line protection for TL202 and TL206 having to operate to clear the fault and resulted in widespread outages to customers.

Root Cause #5: Problem Not Anticipated

The Sunnyside Terminal Station protection scheme was not designed at the time utilizing conventional applications of the re-trip function with respect to breaker failure applications.

Recommendation #	Recommendation
TA9	Review breaker failure protection applications of all transformer protection designs at stations using the same breaker failure relay (Schweitzer Engineering Laboratories type SEL-501). This review would determine whether the breaker failure protection re-trip function (if applied in the SEL-501) is being used in a similar non-conventional application to that at Sunnyside. If it is, modify the scheme to prevent undesirable or unexpected response from the non-conventional application.

5.4 Incident 4: Holyrood Breaker B1L17 failure

At 21:27 on January 5, 2014 while attempting to connect Holyrood Generating Unit G1 to the grid, the Holyrood 230kV disconnect B1T1 was closed and a fault occurred on the system. It was subsequently determined that breaker B1L17 had previously failed during a trip operation and the failure allowed one of its phases to remain closed while the other two were open. There were no issues with Holyrood Generating Unit G1 that caused this incident. Figure 10 below is the SnapCharT® of the incident which shows the sequence of events and associated information.

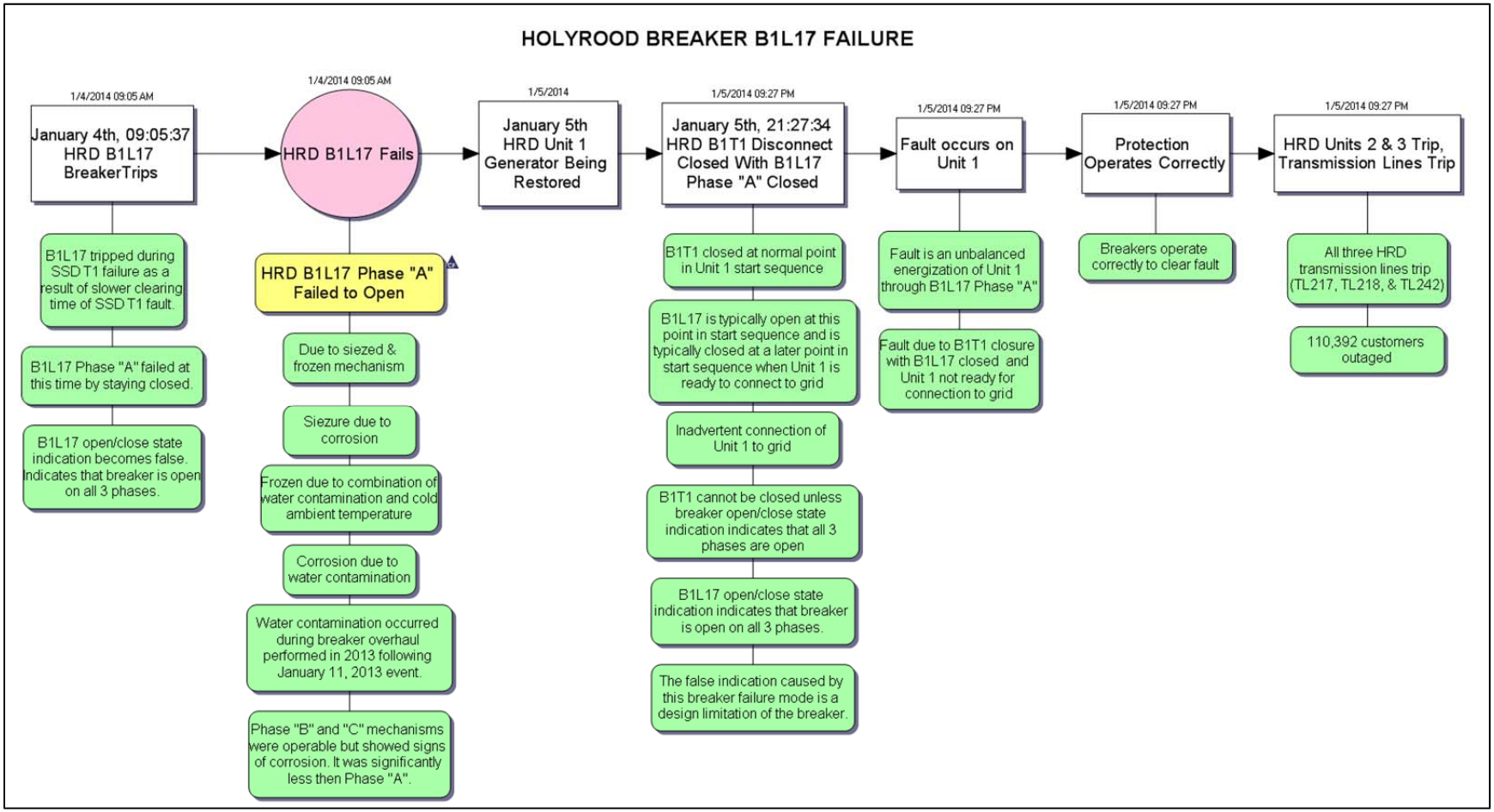


Figure 10 – Holyrood Breaker B1L17 Failure SnapCharT®

Causal Factor #7: Holyrood Breaker B1L17 Phase "A" Failed to Open

Based on an inspection conducted by Hydro maintenance personnel, supported by an expert from the OEM ABB, it was determined that moisture in the main receiver tank for the phase "A" on breaker B1L17 at Holyrood was the immediate cause of its failure to operate correctly on January 5, 2014. Moisture in the main receiver tank lead to corrosion of the main control rod drive on phase "A". This combination of moisture and cold temperatures on January 4, 2014 resulted in the control rod on phase "A" seizing/freezing and failing to open.

In early 2013 breaker B1L17 had work performed on it. This work consisted of the application of RTV coating to its porcelain insulators to reduce the probability of flashover. This work was in response to the flashover that occurred on this breaker on January 11, 2013. The work involved removing the breaker interrupters to apply the RTV coating and protecting the breaker air receiver tanks from environmental contamination while the interrupters are off. For this job, the interrupters were planned to be removed for two weeks, but were actually removed for six weeks due to a reprioritization of work at that time. This increased the exposure time of the breaker without adequate coverage which is the most probable cause of how water got into the receiver tanks of all three phases.

Root Cause #6: Situation Not Covered

The work method SWM-000318 entitled Interrupter Head (Air Blast Circuit Breaker) – Replace, does not contain instructions on how to prevent moisture contamination of the breaker air receiver tanks while the interrupters are removed.

Recommendation #	Recommendation
TA10	Revise work method SWM-000318 to include: i) Correct procedure to seal the breaker air receiver tanks to prevent moisture ingress while the interrupters are removed; and ii) Visual inspection of the breaker air receiver tanks prior to the reinstallation of the interrupters.

Root Cause #7: Work Package Needs Improvement

The current approach to applying the RTV coating is to apply it to the existing interrupters at the Whitbourne maintenance shop. This requires the interrupters and supporting insulator columns being removed from the main receiver tank for the duration of the RTV application, which takes two weeks.

Recommendation #	Recommendation
TA11	Conduct a risk/reward review of the current practice for the application of the RTV coating with consideration given to the following alternatives which would reduce the amount of time the interrupters are removed from the main receiver tank: i) Materials that can be applied without having to disassemble the breaker; ii) Installing spare interrupters that have the RTV coating applied; and iii) Applying RTV in a nearer controlled environment (Holyrood has some facilities).

Root Cause #8: Scheduling Needs Improvement

As a result of maintenance personnel being rescheduled to perform other high-priority work, the reinstallation of the breaker B1L17 interrupters was deferred for four weeks.

Recommendation #	Recommendation
TA12	Conduct a review of the TRO Central Annual Work Plan to identify opportunities for improvement as it relates to the prioritization and timely execution of work. The review should include, but not be limited to, factors affecting the priority and execution of work, such as the availability of resources (staff, tools and equipment), to effectively execute the annual work plan.

Appendices



Figure 1 – Sunnyside T1 Transformer



Figure 2 – Sunnyside T1 Transformer Tank Rupture



Figure 3 – Western Avalon T5 Transformer



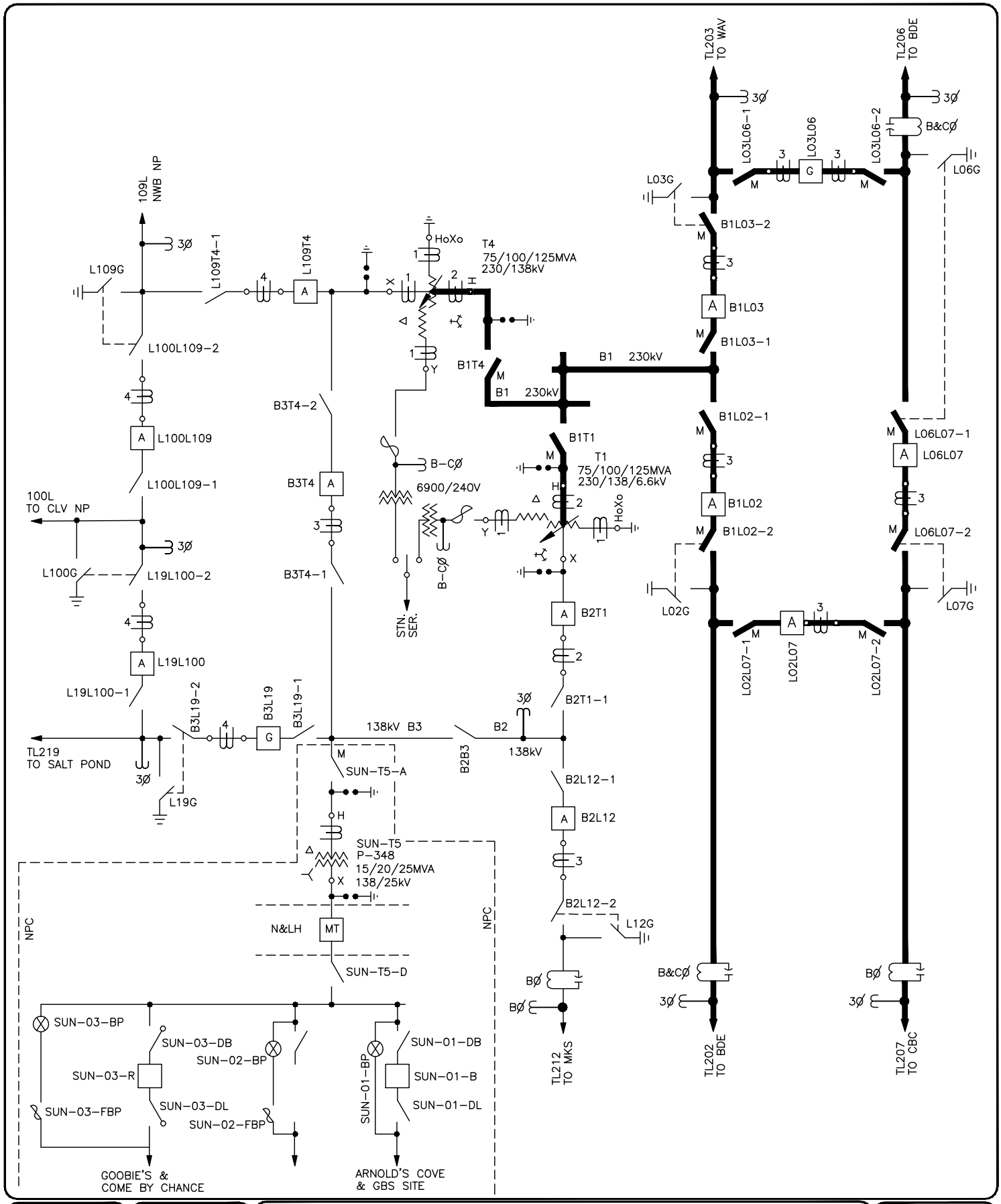
Figure 4 – Western Avalon T5 Transformer Tap Changer Diverter Switch



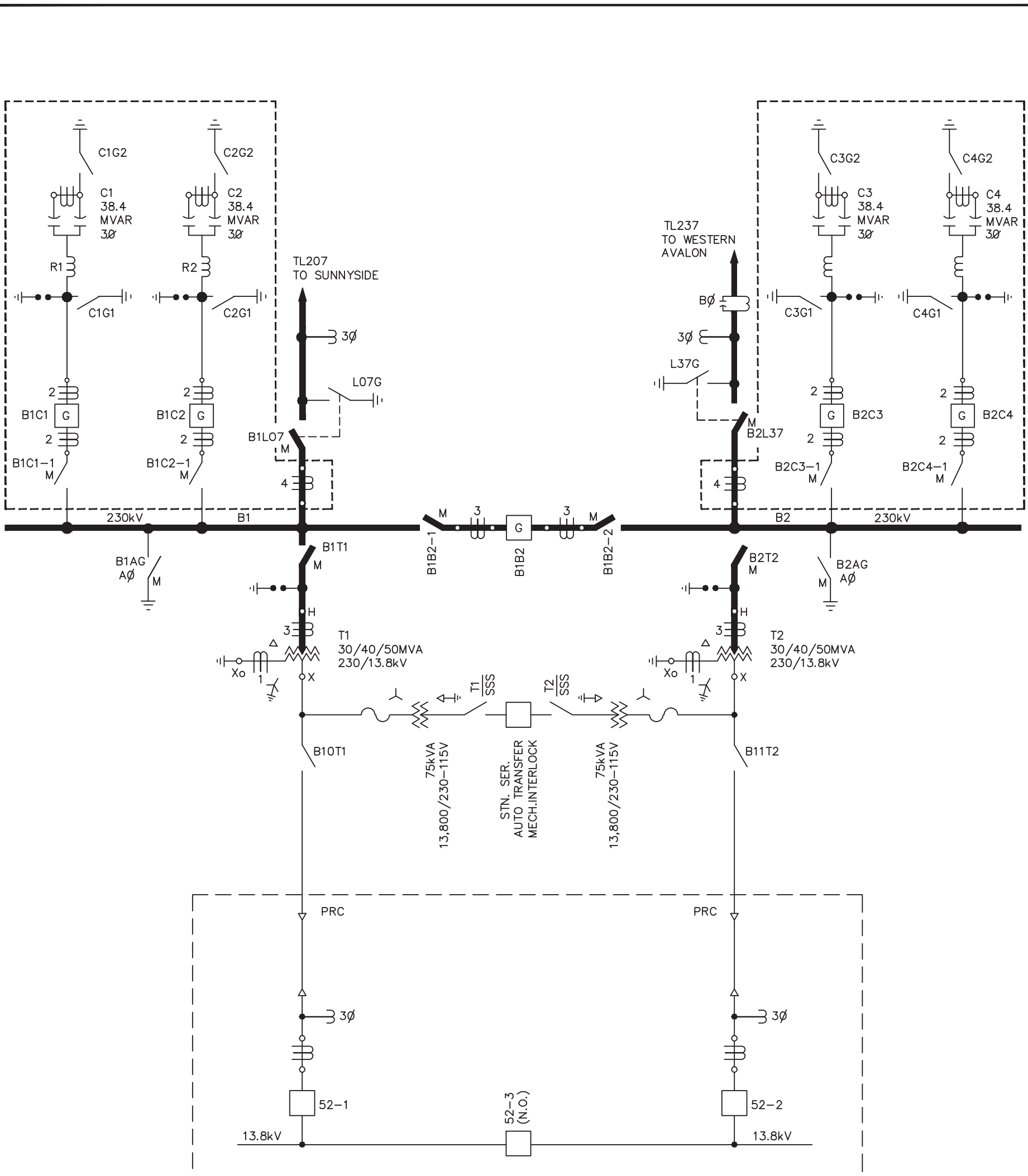
Figure 5 - Holyrood 230kV DLF Breaker



Figure 6 – Holyrood B1L17 Seized Control Rod Drive

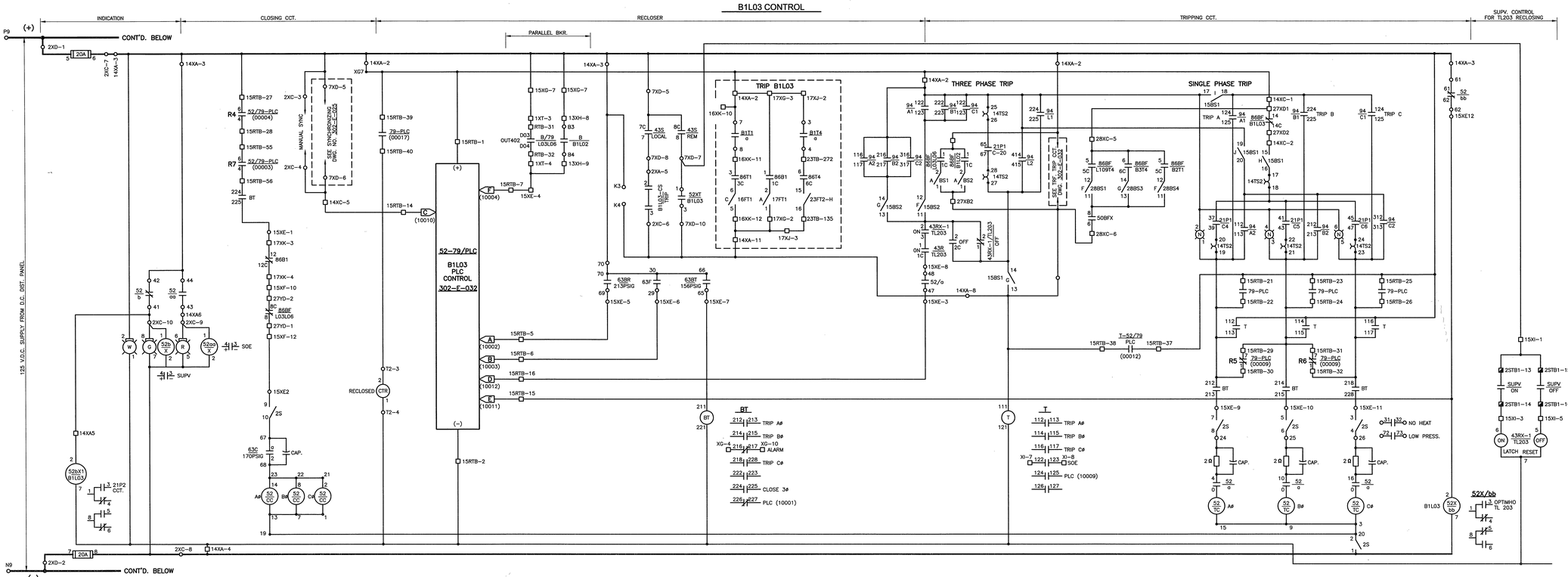


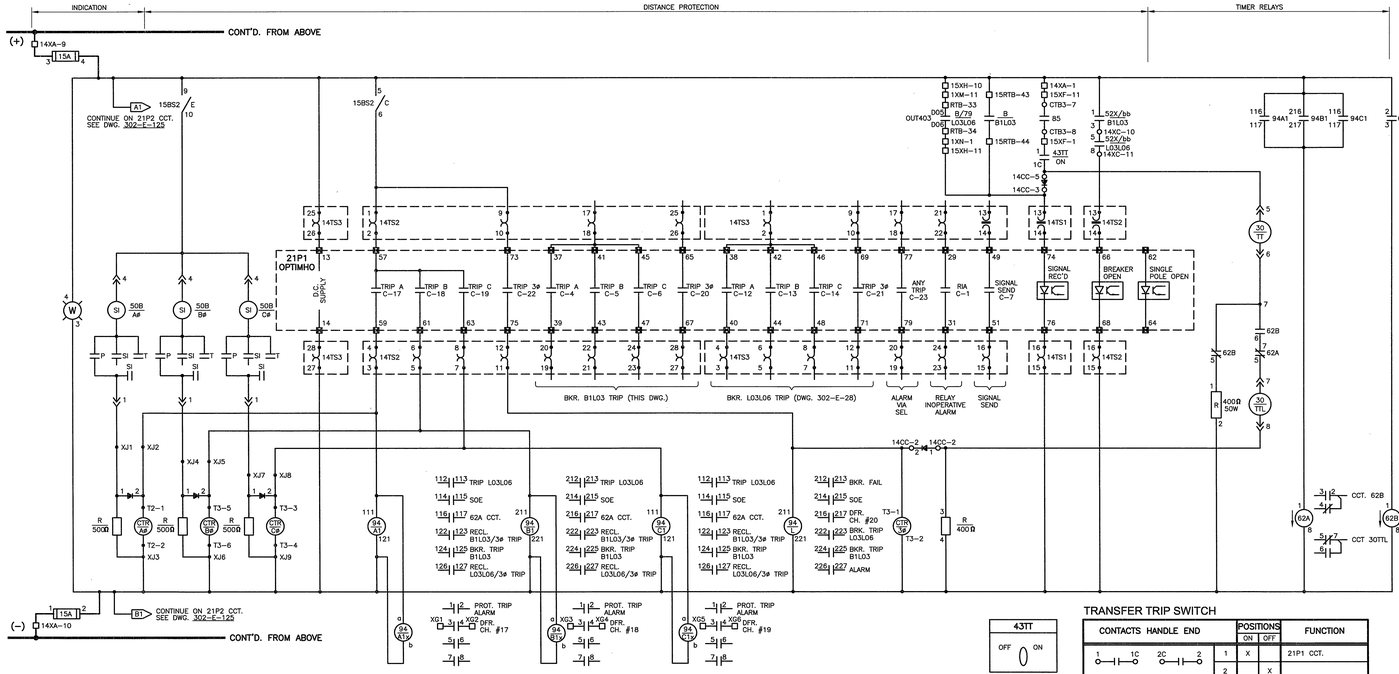
DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO SSD-1
APPROVED BY: D. KING		SYSTEM OPERATING DIAGRAM SUNNYSIDE TERMINAL STATION	REV NO 12
DATE: 2012/12/18			



DRAWN BY J.T.	REVISED BY D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO
APPROVED BY G. BRODERICK		SYSTEM OPERATING DIAGRAM COME BY CHANCE TERMINAL STATION	REV NO 5
DATE 2012–02–21			

B1L03 CONTROL





DEVICE	DESCRIPTION	REF DWG.	LOCATION	TYPE
T	3–PHASE TRIP AUX. RELAY		PANEL 15	ABB RXMS1
BT	BLOCK TRIP RELAY		PANEL 15	ABB RXMB1
21P1	LINE PROT. DISTANCE RELAY – GEC OPTIMHO		PANEL 14	LFZP111
29M	MANUAL OPERATED DISC. IND. LIGHT CONTACT		230kV DISC.	
30TT	TRANSFER TRIP RECEIVER TARGET RELAY		PANEL 15	HSA–16A
30TTL	TRANSFER TRIP LOCKOUT TARGET RELAY		PANEL 15	HSA–16A
25W	SYNCHRONIZING RELAY	302–E–24	PANEL 7	
25X3	SYNCHRONIZING AUX. RELAY		PANEL 7	
43TT	TRANSFER TRIP SWITCH		PANEL 15	SBM
43R	RECLOSER OFF & ON SWITCH		PANEL 15	SBM
43S	SUPERVISORY TRANSFER SWITCH		PANEL 7	
50B	LINE BACK–UP PROT. RELAY	302–E–24	PANEL 15	
52X/bb	AUX. RELAY FOR BREAKER OPEN		PANEL 14	KRPA–11DG
52CS	BREAKER CONTROL SWITCH		PANEL 14	SBM
52y/o	AUX. RELAY FOR SUPV. IND.		PANEL 2	P & B KRP11DG
62 A,B	TRANSFER TRIP TIMER AUX. RELAYS		PANEL 15	AGAST.–2122–D–9
63BR	PRESSURE SWITCH RECLOSING INTERLOCK		230kV BKR.	
63BT	PRESSURE SWITCH TRIPPING INTERLOCK		230kV BKR.	
63C	PRESSURE SWITCH CLOSING INTERLOCK		230kV BKR.	
63F	PNEUMATIC BACK–UP TRIP CONTACT		230kV BKR.	
85	CARRIER TRANSFER TRIP RELAY		CARR. CAB.	
94 A,B,C(1,2)	PHASE TRIP RELAY		PANEL 14	ABB RXMS1
94L(1,2)	LOCKOUT TRIP RELAY		PANEL 14	ABB RXMS1
	PHASE TRIP AUX. RELAY		PANEL 14	
CTR	COUNTER FOR SINGLE PHASE		PANEL 15	4Y9434–PS
CTR/L	COUNTER FOR 3 PHASES		PANEL 15	4Y9434–PS
43RX–1	LATCH RELAY FOR RECLOSER SUPV. CONTROL		PANEL 15	S & D 255XCXP
43RX–2	AUX. RELAY FOR SUPV. INDICATION		PANEL 15	P & B KRP11DG
52bX1	AUX. RELAY FOR BREAKER OPEN		PANEL 14	P & B KRP11DG
21P2	LINE PROTECTION DISTANCE RELAY – PRIMARY No.2		PANEL 14	SEL 321–1
86BF	BKR FAIL LOCKOUT RELAY		PNL 27, 28	HEA–61
52–79 PLC	PROGRAMMABLE LOGIC CONTROLLER (BREAKER CONTROL/RECLOSING)		PANEL 15	COMPACT 984
79–L03L06	L03L06 RECLOSING CONTROL (SEL AUTOMATION CONTROLLER)		PANEL 1	SEL–2411

B1L03–CS

TRIP / CLOSE

BREAKER CONTROL SWITCH

CONTACTS HANDLE END				POSITIONS		
				CLOSE	NORM.	TRIP
1 1C	2C 2	1				
		2				X
3 3C	4C 4	3	X			
		4	X			

TARGET TYPE WITH PISTOL GRIP HANDLE SPRING RETURN TO NORMAL POSITION

43R

OFF / ON

RECLOSER SWITCH

CONTACTS HANDLE END				POSITIONS	
				ON	OFF
1 1C	2C 2	1	X		
		2			X
3 3C	4C 4	3	X		
		4			X
5 5C	6C 6	5	X		
		6			X
7 7C	8C 8	7	X		
		8			X

OVAL HANDLE MAINTAINED CONTACTS

43TT

OFF / ON

TRANSFER TRIP SWITCH

CONTACTS HANDLE END				POSITIONS		FUNCTION
				ON	OFF	
1 1C	2C 2	1	X			21P1 CCT.
		2			X	
3 3C	4C 4	3	X			TRANSFER TRIP SEND
		4			X	
5 5C	6C 6	5	X			21P2 CCT.
		6			X	
7 7C	8C 8	7	X			
		8			X	

OVAL HANDLE MAINTAINED CONTACTS

NOTES:

1. 52aa – AUX. SW. OPEN WHEN BREAKER IS OPEN. – CLOSE WHEN BREAKER IS CLOSED. IN CASE OFDISAGREEMENT , CONTACT REMAIN CLOSED UNTIL THE FAULTY POLE OR POLES ARE TRIPPED BY THE PNEUMATIC BACK–UP TRIP DEVICE. 52bb – AUX. SW. CLOSE WHEN BREAKER IS OPEN. – OPEN WHEN BREAKER IS CLOSED. IN CASE OFDISAGREEMENT , CONTACT REMAIN OPEN UNTIL THE FAULTY POLE OR POLES ARE TRIPPED BY THE PNEUMATIC BACK–UP TRIP DEVICE.
2. T – TERMINALS ARE LOCATED ON TRIP RELAY ASSEMBLY SUB–PANEL.
3. —□— DENOTES TERMINALS ON "CANSFIELD" RECLOSER CASE.
4. 2STB REFERS TO SUPERVISORY JUNCTION BOX NO. 2, 1STB IS BOX NO. 1

		37.	10–09–28	MINOR REVISIONS	C.R.H.	FLD REV		
		36	09–05–28	L03L06 RECLOSING CONTROL UPGRADE	W.B.			
		35.	08–06–20	B1L03, L06L07 BREAKER CONTROL PLC INSTALL	C.R.H.	FLD. REV		
		34	05–08–18	REVISED AS BUILT	C.M.	FLD. REV		
302–E–032	B1L03 PLC CONTROL SCHEMATIC	33	01–09–11	138kV BKR. FAIL ADDITION	G.W.			
302–E–049	125V D.C. DISTRIBUTION PANEL	32	00–11–23	AS BUILT (FOR TL207 BACK–UP PROT. UPGRADE)	W.B.			
302–E–062	ANNUNCIATOR SCHEMATIC DIAGRAM	31	99	TRANSCAN DFR ADDED				
DWG.NO.	TITLE	NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
REFERENCE DRAWINGS		REVISIONS						

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ORIGINAL DRAWING NOT SEALED

NEWFOUNDLAND AND LABRADOR HYDRO

SUNNYSIDE TERMINAL STATION
230kV .B.C.B. B1L03 CONTROL
& TL203 PRIMARY No. 1 PROTECTION
D.C. SCHEMATIC DIAGRAM

ELECT.	SCALE:	N.T.S.	
CIVIL	DESIGNED:	C. WARREN	
TRANS.	DRAWN:	D. MONTAGUE	
MECH.	DATE:	1991–10–09	
P&C	CHECKED:		
TELC.	APPROVED:		

W.O. NO.

DWG. NO. A0 - 302 - E - 093

REV. 37.

PLOT SCALE 1:1 C.A.D.

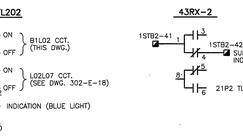
9/28/2010 10:43:33 AM

DEVICE	DESCRIPTION	REF DWG.	LOCATION	TYPE
A	RECLOSER START–TIMING RELAY		PANEL 13	ESNA–2122–D–5
B	LOCKOUT ANTIPUMP RELAY		PANEL 13	B.B. – P16
C	INTERVAL TIMER BETWEEN SUCCESSIVE CLOSE/RECLOSE OPERATIONS		PANEL 13	ESNA–2122–D–5
D	CLOSE CONTROL RELAY		PANEL 13	B.B.–P8
E	RELAY TO OPERATE LOCKOUT TRIP DURING RECL. & SEAL–IN FOR "BR"		PANEL 13	CLARE "E"
F	AUX. RELAY FOR TRANSIENT PRESS. DROP & DISAGREEMENT TRIP		PANEL 13	ESNA–2122–D–5
T	3–PHASE TRIP AUX. RELAY		PANEL 13	B.B. – P8
BR	LOW AIR PRESSURE BLOCK RECLOSE RELAY		PANEL 13	C.P. CLARE "E"
BT	BLOCK TRIP RELAY		PANEL 13	B.B. – P8
BX	3–POLE TRIP RELAY AFTER UNSUCC. CLOSE/RECLOSE		PANEL 13	B.B. – P8
21P1	LINE PROT. DISTANCE RELAY – ZONE 1,2,3 PRIMARY No.1	302–E–024	PANEL 12	GEC OPTIMHO
29M	MANUAL OPERATED DISC. IND. LIGHT CONTACT		230kV DISC.	
30TT	CARRIER RECEIVER TARGET RELAY		PANEL 13	HSA–16A
30TTL	CARRIER LOCKOUT TARGET RELAY		PANEL 13	HSA–16A
25W	SYNCHRONIZING RELAY		PANEL 7	
25X3	SYNCHRONIZING AUX. RELAY	302–E–024	PANEL 7	
43TT	TRANSFER TRIP SWITCH		PANEL 13	SBM
43R	RECLOSER OFF & ON SWITCH		PANEL 13	SBM
43S	SUPERVISORY TRANSFER SWITCH		PANEL 7	
50B	LINE BACK–UP PROT. RELAY	302–E–024	PANEL 13	
52Y/a	AUX. RELAY FOR SUPV. IND.		PANEL 2	P&B KRP11DG
52CS	BREAKER CONTROL SWITCH		PANEL 12	SBM
62 A,B	TRANSFER TRIP TIMER AUX. RELAYS		PANEL 13	AGAST.–2122–D–9
63BR	PRESSURE SWITCH RECLOSING INTERLOCK		230kV BKR.	
63BT	PRESSURE SWITCH TRIPPING INTERLOCK		230kV BKR.	
63C	PRESSURE SWITCH CLOSING INTERLOCK		230kV BKR.	
63F	PNEUMATIC BACK–UP TRIP CONTACT		230kV BKR.	
85	CARRIER TRANSFER TRIP RELAY		CARR. CAB.	
85X	CARRIER AUX. RELAY		PANEL 13	
94 A,B,(1,2)	PHASE TRIP RELAY		PANEL 13	ABB RXMS1
94L(1,2)	LOCKOUT TRIP RELAY		PANEL 13	ABB RXMS1
94 A1x,B1x,C1x	PHASE TRIP AUX. RELAY		PANEL 13	
TS1,2,3	OPTIMHO TEST BLOCK		PANEL 12	GEC
52X/bb	OPEN BREAKER INDICATION RELAY		PANEL 13	P&B KRP11DG
CTR	COUNTER FOR SINGLE PHASE		PANEL 13	4X9434–PS
CTR/L	COUNTER FOR 3 PHASES		PANEL 13	4X9434–PS
43RX–1	LATCH RELAY FOR RECLOSER SUPV. CONTROL		PANEL 13	S&D 255XCXP
43RX–2	AUX. RELAY FOR SUPV. INDICATION		PANEL 13	P&B KRP11DG
27A,B,C	VOLTAGE RELAYS		PANEL 12	ASEA–RXMB
27X	AUX. TIMER FOR 27 RELAYS		PANEL 12	ASEA–RXKM2H
94AR	TRIP RELAY FOR AUTO RESTORATION		PANEL 12	ASEA–RXMS1
52bx1	AUX. RELAY FOR BREAKER OPEN		PANEL 12	P&B–KRPA–11DG
21P2	LINE PROTECTION DISTANCE RELAY – PRIMARY No.2		PANEL 12	SEL 321–1
86BF	BKR. FAIL. LOCKOUT RELAY – G.E.		PNL. 27,28	HEA–61
21P1/TTX	AUXILIARY TRANSFER TRIP RELAY		PANEL 12	ABB RXMS1

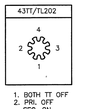
NOTES:

1. 52aa – AUX. SW. OPEN WHEN BREAKER IS OPEN. – CLOSE WHEN BREAKER IS CLOSED.
   IN CASE OF DISAGREEMENT , CONTACT REMAIN CLOSED UNTIL THE FAULTY POLE OR POLES ARE TRIPPED BY THE PNEUMATIC BACK–UP TRIP DEVICE.
   52bb – AUX. SW. CLOSE WHEN BREAKER IS OPEN. – OPEN WHEN BREAKER IS CLOSED.
   IN CASE OF DISAGREEMENT , CONTACT REMAIN OPEN UNTIL THE FAULTY POLE OR POLES ARE TRIPPED BY THE PNEUMATIC BACK–UP TRIP DEVICE.
2. T – TERMINALS ARE LOCATED ON TRIP RELAY ASSEMBLY SUB–PANEL.
3. –□– DENOTES TERMINALS ON "CANSFIELD" RECLOSER CASE.
4. 2STB REFERS TO SUPERVISORY JUNCTION BOX NO. 2, 1STB IS BOX NO. 1

TL202 RECLOSER (SUPV. CONTROL)



TRANSFER TRIP CONTROL SWITCH - 43TT PRIMARY/SECONDARY T.T.



CONTACTS HANDLE END		IND. POS. 1	2	3	4	FUNCTION
1C 3C 2	1			×		
	2		×		×	21P1 RECV. (SEC.)
3C 4C 4	3			×	×	21P1 RECV. (PRI.)
	4	×	×	×		
5C 6C 6	5		×		×	21P2 RECV. (SEC.)
	6			×	×	21P2 RECV. (PRI.)
7C 8C 8	7		×		×	SEC. T.T. SEND
	8			×	×	PRIM. T.T. SEND
9C 10C 10	9				×	
	10		×		×	ALARM
11C 12C 12	11			×	×	ALARM
	12	×	×	×		
13C 14C 14	13		×		×	SUPV. – SEC. ON
	14			×	×	SUPV. – PRI. ON
15C 16C 16	15		×		×	
	16			×	×	

SBM (C.E.) – KNURLED HANDLE MAINTAINED CONTACT

BREAKER CONTROL SWITCH

B1L02–CS: TRIP / CLOSE

CONTACTS HANDLE END		POSITIONS CLOSE	NORM.	TRIP
1 1C 2C 2	1	X		
	2			X
3 3C 4C 4	3	X		X
	4	X		

TARGET TYPE WITH PISTOL GRIP HANDLE SPRING RETURN TO NORMAL POSITION

43R: OFF / ON

CARRIER RECLOSER SWITCH

CONTACTS HANDLE END		POSITIONS ON	OFF
1 1C 2C 2	1	X	
	2		X
3 3C 4C 4	3	X	
	4		X
5 5C 6C 6	5	X	
	6		X
7 7C 8C 8	7	X	
	8		X

OVAL HANDLE MAINTAINED CONTACTS

SEE DWG. 302–E–024 (230kV A.C. SCHEMATIC)

27A/TL202	27B/TL202	27C/TL202
114/115	214/215	314/315
124/125	224/225	324/325
116/117 SUPV. IND. CCT.	216/217 SUPV. IND. CCT.	316/317 SUPV. IND. CCT.
126/127 94AR/TL202&7 CCT.	226/227 94AR/TL202&7 CCT.	326/327 94AR/TL202&7 CCT.

SUPERSEDE DWG.: F–302–E–28
F–302–E–29

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D.
32.	08–04–28	B1L03, L06L07 BKR. CONTROL PLC INSTALLED	C.R.H.	FLD.REV.		
31	05–06–10	TELEPROTECTION UPGRADE (TL202, TL206)	C.M.			
30	01–09–08	138kV BKR. DFAIL ADDITION & REVISED AS BUILT	W.B.			
29	00–11–23	AS BUILT (FOR TL207 BACK–UP PROT. UPGRADE)	W.B.			
28	99	TRANSCAN DFR ADDED	–			
27	97	TL202 21P2 ADDED	–			
26	97–09–04	TL202/206 AUTO RESTORATION ADDITIONS	W.B.			

302–E–125 230kV TL202,203,206,207 PRIMARY #2 & B.U. PROTECTION D.C.
DWG.NO. TITLE
REFERENCE DRAWINGS

NOTICE:
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO

ORIGINAL DRAWING NOT SEALED

HYDRO — NEWFOUNDLAND AND LABRADOR HYDRO

SUNNYSIDE TERMINAL STATION
230kV A.B.C.B. B1L02 CONTROL & TL202
PROTECTION D.C. SCHEMATIC DIAGRAM

ELECT.	SCALE: NONE
CIVIL	DESIGNED: J. FOLEY
TRANS.	DRAWN: D. MONTAGUE
MECH.	DATE: 1994–07–21
P&C	CHECKED:
TELC.	APPROVED:

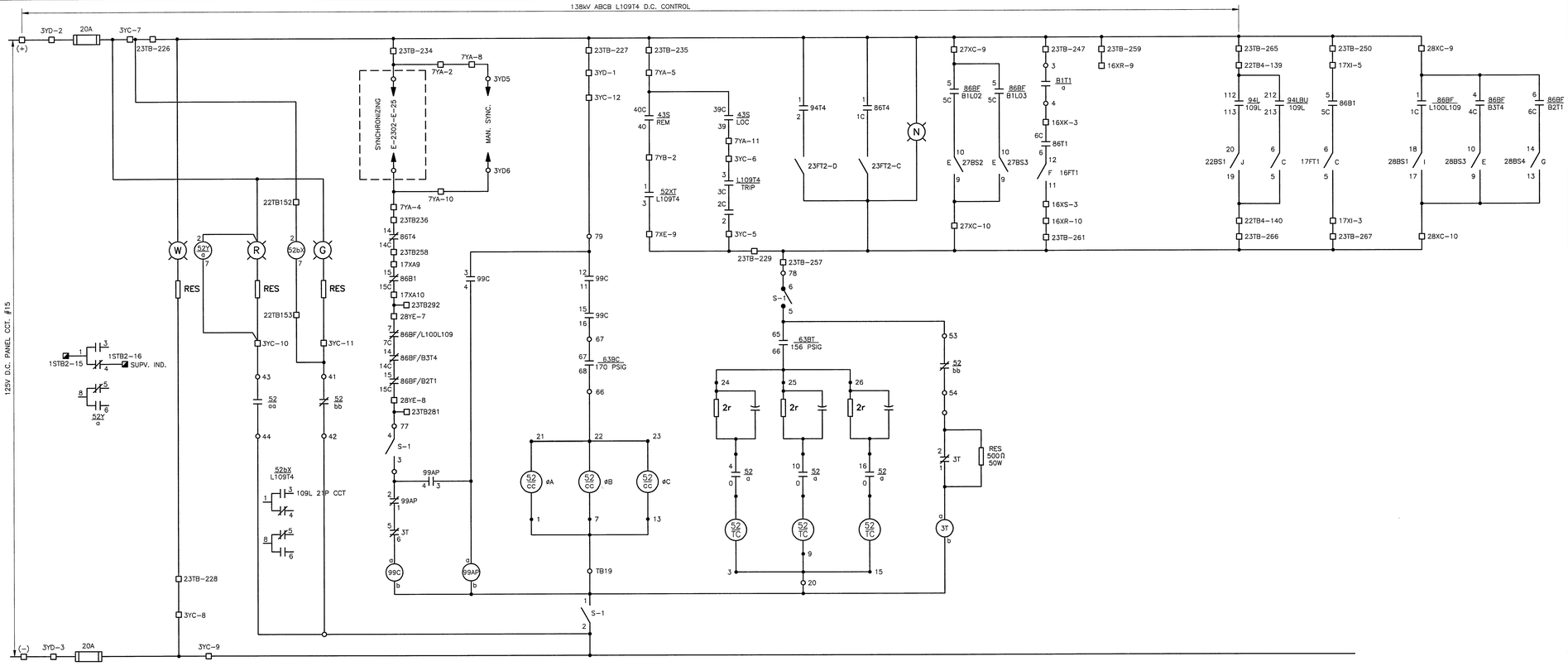
W.O. NO.

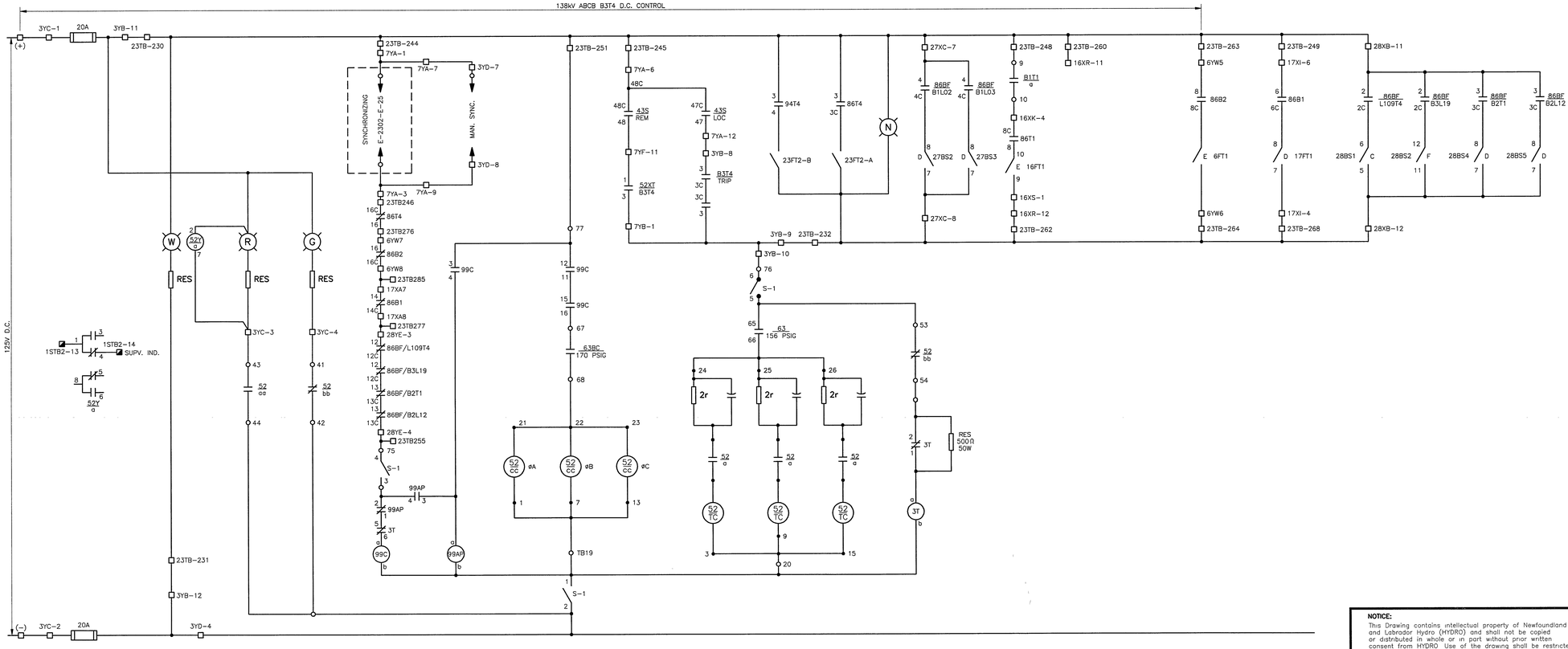
DWG. NO. A0 - 302 - E - 092

REV. 32.

Apr 28, 2008 – 2:44pm

PLOT SCALE 1:1 C.A.D.





DEVICE	DESCRIPTION	DEV. DEVEL.	LOCATION	TYPE
99C	ABCB CLOSING AUX. RELAY		ABCB	B. BOV. P8AXM
99AP	ABCB ANTI-PUMP RELAY		ABCB	B. BOV. P8AXM
3T	TRIP CHECK RELAY		ABCB	B. BOV. P8AXM
52 CC	ABCB CLOSING COIL		ABCB	B. BOV. DCF
52 TC	ABCB TRIPPING COIL		ABCB	B. BOV. DCF
43S	SUPERVISORY SELECT SWITCH		LINE CONTROL PNL.	CCE. SBM
63BC	PRESS. SWITCH INTERLOCK FOR CLOSING		ABCB	B. BOV. DCF
63BT	PRESS. SWITCH INTERLOCK FOR TRIPPING		ABCB	B. BOV. DCF
52 a	ABCB AUX. CONTACT		ABCB	B. BOV. DCF
52 aa,bb	ABCB AUX. SWITCHES		ABCB	B. BOV. DCF
94L 109L	TRIP RELAY 109L		PANEL NO. 22	ABB RXMS1
94L 100L	TRIP RELAY 100L		PANEL NO. 21	ABB RXMS1
86B	138kV BUS DIFF.			
86T1	TRF. NO. 1 LOCKOUT RELAY			
86T2	TRF. NO. 2 LOCKOUT RELAY			
52Y/a	AUX. RELAY FOR SUPV. IND.	A0-302-E-35	PNL 4 (SHOWN ON PNL 3 DRAWING)	P&B KRP11DG
86BF	BREAKER FAIL LOCKOUT RELAY – GE			HEA-G1
52bX	AUX. RELAY FOR BREAKER OPEN		PANEL NO. 22	P&B KRP11DG

LEGEND:

- OUTDOOR EQUIPMENT TERMINAL WITH CONNECTION TO OTHER EQUIPMENT
- INDOOR PANEL TERMINAL WITH CONNECTION TO OTHER EQUIPMENT
- OUTDOOR EQUIPMENT TERMINAL INTERNAL CONNECTION

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NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
14	05-06-08	100L & 109L PROTECTION UPGRADE	C.M.	AYL	EFB	
13	03-02-04	REVISED AS BUILT	H.P.	FLD.REV.		
12	00-09-09	138kV BKR. FAIL. PROT. ADDITION, REVISED AS BUILT & REDRAWN ON CAD	C.M.	LS	AYL	
11	94-10-24	REVISED AS BUILT	W.B.			
10	94-08-14	AS BUILT	D.M.			
9	90-09-28	T.L. 219 ADDED	C.H.			

DWG.NO. | TITLE

REFERENCE DRAWINGS

REVISIONS

ORIGINAL DRAWING NOT SEALED

NEWFOUNDLAND AND LABRADOR HYDRO

ELECT.	SCALE: N.T.S.
CIVIL	DESIGNED: E. FERRER
TRANS.	DRAWN: W.R.L.
MECH.	DATE: 1976-05-28
P&C	CHECKED:
TELC.	APPROVED:

SUNNYSIDE TERMINAL STATION
138 kV ABCB L109T4 & ABCB B3T4
D.C. CONTROL SCHEMATIC

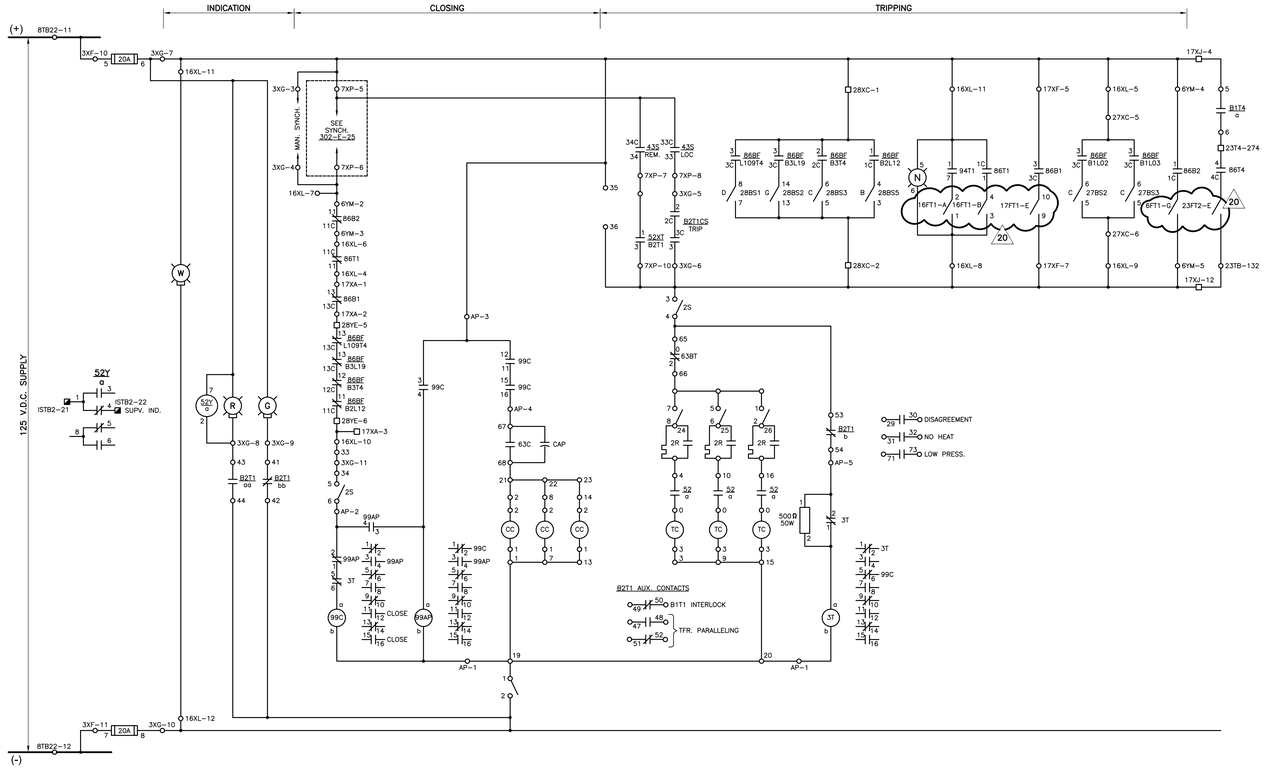
W.O. NO.

DWG. NO. B1- 302 - E - 70

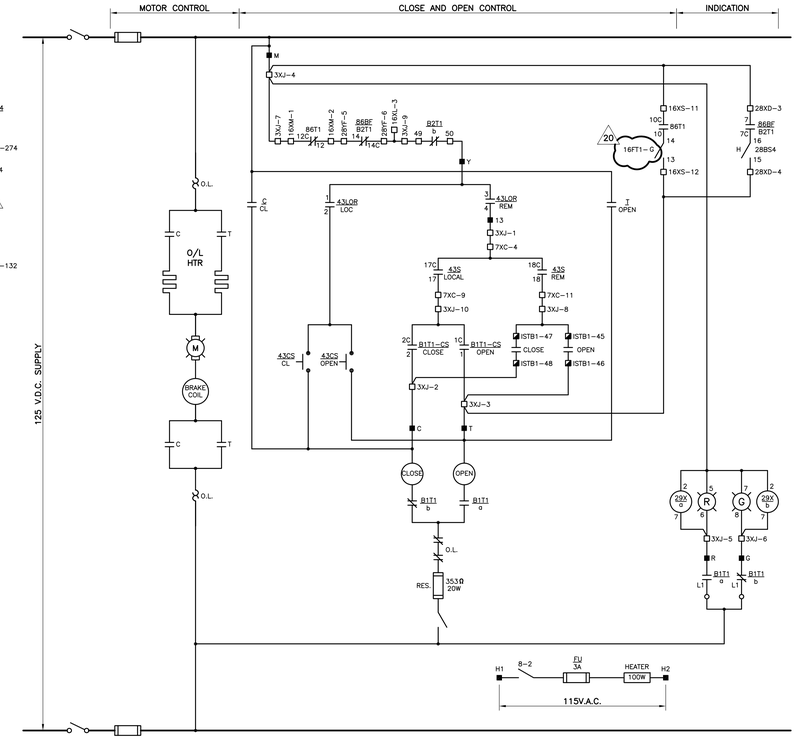
REV. 14

PLOT SCALE 1:1 C.A.D.

BREAKER B2T1

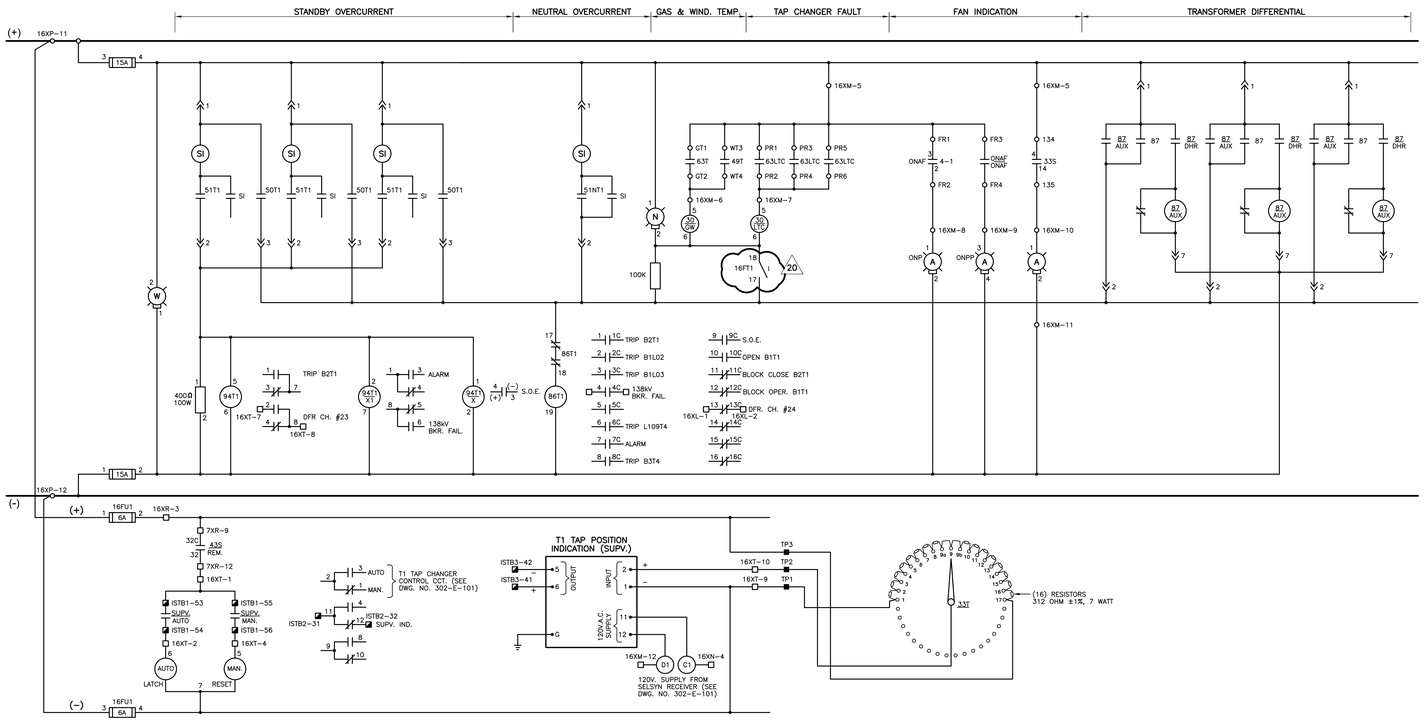


M.O.D. B1T1



DEVICE	DESCRIPTION	DEVICE DEV. REF. DWG.	LOCATION	TYPE
4-1	TFR. FAN CONT. STARTER		TFR.	
63 RAM	TFR. TAP CHANGE TRANSFER SW.		PNL. 16	SBM
50/51T1	TFR. STANDBY OVERCURRENT REL.		PNL. 16	IAC53B
51NT1	TFR. GROUND OVERCURRENT REL.		PNL. 16	IAC
3OLTC	TFR. TAP CHANGE FAULT TARGET REL.		PNL. 16	HSA
3OGW	TFR. GAS AND WINDING TEMP. TARGET REL.		PNL. 16	HSA
49T	TFR. WINDING TEMP. DEVICE		TFR.	
63T	TFR. GAS PRESS. REL.		TFR.	
63LTC	TFR. TAP CHANGER FAULT DEV.		TFR.	
84CS	TFR. TAP CHANGE REMOTE C. SW.		PNL. 16	SBM
86T1	TFR. PROT. LOCKOUT REL.		PNL. 16	HEA
94T1	TFR. PROT. TRIPPING REL.		PNL. 16	HGA
CC	BKR. CLOSING COIL		BKR.	
TC	BKR. TRIPPING COIL		BKR.	
KI	BKR. KEY INTERLOCK		BKR.	
3T	BKR. TRIP CHECK REL. + RES. 500Ω, 50W		BKR.	B.BOV. P8 24V.D.C.
52/a-b	BKR. AUX. CONTACT		BKR.	
63C	BKR. BLOCK CLOSE PRESS. SWITCH		BKR.	
63BT	BKR. BLOCK TRIP PRESS. SWITCH		BKR.	
99C	BKR. CLOSING REL.		BKR.	B.BOV. P8 125V.D.C.
99AP	BKR. ANTI-PUMP REL.		BKR.	B.BOV. P8 125V.D.C.
43S	BKR. SUPERV. SELECTOR SW.		PNL. 7	SBM
B2T1-CS	BKR. CONTROL SW.		PNL. 3	SBM
86B	138kV BUS. DIFF. LOCKOUT REL.		PNL. 6	HEA
94T	TFR. DIFF. TRIPPING REL.		PNL. 16	B.BOV. P8
29X/a,b	AUX. RELAYS FOR SUPV. INDICATION		PNL. 3	P & B KRPIIDG
43X	LATCH RELAY FOR T1 AUTO/MAN. (SUPV.		PNL. 16	S & D 255XCXP
5	M. O. DISC. FOR DETAIL ITE DWGS.			
8-1,2				
9				
33				
33LS		M.O.DISC.		
43				
43CS				
43LOR				
29T/a-b	DISC. AUX. CONTACT	M.O.DISC.		
B1T1-CS	DISC. CONTROL SW.		PNL. 3	SBM
94T1/X	AUX. RELAY FOR S.O.E. STATUS		PNL. 16	GE ETS201A
86BF	138kV BKR. FAIL. LOCKOUT RELAYS - GF		PNL. 28	HEA-61

TRANSFORMER T1



BREAKER B2T1 C.S.

B2T1 CS: TRIP / CLOSE

CONTACTS HANDLE END		POSITION		
		CLOSE	NORM	TRIP
1-2	1	X		
	2			X
3-4	3	X		X
	4	X		

PISTOL GRIP HANDLE
SPRING RETURN TO NORM.

M.O. DISC. B1T1 C.S.

B1T1 CS: OPEN / CLOSE

CONTACTS HANDLE END		POSITION		
		CLOSE	NORM	OPEN
1-2	1			X
	2	X		
3-4	3			X
	4	X		

PISTOL GRIP HANDLE
SPRING RETURN TO NORM.

29X a: ISTB2-23, ISTB2-24, SUPV. IND. CONTACT 1

29X b: ISTB2-25, ISTB2-26, SUPV. IND. CONTACT 2

ALARMS: 136, 138, OT1, 27 OUT OF STEP, TOP OIL, 137, 139, OT2 — ANNUNCIATOR PANEL

ALARMS: GA1, OL3, OL1, WT1, 63T LOW OIL, LTC LOW OIL, 49T, GA2, OL4, OL2, WT2 — ANNUNCIATOR PANEL

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NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
20	13-04-10	FIELD REVISIONS	W.B.	F. REV.		
19	05-08-17	REVISED AS BUILT	C.M.	FLD.REV.		
18	03-02-03	REVISED AS BUILT	H.P.	FLD.REV.		
17.	01-09-08	REV. "AS BUILT" (138kV BKR. FAIL. ADD.) & REDRAWN	C.R.H.			
16.	00-10-16	AS BUILT	D.O.			
15.	99-	TRANSCAN DFR ADDED	D.O.			
14.	95-04-18	S.O.E. ADDITIONS	C.M.			

DWG.NO. | TITLE
REFERENCE DRAWINGS
REVISIONS

ORIGINAL DRAWING NOT SEALED

HYDRO — NEWFOUNDLAND AND LABRADOR HYDRO

ELECT.	SCALE:	N.T.S.
CIVIL	DESIGNED:	
TRANS.	DRAWN:	C.R.H.
MECH.	DATE:	2001-09-08
P&C	CHECKED:	
TELC.	APPROVED:	

SUNNYSIDE TERMINAL STATION
M.O. DISC. B1T1, T1 AND A.B.C.B. B2T1
D.C. SCHEMATIC DIAGRAM

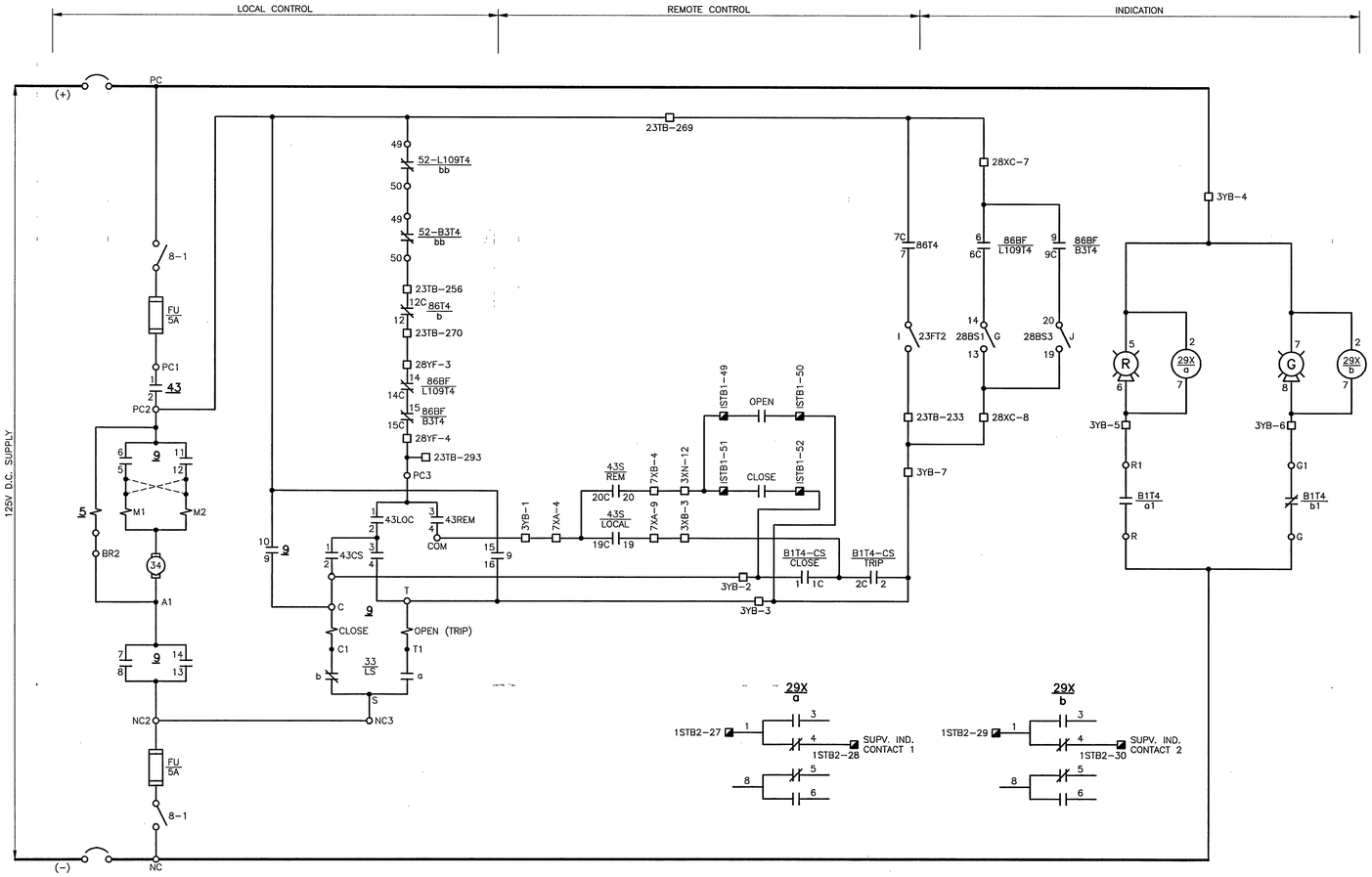
W.O. NO.

DWG. NO. A0 - 302 - E - 030

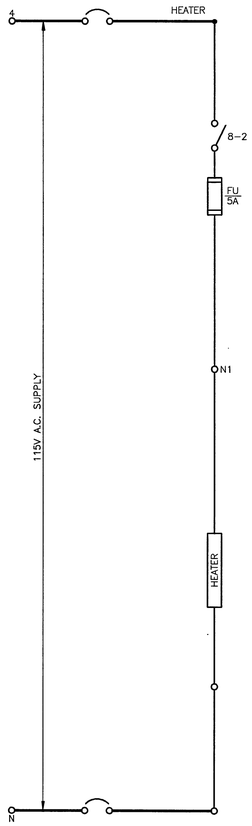
REV. 20

PLOT SCALE 1:1 C.A.D.

DEVICE	DESCRIPTION	LOCATION	TYPE
5	ELECTROMAGNETIC BRAKE	B1T4 DISCONNECT	
9	MOTOR REVERSING CONTACTORS	B1T4 DISCONNECT	
8–1	DPST CONTROL POWER SWITCH	B1T4 DISCONNECT	
8–2	SPST HEATER SWITCH	B1T4 DISCONNECT	
33	POSITION AUX. CONTACTS	B1T4 DISCONNECT	
33/LS	LIMIT CONTACT ON DEVICE 33	B1T4 DISCONNECT	
43	MANUAL SELECTOR SWITCH	B1T4 DISCONNECT	
52–L109T4/bb	BREAKER AUX. CONTACT	L109T4 BREAKER	
84	1/2 H.P. MOTOR	B1T4 DISCONNECT	
86T4/b	TRANSFORMER LOCKOUT RELAY CONTACT	TRANS. T4 PANEL	C.G.E. HAE
B1T4–CS	B1T4 REMOTE CONTROL SWITCH	CONTROL PNL.	C.G.E. SBM
43CS	LOCAL PUSH BUTTON	B1T4 DISCONNECT	
43 LOR	LOCAL OFF REMOTE SELECTOR SWITCH	B1T4 DISCONNECT	
52–B2T4/bb	BREAKER AUX. CONTACT	B2T4 BREAKER	
29X/a,b	AUX. RELAY FOR SUPV. INDICATION	PANEL No. 3	P&B KRP11DG
86BF	BREAKER FAIL LOCKOUT RELAY–GE	PANEL No. 28	HEA–61



B1T4 D.C. SCHEMATIC



A.C. SCHEMATIC

DISCONNECT B1T4 CONTROL SWITCH

CONTACTS		POSITIONS		
		CLOSE	NORM.	TRIP
1 1C 2C 2	1	X		
	2			X
3 3C 4C 4	3	X		X
	4	X		

TARGET TYPE WITH PISTOL GRIP HANDLE
SPRING RETURN TO NORMAL POSITION



CONTACT DIAG. 9		
CONTACT NO.	POSITIONS	
	CLOSE	OPEN
1–2		
3–4		
5–6	X	
7–8	X	
9–10	X	
11–12		X
13–14		X
15–16		X

CONTACT DIAG. 33		
CONTACT NO.	POSITIONS	
	CLOSE	OPEN
a	X	
b		X
a1	X	
b1		X

CONTACT DIAG. 43		
CONTACT NO.	POSITIONS	
	MAN.	MOTOR
1–2		X

X – CONTACT CLOSED

NOTES:
1. TO CHANGE ROTATION OF MOTOR REVERSE M1 & M2 LEADS.
2. REVERSING CONTACTOR IS MECHANICALLY INTERLOCKED.
3. □ INDICATES TERMINALS IN CONTROL/RELAY PANELS.
4. ○ INDICATES TERMINALS IN EXTERNAL EQUIPMENT.
5. ● INDICATES INTERNAL CONNECTIONS.

NOTICE:
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NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
6	05–08–17	REVISED AS BUILT	C.M.	FLD. REV.		
5	03–02–04	REVISED AS BUILT	H.P.	FLD.REV.		
4	08–09–01	138kV BKR. FAIL ADDITION & AS BUILT. (REDRAWN)	D.O.		AYL	
3	10–90	SUPV. CONTROL & IND. ADDED	D.C.M.			
2	26–02–77	AS BUILT	D.B.F.			
1	05–76	GEN. REVISIONS	D.B.F.			

DWG.NO. | TITLE — REFERENCE DRAWINGS

REVISIONS

ORIGINAL DRAWING NOT SEALED

ELECT.	SCALE: N.T.S.
CIVIL	DESIGNED:
TRANS.	DRAWN: J.G.
MECH.	DATE: SEPT. 9, 1975
P&C	CHECKED:
TELC.	APPROVED:

NEWFOUNDLAND AND LABRADOR HYDRO

SUNNYSIDE TERMINAL STATION
MOTOR OPERATED DISCONNECT B1T4
A.C. & D.C. SCHEMATIC DIAGRAM

W.O. NO.

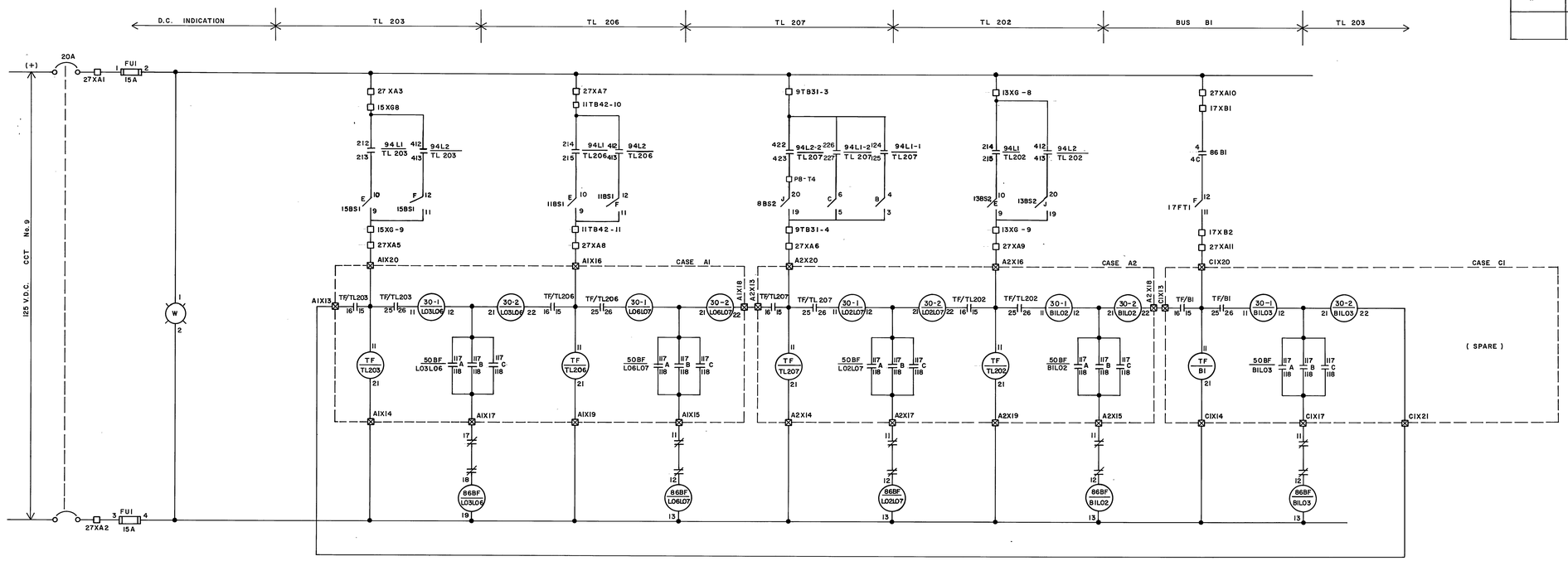
DWG. NO. A1 - 302 - E - 71

REV. 6

PLOT SCALE 1:1 C.A.D.

DEVICE	DECRIPTION	LOCATION	TYPE
50BF	DETECTOR OVERCURRENT RELAY I-2/2-4A	PNL. No 27	RXIL 23 (RK-412 114-DL)
TF	TIME LAG RELAY (20MS - 99S) - ASEA	" "	RXKEI (RK-333-001-AN)
30	SIGNAL RELAY, 2 RED FLAGS, MAN. RESET, 0.2A OPERATING - ASEA	" "	RXSFI (RK-271-007-AX)
86BF	LOCKOUT TRIPPING RELAY, 125 V.D.C. - CGE	" "	HEA-61B-237 HEA-61C-242
W	INDICATING LAMP, 125 V.D.C. WHITE CAP-WESTINGHOUSE	" "	ET-16 (169A 874002)

230 KV BREAKER FAILURE SCHEME



86BF-L03L06 (HEA 61C) - 239

27BS1

27XB1 1 1C 2/A 1 27XB2 TRIP BIL03
27XB3 2 2C 4/B 3 27XB4 TRIP L06L07
27XD-5 3 3C 27XD-6 SOE
4 4C
5 5C
6 6C
7 7C ANNUNCIATOR
8 8C
27XD-9 9 9C 27XD-10 DFR CH.# 27
10 10C BLK. CLOSE BIL03
11 11C BLK. CLOSE L06L07
12 12C OPEN L03L06 TRIP CCT.
27XD-3 13 13C 27XD-4
14 14C
15 15
16 16C
17 18
19
86BF/L03L06 CCT.

TF (RXKEI)

11 + 21 BF CCT
15 16 17 30-1 CCT.
25 26 27 30-2 CCT

86BF-L06L07 (HEA 61B)

27BS1

27XB5 1 1C 8/D 7 27XB6 TRIP L02L07
27XB3 2 2C 10/E 9 27XB4 TRIP L03L06
27YB-8 3 3C 27YB-9 SOE
27XD-11 4 4C 27XD-12 DFR CH.# 28
5 5C
6 6C
7 7C ANNUNCIATOR
8 8C BLK. CLOSE L03L06
9 9C BLK. CLOSE L02L07
10 10C OPEN L06L07 TRIP CCT.
11 12
13
86BF/L06L07 CCT

30 (RXSFI)

X: 11 12 BF CCT; 13 14; 15 16; 17 18
Y: 21 22 BF CCT; 23 24; 25 26; 27 28

86BF - L02L07 (HEA 61B)

27BS1

27XB3 1 1C 14/G 13 27XB4 TRIP L06L07
27XC3 2 2C 16/H 15 27XC4 TRIP BIL02
27YB-6 3 3C 27YB-7 SOE
27YE-5 4 4C 27YE-6 DFR CH.# 29
5 5C
6 6C
7 7C ANNUNCIATOR
8 8C BLK. CLOSE L06L07
9 9C BLK. CLOSE BIL02
27YA-11 10 10C 27YA-12 OPEN L02L07 TRIP CCT
11 12
13
86BF/L02L07 CCT

50BF (RXIL)

141 131 BF CCT
117 118 BF CCT
218

86 BF - BIL02 (HEA 61C)

27BS2

27XB1 1 1C 2/A 1 27XB2 TRIP BIL03
27XB5 2 2C 4/B 3 27XB6 TRIP L02L07
27XC5 3 3C 6/C 5 27XC6 TRIP B2T1
27XC7 4 4C 8/D 7 27XC8 TRIP B2T4
27XC9 5 5C 10/E 9 27XC10 TRIP L109T4
27XC11 6 6C 12/F 11 27XC12 86/B1 CCT
27YE-3 7 7C 27YE-4 SOE
27YE-7 8 8C 27YE-8 DFR CH.#30
9 9C
10 10C
11 11C
12 12C ANNUNCIATOR
13 13C BLK. CLOSE L02L07
14 14C OPEN TRIP CCT/BIL02
15 15C
16 16C
17 18
19
86BF/BIL02 CCT.

86 BF - BIL03 (HEA-61C)

27BS3

27XC3 1 1C 2/A 1 27XC4 TRIP BIL02
27XB7 2 2C 4/B 3 27XB8 TRIP L03L06
27XC5 3 3C 6/C 5 27XC6 TRIP B2T1
27XC7 4 4C 8/D 7 27XC8 TRIP B2T4
27XC9 5 5C 10/E 9 27XC10 TRIP L109T4
27XC11 6 6C 12/F 11 27XC12 86/B1 CCT
27XD-7 7 7C 27XD-8 SOE
8 8C
27YE-9 9 9C 27YE-10 DFR CH.# 31
10 10C
11 11C
12 12C ANNUNCIATOR
13 13C BLK CLOSE L03L06
14 14C OPEN TRIP CCT/BIL03
15 15C
16 16C
17 18
19
86BF/BIL03 CCT

TERMINAL LEGEND

- ☐ AT PANEL TERMINAL BLOCKS
- ☒ AT ASEA COMBIFLEX RELAY CASE.

APPROVED FOR CONST. 84-07-23

REFERENCE DRAWINGS		
B1-302-E-123	PANEL NO. 27	LAYOUT
B1-302-E-121	PANEL NO. 27	WIRING DIAGRAM
DWG. No.		TITLE

No	DATE	DESCRIPTION		BY	CKD.
10	97-	TL202 & TL206 21P2 ADDED		AYL	LT
9	89-04-18	SOE ADDITIONS		C.M.	
8	84-08-17	AS BUILT		C.M.	
7	91-10-21	TL203 LINE PROTECTION MODIFICATIONS		D.C.M.	
6	91-04-26	TL207 LINE IMPROVEMENT		C.M.	
5	90-11-14	TL 206 IMPROVEMENT.		W.R.L	
14	00-11-21	REVISED AS BUILT	D.D.	LT	AYL
13	00-11-21	TL207 BACK-UP RROT. UPGRADE	D.D		
12	99-	TRANSCAN DFR ADDED		AYL	LT
11	99-	TL203 21P2 ADDED		AYL	LT

REVISIONS

ELECT. | CIVIL | TRANS. | MECH. — PASSED

REGISTERED PROFESSIONAL ENGINEER — P. H. MARTIN — PROVINCE OF NEWFOUNDLAND

NEWFOUNDLAND AND LABRADOR HYDRO

SUNNYSIDE TERMINAL STATION

230 KV BREAKER FAILURE PROTECTION

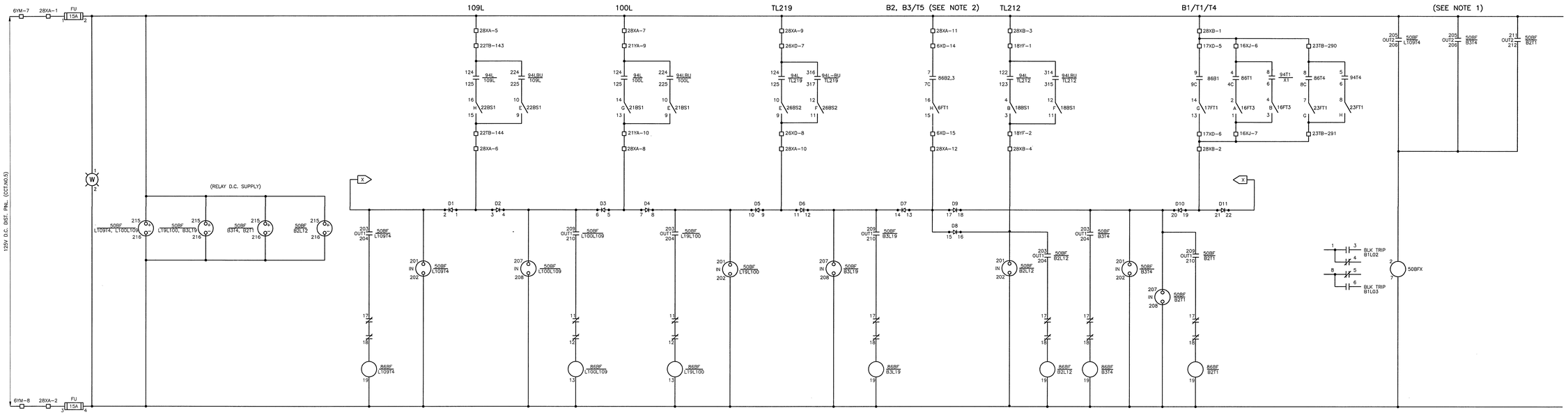
D.C. SCHEMATIC DIAGRAM

SCALE N.T.S.	DESIGNED LT	DRAWN G.W.	
CHECKED	APPROVED	DATE 84-04-15	
W.O. No.	DWG No. B1-302-E-122		REV 14

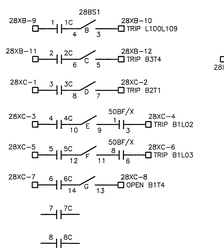
Transfer 003

DEVICE	DESCRIPTION	LOCATION	TYPE
50BF	BREAKER FAIL DUAL OVER CURRENT MONITORING RELAY – SEL	PNL 28	SEL–501
86BF	BREAKER FAIL LOCKOUT TRIP RELAY – GE	PNL 28	HEA–61C–240 OR HFA–61B–216
W	INCANDESCENT INDICATING LIGHT – GE	PNL 28	ET–16
D1 – 22	DIODE – 6A (IFM SURGE 400A, PRV 1000V)	PNL 28	ECG–5817
50BFX	OVER CURRENT MONITOR AUX. RELAY – P & B	PNL 28	KRP11DG–110
94L	TRIP RELAY – PRIMARY PROTECTION	PNL 21,22,26	ABB RXMS1
94LBU	TRIP RELAY – BACKUP PROTECTION	PNL 21,22,26	ABB RXMS1

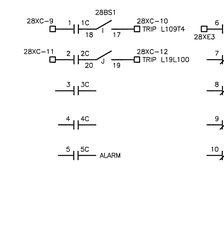
138kV BREAKER FAILURE PROTECTION CIRCUIT



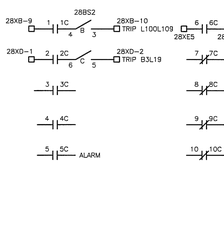
86BF / L109T4



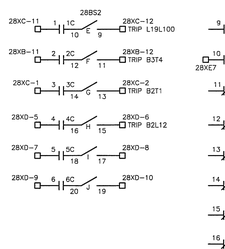
86BF / L100L109



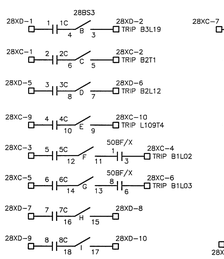
86BF / L19L100



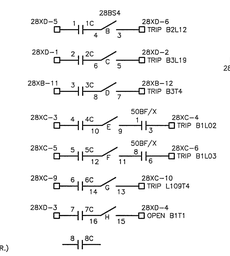
86BF / B3L19



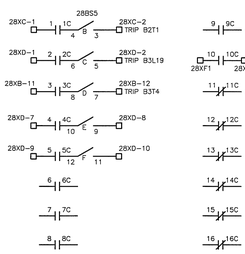
86BF / B3T4



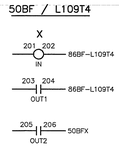
86BF / B2T1



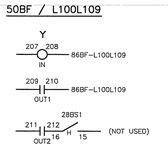
86BF / B2L12



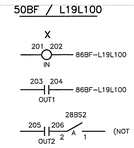
50BF / L109T4



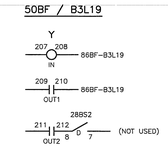
50BF / L100L109



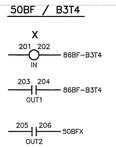
50BF / L19L100



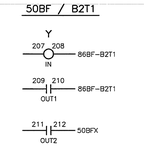
50BF / B3L19



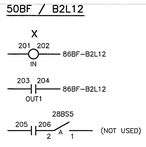
50BF / B3T4



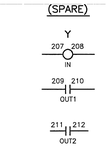
50BF / B2T1



50BF / B2L12



(SPARE)



TEMP. NOTE:

1. ALL SOE COMMON IN SJB #2 2TB5–27, –28 .

NOTE:

1. 50BF/L109T4, 50BF/B3T4, AND 50BF/B2T1 'OUT 2' ARE SET FOR RETRIP, BUT THEIR FUNCTIONS ARE TO BLOCK TRIP THE 230kV BREAKERS B1L02 OR B1L03, PERMITTING TO CLOSE BACK THE BREAKERS TO NORMAL, AFTER A 138kV BREAKER FAIL OPERATION OCCURRED.
2. T5 (NP) PROTECTION TRIPS VIA 86B2,3.

NOTICE:
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.

REFERENCE DRAWINGS

DWG.NO.	TITLE

REVISIONS

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
3	05–09–28	100L & 109L LINE PROTECTION UPGRADE	C.M.	AYL	PJB	
2	05–09–28	TL212 LINE PROTECTION UPGRADE	C.M.		PJB	
1	01–09–08	REVISED AS BUILT	W.B.	LT	AYL	
0	00–11–10	ISSUED FOR CONSTRUCTION	H.P.	LT	AYL	

REGISTERED PROFESSIONAL ENGINEER — PROVINCE OF NEWFOUNDLAND — L. T. TRAN — SIGNATURE — Nov.12,2000

ELECT.	SCALE:	N.T.S.
CIVIL	DESIGNED:	L. TRAN
TRANS.	DRAWN:	H. PARSONS
MECH.	DATE:	2000–08–09
P&C	CHECKED:	
TELC.	APPROVED:	

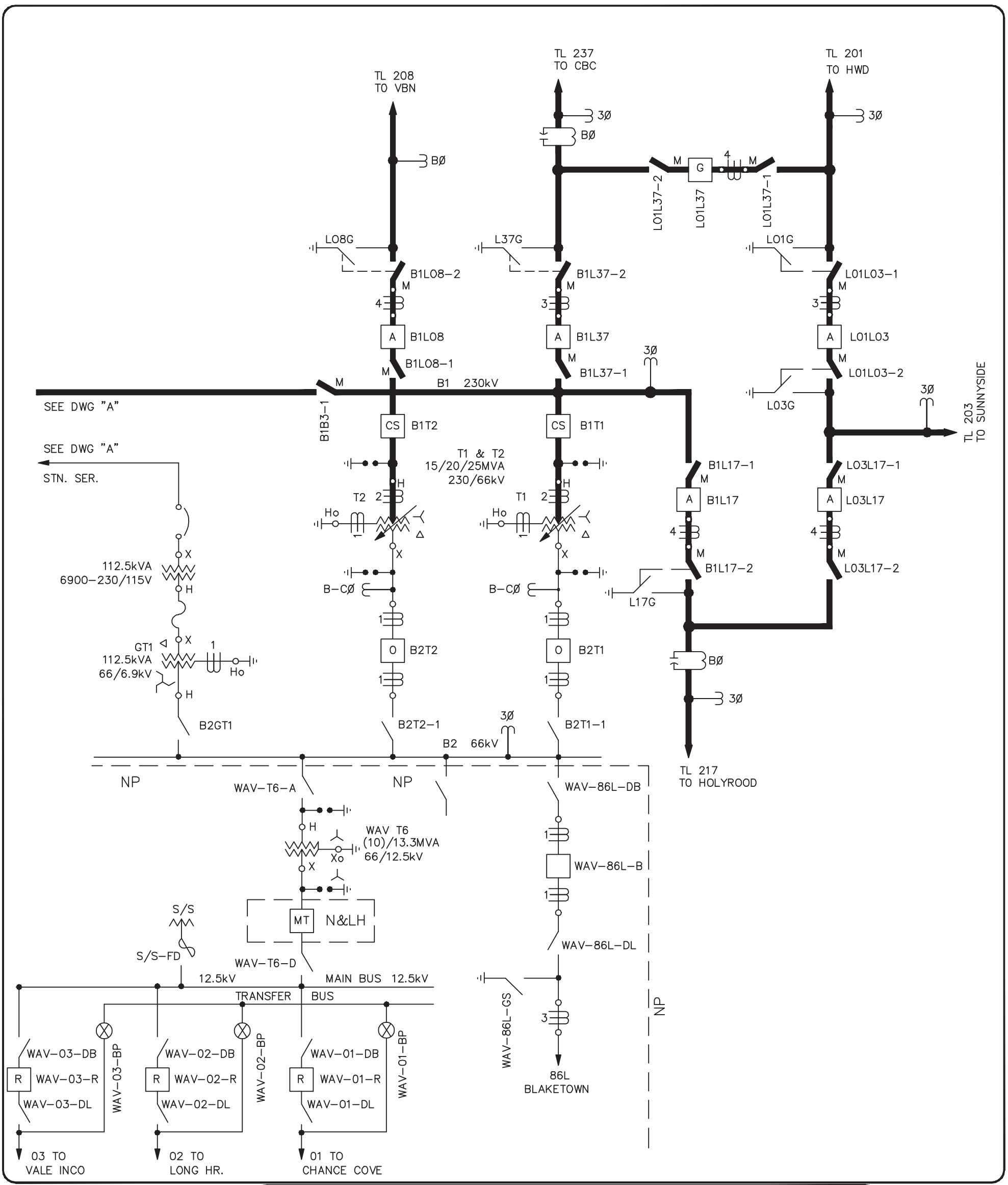
HYDRO — NEWFOUNDLAND AND LABRADOR HYDRO

SUNNYSIDE TERMINAL STATION
138kV BREAKER FAILURE
PROTECTION D.C. SCHEMATIC

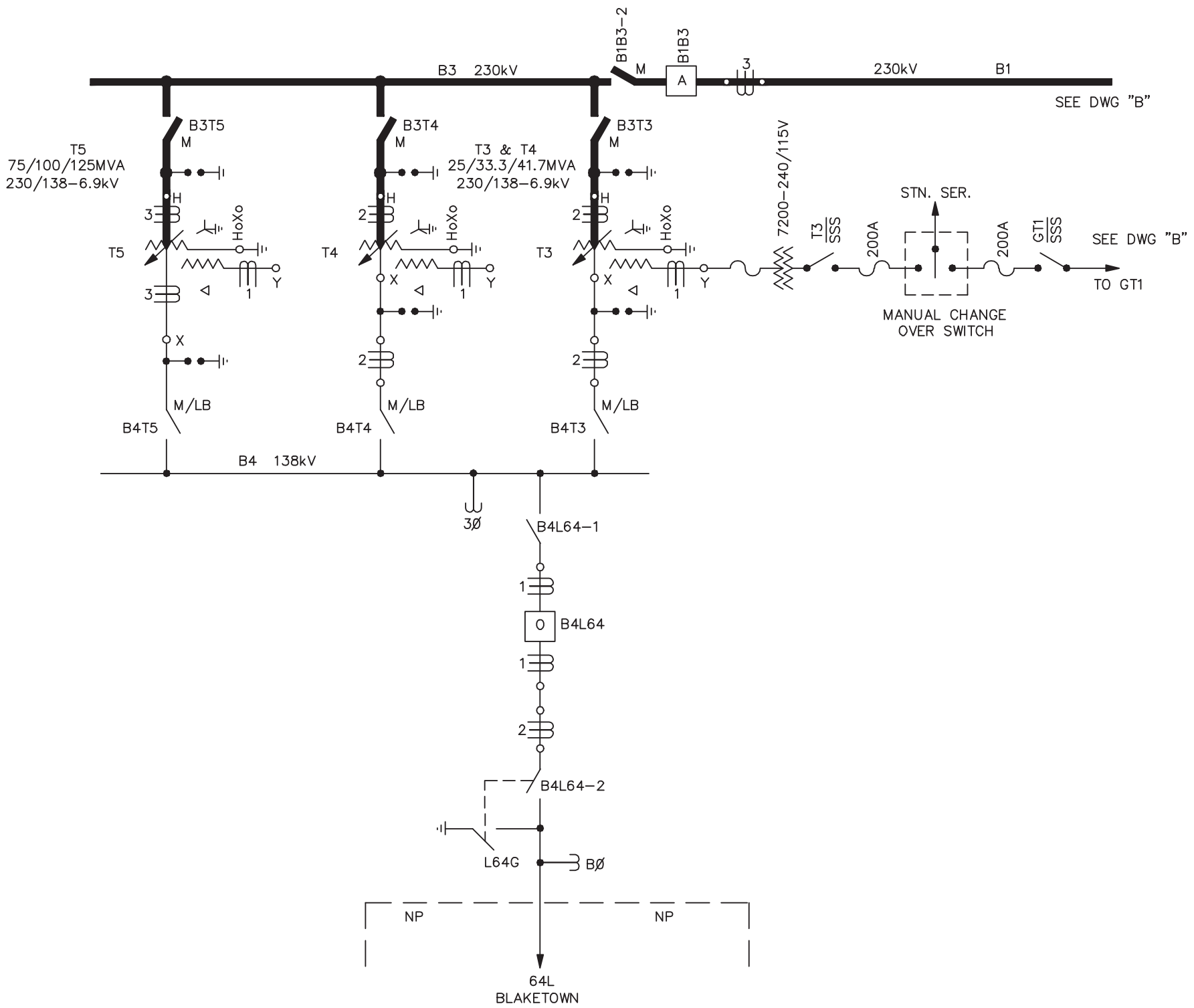
W.O. NO.

DWG. NO. A0 - 302 - E - 130 REV. 3

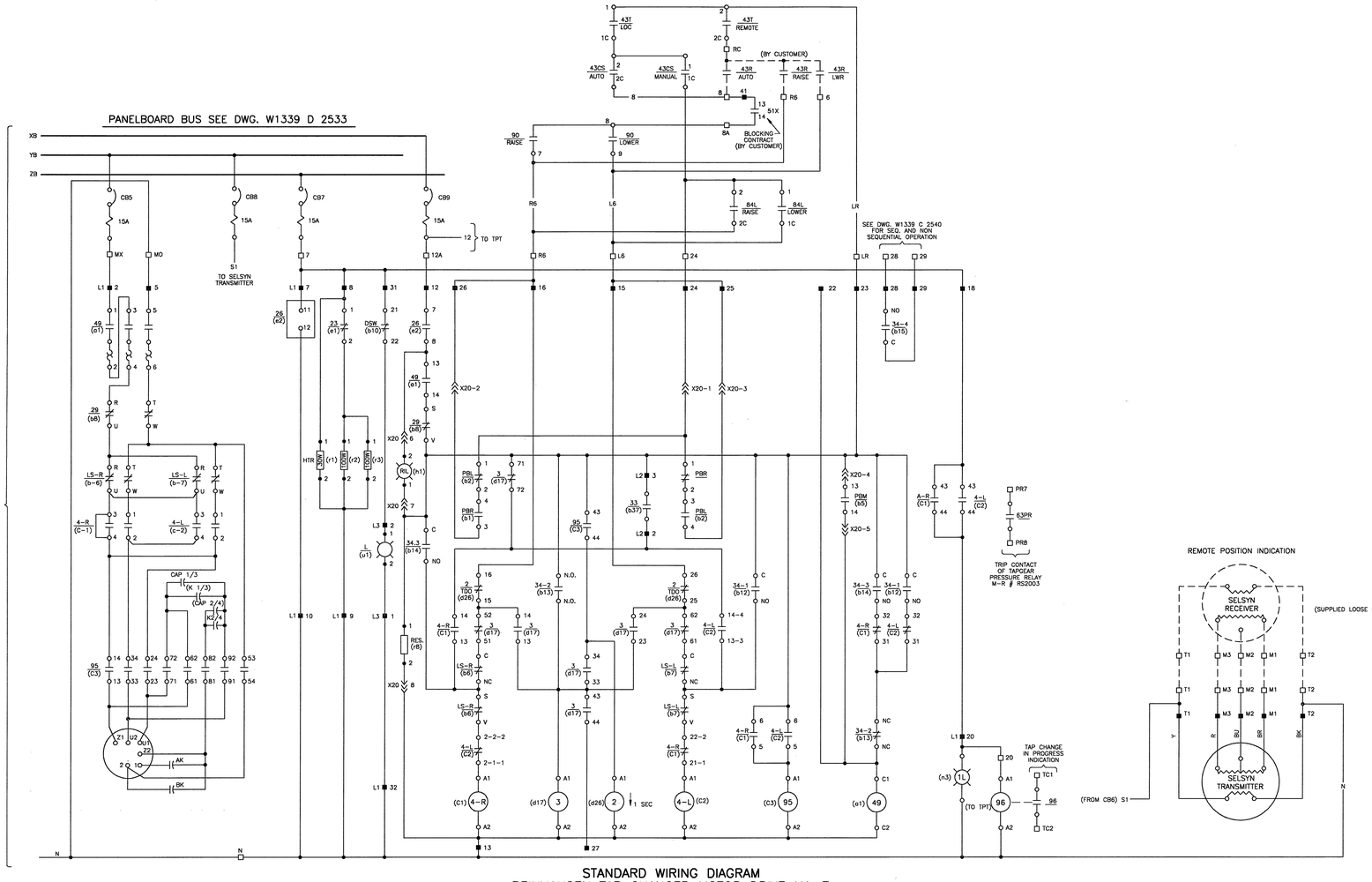
PLOT SCALE 1:1 C.A.D.



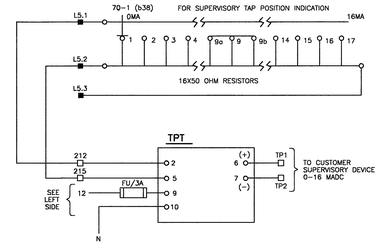
DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO WAV-B
APPROVED BY: G.B.		SYSTEM OPERATING DIAGRAM WESTERN AVALON TERMINAL STATION (B)	REV NO 15
DATE: 2012/06/12			

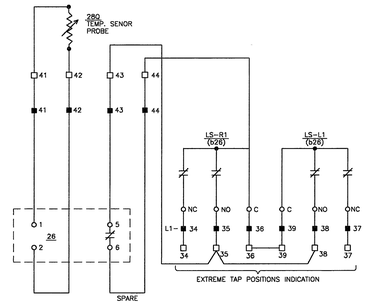


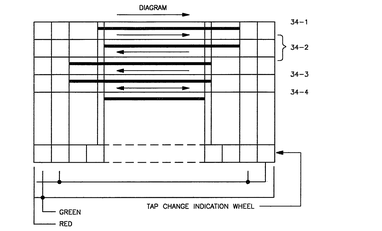
DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO WAV-A
APPROVED BY: R.S.		SYSTEM OPERATING DIAGRAM WESTERN AVALON TERMINAL STATION (A)	REV NO 6
DATE: 2010/04/29			



STANDARD WIRING DIAGRAM
REINHAUSEN TAP CHANGER MOTOR DRIVE MA-7
(FOR REFERENCE USE ONLY – REFER TO TRANSFORMER MANUAL FOR MORE DETAIL)

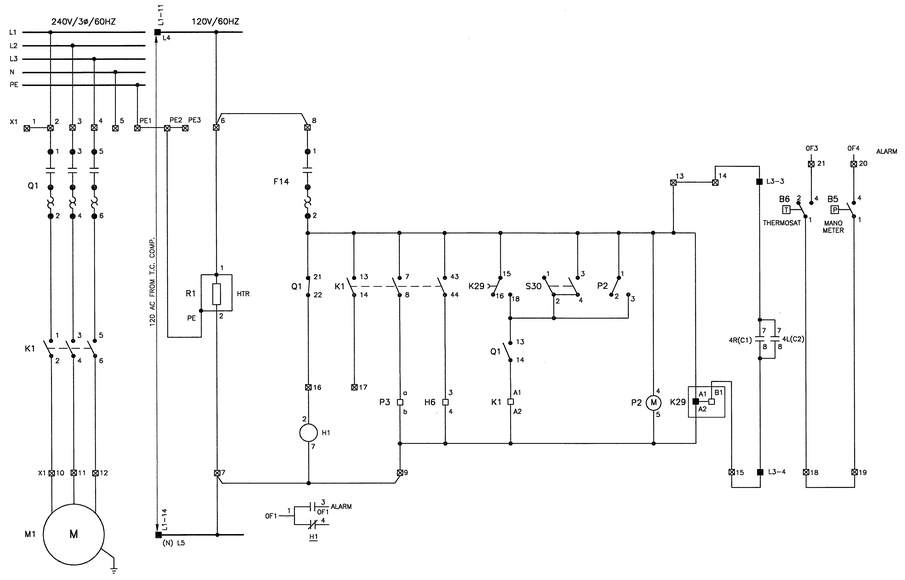




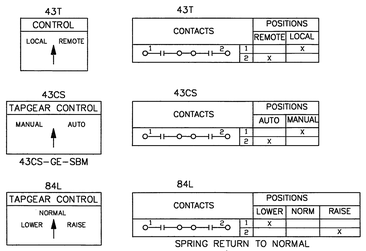


DEVICE NO.	DESCRIPTION (MOTOR CIRCUIT)
49	MOTOR PROTECTIVE SWITCH
PBR/L	OPERATING PUSH BUTTON RAISE/LOWER
PBM	PUSH BUTTON FOR TRIPPING MOTOR PROTECTIVE SWITCH
LS-R/L	POSITION LIMIT SWITCH WITH MICROSWITCH
29	SAFETY SWITCH FOR MANUAL OPERATION
DSW	DOOR CONTACT FOR HAND LAMP ON – OFF
34-1/3	CAM SWITCH OPERATES MICROSWITCH
34-2	CAM SWITCH OPERATES MICROSWITCH (STEP BY STEP)
34-4	CAM OPERATED CONTACT
33	POSITION PASSAGE CONTACT CLOSED ON POS. 9a,9b.
70-1	KPO ROW RESISTORS 16X50 OHM 1 WATT
4-R/L	MOTOR CONTACTOR RAISE/LOWER
95	BRAKE CONTACTOR FOR MOTOR OPERATING
3	AUX CONTACTOR FOR STEP BY STEP OPERATION
2	TIME RELAY OPENING RELAY DELAY 1 SEC.
23	THERMOSTAT FOR HEATERS
26Q	ELECTROSTATIC THERMO DEVICE
1L	TAPCHANGE IN PROGRESS LAMP
R1L	LAMP FOR SIGNALLING THE TRIPPING OF 49
88	DRIVING MOTOR 120VAC. 60HZ 0.75KW
HTR	HEATERS THERMOSTAT CONTROLLED 2X100W , 1X30W , 120VAC
RES	SERIES RESISTOR FOR RL
L	HAND LAMP PORTABLE SERVICE LIGHT
CAP 1/2	CONDENSERS FOR MOTOR BREAKING CIRCUIT
	AK – STARTING CONDENSER
	BK – SERVICE CONDENSER
TPT	TRANSDUCER CREWE CTH01 INPUT 0-800 OHM OUTPUT 0-16MADC 120VAC SUPPLY
RPI	REMOTE POSITION INDICATION SELSYN CGE 230123A1A 120VAC 60HZ
84L	SELECTOR SWITCH LOWER NORMAL RAISE GE SBM
90	VOLTAGE REGULATING RELAY BECKWITH No. M0067E
43	SELECTOR SWITCHES GE SBM
96,51X	AUXILIARY RELAY K-M DIL-OOL-22NA 120VAC COIL

DEVICE NO.	DESCRIPTION (FILTER CIRCUIT)
B5	MANOMETER, CLOSES ABOVE 3.3 BAR
B6	THERMOSTAT, OPENS BELOW 25° C
F14	AUTOMATIC CUT-OUT
H6	ELECTRICAL COUNTER
K1	MOTOR CONTACTOR FOR PUMP
K29	TIME RELAY
M1	MOTOR FOR PUMP
P2	TIME SWITCH
P3	SERVICE HOUR METER
Q1	MOTOR PROTECTIVE SWITCH
R1	HEATER
S30	SWITCH FOR PUMP-TEST
H1	P/B AUX RELAY



REINHAUSEN OIL FILTER TYPE 51



NOTES

- ■ – DENOTES TERMINAL BLOCKS IN TAPGEAR CONTROL BOX (MOTOR DRIVE MA-7)
- □ – DENOTES TERMINAL BLOCKS IN MAIN CONTROL BOX
- ››› – DENOTES PLUG TYPE TERMINALS
- ⊠ – DENOTES TERMINAL BLOCKS IN OIL FILTER CONTROL BOX (TYPE 51)

REFERENCE DRAWINGS			REVISIONS					
DWG.NO.	TITLE	NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
306-E-122	230/138kV TRANSFORMERS 3, 4 & 5 PARALLELING SCHEMATIC	1	97-02-05	"REVISED AS BUILT"	G.W.	A&B	AYC	

ARTHUR G. BURSEY
Licensed to Practice
PROFESSIONAL ENGINEER
NEWFOUNDLAND
97 June 05
Date
PROFESSIONAL ENGINEERS AND GEOSCIENTISTS

ELECT.	SCALE:	N.T.S.
CIVIL	DESIGNED:	A. BURSEY
TRANS.	DRAWN:	G.E.M.
MECH.	DATE:	1996-08-02
P&C	CHECKED:	
TELC.	APPROVED:	

HYDRO
NEWFOUNDLAND AND LABRADOR HYDRO

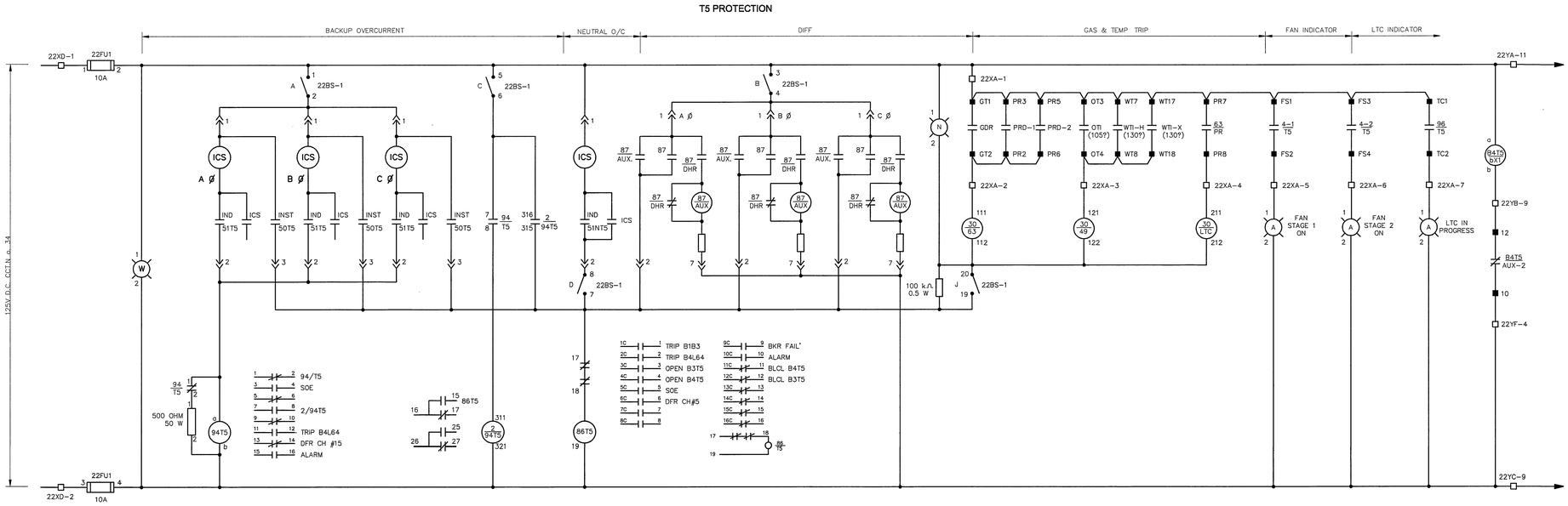
WESTERN AVALON TERMINAL STATION
T5 TAP CHANGER MOTOR AND FILTER CONTROL SCHEMATIC

W.O. NO.
DWG. NO. A0 – 306 – E – 21
REV. 1

PLOT SCALE 1:1 C.A.D.

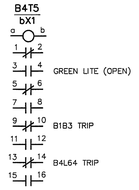
97-03-25

T5 PROTECTION

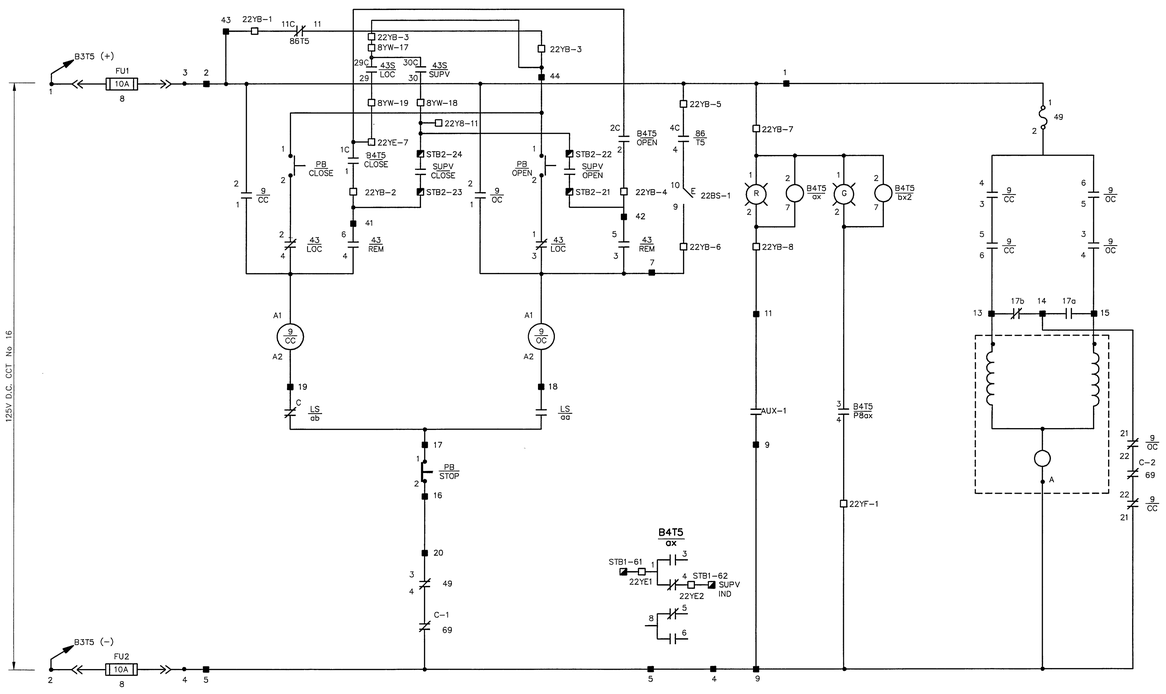


DEVICE	DESCRIPTION	LOCATION	TYPE
50/51 T5	O/C RELAY 1.5–12A IND, 10–8A INST. – CGE	PNL. 22	12IAC53BB11A
94/T5	TRIPPING RELAY – BBC	PNL. 22	P8nax
2/94T5	TIMER RELAY – ASEA RXKF1 – 0.2 – 3 SEC	PNL. 22	RK334 002–AN
51N/T5	NEUTRAL O/C RELAY 1.5–12A – CGE	PNL. 22	12IAC53AB03A
87/T5	DIFFERENTIAL RELAY – CGE	PNL. 22	12BDD15–B11A
30/63	TARGET RELAY 0.2A DC RATED CURRENT – ASEA RXSF–1	PNL. 22	RK271007–HB
30/49	"	PNL. 22	"
30/LTC	"	PNL. 22	"
86/T5	LOCKOUT RELAY – CGE	PNL. 22	HEA61C240
W,A	INDICATION LAMP – CGE ET–16	PNL. 22	169A8738G3
N	NEON LAMP – CGE ET–17	PNL. 22	169A8739G1
22BS–1	BLOCKING SWITCH – WESTINGHOUSE FT–1	PNL. 22	129A501G01
22BS–2	"	PNL. 22	"
B3T5/ax	AUXILLIARY RELAY – POTTER & BRUMFIELD	PNL. 22	KRP11DG
B4T5/ax,bX2	"	PNL. 22	"
B3T5,B4T5	CONTROL SWITCH – CGE	PNL. 22	SBM
B3T5,B4T5	"	PNL 22	"
49	MOTOR PROTECTIVE SWITCH	T5 CAB	
69	PERMISSIVE SWITCH	"	
9	REVERSING CONTACTOR	"	
B4T5/bX1	AUXILIARY RELAY – BBC	PNL. 22	P8nax

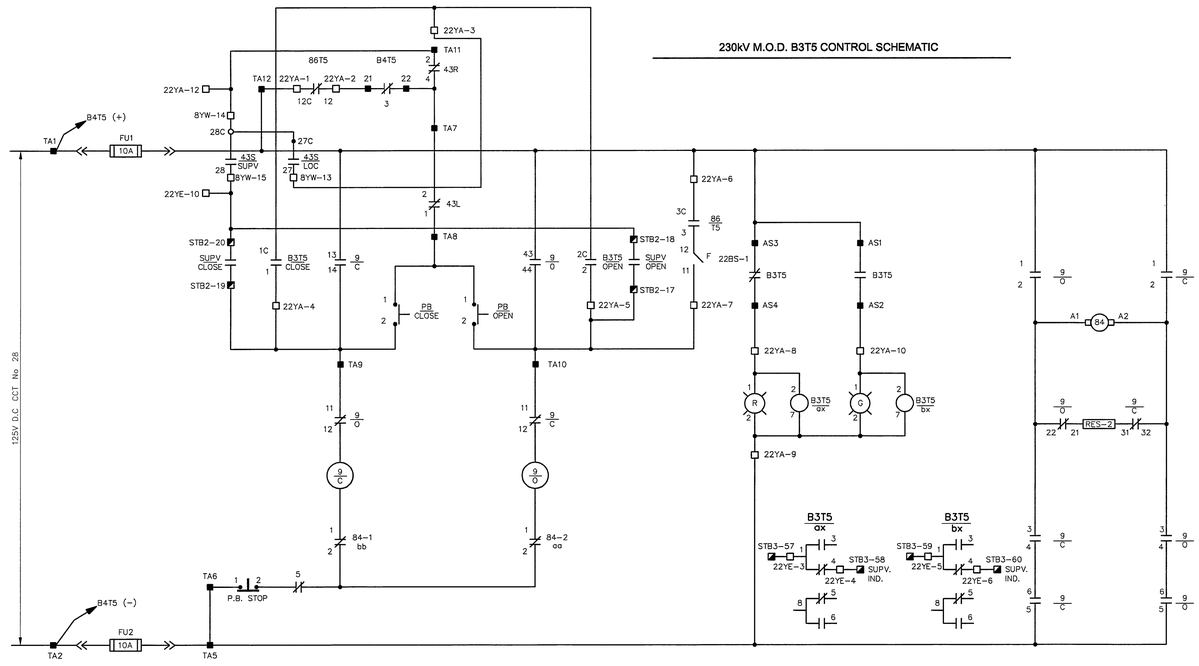
B4T5 bX1



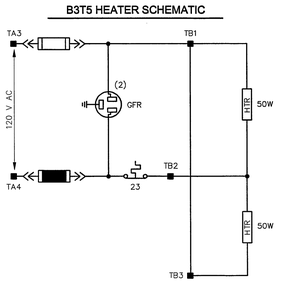
138KV LOAD BREAK SWITCH B4T5 CONTROL SCHEMATIC



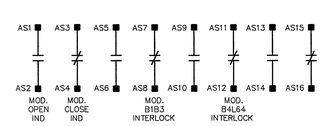
230kV M.O.D. B3T5 CONTROL SCHEMATIC



B3T5 HEATER SCHEMATIC



B3T5 AUX CONTACTS

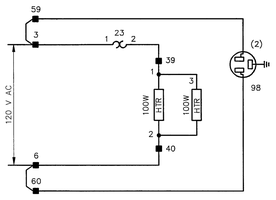


B3T5 MOD CONTROL SWITCH

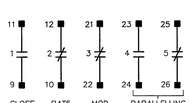
(SBM SPRING RETURN TO NORMAL, WITH TARGET)

CONTACTS HANDLE END		POSITION CLOSE	NORM	OPEN
1c	1	X		
2c	2			X
3c	3	X		
4c	4			X
5c	5	X		
6c	6			X

B4T5 HEATING SCHEMATIC



B4T5 AUX CONTACTS

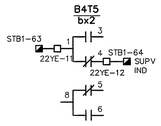


B4T5 LOAD BREAK CONTROL SWITCH

(SBM SPRING RETURN TO NORMAL, WITH TARGET)

CONTACTS HANDLE END		POSITION CLOSE	NORM	OPEN
1c	1	X		
2c	2			X
3c	3	X		
4c	4			X
5c	5	X		
6c	6			X

B4T5 bx2



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NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
6	01–11–03	RELOCATION OF M.O.D. AUX. IND. RELAYS. AS BUILT	C.M.			
5	98–09–14	REVISED "AS BUILT" FOR DFR REPLACEMENT	W.B.			
4	95–04–06	SOE ADDITIONS	W.B.			
3	94–05–05	AS BUILT	W.B.			
2	92–03–07	AS BUILT	W.B.			
1	91–05–02	T5 ADDED AND REVISED AS BUILT	G.E.M.			

REVISIONS

DWG.NO.	TITLE
B1–306–E–124	T5 A.C. SCHEMATIC

REFERENCE DRAWINGS

NEWFOUNDLAND AND LABRADOR HYDRO

ELECT.	
CIVIL	
TRANS.	
MECH.	
P&C	
TELC.	
SCALE:	N.T.S.
DESIGNED:	K.W.
DRAWN:	W.H./G.E.M.
DATE:	1989–05–01
CHECKED:	
APPROVED:	

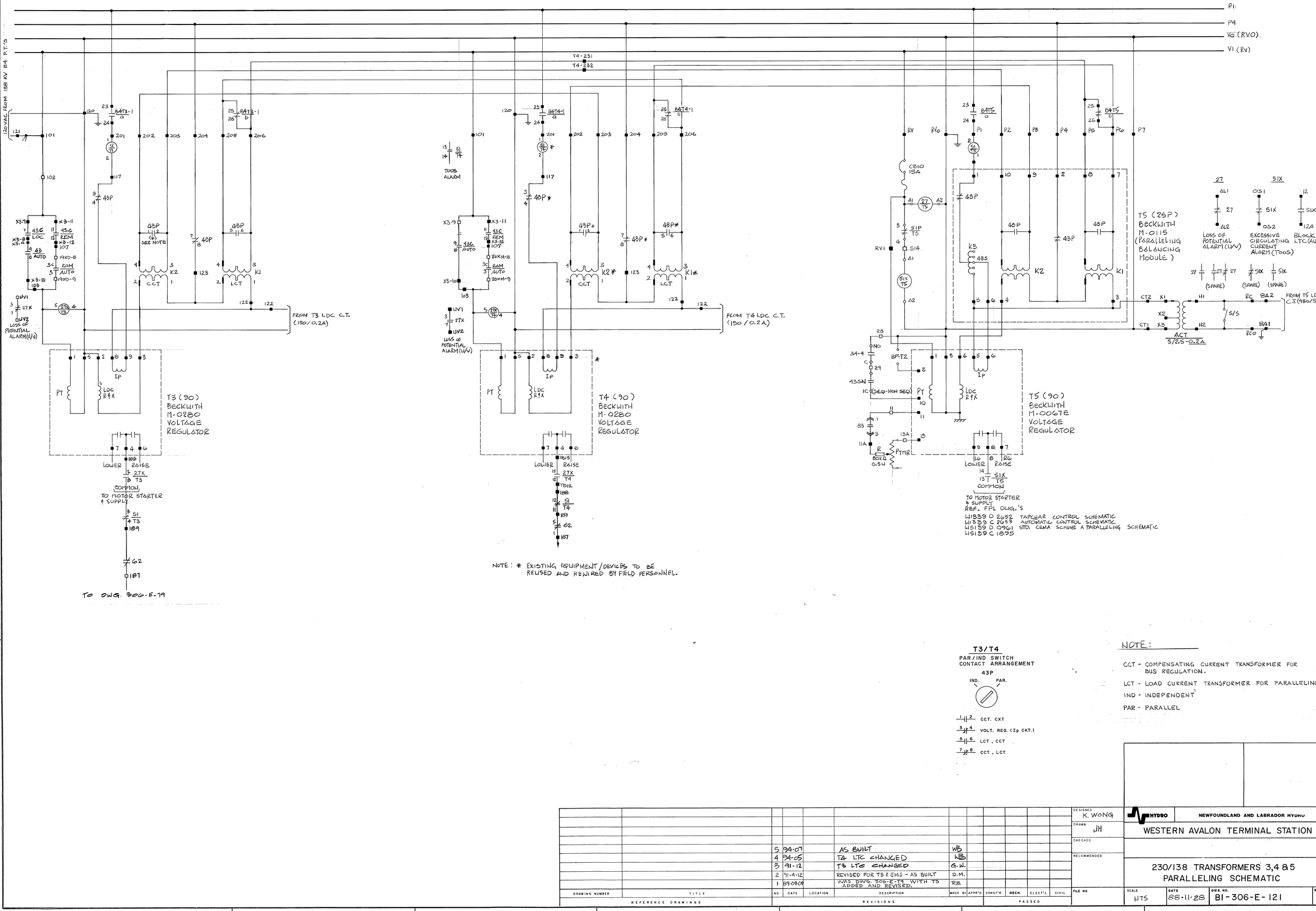
WESTERN AVALON TERMINAL STATION
T5 PROTECTION, 230kV B3T5 & 138kV B4T5 D.C. CONTROL SCHEMATICS

W.O. NO.

DWG. NO. B1- 306 - E - 120

REV. 6

PLOT SCALE 1:1 C.A.D.



T3/T4
PAR/IND SWITCH CONTACT ARRANGEMENT
43P

NOTE:

CCT - COMPENSATING CURRENT TRANSFORMER FOR BUS REGULATION.

LCT - LOAD CURRENT TRANSFORMER FOR PARALLELING.

IND - INDEPENDENT

PAR - PARALLEL

DRAWING NUMBER	TITLE	NO	DATE	LOCATION	DESCRIPTION	MADE BY	APPR'D
REFERENCE DRAWINGS		5	94-07		AS BUILT	WB	
		4	94-05		T4 LTC CHANGED	WB	
		3	91-12		T3 LTC CHANGED	G.W.	
		2	91-04-12		REVISED FOR T5 & EMS - AS BUILT	D.M.	
		1	89-09-01		WAS DWG. 306-E-79 WITH T5 ADDED AND REVISED.	RB	

CONST'N	MECH.	ELECT'L	CIVIL
PASSED			

DESIGNED K. WONG
DRAWN JH
CHECKED
RECOMMENDED
FILE NO

NEWFOUNDLAND AND LABRADOR HYDRO

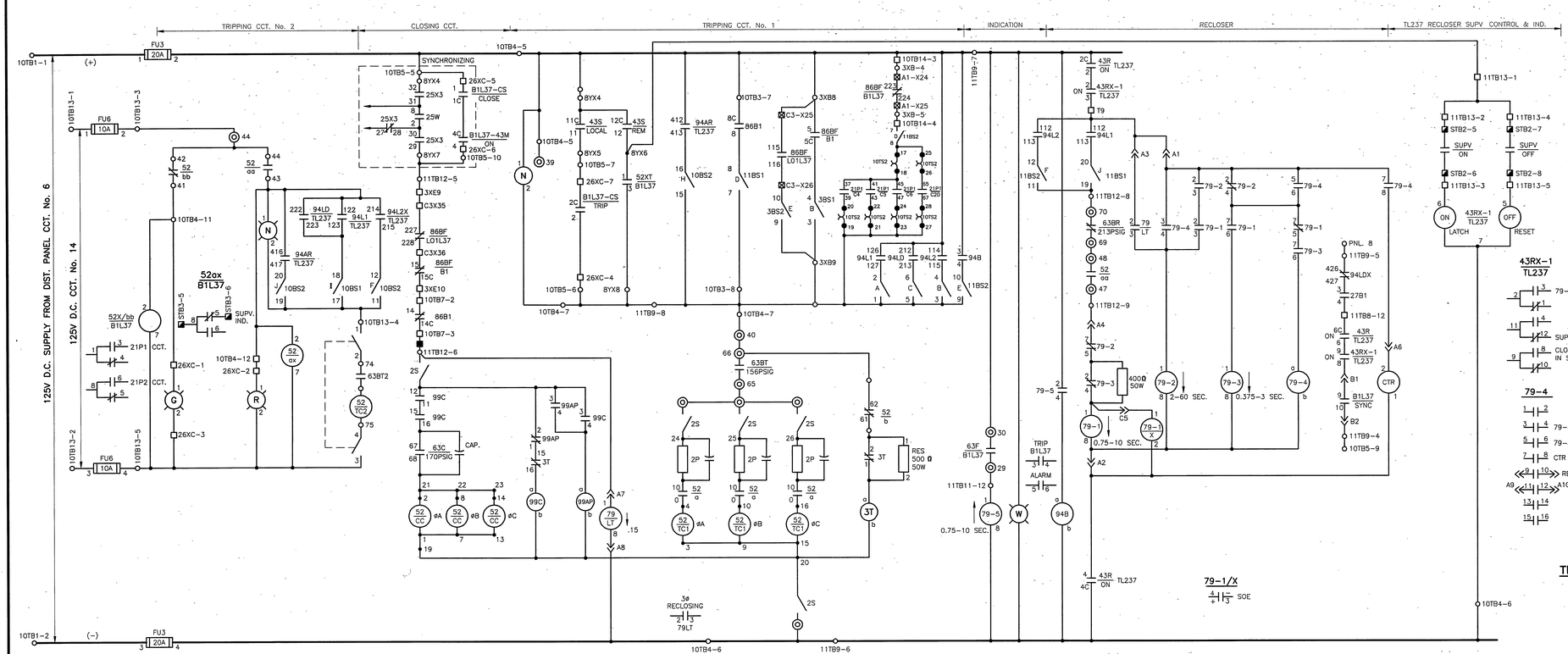
WESTERN AVALON TERMINAL STATION

230/138 TRANSFORMERS 3,4 & 5 PARALLELING SCHEMATIC

SCALE NTS | DATE 88-11-28 | DWG. NO. BI-306-E-121 | REV 5

NORMAN WADE

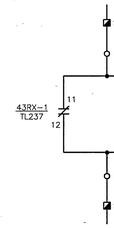
B1L37 CONTROL



DEVICE TABLE

DEVICE No.	DESCRIPTION AND FUNCTION	REFERENCE DRAWING	LOCATION	DEVICE TYPE
21P1	DISTANCE PROTECTION RELAY – PRIMARY No.1		PANEL No. 10	OPTIMHO – LFZP111
21P2	DISTANCE PROTECTION RELAY – PRIMARY No.2		PANEL No. 10	SEL–321–1
30TT1–TT2	TRANSFER TRIP RECEIVE TARGET RELAYS			RRSH
50	OVERCURRENT SUPERVISION RELAY			BCD
43TT	CARRIER SELECTOR SWITCH			SBM
43R	RECLOSER SELECTOR SWITCH			SBM
43S	LOCAL/REMOTE SWITCH (2 STACKS)	306–E–117	PANEL No. 8	SB–1 CGE
85–1	CAR. DIRECT TRANSFER TRIP		TL237 CAR. CAB.	
85–2	CAR. PERMISSIVE TRANSFER TRIP		TL237 CAR. CAB.	
94L1, L2, LD	AUXILIARY TRIP RELAYS		PANEL No. 11	ASEA – RXMS1
TS1–3	TEST BLOCKS		PANEL No. 10	GEC – MMLG
T3	TIME RELAY 0.3–2 SEC.			RRKH23
79–1	3ø RECLOSER AUX. RELAY			AGASTAT 2122 (0.75–10 SEC.)
79–2	3ø RECLOSER AUX. RELAY			AGASTAT 2122 (2–60 SEC.)
79–3	3ø RECLOSER AUX. RELAY			AGASTAT 2122 (0.375–3 SEC.)
79–4	3ø RECLOSER AUX. RELAY			B.B.–PB
79–LT	BLOCK RECLOSER RELAY			AGASTAT 2122 (0.15–1 SEC.)
K1	KIRK INTERLOCK			
25W	SYNC. RELAY		PANEL No. 8	
25X3	SYNC. AUX. RELAY			
50–51N	LINE BACK–UP GND. PROT. RELAY			IAC53
B1L37–CS	BREAKER CONTROL SWITCH			SBM
63BR	PRESSURE SWITCH RECLOSING INTERLOCK		230kV BKR.	
6EBT	PRESSURE SWITCH TRIPPING INTERLOCK		230kV BKR.	
63C	PRESSURE SWITCH CLOSING INTERLOCK		230kV BKR.	
86T1X	TRF. No. 1 PROT. LOCKOUT RELAY	306–E–34	PANEL No. 16	
CTR	COUNTER FOR 3ø RECLOSING			
79–5	TIMER FOR DISAGREEMENT TRIP			
94B	AUX.–TRIP RELAY			B.B–PB
63F	PNEUMATIC BACK–UP TRIP CONTACT		B1L37 BKR.	AGASTAT 2112 (0.75–10 SEC.)
86T2X	TRF. No. 2 PROT. LOCKOUT RELAY		PANEL No. 18	HEA
86B	BUS DIFF. LOCKOUT RELAY		PANEL No. 11	HEA
43RX–1	LATCH RELAY FOR RECLOSER SUPV. CONT.	THIS DRAWING	PANEL No. 11	S&D 255XCXP
43RX–2	AUX. RELAY FOR RECLOSER SUPV. IND.	THIS DRAWING	PANEL No. 11	P&B KRP11DG
3T	TRIP CHECK RELAY		B1L37 BKR.	B. BOV PB, 24 VDC
99C	BREAKER CLOSING RELAY		B1L37 BKR.	B. BOV PB, 125 VDC
99AP	BREAKER ANTI–PUMP RELAY		B1L37 BKR.	B. BOV PB, 125 VDC
94AR/TL237	AUX. RELAY FOR TL202/6 AUTO RESTORATION		PANEL No. 10	ASEA–RXMS1
27A,B,C/TL237	VOLTAGE RELAY FOR TL202/6 AUTO RESTORATION		PANEL No. 10	B. BOV PB, 125 VDC

TL237 RECLOSER IND. TO ECC



43RX–1 UNLATCHED OR 43R OFF
TL237 RECLOSER OFF INDICATION TO ECC

BREAKER CONTROL SWITCH

B1L37–CS: TRIP / CLOSE

CONTACTS HANDLE END		POSITIONS		
		CLOSE	NORMAL	TRIP
1 1C 2C 2	1	X		
	2			X
3 3C 4C 4	3	X		
	4			X
5 5C 6C 6	1	X		
	2			X
7 7C 8C 8	3	X		
	4			X

TARGET TYPE WITH PISTOL GRIP HANDLE
SPRING RETURN TO NORMAL POSITION

RECLOSER SWITCH

43R: OFF / ON

CONTACTS HANDLE END		POSITION	
		ON	OFF
1 1C 2C 2	1		X
	2	X	
3 3C 4C 4	3		X
	4	X	
5 5C 6C 6	5		X
	6	X	
7 7C 8C 8	7		X
	8	X	

OVAL HANDLE
MAINTAINED CONTACTS

X CLOSED CONTACT

TRANSFER TRIP SWITCH

43TT: OFF / ON

CONTACTS HANDLE END		IND. POS. OFF	IND. POS. ON	FUNCTION
1 1C 2C 2	1		X	
	2	X		21P1 & DIRECT T.T. RECEIVED
3 3C 4C 4	3		X	
	4	X		PERM. T.T. SEND
5 5C 6C 6	5		X	
	6	X		21P2 T.T. RECEIVED
7 7C 8C 8	7		X	ALARM
	8	X		

OVAL HANDLE
MAINTAINED CONTACTS

X CLOSED CONTACT

NOTES :

1. BREAKER PRESSURE SWITCHES SHOWN AT NORMAL OPERATING PRESSURE.
2. ■ DENOTES TERMINALS AT OPTIMHO DISTANCE RELAY CASE

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DWG.NO.	TITLE
REFERENCE DRAWINGS	

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
33	07–07–12	REVISED AS BUILT	W.B.	F. REV.	RL	RL
32	01–11–03	TL237 BACKUP PROTECTION UPGRADE/AS BUILT	W.B.	AVL		
31	98–09–02	REVISED "AS BUILT" FOR DFR REPLACEMENT	W.B.			
30	97–11–06	TL202/6 AUTO RESTORATION ADDITIONS	G.E.M.			
29	95–03–31	SOE ADDITIONS	W.B.			
28	94–04–14	ANTI–PUMP/CLOSED ADDED TO B1L37/AS BUILT	W.B.			
27	93–09–18	RING BUS MODS 1	K.B.R.			

REVISIONS

ELECT.	SCALE: NONE
CIVIL	DESIGNED: J. FOLEY
TRANS.	DRAWN: D. MONTAGUE
MECH.	DATE: 1991–04–12
P&C	CHECKED:
TELC.	APPROVED:

NEWFOUNDLAND AND LABRADOR HYDRO

WESTERN AVALON TERMINAL STATION
230kV ABCB B1L37 CONTROL SCHEMATIC

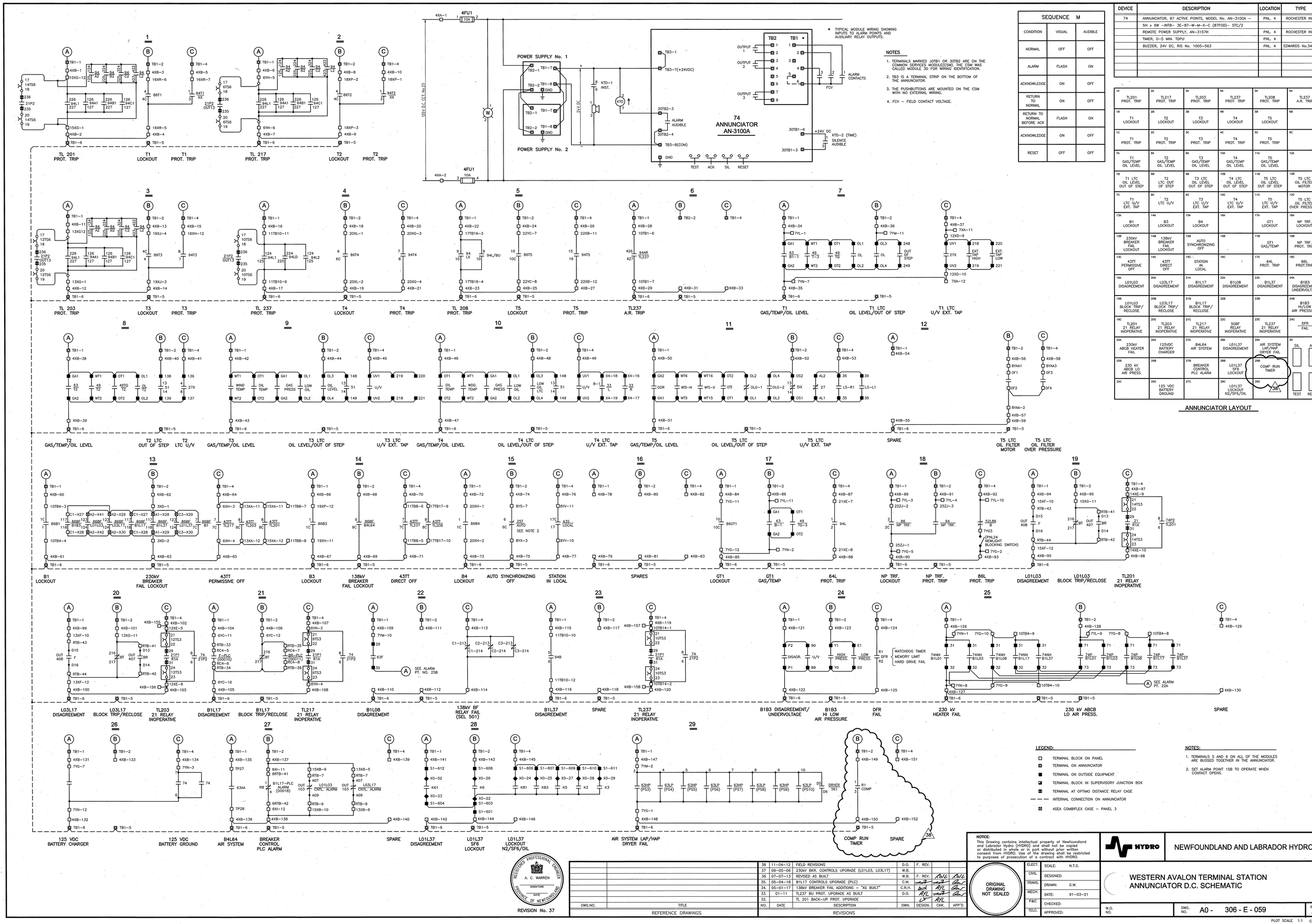
W.O. NO.

DWG. NO. B1- 306 - E - 018

REV. 33

PLOT SCALE 1:1 C.A.D.

Feb 05, 2008 – 4:02pm



SEQUENCE M		
CONDITION	VISUAL	AUDIBLE
NORMAL	OFF	OFF
ALARM	FLASH	ON
ACKNOWLEDGE	ON	OFF
RETURN TO NORMAL	ON	OFF
RETURN TO NORMAL BEFORE ACK	FLASH	ON
ACKNOWLEDGE	ON	OFF
RESET	OFF	OFF

NOTES

1. TERMINALS MARKED 30TB1 OR 30TB2 ARE ON THE COMMON SERVICES MODULE(CSM). THE CSM WAS CALLED MODULE 30 FOR WIRING IDENTIFICATION.
2. TB3 IS A TERMINAL STRIP ON THE BOTTOM OF THE ANNUNCIATOR.
3. THE PUSHBUTTONS ARE MOUNTED ON THE CSM WITH NO EXTERNAL WIRING.
4. FCV – FIELD CONTACT VOLTAGE.

DEVICE	DESCRIPTION	LOCATION	TYPE
74	ANNUNCIATOR, 87 ACTIVE POINTS, MODEL No. AN–3100A –	PNL. 4	ROCHESTER INST.
	5H x 6W –INTB– 3E–87–W–M–X–C (B7F0D)– STC/2		
	REMOTE POWER SUPPLY, AN–3157H	PNL. 4	ROCHESTER INST.
	TIMER, 0–5 MIN. TDPU	PNL. 4	
	BUZZER, 24V DC, RIS No. 1005–563	PNL. 4	EDWARDS No.343–A

1A TL201 PROT. TRIP	2A TL217 PROT. TRIP	3A TL203 PROT. TRIP	4A TL237 PROT. TRIP	5A TL208 PROT. TRIP	6A TL237 A.R. TRIP	
1B T1 LOCKOUT	2B T2 LOCKOUT	3B T3 LOCKOUT	4B T4 LOCKOUT	5B T5 LOCKOUT	6B	
1C T1 PROT. TRIP	2C T2 PROT. TRIP	3C T3 PROT. TRIP	4C T4 PROT. TRIP	5C T5 PROT. TRIP	6C	
7A T1 GAS/TEMP OIL LEVEL	8A T2 GAS/TEMP OIL LEVEL	9A T3 GAS/TEMP OIL LEVEL	10A T4 GAS/TEMP OIL LEVEL	11A T5 GAS/TEMP OIL LEVEL	12A	
7B T1 LTC OIL LEVEL OUT OF STEP	8B T2 LTC OUT OF STEP	9B T3 LTC OIL LEVEL OUT OF STEP	10B T4 LTC OIL LEVEL OUT OF STEP	11B T5 LTC OIL LEVEL OUT OF STEP	12B T5 LTC OIL FILTER MOTOR	
7C T1 LTC U/V EXT. TAP	8C T2 LTC U/V	9C T3 LTC U/V EXT. TAP	10C T4 LTC U/V EXT. TAP	11C T5 LTC U/V EXT. TAP	12C T5 LTC OIL FILTER OVER PRESSURE	
13A B1 LOCKOUT	14A B3 LOCKOUT	15A B4 LOCKOUT	16A	17A GT1 LOCKOUT	18A NP TRF. LOCKOUT	
13B 230kV BREAKER FAIL LOCKOUT	14B 138kV BREAKER FAIL LOCKOUT	15B AUTO SYNCHRONIZING OFF	16B	17B GT1 GAS/TEMP	18B NP TRF. PROT. TRIP	
13C 43TT PERMISSIVE OFF	14C 43TT DIRECT OFF	15C STATION IN LOCAL	16C	17C 64L PROT. TRIP	18C 86L PROT.TRIP	
19A L01L03 DISAGREEMENT	20A L03L17 DISAGREEMENT	21A B1L17 DISAGREEMENT	22A B1L08 DISAGREEMENT	23A B1L37 DISAGREEMENT	24A B1B3 DISAGREEMENT UNDERVOLTAGE	
19B L01L03 BLOCK TRIP/ RECLOSE	20B L03L17 BLOCK TRIP/ RECLOSE	21B B1L17 BLOCK TRIP/ RECLOSE	22B	23B	24B B1B3 HI/LOW AIR PRESSURE	
19C TL201 21 RELAY INOPERATIVE	20C TL203 21 RELAY INOPERATIVE	21C TL217 21 RELAY INOPERATIVE	22C 50BF RELAY INOPERATIVE	23C TL237 21 RELAY INOPERATIVE	24C DFR FAIL	
25A 230kV ABCB HEATER FAIL	26A 125VDC BATTERY CHARGER	27A B4L64 AIR SYSTEM	28A L01L37 DISAGREEMENT	29A AIR SYSTEM LAP/HAP DRYER FAIL	30 SIL ACK	
25B 230 kV ABCB LO AIR PRESS.	26B	27B BREAKER CONTROL PLC ALARM	28B L01L37 SF6 LOCKOUT	29B COMP RUN TIMER	TEST RESET	
25C	26C 125 VDC BATTERY GROUND	27C	28C L01L37 LOCKOUT N2/SF6/OIL	29C 38		

ANNUNCIATOR LAYOUT

LEGEND:

- TERMINAL BLOCK ON PANEL
- TERMINAL ON ANNUNCIATOR
- TERMINAL ON OUTSIDE EQUIPMENT
- TERMINAL BLOCK IN SUPERVISORY JUNCTION BOX
- TERMINAL AT OPTIMO DISTANCE RELAY CASE
- INTERNAL CONNECTION ON ANNUNCIATOR
- ASEA COMBIFLEX CASE – PANEL 3

NOTES:

1. TERMINALS 5 AND 6 ON ALL OF THE MODULES ARE BUSSED TOGETHER IN THE ANNUNCIATOR.
2. SET ALARM POINT 15B TO OPERATE WHEN CONTACT OPENS.

REVISION No. 37

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
38	11–04–12	FIELD REVISIONS	D.O.	F. REV.		
37	09–05–06	230kV BKR. CONTROLS UPGRADE (L01L03, L03L17)	W.B.			
36	07–07–13	REVISED AS BUILT	W.B.	F. REV.		
35.	05–04–18	B1L17 CONTROLS UPGRADE (PLC)	C.M.			
34.	05–01–17	138kV BREAKER FAIL ADDITIONS – "AS BUILT"	C.R.H.			
33.	01–11	TL237 BU PROT. UPGRADE AS BUILT	D.O.			
32.		TL 201 BACK–UP PROT. UPGRADE				

REVISIONS

REFERENCE DRAWINGS

DWG.NO. TITLE

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ORIGINAL DRAWING NOT SEALED

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

WESTERN AVALON TERMINAL STATION
ANNUNCIATOR D.C. SCHEMATIC

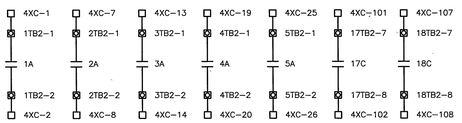
ELECT.	SCALE: N.T.S.
CIVIL	DESIGNED:
TRANS.	DRAWN: G.W.
MECH.	DATE: 91–03–21
P&C	CHECKED:
TELC.	APPROVED:

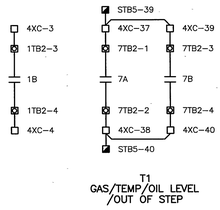
W.O. NO.

DWG. NO. A0 - 306 - E - 059

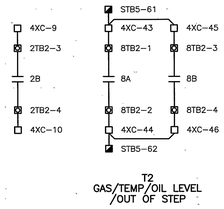
REV. 38

PLOT SCALE 1:1 C.A.D.

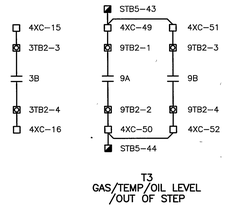




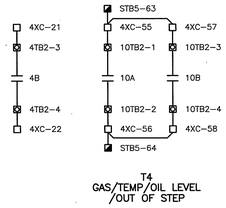
T1
GAS/TEMP/OIL LEVEL
/OUT OF STEP



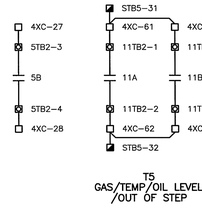
T2
GAS/TEMP/OIL LEVEL
/OUT OF STEP



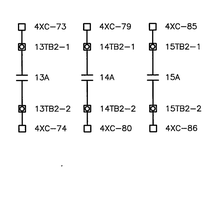
T3
GAS/TEMP/OIL LEVEL
/OUT OF STEP

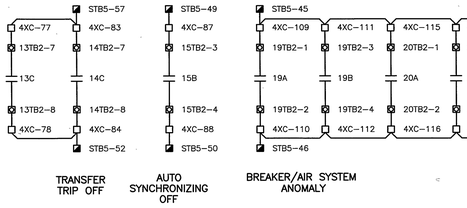


T4
GAS/TEMP/OIL LEVEL
/OUT OF STEP



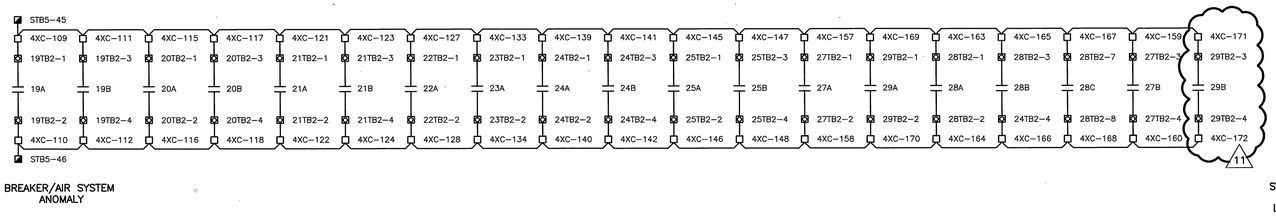
T5
GAS/TEMP/OIL LEVEL
/OUT OF STEP



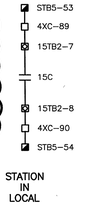


TRANSFER
TRIP OFF

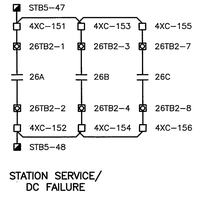
AUTO
SYNCHRONIZING
OFF



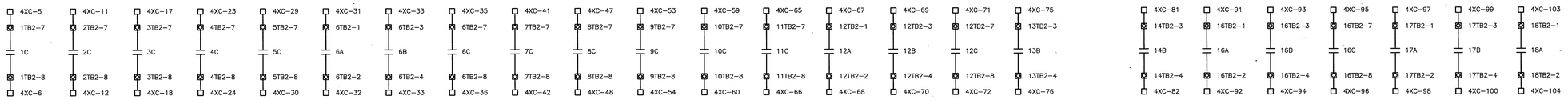
BREAKER/AIR SYSTEM
ANOMALY

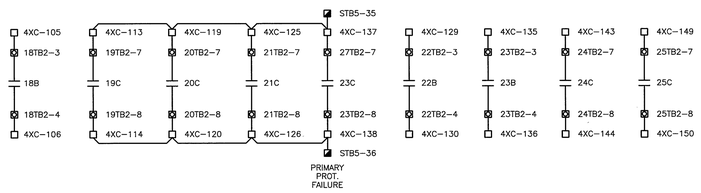


STATION
IN
LOCAL

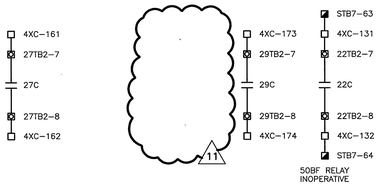


STATION SERVICE/
DC FAILURE





PRIMARY
PROT.
FAILURE



50BF RELAY
INOPERATIVE

POINT	ANNUNCIATOR POINT DESCRIPTION	SUPERVISORY ALARM DESCRIPTION
1A	TL 201 PROT. TRIP	
1B	T1 LOCKOUT	
1C	T1 PROT. TRIP	
2A	TL 217 PROT. TRIP	
2B	T2 LOCKOUT	
2C	T2 PROT. TRIP	
3A	TL 203 PROT. TRIP	
3B	T3 LOCKOUT	
3C	T3 PROT. TRIP	
4A	TL 237 PROT. TRIP	
4B	T4 LOCKOUT	
4C	T4 PROT. TRIP	
5A	TL 208 PROT. TRIP	
5B	T5 LOCKOUT	
5C	T5 PROT. TRIP	
6A	TL237 AR TRIP	
6B		
6C		
7A	T1 GAS/TEMP/OIL LEVEL	T1 GAS/TEMP/OIL LEVEL/OUT OF STEP
7B	T1 LTC OIL LEVEL/OUT OF STEP	T1 GAS/TEMP/OIL LEVEL/OUT OF STEP
7C	T1 LTC U/V EXT. TAP	–
8A	T2 GAS/TEMP/OIL LEVEL	T2 GAS/TEMP/OIL LEVEL/OUT OF STEP
8B	T2 LTC OUT OF STEP	T2 GAS/TEMP/OIL LEVEL/OUT OF STEP
8C	T2 LTC U/V	–
9A	T3 GAS/TEMP/OIL LEVEL	T3 GAS/TEMP/OIL LEVEL/OUT OF STEP
9B	T3 LTC OIL LEVEL/OUT OF STEP	T3 GAS/TEMP/OIL LEVEL/OUT OF STEP
9C	T3 LTC U/V, EXT. TAP	–
10A	T4 GAS/TEMP/OIL LEVEL	T4 GAS/TEMP/OIL LEVEL/OUT OF STEP
10B	T4 LTC OIL LEVEL/OUT OF STEP	T4 GAS/TEMP/OIL LEVEL/OUT OF STEP
10C	T4 LTC U/V, EXT. TAP	–
11A	T5 GAS/TEMP/OIL/ LEVEL	T5 GAS/TEMP/OIL LEVEL/OUT OF STEP
11B	T5 LTC OIL LEVEL/OUT OF STEP	T5 GAS/TEMP/OIL LEVEL/OUT OF STEP
11C	T5 LTC U/V, EXT. TAP	–
12A	SPARE	
12B	SPARE	–
12C	SPARE	–
13A	B1 LOCKOUT	
13B	BREAKER FAIL LOCKOUT	–
13C	43TT PERMISSIVE OFF	–
14A	B3 LOCKOUT	
14B	SERVICE RESTORER LOCKOUT	–
14C	43TT DIRECT OFF	TRANSFER TRIP OFF
15A	B4 LOCKOUT	
15B	AUTO SYNCHRONIZING OFF	AUTO SYNCHRONIZING OFF
15C	STATION IN LOCAL	STATION IN LOCAL
16A	SPARE	–
16B	SPARE	–
16C	SPARE	–
17A	GT1 LOCKOUT	–
17B	GT1 GAS/TEMP	–
17C	64L PROT. TRIP	
18A	NP TRF. LOCKOUT	–
18B	NP TRF. PROT. TRIP	–
18C	86L PROT. TRIP	
19A	L01L03 DISAGREEMENT	BREAKER/AIR SYSTEM ANOMALY
19B	L01L03 BLOCK TRIP/RECLOSE	BREAKER/AIR SYSTEM ANOMALY
19C	TL201 RELAY 21 INOPERATIVE	PRIMARY PROTECTION FAILURE
20A	L03L17 DISAGREEMENT	BREAKER/AIR SYSTEM ANOMALY
20B	L03L17 BLOCK TRIP/RECLOSE	BREAKER/AIR SYSTEM ANOMALY
20C	TL203 RELAY 21 INOPERATIVE	PRIMARY PROTECTION FAILURE
21A	B1L17 DISAGREEMENT	BREAKER/AIR SYSTEM ANOMALY
21B	B1L17 BLOCK TRIP/RECLOSE	BREAKER/AIR SYSTEM ANOMALY
21C	TL217 RELAY 21 INOPERATIVE	PRIMARY PROTECTION FAILURE
22A	B1L08 DISAGREEMENT	BREAKER/AIR SYSTEM ANOMALY
22B	SPARE	–
22C	SPARE	–
23A	B1L37 DISAGREEMENT	BREAKER/AIR SYSTEM ANOMALY
23B	SPARE	–
23C	TL237 RELAY 21 INOPERATIVE	PRIMARY PROTECTION FAILURE
24A	B1B3 DISAGREEMENT, UNDERVOLTAGE	BREAKER/AIR SYSTEM ANOMALY
24B	B1B3 HI/LOW AIR PRESSURE	BREAKER/AIR SYSTEM ANOMALY
24C	HATHAWAY RECORDER	–
25A	230KV ABCB HEATER FAIL	BREAKER/AIR SYSTEM ANOMALY
25B	230KV ABCB LO AIR PRESS.	BREAKER/AIR SYSTEM ANOMALY
25C	SPARE	–
26A	125VDC BATTERY CHARGER	STATION SERVICE/DC FAILURE
26B	125V DC CB OPEN	STATION SERVICE/DC FAILURE
26C	125V DC BATTERY GROUND	STATION SERVICE/DC FAILURE
27A	B4L64 AIR SYSTEM	BREAKER/AIR SYSTEM ANOMALY
27B	BREAKER CONTROL PLC ALARM	BREAKER/AIR SYSTEM ANOMALY
27C	SPARE	–
28A	L01L37 DISAGREEMENT	–
28B	L01L37 SF6 LOCKOUT	–
28C	L01L37 N2/SF6/OIL LOCKOUT	–
29A	AIR SYSTEM LAP/HAP DRYER FAIL	BREAKER/AIR SYSTEM ANOMALY
11 29B	COMP RUN TIMER	BREAKER/AIR SYSTEM ANOMALY
29C		

L E G E N D :

- ◪ — TERMINAL BLOCK IN SUPERVISORY JUNCTION BOX
- □ — TERMINAL BLOCK ON CONTROL PANEL
- ⊠ — TERMINAL ON BACK OF ANNUNCIATOR

REGISTERED PROFESSIONAL ENGINEER
A. C. WARREN
SIGNATURE
DATE
PROVINCE OF NEWFOUNDLAND

REVISION No. 10

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
11	11-04-12	FIELD REVISIONS	D.O.	F. REV.		
10	09-05-14	230kV BKR. CONTROLS UPGRADE (L01L03, L03L17)	W.B.			
9	05-04-19	B1L17 CONTROLS UPGRADE (PLC)	C.M.			
8	00-05-27	REVISED "AS BUILT"	G.W.			
7	00-05-27	TL203 & TL217 BACKUP PROTECTION MOD.	G.W.			
6	95-04-06	REMOVED REM. LOCKOUT & LINE PROT. TRIPS (SOE)	W.B.			
5	94-05-05	AS BUILT	W.B.			

REVISIONS

DWG.NO.	TITLE
A0-306-E-69	ANNUNCIATOR PANEL NO. 4 WIRING DIAGRAM
A0-306-E-67	SUPERVISORY JUNCTION BOX WIRING DIAGRAM

REFERENCE DRAWINGS

NOTICE:
This Drawing contains intellectual property of Newfoundland and Labrador Hydro (HYDRO) and shall not be copied or distributed in whole or in part without prior written consent from HYDRO. Use of the drawing shall be restricted to purposes of prosecution of a contract with HYDRO.

ORIGINAL
DRAWING
NOT SEALED

ELECT.	SCALE:	N.T.S.
CIVIL	DESIGNED:	R.L.
TRANS.	DRAWN:	W.B.
MECH.	DATE:	1991-03-01
P&C	CHECKED:	
TELC.	APPROVED:	

HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

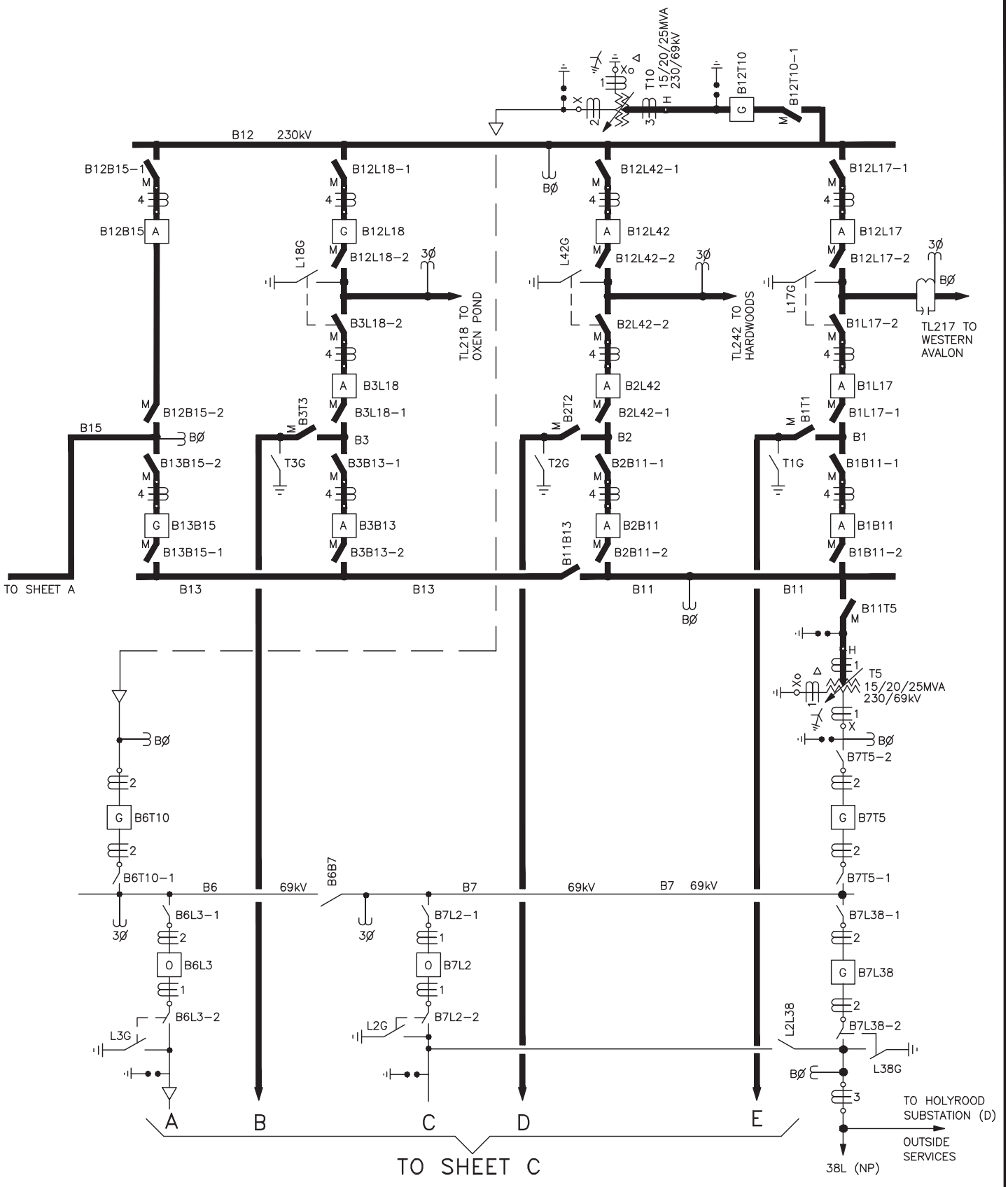
WESTERN AVALON TERMINAL STATION ANNUNCIATOR REMOTE AUXILIARY CONTACTS GROUPING SCHEMATIC

W.O. NO.

DWG. NO. B1- 306 - E - 127

REV. 11

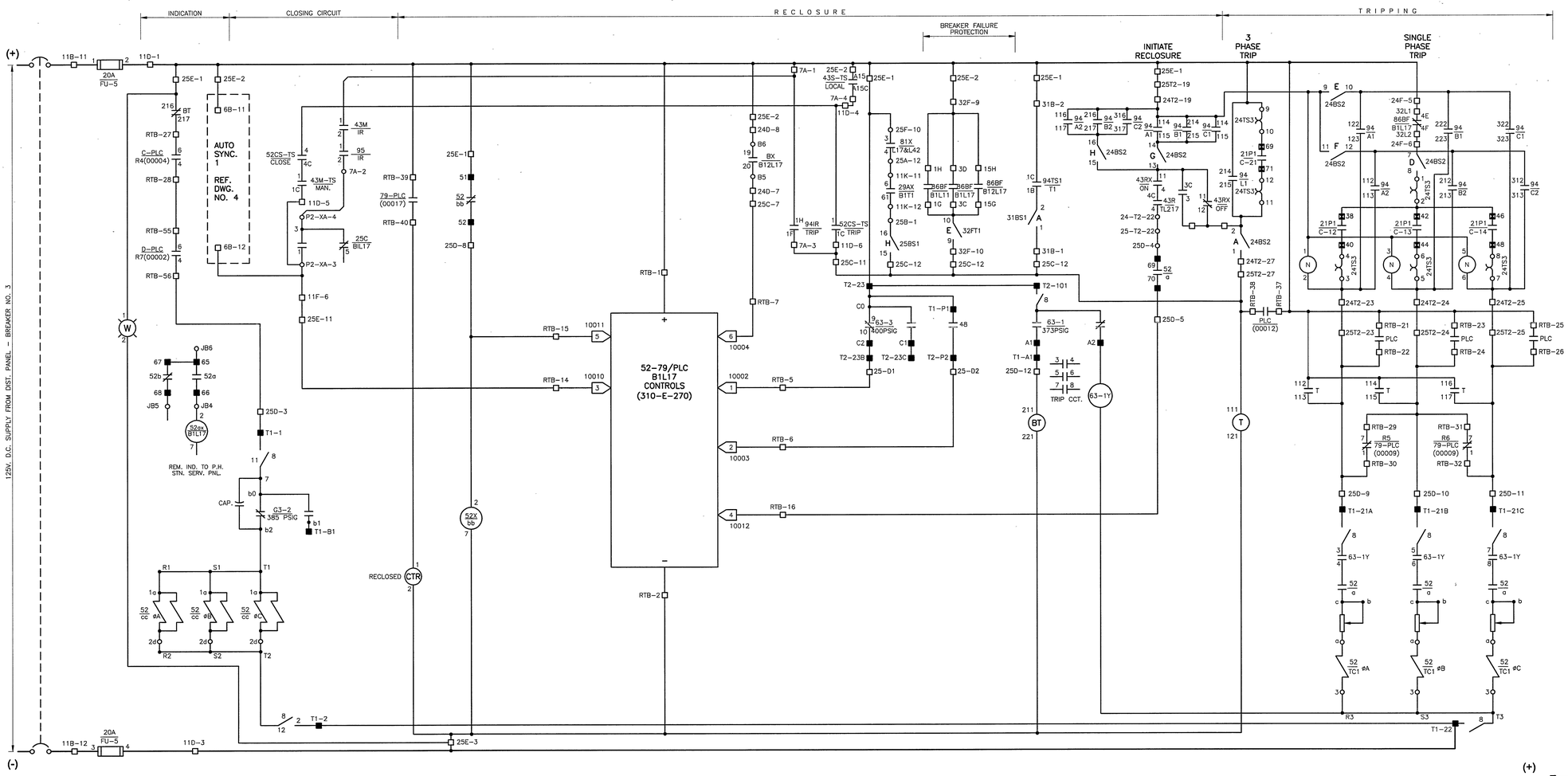
PLOT SCALE 1:1 C.A.D.

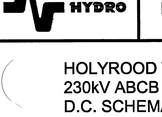


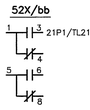
DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG. NO. HRD–B
APPROVED BY: D. KING		SYSTEM OPERATING DIAGRAM HOLYROOD TERMINAL STATION (B)	REV. NO. 11
DATE: 2013/11/22			

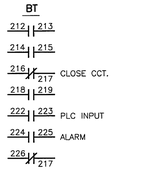
BREAKER NO. B1L17

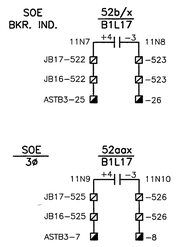
DEVICE	DESCRIPTION	LOCATION	TYPE
T	3 PHASE TRIP AUX. RELAY	PNL. 25	ABB RXMS1
KI	KIRK INTERLOCK	230kV BKR.	
81X	OVER FREQUENCY AUX. RELAY	PNL. 25	B.B.–P8
43R	RECLOSE "OFF & ON SWITCH"	PNL. 11	S.B.M.
43S	SUPERVISORY TRANSFER SWITCH	PNL. 7	
52CS	BREAKER CONTROL SWITCH	PNL. 11	EXTRA STAGE
86	BKR. FAILURE PROT. LOCKOUT RELAY REFER TO 310–E–18	PNL. 32	
FC	FORCE CLOSE AUX. RELAY	BKR. CAB.	
LC	LOW PRESS. BLOCKING RELAY, TRIP & CLOSE	BKR. CAB.	
BT	BLOCK TRIP RELAY	PNL. 25	ABB RXMA1
RE–1	52CS LOCATED IN GEN. STATION		
RE–2	52CS LOCATED IN BAY D'ESPOIR		
CTR	COUNTER FOR SINGLE PHASE	PNL. 24	4Y9434–PS
UT–1	GENERATOR UNIT TRANSFORMER NO. 1		SBM10AA106 &
T–2	TIME RELAY	PNL. 24	ASEA–RRKN
94A,B,C(1,2)	PHASE TRIP RELAY	PNL. 24	ABB–RXMS–1
94L(1,2)	LOCKOUT TRIP RELAY	PNL. 24	ABB–RXMS–1
TS	INDICATES EQUIPMENT LOCATED IN TERMINAL STATION		
P	INDICATES EQUIPMENT LOCATED IN POWERHOUSE		
IR	INTERPOSING RELAY	PNL. 7	CR120A
25C/B1L17	SYNCH. CHECK RELAY FOR MANUAL SYNCH.	PNL. 2	GEC MAVSO3
63–1Y	BLOCK TRIP AUX. RELAY	230kV BKR.	P8 a x m.
52bx1	AUX. TRIP RELAY FOR BREAKER OPEN	PNL. 11	P&B KRPA–11DC
21P2	LINE PROT. DISTANCE RELAY – PRIMARY # 2	PNL. 24	SEL 321–1
52–79/PLC	PROGRAMMABLE LOGIC CONTROLLER (BKR. CONTROL)	PNL. 25	COMPACT 984











BIL17 52CS–TS

TRIP CLOSE

BREAKER CONTROL SWITCH

CONTACTS HANDLE END		IND. POS. CLOSE	NOR.	TRIP	FUNCTION
1C 2C	1			X	TRIP
	2			X	
3C 4C	3		X	X	25X
	4	X			CLOSE
5C 6C	5	X	X		25X
	6	X	X		
7C 8C	7	X			25X
	8				

RECL. SEL. SW.

OFF ON

RECLOSER SWITCH

CONTACTS HANDLE END		IND. POS. ON	OFF
1C 1C	1		X
2C 2C	2	X	
3C 3C	3		X
4C 4C	4	X	
5C 5C	5		X
6C 6C	6	X	
7C 7C	7		X
8C 8C	8	X	

OVAL HANDLE
MAINTAINED CONTACTS

NOTE:

1. ABCB IS SHOWN IN OPEN POSITION AND AT NORMAL PRESSURE (426 PSIG) WITH D.C. SUPPLY CIRCUIT SWITCHED OFF.

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HYDRO

NEWFOUNDLAND AND LABRADOR HYDRO

HOLYROOD TERMINAL STATION
230kV ABCB B1L17 CONTROL
D.C. SCHEMATIC DIAGRAM

REFERENCE DRAWINGS		REVISIONS						
		24	07–07–25	REVISED AS BUILT	W.B.	F. REV.		
		23	05–04–20	B1L17 CONTROLS UPGRADE (PLC). AS BUILT	D.O.	—		
310–E–198	BREAKER FAILURE PROTECTION DIA.	22.	05–02–08	REVISED "AS BUILT"	C.R.H.			
310–E–188	125V D.C. DISTRIBUTION SCHEMATIC	21	03–04–04	REVISED AS BUILT (LINE SWAP)	D.O.	A/L	BTB	
310–E–191	SYNCHRONIZING D.C. SCHEMATIC DIAGRAM	20	00–10–02	TL217 21P2 ADDED. AS BUILT	D.O.	A/L	LT	
310–E–29	ANNUNCIATOR SCHEMATIC DIAGRAM	19	97–03–20	REVISED AS BUILT	W.B.			
310–E–207	REL. & MET. SINGLE LINE DIAGRAM	18	95–11–02	SOE ADDITIONS & TRIP COIL 2	W.B.			
DWG.NO.	TITLE	NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D

ORIGINAL DRAWING NOT SEALED

ELECT.	SCALE: N.T.S.
CIVIL	DESIGNED:
TRANS.	DRAWN: C. R. HARNUM
MECH.	DATE: 1992–01–22
P&C	CHECKED:
TELC.	APPROVED:

W.O. NO.

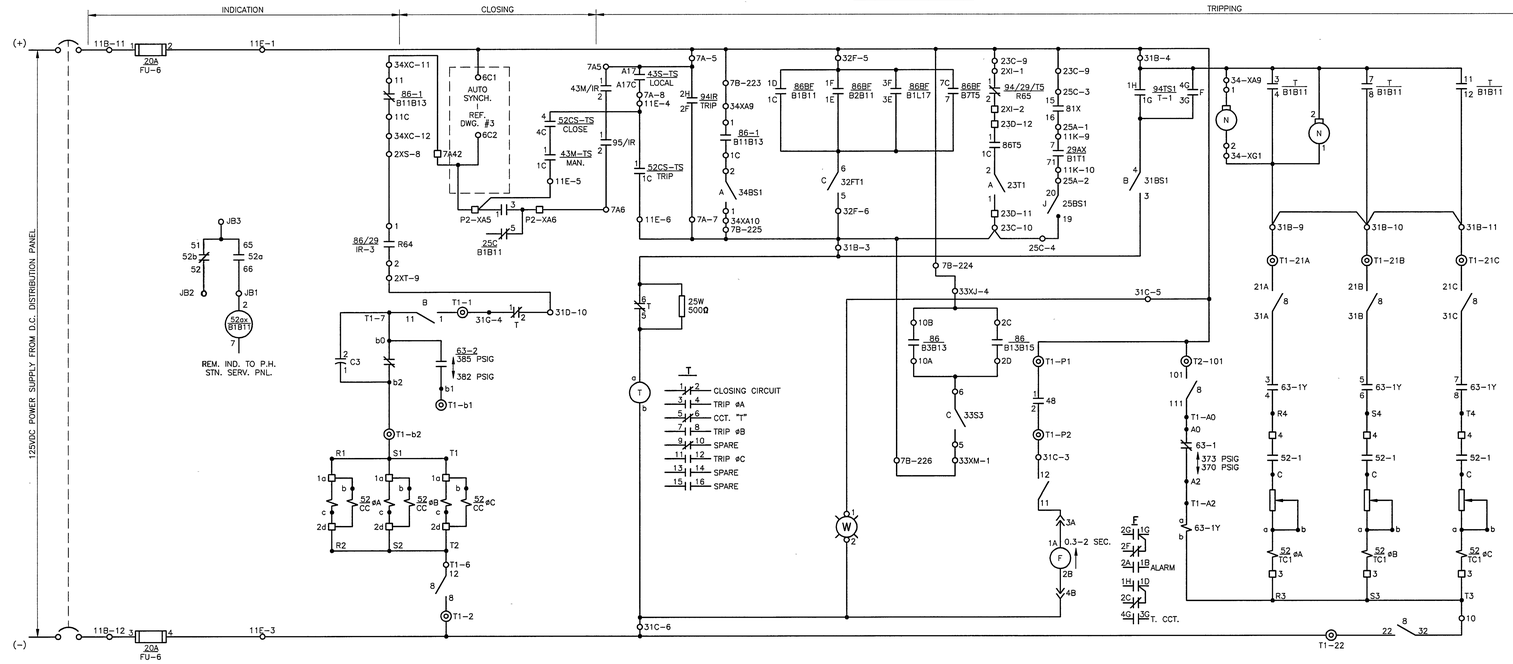
DWG. NO. B1- 310 - E - 034

REV. 24

PLOT SCALE 1:1 C.A.D.

Jul 25, 2007 – 9.08am

BKR. NO. B1B11

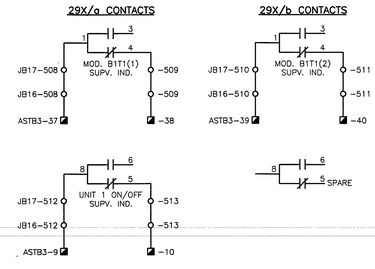


DEVICE	DESCRIPTION	LOCATION	TYPE
F.C.	FORCE CLOSE AUX. RELAY		
K.I.	KIRK INTERLOCK	230kV BKR.	
T	3 PHASE AUX. TRIP RELAY	PNL. 31	B.B.–PB
.5	M.O.D. SPEED SWITCH FOR BRACKING	M.O.D. B1T1	
29 OPEN/CLOSE	M.O. DISC SWITCH OPERATING COILS	M.O.D. B1T1	
L.S.	M.O. DISC LIMIT SWITCHES	M.O.D. B1T1	
43ES	LOCAL TRANSFER SWITCH	M.O.D. B1T1	
43S–TS	SUPERVISORY TRANSFER SWITCH "TERMINAL STA."	PNL. 7	
50–51TS T1	TRF. OVERCURRENT STBY. PROT. RELAY	PNL. 31	IAC 53
F	DISAGREEMENT TRIP RELAY	PNL. 31	AESA RRKH 23
FX	DISAGREEMENT AUX. TRIP RELAY	PNL. 31	ASEA RRMH–2(2306)
52 a–b	BREAKER AUX. CONTACTS	230kV BKR.	
52 C.C.	BREAKER CLOSING COILS	230kV BKR.	
52 TC1	BREAKER TRIPPING COILS	230kV BKR.	
52C–1 TC	BREAKER AUX. TRIPPING COILS "NOT USED"	230kV BKR.	
52ELCS	BREAKER CONTROL SWITCH "LOCAL"	230kV BKR.	SBM
52CS–TS	BREAKER CONTROL SWITCH "TERMINAL STA."	PNL. 11	SBM
52/aX	BREAKER IND. AUX. RELAY	PNL. 11	P&B KRPA
52/TC2	BREAKER 2ND TRIP COIL		BBC
63 O.P.	PRESSURE SWITCH "LOCKOUT CONTACTOR"	230kV BKR.	
81X	OVER FREQUENCY AUX. RELAY	PNL. 25	B.B.–PB
84/29 IR–1, –3	CLOSING COIL LOCKOUT RELAY – ALLAN BRADLEY	PNL. 2	700DC–N400
86/B11B13	BUS B11B13 PROT. LOCKOUT RELAY – CGE	PNL. 34	HEA 61C
86T	TRF. LOCKOUT TRIP RELAY	P.H.	GE HEA
86 BKR. NO.	BREAKER FAILURE PROTECTION LOCKOUT RELAY – ASEA	PNLS. 32,33	RRMVB–4 RRMVB–2
25C/B1B11	SYNCH. CHECK RELAY FOR MAN. SYNCH.	PNL. 2	GEC. MAVS03
94–TS	PHASE TRIP RELAY "TERMINAL STA."	PNL. 31	ASEA RRMS–2(2606)
94 IR	INTERPOSING TRIP RELAYS	PNL. 7	A.B.
95 IR	INTERPOSING CLOSE RELAYS	PNL. 7	A.B.
48	DISAGREEMENT TRIP RELAY	230kV BKR.	
63–1	PRESSURE SWITCH INTERLOCK FOR TRIPPING CCT.	230kV BKR.	
63–2	PRESSURE SWITCH INTERLOCK FOR CLOSING CCT.	230kV BKR.	
63–1Y	AUXILIARY RELAY FOR 63–1	230kV BKR.	
29AX	AUXILIARY RELAY FOR AUX. CONTACTS	PNL. 11	AGASTAT GPD

2ND TRIP COIL CCT.

29 B1T1 AUX. CONTACTS (OPEN POS.)

CONTACTS	FUNCTION	
G G1	IND. LIGHT (GREEN) TS	DWG. NO. 310–E–035
R R1	IND. LIGHT (RED) TS	
1 2	IND (G) PH	
3 4	IND (R) PH	
5 6	SYNC. AC CKT. B11	B1L17 DWG. NO. 310–E–192
7 8	SYNC. AC CKT. G1	
9 10	SYNC. AC CKT. L17	B1B11 DWG. NO. 310–E–192
11 12	SYNC. AC CKT. G1	
13 14	D.C. AUTO SYNC UNIT 1	DWG. NO. 550–E–008
15 16	P/U 29AX P.H.	DWG. NO. 310–E–191
17 18	D.C. AUTO SYNC UNIT 1	DWG. NO. 550–E–008
O1 S	OPEN LIMIT B1T1	DWG. NO. 310–E–035
C1 S	CLOSE LIMIT B1T1	



BREAKER CONTROL SWITCH

CONTACTS HANDLE END		POSITION			
		CLOSE	NORMAL		TRIP
1 1C 2C 2	1				X
	2				X
3 3C 4C 4	3		X	X	
	4	X			
5 5C 6C 6	5	X	X		
	6	X	X		
7 7C 8C 8	7	X			
	8	X			

TARGET TYPE WITH PISTOL GRIP HANDLE SPRING RETURN TO NORMAL POSITION

NOTES:

1. ◎ DENOTES TERMINALS ON ABCB.
2. BREAKER IS SHOWN IN OPEN POSITION AND NORMAL AIR PRESSURE (426 psig) WITH D.C. SUPPLY OFF.
3. ⊠ TERMINAL IN SUPERVISORY JUNCTION BOX.
4. ◪ AGC SUPERVISORY JUNCTION BOX IN POWERHOUSE.

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WAS ORIGINALLY SIGNED BY R.M. JOST FEB. 19, 1969

REFERENCE DRAWINGS			REVISIONS					
DWG.NO.	TITLE	NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D.
310–E–38	230/69kV T5 D.C. SCHEMATIC & B11T5	24.	05–02–08	REVISED"AS BUILT"	C.R.H.	FW/KeL	AYL	AYL
310–E–114	230/138kV T6 A.C., D.C. SCHEMATIC	23	03–04–04	REVISED AS BUILT	D.O.		AYL	Clear
310–E–205	BUS B11B13 A.C., D.C. SCHEMATIC	22	97–03–20	REVISED AS BUILT	W.B.			
310–E–203	T1,T2,T3 TRANSFORMER BACKUP PROT.	21	96–02–01	AS BUILT & REDRAWN ON CAD	C.M.			
310–E–191	SYNCHRONIZING D.C. SCHEMATIC	20	92–07–16	ADD 2ND TRIP COILS				
310–E–188	125V D.C. DISTRIBUTION SCHEMATIC	19	92–01–10	T10 EXT., EMS, TL217 PROT. MOD.	C.R.H.			
310–E–207	RELAYING & METERING SINGLE LINE	18	90–10–20	T10 ADDITION	D.C.M.			

HYDRO — NEWFOUNDLAND AND LABRADOR HYDRO

HOLYROOD TERMINAL STATION
230kV ABCB #B1B11 & MOD. #B1T1
CONTROL D.C. SCHEMATIC DIAGRAM

ELECT.	SCALE: N.T.S.		
CIVIL	DESIGNED:		
TRANS.	DRAWN: C. MURPHY		
MECH.	DATE: 1996–01–29		
P&C	CHECKED:		
TELC.	APPROVED:		

W.O. NO.

DWG. NO. B1- 310 - E - 35

REV. 24.

PLOT SCALE 1:1 C.A.D.

Feb 08, 2005 – 1 34pm

Verbal Safety Talk _____

THINK SAFETY FIRST

WO TYPE : 2 PM Wo SSDTS,T1,XFMR PM MTNCE PARENT #: 00601395
STATUS : 45 PRIORITY: 3 Plann
ITEM # : 00005810 UNIT #: SSDT1 TRANSFORMER T1,SSD TS
PLT COND: SD B.U. #: 1325 SUPV: WHB Station Mtce Dept
LOCN: SSDTS SSD Term Stn, Sunnyside ORIG: Lyver, Gerard J.
W/H : 1829 Bishop Falls Warehouse PLNR: Lyver, Gerard J.
EMPL: W.O.#: 601395 W.O. SUBCODE: PMN

--- Full Description of Request ----------

1. PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK SHEET.
2. RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK ORDER REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A LATER DATE.
3. CONSIDER & REPORT ANY ENVIROMENTAL IMPACTS.

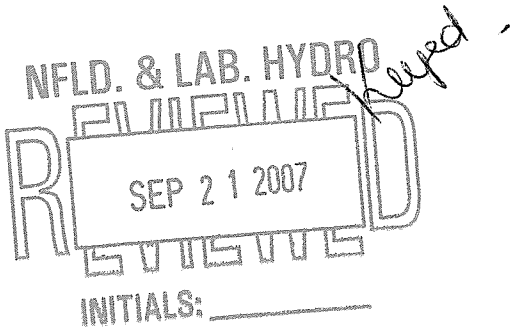
OP#	CRAFT	DESCRIPTION	SIZE	MHRS
1.00	WHBCRSEM	WHB ELEC Term. Stn Mtce. Crew	2.0	
2.00	WHBCRTM	WHB Term. Stn Mtce	1.0	

--- Safety Provisions ----------

1. ENSURE NECESSARY WORK PROTECTION IS IN PLACE BEFORE STARTING WORK.
2. COMPLETE TAILBOARD SAFETY TALK BEFORE BEGINNING WORK.

--- Maintenance Loops ----------

00005810 TRANSFORMER T1,SSD TS Y06A



T A I L B O A R D S A F E T Y T A L K
RISK ASSESSMENT

FORM # 30-0266

REV. DATE 06/05/01

TASK PM T1 @ SSD T.S.

PEOPLE: (Have I/We Considered)

Crew members know who is in charge?
How missing crew members will be briefed?
Workers capabilities adequate?
Other work groups/general public that may affect this work?
Personal Protective Equipment?
Hazards within the work area?

HARDWARE/EQUIP: (Have I/We Considered)

Safe working loads/rigging?
Tool conditions/adequacy?
Climbing hazards?
Temporary support of structure?
Equipment pre-use checks?
Communications?

PROCEDURES: (Have I/We Considered)

Scope of work?
The work method?
Work Protections/Hold-Off/Special Permits?
Limits of approach?(_____)
Back feeds?
Temporary grounding?
Test for isolation?
Fall Arrest?
Controlled products/data sheets?
Transportation of Dangerous Goods?
Confined space entry?
Rescue methods?
Cover up required?
Applicable engineering standards?

ENVIRO/OTHER: (Have I/We Considered)

Overhead power line hazards?
Underground uitlities?
Trenching/excavation hazards?
Traffic control/barricades/signs?
Weather conditions?
Hazardous products spills?
Terrain?
Deteriorated Plant?
ENV SOP's?
Other?_____

PARTICIPANTS:

W. Downing
S. Tucker

HAZARDS IDENTIFIED	CONTROLS
Falling	PPE
Cherry picker	Care & caution

(use back if necessary)

Supervisor/Lead Hand/Worker

2007/09/04
Date

FORM II - TRANSFORMER MAINTENANCE HISTORY

System ID: Station:Serial No.: T1 SSDTS # 289147
Manufacturer: Type: M.V.A:
Test Date: 2007/09/05 Test Completed By: WM/ST J.D.E. W/O #: _____

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

☐ ☐ ☐

WEATHER CONDITIONS: dry: rain: humidity: ambient temperature: ^{0}C 15

DIELECTRIC OIL TEST ASTM D-1816 (kV): Conservator Main Tank: 40 Conservator Diverter Switches: –
Diverter Switch # 1 _____ Diverter Switch # 2 ____ Diverter switch # 3 _____ Transformer main tank 45

WINDING TEMP RELAY: (Check if Applicable)					
First Stage Fans: Setting: ____ °C	Found	75	°C	Left 75	°C
Second Stage Fans: Setting: ____ °C	Found	80	°C	Left 80	°C
Alarm: Setting: ____ °C	Found	105	°C	Left 105	°C
Trip: Setting: ____ °C	Found	120	°C	Left 120	°C

LIQUID TEMP RELAY: (Check if Applicable)					
Alarm: Setting: ____ °C	Found	90	°C	Left 90	°C
Trip: Setting: ____ °C	Found	/	°C	Left /	°C

FAULT PRESSURE RELAY: (GAS DETECTOR) Main Tank					
Alarm:	Found	200	(cc)	Left 200	(cc)
Trip;	Found	OK	(kpa)	Left OK	(kpa)

FAULT PRESSURE RELAY: (IN LINE GAS DETECTOR) diverter Switches (Check if Applicable)
(Function test Control Circuits) Tested OK ____ N/A ____ NA

FAULT PRESSURE RELEASE RELAYS: (Function test Control Circuit if Applicable)
Main Tank: Tested Ok ____ N/A ✓

Diverter Sw: A ph:Tested OK ✓ N/A ____	**Diverter Sw: B ph:Tested OK ✓ N/A ____**	**Diverter Sw: C ph:Tested OK ✓ N/A ____**

CONSERVATOR MAIN TANK: (Function Test Low-level Alarm) OK ✓
CONSERVATOR DIVERTER SWITCHES: (Function Test Low level Alarm) OK ✓

RESISTANCE CHECKS: (including Wiring to Terminal Boards) **500 Volt Test**
Test & record in Mega Ohms or N/A

	Line 1 – Line 2	Line 1 / 2 - GND		Line 1 – Line 2	Line 1 / 2 GND
Winding Temp Relay: **Alarm**	80 mΩ	80 mΩ	**Trip**	95 mΩ	105 mΩ
Liquid Temp Relay: **Alarm**	1064 mΩ		**Trip**		

FORM II - TRANSFORMER MAINTENANCE HISTORY

2.28
3.46

System ID: Station:Serial No.:
Manufacturer: Type: M.V.A:
Test Date: 2007/09/05 Test Completed By: GH J.D.E. W/O #:

Y - HL Grounded	1 min - 1.84	10 min 5.95	3.18 %
~~[redacted]~~	1 min	10 min	
~~T-HG~~	1 Min. Mega Ω	10 Min. Mega Ω	Index. %
HL-G Y Grounded Tert - Grounded	1 Min. 2.28 Mega Ω	10 Min. 3.46 Mega Ω	Index. 1.52 %

CORE GROUND: (500 Volt test)	
Externally Connected Yes ____ No ____	
RESISTOR: (Ohms)	CORE GROUND: (Mega Ohms)

Cabinet Heater - 2.1 Amp.

RUST/PAINT CONDITION (A - Minor , B – Moderate , C – Severe)

MAIN TANK:	B good condition	RADIATORS:	B - good condition
CONTROL CABINET:	B good condition	OTHER:	—

CHECKS COMPLETED:

- ✓ Check Explosion Vent
- ✓ Check HV & LV Connections
- ✓ Ladder Guards
- Check porcelain insulators for chips or cracks
- ✓ Manually Operate Fans
- n/a Check Oil Filtering Unit (type 51) { check Oil Pressure gauge } Replace Filter if Required (Pumps Located on BBKTS T3, HRDTS T8 & WAVTS T5 ONLY)
- Silica Gel Checked replace if 50% or more Contaimated
- Silica Gel Replaced NO
- Visual Check For Dirty Insulators & Clean if required ✓
- Check ConservatorTanks For Water, Drain if Necessary

CHECKS COMPLETED ONLY IF INSTRUCTED:

- Obtain Gas Analysis Sample
- Transformer Ratio Readings (Form III)
- Capacitive Bridge Testing
- ✓ Doble Test

COMMENTS: Ladder door needs new Hinges — " compl "

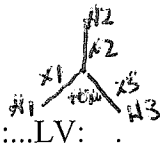
Auto. Transformer - 230 K.V. - 138 K.V - Tert. winding 6.9 K.

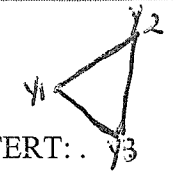
System ID: Station:Serial No.:
Manufacturer: Type: M.V.A:
Test Date: _____ Test Completed By: ___ J.D.E. W/O #: _____

FORM IV – TRANSFORMER WINDING RESISTANCE

System ID: T1 Station: 5075 Serial No: 289147 Manufacture: CGE
Type: OLTC ✓ TC ____ High voltage 230 KV Low Voltage 138 KV Tester Serial No: ____
Test Date: 2007 08 08 Test Completed By: JW WD J.D.E. W/O #:

VECTORS: HV:...LV: . . . TERT: . . .





NOTE: 1. Complete Winding Resistance Test on Tap Position **Found**.
2. Complete Winding Resistance Test on Maximum Tap Position **Raise**.
3. Complete Winding Resistance Test on Maximum Tap Position **Lower**.
4. Confirm Mechanical Center (Off Load Tap Changers).
5. Complete Winding Resistance Test on Tap Position **Left**.

TAP CHANGER LOCATION: HV _____ LV _____

TAP POSITION	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTANCE DELTA x 1.5
Found 6	6 Ø A	500mA	2	106.6%	.405	
Found 6	6 Ø B	500mA	2	106.5%	.442	
Found 6	6 Ø C	500mA	2	106.6%	.412	
Max. Raise 17	Ø A	500mA	2	106.4	.485	
Max. Raise 17	Ø B	500 mA	2	106.5%	.461	
Max. Raise 17	Ø C	500mA	2	x 106.5%	.464	
Max. Lower 1	Ø A	500mA	2	* 106.4%	.452	
Max. Lower 1	Ø B	500mA	2	106.4%	.458	
Max. Lower 1	Ø C	500 mA	2	106.4%	.458	
Left 6	Ø A	500mA	2	106.5%	.407	
Left 6	Ø B	500mA	2	106.4%	.437	
Left 6	Ø C	500mA	2	X 106.5%	.407	
Non Tap Winding	Ø A	500mA	2	104%	.570	
Non Tap Winding	Ø B	500mA	2	104.1%	.577	
Non Tap Winding	Ø C	500mA	2	104.1%	.570	
Tertiary Winding	Ø A B gnd	500mA	200m	107.2	5.7	
Tertiary Winding	Ø B C gnd	500 mA	200m	107.2	5.5	
Tertiary Winding	Ø A C gnd	500 mA	200m	107.2	5.3	

Note: Observe Indicator Light & Record OHMS or MILLI-OHMS

REMARKS:

A .562 – .577

Nameplate - Autotransformer with Tertiary

Company	Newfoundland & Labrador Hydro	**Serial Number**	289147
Location	SSD	**Special ID**	SSD T1
Division	EASTERN	**Circuit Designation**	T1
Manufacturer	CGE	**Configuration**	Y-Y-D
Year Manufactured	1977	**Tank Type**	OPEN-CONSER
Mfr Location	GUELPH ONTARIO CCANADA	**Oil Volume**	12300 IG
Phases	3	**BIL**	900 kV
Class	ONAN/ONAF/ONAF	**Coolant**	OIL
Weight	263000 LB		
kV	230, 138, 6.9	**VA Rating**	75, 100, 125, MVA
Note			

Test Date	8/16/2007	**Test Time**	12:00:00 PM	**Weather**	PTCLDY
Air Temperature	17 °C	**Tank Temperature**	°C	**Rel. Humidity**	42 %
Tested by	P&C	**Work Order #**	S	**Last Test Date**	
Checked by		**Test Set Type**	M4K	**Retest Date**	
Checked Date		**Set Top S/N**		**Reason**	ROUTINE
Last Sheet #		**Set Bottom S/N**		**Travel Time**	
P.O. #		**Ins. Book #**		**Duration**	
Copies		**Sheet #**		**Crew Size**	

Arrester Nameplate

Location	Serial #	Mfr	Overall Catalog	Unit Catalog	Type	Rated kV	Order
H1 TOP	D-3708	OB	219652	215920-3013	VN	82.000	TOP
H1 - BOTTOM	D-3709	OB	219652	215920-3008	VN	70.000	BOTTOM
H2 TOP	89m5037	JOS	8110D0001J192	<None>	ZS	51.000	TOP
H2 MID	89m5037-2	JOS	8110D0001J192	<None>	ZS	51.000	MIDDLE
H2 BOT	89m5037-1	JOS	8110D0001J192	<None>	ZS	51.000	BOTTOM
X1 TOP	D-8963	OB	219598	215920-3005	VN	56.000	TOP
H3 TOP	89M5038-2	JOS	8110D0001J192	<None>	ZS	51.000	TOP
H3 MID	89M5038-1	JOS	8110D0001J192	<None>	ZS	51.000	MIDDLE
H3 BOT	89M5038	JOS	8110D0001J192	<None>	ZS	51.000	BOTTOM
X1 BOT	D-8964	OB	219598	215920-3001	VN	42.000	BOTTOM
X2 TOP	28440	MC-ED	ATZ11A60	<None>		48.000	TOP
X2 BOT	28431	MC-ED	ATZ11A60	<None>		48.000	BOT
X3 TOP	28444	MC-ED	ATZ11A60	<None>		48.000	TOP
X3 BOT	28442	MC-	ATZ11A60	<None>		48.000	BOT

ED

Bushing Nameplate

Desig.	Serial #	Mfr	Type	C1 % PF	C1 Cap	C2 % PF	C2 Cap	kV	Amps	Year
H1	250663	CGE	U	.28	431		379	196	600	
H2	250881	CGE	U	.27	422		384	196	600	
H3	251439	CGE	U	.27	420		390	196	600	
X1	251307	CGE	U	.24	359		339	115	800	
X2	251308	CGE	U	.24	359		341	115	800	
X3	251311	CGE	U	.24	344		366	115	800	
Y1	251458	CGE	LC	.82				15	1200	
Y2	251459	CGE	LC	.84				15	1200	
Y3	251457	CGE	LC	.78				15	1200	
N	251456	CGE	LC	.76				15	1200	

Overall Tests

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10.016	116.87	3.600	0.31	1.00	31000.6		
CH	10.010	116.15	3.605	0.31	1.00	30808.1	G	
CHT(UST)	10.008	0.7090	-000.02	-0.28	1.00	188.02	I	
CHT		0.720	-0.005	-0.07	1.00	192.500	I	
CT + CHT	5.001	132.63	5.960	0.45	1.00	35180.3		
CT	5.003	131.92	5.973	0.45	1.00	34991.9	G	
CHT(UST)	5.004	0.7070	-000.02	-0.28	1.00	187.58	I	
CHT		0.710	-0.013	-0.18	1.00	188.400	I	

Bushing C1

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	250663	.28	431	10.006	1.599	0.0400	0.25	1.00	424.25	G	
H2	250881	.27	422	10.005	1.571	0.0350	0.22	1.00	416.75	G	
H3	251439	.27	420	10.005	1.564	0.0330	0.21	1.00	414.79	G	
X1	251307	.24	359	10.005	1.348	0.0310	0.23	1.00	357.50	G	
X2	251308	.24	359	10.005	1.350	0.0300	0.22	1.00	358.05	G	
X3	251311	.24	344	10.006	1.295	0.0180	0.14	1.00	343.54	G	

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	250663		379	2.001	1.606	0.0750	0.47	1.00	425.88	I	
H2	250881		384	2.000	1.613	0.0910	0.56	1.00	427.82	I	

H3	251439		390	2.000	1.643	0.0890	0.54	1.00	435.76	I	
X1	251307		339	2.000	1.432	0.0950	0.66	1.00	379.89	I	
X2	251308		341	2.000	1.434	0.0980	0.68	1.00	380.48	I	
X3	251311		366	2.000	1.535	0.1250	0.81	1.00	407.20	I	

Hot Collar Tests

Serial #	ID	Test Mode	Skirt #	Test kV	mA	Watts	IR_{auto}	IR_{man}
251458	Y1	GROUND	1	10.003	0.1170	0.0360	G	
251459	Y2	GROUND	1	10.004	0.1210	0.0370	G	
251457	Y3	GROUND	1	10.003	0.1210	0.0450	G	
251456	N	GROUND	1	10.003	0.1180	0.0790	G	

Insulating Fluid Tests

Sample Location	Deg C	Test kV	mA	Watts	%PF corr	Corr Fctr	IR_{auto}	IR_{man}
TANK BOTTOM		10.00	0.8790	0.0060	0.07	1.00	G	
LTC		10						

Surge Arrester Tests

Location	Test Mode	Test kV	mA	Watts	IR_{auto}	IR_{man}
H1 TOP	UST RB	10.004	0.1370	0.0660	G	
H1 - BOTTOM	GAR RB	10.004	0.2450	0.1120	G	
H2 TOP	UST RB	10.004	0.2970	0.2560	G	
H2 MID	UST RB	10.003	0.2820	0.2570	G	
H2 BOT	GAR RB	10.003	0.3540	0.2610	G	
H3 TOP	UST RB	10.004	0.3000	0.2610	G	
H3 MID	GAR RB	10.017	0.4090	0.6470	I	
H3 BOT	GAR RB	10.004	0.3540	0.2700	G	
X1 TOP	UST RB	10.004	0.1830	0.0890	G	
X1 BOT	GAR RB	10.011	0.3610	0.2000	I	
X2 TOP	UST RB	10.004	0.2220	0.0640	G	
X2 BOT	GAR RB	10.004	0.3440	0.1050	G	
X3 TOP	UST RB	10.004	0.2250	0.0690	G	
X3 BOT	GAR RB	10.005	0.3220	0.0950	G	

Exciting Current Tests

	Mfr	Type	Steps	Boost %	Buck %	Position Found	Position Left	Oil Volume
De-Energized Tap Changer	CGE							
On-Load Tap Changer	CGE	C2	16	5	15			

	H1 - H0		H2 - H0		H3 - H0		

DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10.018	16.391	160.41	L	10.096	100.62	C	15.702	154.98	L	G	
	5	9.995	17.782	172.67	L	10.996	109.95	C	17.073	167.32	L	G	
	9	10.011	19.436	188.16	L	12.059	120.59	L	18.687	182.66	L	G	
	13	10.011	21.338	205.56	L	13.347	133.12	L	20.553	199.73	L	G	
	17	10.018	23.595	226.91	L	14.837	147.66	L	22.763	220.82	L	G	

Fluid Analysis Report

Equipment	289147	*MVA ratings*	125
Serial No.	289147	*Rated kV*	230.000
Apparatus type	TRN	*Oil preservation type*	CONSERVATOR
Owner	N.F.L.D HYDRO	*Cooling*	OA/FA/FA
Region	WHITBOURNE	*Fluid volume*	14662
Substation	SSD	*Tank*	Main
Designation	T1	*Norms used*	TRN_IEEE_69_288KV
Norms	TRN_IEEE_69_288KV	*DGA result*	2/3
Fluid type	OIL	*Fluid condition*	1/1
Description	POWER TRANSFORMER	*Moisture code*	1/1
Manufacturer	CGE	*PCB result code*	0/1
Year manufactured	1978	*Oil test status*	UNREVIEWED
Model	AUTO		

Gas Analysis

Lab Report Number	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Sample date	2013-09-11	2012-03-13	2012-02-24	2010-03-22 14:31:00	2009-05-05 14:46:00
Fluid temp	35	20	20	25	30
Hydrogen (H2)	30	10	20	25	25
Methane (CH4)	0	0	0	0	0
Ethane (C2H6)	4.0	4.0	3.0	4.0	4.0
Ethylene (C2H4)	52.0	47.0	49.0	50.0	50.0
Acetylene (C2H2)	11.0	7.0	8.0	8.0	7.0
Carbon Monoxide (CO)	373	267	310	341	327
Propylene (C3H6)	0	0	0	0	0
Carbon Dioxide (CO2)	3160	2610	2640	3070	3020
Oxygen (O2)	26600	26400	25900	27400	21700
Nitrogen (N2)	64100	62100	61100	65200	62100
Total heat gas	56	51	52	54	54
TDCG	470	335	390	428	413
Equivalent TCG	0.414	0.277	0.346	0.364	0.382
Total partial press	85.6	88.4	87.0	90.7	82.1
Est. safe handling limit	9.1	10.2	9.4	9.2	9.1
Calculated monitor ppm	99	59	77	88	85
CO2/CO	8.472	9.775	8.516	9.003	9.235
Oxygen/Nitrogen (O2/N2)	0.415	0.425	0.424	0.420	0.349
DGA retest days	30	90	90	90	90
DGA retest date	2013-10-11	2012-06-11	2012-05-24	2010-06-20	2009-08-03
DGA reference days	547.0	18.0	703.4	321.0	336.6
DGA result	3	2	2	2	2
DGA diagnosis	DT	T3	T3	T3	T3

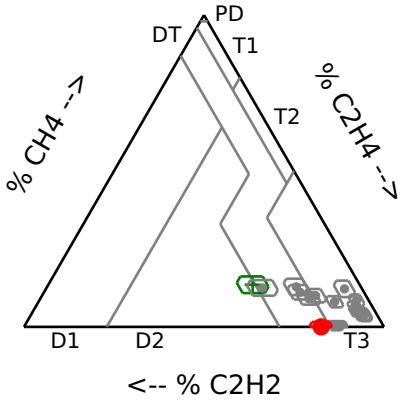
Gas Analysis Remarks

One or more combustible gases have a positive long-term average rate. (C2H2) Significant increase (^). High level (*). Electrical discharge or thermal fault. Consider investigative sampling.

Gas Analysis Summary

```
c2h4* c2h2*^ co*!
```

Diagnosis



Triangle Diagnosis: DT

Rogers Diagnosis: ?

Fluid Quality

Lab Report Number	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Sample date	2013-09-11	2012-03-13	2012-02-24	2010-03-22 14:31:00	2009-05-05 14:46:00
Fluid temp	35	20	20	25	30
Dielectric breakdown D877	52.0	49.0	59.0	45.0	55.0
PF at 25 C	0.166	0.115	0.123	0.035	0.062
PF at 100 C	2.940	3.280	2.620	1.280	1.380
Acid number	0.030	0.030	0.030	0.030	0.030
Interfacial tension	28.1	27.5	26.9	27.8	28.6
Specific Gravity	0.860	0.859	0.858	0.858	0.862
Color	1.5	1.5	1.5	2.0	1.5
Oil quality index	1.1	1.1	1.1	1.1	1.0
PF100/PF25	17.711	28.522	21.301	36.571	22.258
Visual	CLEAR	CLEAR	CLEAR	CLEAR	CLEAR
Fluid quality retest days	365	365	365	365	365
Fluid quality retest date	2014-09-11	2013-03-13	2013-02-23	2011-03-22	2010-05-05
Fluid condition	1	1	1	1	1

Fluid Quality Analysis Remarks

No oil quality problems were detected.

Moisture Analysis

Lab Report Number	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Sample date	2013-09-11	2012-03-13	2012-02-24	2010-03-22 14:31:00	2009-05-05 14:46:00
Fluid temp	35	20	20	25	30
Moisture	3	2	2	5	2
Relative saturation	3	4	4	7	2
Dew point	-34	-40	-40	-26	-40
Solubility parameter A	7.3000	7.3000	7.3000	7.3000	7.3000
Solubility parameter B	1630	1630	1630	1630	1630
Moisture code	1	1	1	1	1

Moisture Remarks

The water content of the oil seems acceptable.

Furans

Lab Report Number	*N/A*
Sample date	2009-05-05 14:46:00
Fluid temp	30
2-furfural (2FAL)	0
5-methyl-2-furfural (5M2F)	0
5-hydroxymethyl-2-furfural (5H2F)	0
Furfuryl alcohol (2FOL)	0
2-acetylfuran (2ACF)	0

PCB Analysis

Lab Report Number	*N/A*
Sample date	2009-05-05 14:46:00
Fluid temp	30
Aroclor 1221	0.0
Aroclor 1242	0.0
Aroclor 1254	0.0
Aroclor 1260	0.0
Total PCB	0.0
PCB result code	1

PCB Remarks

Not PCB contaminated.

OIL ANALYSIS REPORT

REFERENCE

Client:	Mr Dave Hicks (CNH04)	Sample No:	M008242
E-mail:		Authorized by:	R.P.
Company:	Nfld. & Labrador Hydro	Sent Date:	2009-05-28

EQUIPMENT

Apparatus Type:	TRN	KV:	230	Sampling Point:	MAIN
Location:	SSD	MVA:	125	Oil Temp. (°C):	30
Equipment No:	289147	Oil type:	OIL	Sampled by:	POG
Serial No.:	289147	Year built:	1978	Sampling Date:	2009-05-05 14:46
Additional info:	POWER TRANSFORMER				
Description:	T1				

DGA

Previous	2009-05-05	Parameter	Screening Code(T/R)	Test Method
	25	Hydrogen		D3612-02
	7	Acetylene		ppm (V/V)
	4	Ethane		at 273 K
	50	Ethylene		and 760 Torr
	< 5	Methane		
	327	Carbon Monoxide		
	3020	Carbon Dioxide		
	62100	Nitrogen		
	21700	Oxygen + Argon		
	8.67	Total Dissolved Gas (%)		

OIL QUALITY

Previous	2009-05-05	Parameter	Screening Code(T/R)	Test Method
	2	Moisture in Oil (ppm)		SOP 5.5-03-01
		Moisture in Oil (ppm)		D 1533-00
	28.6	Interfacial Tension (dynes/cm)		D 971-99
	0.03	Acid Number (mg KOH/g)		D 974-07
	1.5	Color Number		D 1500-04
	None	Free Water		D 1524-94
	Clear	Visual Examination		D 1524-94
	None	Sediment Examination		D 1524-94
	55	Dielectric Breakdown (kV)		D 877-02
		Dielectric Breakdown 2 mm (kV)		D 1816-04
	0.062	Power Factor @ 25 °C (%)		D 924-04
	1.38	Power Factor @ 100 °C (%)		D 924-04
	0.8615	Specific Gravity		D 1298-99
		Oxidation Inhibitor DBP (wt. %)		D 4768-03
		Oxidation Inhibitor DBPC (wt. %)		D 4768-03
	< 1	PCB - Total Arochlor Content (ppm)		D 4059-00
		Corrosive Sulphur Method B		D 1275-06
	< 5	5-hydroxymethyl-2-furaldehyde (ppb)		D 5837-99
	< 5	furfuryl alcohol (ppb)		D 5837-99
	< 5	2-furaldehyde (ppb)		D 5837-99
	< 5	2-acetylfuran (ppb)		D 5837-99
	< 5	5-methyl-2-furaldehyde (ppb)		D 5837-99

COMMENTS:
NCR 1415 - This report replaces the previous report. A typo occured on the name of methyl-2-furaldehyde. It should read 5-methyl instead of 2-methyl.

**** Morgan Schaffer is an ISO/IEC 17025 certified laboratory ****

The analyses and screening codes contained in this report are based upon material and information supplied by the client. Morgan Schaffer Inc does not imply that the contents of the sample received at its laboratory are the same as all such material in the environment from which the sample was taken. Our test results relate only to the sample or samples tested. Morgan Schaffer Inc assumes no responsibility and makes no warranty or representation, expressed or implied as to the condition, productivity or proper operation of any equipment or other property for which this report may be used or relied upon for any reason whatsoever. This report must not be reproduced, unless in its entirely, without the written consent of Morgan Schaffer Inc.(* Subcontracted, † Non-accredited test)

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA™

David Hicks
Newfoundland Labrador Hydro

P.O. Box 12400
St John's, NF A1B 4K7

Location : SSDTS
Bank & Phase : T1-A
Serial Number : 289147-LTC-A
Ventilation :
Compartment : Common

Date : 11/7/2012
Report Number : 5042845
Purchase Order Number: 847577
Manufacturer : CGE
Model :

		Sample Date :	10/2/2012	4/29/2008	6/27/2007
		Laboratory No. :	5042845	5019672	5016462
		Container No. :	201177	40377	8887
		Temperature :	35	45	30
H2	Hydrogen	(ppm) :	33016	29115	28078
CH4	Methane	(ppm) :	2833	3857	3961
C2H6	Ethane	(ppm) :	257	240	355
C2H4	Ethylene	(ppm) :	4605	5441	4430
C2H2	Acetylene	(ppm) :	33979	38919	29282
CO	Carbon monoxide	(ppm) :	246	388	517
CO2	Carbon dioxide	(ppm) :	2497	3753	3289
N2	Nitrogen	(ppm) :	39837	52562	63895
O2	Oxygen	(ppm) :	7690	13115	5572
		Total (ppm) :	124960	147390	139379
		TDCG (ppm) :	74936	77960	66623
		SHL (%) :	3.91	3.89	3.93
		ETCG (% in blanket) :	58.01	47.87	43.90
Particles		5 to 15 um :	5658800	1162305	26948834
Particles		15 to 25 um :	345800	86990	4029760
Particles		25 to 50 um :	81900	6230	680695
Particles		50 to 100 um :	11100	165	39325
Particles		> 100 um :	400	0	2500
D1533	Moisture	(ppm) :	26	14	43
D1816	Dielectric BV	(kV) :	22	25	14
D974	Acid Number	(mg KOH/g) :	0.011	0.016	0.012
D971	Interfacial Tension	(dynes/cm) :	38.7	36.3	35.0
D1500	Color Number	:	<4.0	<2.0	<3.0

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment : 2
Sampling Interval : Recommend retest within 150 days (5 months) for trending.
Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.
Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.
Partial discharge is indicated.
Heating is indicated.
Abnormal arcing is indicated.
Follow guidelines for oils with high flammable gas content.

TJ | H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA™

David Hicks
Newfoundland Labrador Hydro

P.O. Box 12400
St John's, NF A1B 4K7

Location : SSDTS
Bank & Phase : T1-B
Serial Number : 289147-LTC-B
Ventilation : Desiccant
Compartment : Common

Date : 11/7/2012
Report Number : 5042842
Purchase Order Number: 847577
Manufacturer : CGE
Model :

		Sample Date :	10/2/2012	4/29/2008
		Laboratory No. :	5042842	5019677
		Container No. :	19603	10371
		Temperature :	35	35
H2	Hydrogen	(ppm) :	15155	33228
CH4	Methane	(ppm) :	2801	3578
C2H6	Ethane	(ppm) :	215	199
C2H4	Ethylene	(ppm) :	4554	4815
C2H2	Acetylene	(ppm) :	31921	35549
CO	Carbon monoxide	(ppm) :	274	458
CO2	Carbon dioxide	(ppm) :	2714	3560
N2	Nitrogen	(ppm) :	59648	63393
O2	Oxygen	(ppm) :	10885	15427
		Total (ppm) :	128167	160207
		TDCG (ppm) :	54920	77827
		SHL (%) :	3.83	3.91
		ETCG (% in blanket) :	31.27	46.21
Particles		5 to 15 um :	1302900	1120400
Particles		15 to 25 um :	64000	38850
Particles		25 to 50 um :	13100	4520
Particles		50 to 100 um :	2500	330
Particles		> 100 um :	0	0
D1533	Moisture	(ppm) :	16	13
D1816	Dielectric BV	(kV) :	22	22
D974	Acid Number	(mg KOH/g) :	0.015	0.014
D971	Interfacial Tension	(dynes/cm) :	38.1	35.5
D1500	Color Number	:	<2.5	<2.5

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment : 2
Sampling Interval : Recommend retest within 150 days (5 months) for trending.
Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.
Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.
Partial discharge is indicated.
Heating is indicated.
Abnormal arcing is indicated.
Follow guidelines for oils with high flammable gas content.

H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA™

David Hicks
Newfoundland Labrador Hydro

P.O. Box 12400
St John's, NF A1B 4K7

Location : SSDTS
Bank & Phase : T1-C
Serial Number : 289147-LTC-C
Ventilation :
Compartment : Common

Date : 11/7/2012
Report Number : 5042841
Purchase Order Number: 847577
Manufacturer : CGE
Model :

		Sample Date :	10/2/2012	4/29/2008
		Laboratory No. :	5042841	5019675
		Container No. :	201171	10372
		Temperature :	35	35
H2	Hydrogen	(ppm) :	28622	29198
CH4	Methane	(ppm) :	1974	2955
C2H6	Ethane	(ppm) :	129	160
C2H4	Ethylene	(ppm) :	3264	3609
C2H2	Acetylene	(ppm) :	23263	28735
CO	Carbon monoxide	(ppm) :	222	404
CO2	Carbon dioxide	(ppm) :	2051	3076
N2	Nitrogen	(ppm) :	59035	71575
O2	Oxygen	(ppm) :	12810	20495
		Total (ppm) :	131370	160207
		TDCG (ppm) :	57474	65061
		SHL (%) :	3.93	3.92
		ETCG (% in blanket) :	44.16	39.49
Particles		5 to 15 um :	6934700	870130
Particles		15 to 25 um :	295900	24520
Particles		25 to 50 um :	55500	1125
Particles		50 to 100 um :	5500	35
Particles		> 100 um :	0	0
D1533	Moisture	(ppm) :	18	9
D1816	Dielectric BV	(kV) :	23	22
D974	Acid Number	(mg KOH/g) :	0.014	0.016
D971	Interfacial Tension	(dynes/cm) :	38.3	36.8
D1500	Color Number	:	<4.0	<2.5

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment : 2
Sampling Interval : Recommend retest within 150 days (5 months) for trending.
Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.
Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.
Partial discharge is indicated.
Heating is indicated.
Abnormal arcing is indicated.
Follow guidelines for oils with high flammable gas content.

H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA™

David Hicks
Newfoundland Labrador Hydro

P.O. Box 12400
St John's, NF A1B 4K7

Location : SSDTS
Bank & Phase : T1-A
Serial Number : 289147-LTC
Ventilation :
Compartment : LTCMain

Date : 8/21/2007
Report Number : 5016461
Purchase Order Number:
Manufacturer : CGE
Model :

		Sample Date :	6/28/2007
		Laboratory No. :	5016461
		Container No. :	8702
		Temperature :	30
H2	Hydrogen	(ppm) :	30141
CH4	Methane	(ppm) :	3602
C2H6	Ethane	(ppm) :	244
C2H4	Ethylene	(ppm) :	4216
C2H2	Acetylene	(ppm) :	29357
CO	Carbon monoxide	(ppm) :	494
CO2	Carbon dioxide	(ppm) :	3381
N2	Nitrogen	(ppm) :	68190
O2	Oxygen	(ppm) :	7764
		Total (ppm) :	147389
		TDCG (ppm) :	68054
		SHL (%) :	3.93
		ETCG (% in blanket) :	43.54
Particles		5 to 15 um :	13739700
Particles		15 to 25 um :	3849250
Particles		25 to 50 um :	486115
Particles		50 to 100 um :	8650
Particles		> 100 um :	250
D1533	Moisture	(ppm) :	61
D1816	Dielectric BV	(kV) :	12
D974	Acid Number	(mg KOH/g) :	0.012
D971	Interfacial Tension	(dynes/cm) :	35.0
D1500	Color Number	:	<3.0

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment : 3
Sampling Interval : Recommend retest within in 90 days.
Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.
Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.
Partial discharge is indicated.
Heating is indicated. Counter: 125541
Abnormal arcing is indicated.
ETCG is 90% of SHL. Plan to follow guidelines for oils with high flammable gas content.

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Tapchanger Activity Signature Analysis TASA™

David Hicks
Newfoundland Labrador Hydro

P.O. Box 12400
St John's, NF A1B 4K7

Location : SSDTS
Bank & Phase : T1-B
Serial Number : 289147-LTC-A
Ventilation :
Compartment : LTCMain

Date : 8/21/2007
Report Number : 5016462
Purchase Order Number:
Manufacturer : CGE
Model :

		Sample Date :	6/27/2007
		Laboratory No. :	5016462
		Container No. :	8887
		Temperature :	30
H2	Hydrogen	(ppm) :	28078
CH4	Methane	(ppm) :	3961
C2H6	Ethane	(ppm) :	355
C2H4	Ethylene	(ppm) :	4430
C2H2	Acetylene	(ppm) :	29282
CO	Carbon monoxide	(ppm) :	517
CO2	Carbon dioxide	(ppm) :	3289
N2	Nitrogen	(ppm) :	63895
O2	Oxygen	(ppm) :	5572
		Total (ppm) :	139379
		TDCG (ppm) :	66623
		SHL (%) :	3.93
		ETCG (% in blanket) :	43.90
Particles		5 to 15 um :	26948834
Particles		15 to 25 um :	4029760
Particles		25 to 50 um :	680695
Particles		50 to 100 um :	39325
Particles		> 100 um :	2500
D1533	Moisture	(ppm) :	43
D1816	Dielectric BV	(kV) :	14
D974	Acid Number	(mg KOH/g) :	0.012
D971	Interfacial Tension	(dynes/cm) :	35.0
D1500	Color Number	:	<3.0

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment : 3
Sampling Interval : Recommend retest within in 90 days.
Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.
Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.
Partial discharge is indicated.
Heating is indicated. Counter: 125541
Abnormal arcing is indicated.
ETCG is 90% of SHL. Plan to follow guidelines for oils with high flammable gas content.

H2b ANALYTICAL SERVICES INCORPORATED

Tapchanger Activity Signature Analysis TASA™

David Hicks
Newfoundland Labrador Hydro

P.O. Box 12400
St John's, NF A1B 4K7

Location : SSDTS
Bank & Phase : T1-C
Serial Number : 289147-LTC-S
Ventilation :
Compartment : LTCMain

Date : 8/21/2007
Report Number : 5016465
Purchase Order Number:
Manufacturer : CGE
Model :

		Sample Date :	6/28/2007
		Laboratory No. :	5016465
		Container No. :	8884
		Temperature :	30
H2	Hydrogen	(ppm) :	21034
CH4	Methane	(ppm) :	2614
C2H6	Ethane	(ppm) :	322
C2H4	Ethylene	(ppm) :	3606
C2H2	Acetylene	(ppm) :	22687
CO	Carbon monoxide	(ppm) :	385
CO2	Carbon dioxide	(ppm) :	2599
N2	Nitrogen	(ppm) :	74506
O2	Oxygen	(ppm) :	19637
		Total (ppm) :	147390
		TDCG (ppm) :	50648
		SHL (%) :	3.92
		ETCG (% in blanket) :	31.57
Particles		5 to 15 um :	20745970
Particles		15 to 25 um :	1324640
Particles		25 to 50 um :	182050
Particles		50 to 100 um :	12730
Particles		> 100 um :	1600
D1533	Moisture	(ppm) :	21
D1816	Dielectric BV	(kV) :	16
D974	Acid Number	(mg KOH/g) :	0.012
D971	Interfacial Tension	(dynes/cm) :	35.8
D1500	Color Number	:	<2.0

Tapchanger Activity Signature Analysis Diagnostic Evaluation

TASA Assessment : 3
Sampling Interval : Recommend retest within in 90 days.
Operating Procedure : Monitor for increased arcing. Evaluate for worn or damaged components.
Comments : A moderately abnormal dissipation of energy is noted. This is an advancing indication of fault or wear activity.
Partial discharge is indicated.
Heating is indicated. Counter: 125541
Abnormal arcing is indicated.
ETCG is 90% of SHL. Plan to follow guidelines for oils with high flammable gas content.

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
93146	8/27/1999	Change Selica Gel T1,SSDTS	Change Selica Gel T1,SSDTS CHANGED SELICA GEL ON MAIN TANK AND TAP CHANGER T1 COMPLETED BY: M. REID DATE: 99-08-27	10187	90
138811	4/28/2000	SSDTS,T1,FUSE BLOWN,REPLACED	T1,FUSE BLOWN,REQUIRES REPLACEMENT, OUTAGE REQUIRED ON B PHASE TERITARY 2000/04/28 COMPLETED BY: G.BRODERICK MODIFIED & REPLACED FUSE HOLDER & FUSE.	47825	90
144225	6/8/2000	SSDTS,T1,OIL LEAK,INSPECT	INSPECT OIL LEAK ON THE TOP OF T1. LOCATION: SUNNYSIDE TERMINAL STATION. 2000/06/08 COMPLETED BY: G.BRODERICK REPAIRED LEAKING VALVE ON RADIATOR & CLEANED UP OIL AROUND TRANSFORMER RADIATORS.	47825	90
184259	2/21/2002	SSDTS,T1,CONTACT ALARM,REPL	SSDTS,T1,CONTACT ALARM,REPLACE WINDING TEMPERATURE RELAY. ALARM CONTACT NEEDS TO REPLACED. needs a 8cond. cable ran from control cabinet to the relay NAME PLATE DATA: 75/100/125 MVA - 230 KV H/S 138 KV L/S BY G.E. SER. #289147. REPLACED WINDING TEMP. GUAGE. PULLED NEW CONDUCTORS FOR GUAGE. CHANGED BRACKET TO ACCOMONDATE NEW NEW GUAGE OK. COMPLETED BY: G. BRODERICK ON 2002-02-20	47825	90
189041	1/11/2001	SSDTS,T1,SILICA GEL,REPLACE	SSDTS,T1,SILICA GEL,REPLACE NO OUTAGE REQUIRED (VERBAL PERMISSION) FOLLOW SAFETY STANDARDS 01/01/11 COMPLETED BY: M.REID CHANGED SILICA GEL ON MAIN CONSERVATOR & TAP	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
199354	2/22/2001	SSDTS,T1,LTC,CHECK	SUNNYSIDE TERMINAL STATION: T1 T1 LTC DOESN'T APPEAR TO BE OPERATING IN AUTO; BOTH TRIES PLACED IN MAN. PRIORITY "B" 01/02/21 COMPLETED BY: J.MCDONALD CHECKED ALL PTS FOR VOLTAGE & ALL SEEMED OK. PUT FORMERS IN AUTO & TESTED 2 TAPS APART ALL OK.	47826	90
258362	6/18/2002	SSDTS,T1,SANDING & PAINTING	SSDTS,T1,SANDING & PAINTING SANDED, PRIMED AND PAINTED. T1 SSD SANDED PRIMED & PAINTED. STATION SERVICE CABINET AND COMPLETED BY: C. SMITH ON 2002-06-18	47825	90
263965	2/28/2002	SSDTS,T1,SILICA-GEL,REPLA	SSDTS,T1,SILICA-GEL,REPLACE FOR CONSERVATOR TANK. SILICA GEL REPLACED ON T1 CONSERVER COMPLETED BY: G. BRODERICK ON 02-02-28	47825	90
264013	3/1/2002	SSDTS,T1,FAN,REPAIR/REPLACE	SSDTS,T1,FAN,REPAIR/REPLACE RAD COOLING FAN (SEIZED) (MIDDLE ROW, FAR RIGHT FAN). POSSIBLE MOTOR REPLACEMENT, POSSIBLE BEARING REPAIRED AND REPLACED ONE FAN AND MOTOR THAT WAS RUSTED AND FULL OF WATER. ALSO ASSESSED OTHER FAN MOTOR ON T1 AND T2. COMPLETED BY: D. BLAKE/S. TUCKER ON 2002-03-01 WORK REMAINING: WORK ORDER NEEDED FOR T1 - FAN RIGHT MOTOR T1 AND T4	47825	90
264284	2/25/2002	SSDTS,T1,OIL TEMP RELAY,REPL	SSDTS,T1,RELAY,REPLACE LIQUID TEMP. RELAY THE PART ORDERED ON THIS WORK ORDER BELONGS TO W/O MAX : ENSURE THIS PART IS ASSIGNED TO PROPER W/O WHEN ARRIVES NEW OIL TEMP GUAGE INSTALLED AND CHECK FOR SETTINGS. COMPLETED BY: G. BRODERICK & W. DOWNING ON 2002-02-25	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
265667	3/14/2002	SSDTS,T1,FANS,INSP & REPAIR	SSDTS,T1,FANS,INSPECT ASSESS & REPAIR FAN MOTOR WIRING INSTALL ELECTRICAL GROUND TO ALL MOTORS REPLACE EXISTING CAB TIRE . RAN GROUND WIRE #2 AWG FROM GROUND GRID GROUND TO INSTALLED GROUNDING BAR IN XFMR CONTROL CABINET. RAN GROUND WIRE FROM GROUNDING BAR TO EACH OF TWO RAD J-BOXES. RAN NEW #14/4 AWG CABTIRE (500W) FROM BOTH TO THE APPLICABLE MOTORS, 9 IN ALL, AND CONNECTED UP MOTORS WITH AN ELECTRICAL GROUND. REMOVED ONE DISSASSEMBLED, CLEANED UP, AND PUT BACK TOGETHER WAS FULL OF WATER WHEN CHECKED. COMPLETED BY: D. BLAKE, S. TUCKER & G. HILLIER COMPLETED ON: 2002-03-13	47825	90
280171	6/5/2002	SSDTS,T1,PM MAINT/DOBLE TRF	DOBLE TRANSFORMER EVERY 6 YEARS. 1. ATTACH TRANSFORMER CHECK SHEETS TO RECORD TEST 2. RECORD ANY DEFICIENCIES ON WORK REQUEST SO THAT CAN GET CORRECTED IF NOT CORRECTED DURING 3. CHECK NAME PLATE FOR ACCURACY,RECORD ANY 4. DOBLE ANY CTS THAT MAY BE ASSOCIATED WITH 5. CHECK LATEST DOBLE TEST RESULTS TO SEE WHEN LAST CTS WERE TESTED. WORK PERFORMED AS PER CHECK SHEET. COMPLETED BY: P. O'GRADY & CREW ON 2002-05-29	47825	90
309966	12/11/2002	SSDTS,T1,SILICA GEL,CHANGE	SSDTS,T1,SILICA GEL,CHANGE REPLACED SILICA-GEL ON MAIN CONSERVATOR AND TAP COMPLETED BY: G. HILLIER & S. TUCKER ON 2002-12-11	47825	90
400483	5/10/2004	SSD,T1 LTC SCREEN FOR PCB	SUNNYSIDE TERMINAL STATION TEST T1 DIVERTER SWITCH OIL FOR PCB'S T1, LTD TESTED FOR PCB. UNDER 50 PARTS PER MILLION. COMPLETED BY: S. TUCKER ON 2004-05-10	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
412731	7/13/2004	SSD T1 INVISTIGATE ALARM	SSD T1 INVISTIGATE ALARM RESTORED STATION SERVICE TO CLEAR ALARMS ON AIR SYSTEM AND D.C. BATTERY CHARGER. T1 ALARMS CLEARED. CHECKED RESISTANCE ACROSS CONTACTS ON GAS, WINDING, AND OIL LEVEL GAUGES. GAS RELAY ALARM CONTACT SOME RESISTANCE BUT CLEARED ON PANEL. RESTORED T1 TO SERVICE. COMPLETED BY: W. DOWNING ON 2004-07-12	47825	90
413126	8/24/2004	SSDTS,T1,GAS RELAY CIR,INVES	SSDTS,T1,RELAY CIRCUIT,INVES INVESTIGATE GAS RELAY CIRCUIT ON T1 CORD MAY NEED TO BE REPLACED. SPARE CORD TO SHORT MADE UP BEFORE OUTAGE. T1 TRANSFORMER TAKEN FROM SERVICE ALARM CONTACTS RELAY OR SHOW LOW RESISTANCE. MAY ALSO BE CABLE GAS RELAY. COMPLETED BY: W.D & B. WALSH ON 2004-07-19 NOTE: INSTALL NEW GAS RELAY OR NEW CABLE FROM JB TO RELAY. CABLE THAT COMES WITH GAS RELAY IS TO SHORT. INSTALLED NEW GAS RELAY CABLE. TESTED THE ALARM AND CIRCUIT WITH PUMP - ALL OK. COMPLETED BY: G. HILLIER ON 2004-08-23	47825	90
450258	5/11/2005	SSDTS. T1 GAS RELAY	EMERGENCY USE GAS RELAY INSTALLED ON T1 IN 2004 THIS W/O IS TO REPLACE THE EMERGENCY USE STOCK	47825	90
494823	8/9/2006	SSDTS,T1,OIL TEMP GAUGE	SSDTS,T1,OIL TEMP GAUGE GAUGE NOT WORKING RELAY INSTALLED ON T1 AT SSDTS. CONTACTS MEGGARED - 1000 TO GROUND 75 BETWEEN WIRES. CONTACT CHECKED AND CLOSES AT 90 DEGREES AM. TEMP COMPLETED BY: W. DOWNING & B. WALSH ON 2006-08-09	47825	90
583571	4/20/2007	SSDTS,T1,SILICA GEL NEEDED	SSDTS,T1,SILICA GEL NEEDED MAIN TANK AND TAP CHARGERS NEED SILCA GEL REPLACED	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
583571	4/20/2007	SSDTS,T1,SILICA GEL NEEDED	SILICONE REPLACED IN MAIN TRANSFORMER AND COMPLETED BY: W. DOWING/S. TUCKER ON 2007-04-17	47825	90
584713	8/17/2007	SSDTS, T1 TAPCHANGER OIL SAM	SSDTS, T1 TAP CHANGER OIL SAMPLE (OUTAGE REQUIRED) OBTAIN OIL SAMPLE FOR AS PER T.SHAVE'S INSTRUCTIONS QUOTE WORK ORDER ON INVOICE 1) If oil volume in the equipment is less than 250 gallons (1200 L) flush 1 quart of oil, otherwise flush a gallon into waste oil container. 2) Bottle Samples: rinse bottle by partially filling and gently swirling and emptying the oil into the waste container. Fill bottle to within an inch of the top, to allow for expansion. Visually examine fluid for water droplets or foreign particles. If present, re-sample. If not, attach the cap securely, identify the sampled unit on the bottle's label. Do not tape the cap. 3) Syringe Samples: the plastic stopcock, which comes with the syringe must remain firmly affixed to the syringe to prevent leaks. Flushing the syringe: a) Move the handle toward the sampling valve. b) Open sampling valve and move the handle toward the syringe allowing oil to flush the tube and stopcock. c) Move the handle towards the side port, allowing oil pressure to enter the syringe barrel, forcing the plunger out. Until the inside of the syringe has been wetted with oil, it may be necessary to pull the plunger. d) When oil reaches the 50 cc mark, move the handle towards the sampling valve and eject oil from ssyringe by pushing in the plunger. Catch this ejected oil in waste container Draw the Sample: a) Move the handle towards the side port and allow oil pressure to fill the syringe. DO NOT PULL ON THE PLUNGER When oil reaches the 40-45cc mark, move the handle towards the syringe. Do not over fill the syringe to avoid gas escape from the plunger side.	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
584713	8/17/2007	SSDTS, T1 TAPCHANGER OIL SAM	b) Examine sample to ensure it is free of bubbles and foreign particles. If sample is good, move handle towards the syringe, close drain valve and remove the syringe with stopcock still firmly attached to the syringe. If sample is not clear, repeat sample procedure. c) Record info: on sample bottle check sheet as per enclosed instructions.	47825	90
595483	7/5/2007	SSDTS,PROTECTION,FAIL,ALARM	SSDTS,PROTECTION,FAIL,ALARM,INVESTIGATE PROTECTION FAIL ALARM CAME UP WHEN RESTORING 138 KV B2, T1 AND BUS 3. ISOLATED BURNED AUX. TRANSFORMER IN T1 CABINET TRANSFORMER ASSOCIATED WITH VOLTAGE STEPPING SWITCH ALSO AUX ACT 5/.7 A HAD TO BE REPLACED DAMAGED BY CHECKED REPLACEMENT C.T., OK, REPLACED WIRING AND INTO SERVICE. TESTED BY ECC, OK, BOTH TRANSFORMERS RETURNED TO PARALLEL AND AUTO. COMPLETED BY: J. MCDONALD ON 2007-07-05	47826	90
601394	9/6/2007	SSDTS,T1,TRF DOBLE PM	DOBLE TRANSFORMER EVERY 6 YEARS. 1. CHECK LATEST DOBLE TEST RESULTS TO SEE WHEN LAST TRANSFORMER WAS TESTED. 2. DOBLE TRANSFORMER AS PER CHECK SHEET AND RECORD 3. ANY VARIATIONS FROM INITIAL DOBLE RESULTS SHOULD BE BROUGHT TO THE ATTENTION OF THE P AND C SUPERVISOR. ALL DOBLING COMPLETED EXCEPT FOR LIGHTNING ARRESTERS. RESULTS DISCUSSED WITH J. WHEELER. TO BE DISCUSSED WITH R. STOYLES AFTER RETURN FROM HOLIDAYS. LIGHTNING ARRESTERS DONE SEPT 5, 2007 COMPLETED BY: L. HOPKINS/G. PARSONS ON 2007-08-17 SEE W/O 601397.	47826	90
601395	9/7/2007	SSDTS,T1,XFMR PM MTNCE	1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK 2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
601395	9/7/2007	SSDTS,T1,XFMR PM MTNCE	DATE. 3.CONSIDER & REPORT ANY ENVIROMENTAL IMPACTS. MAINTENANCE PERFORMED AS PER CHECK SHEETS. COMPLETED BY: P. O'GRADY & CREW ON 2007-09-07	47825	90
603694	5/30/2008	SSDTS,T1 TAP CHANGER OIL SAMPL	SSDTS,T1 RETEST TAP CHANGER OIL SAMPLE RETEST IN 90 DAYS AS PER LAB REPORT 3 SAMPLES REQUIRED T1-A, T1-B, T1-C QUOTE WORK ORDER ON INVOICE (OUTAGE REQUIRED) 3 TAP CHANGER OIL SAMPLES TAKEN. COMPLETED BY: W. DOWNING & B. WALSH ON 2008-04-28	47825	90
657773	2/22/2010	SSDTS,T1,LEAK,RAD VALVE,REPAIR	SSDTS: Eastern Terminal Station Equipment T1 - Rad valve has a small leak. Need to be repaired. SWOP#2008002855 OUTAGE REQUIRED TO PERFORM PROPER INSPECTION BOTH UP DOWN VALVE ON THE RAD OF T1 SSD. COMPLETED BY: P. O'GRADY NOT ADVISABLE TO ADJUST OR TIGHTEN GLAND NUT OR UNLESS PREPARED TO DRAIN RAD. COMPLETED BY: H. MOORES & W. DEAN ON 2008-11-25	47825	90
821736	12/29/2010	SSDTS HIGH PT VOLTAGE TL206	SSDTS HIGH PT VOLTAGE TL206 LOW P.T. VOLTAGE AND PROTECTION INOPRATIVE ALARM A PHASE FUSE BLOWN REPLACED FUSE WITH GLASS TYPE OK COMPLETED BY: L. HOPKINS ON 2010-12-29	47825	80
847577	10/2/2012	SSDTS,T1 TAPCHANGER OIL SAM	SSDTS, T1 TAP CHANGER OIL SAMPLE (OUTAGE REQUIRED) OBTAIN OIL SAMPLE FOR AS PER T.SHAVE'S INSTRUCTIONS QUOTE WORK ORDER ON INVOICE SAMPLE EACH PHASE (3) 1) If oil volume in the equipment is less than 250 gallons (1200 L) flush 1 quart of oil, otherwise flush a gallon into waste oil container. 2) Bottle Samples: rinse bottle by partially filling and	47825	80

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
847577	10/2/2012	SSDTS,T1 TAPCHANGER OIL SAM	gently swirling and emptying the oil into the waste container. Fill bottle to within an inch of the top, to allow for expansion. Visually examine fluid for water droplets or foreign particles. If present, re-sample. If not, attach the cap securely, identify the sampled unit on the bottle's label. Do not tape the cap. 3) Syringe Samples: the plastic stopcock, which comes with the syringe must remain firmly affixed to the syringe to prevent leaks. Flushing the syringe: a) Move the handle toward the sampling valve. b) Open sampling valve and move the handle toward the syringe allowing oil to flush the tube and stopcock. c) Move the handle towards the side port, allowing oil pressure to enter the syringe barrel, forcing the plunger out. Until the inside of the syringe has been wetted with oil, it may be necessary to pull the plunger. d) When oil reaches the 50 cc mark, move the handle towards the sampling valve and eject oil from ssyringe by pushing in the plunger. Catch this ejected oil in waste container Draw the Sample: a) Move the handle towards the side port and allow oil pressure to fill the syringe. DO NOT PULL ON THE PLUNGER When oil reaches the 40-45cc mark, move the handle towards the syringe. Do not over fill the syringe to avoid gas escape from the plunger side. b) Examine sample to ensure it is free of bubbles and foreign particles. If sample is good, move handle towards the syringe, close drain valve and remove the syringe with stopcock still firmly attached to the syringe. If sample is not clear, repeat sample procedure. c) Record info: on sample bottle check sheet as per enclosed instructions. --- ENSURE THAT LAB RESULTS ARE FORWARDED TO JIM HUGHIE IRELAND IN BISHOP'S FALLS AND A COPY OF THE	47825	80

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
847577	10/2/2012	SSDTS,T1 TAPCHANGER OIL SAM	ORDER BE SENT WITH THE LAB SAMPLE.CONTACT FOLLOWS.JIM:258-2331,JWHEELER@NLH.NL.CA,HUGHIE:258-23 HIRELAND@NLH.NL.CA OIL SAMPLE TAKEN AND MADE READY FOR SHIPMENT COMPLETED BY: P. O'GRADY (ONE SAMPLE TAKEN - RESAMPLE ALL THREE PHASES) 9 OIL SAMPLES TAKEN 3 FROM EACH PHASE. COMPLETED BY: W. DOWNING & I. ORGAN ON 2012-10-02	47825	80
861948	3/20/2012	SSDTS,T1 TAP CHANGER PCB TEST	SSDTS,T1 TAP CHANGER PCB TEST OBTAIN OIL SAMPLE(S) FROM TAP CHANGER AND SEND TO LAB ANALYSIS OF PCB CONTENT.PLEASE RECORD THE FOLLOWING ON SAMPLE BOTTLE LABELS: SAMPLE TKEN AND MADE READY FOR SHIPMENT COMPLETED BY: P. O'GRADY ON 2012-03-20	47825	80
907578	3/27/2012	SSDTS,T1,SILICA GEL REPLACE	SSDTS,T1,SILICA GEL REPLACE REPLACED SILICA GEL ON T1 SSD T.S COMPLETED BY: P. O'GRADY ON 2012-03-07	47825	80
928134	10/2/2012	SSDTS,T1 TAP CHANGER PCB TEST	SSDTS,T1 TAP CHANGER PCB TEST OBTAIN OIL SAMPLE(S) FROM TAP CHANGER AND SEND TO LAB ANALYSIS OF PCB CONTENT.PLEASE RECORD THE FOLLOWING ON SAMPLE BOTTLE LABELS: SAMPLE TKEN AND MADE READY FOR SHIPMENT COMPLETED BY: P. O'GRADY ON 2012-03-20 OIL SAMPLE TAKEN AND SENT TO LAB FOR TESTING. COMPLETED BY: W. DOWNING & I. ORGAN ON 2012-10-02	47825	80
944074	10/25/2012	SSDTS,T1,CONDUIT TO LL SWITCH	SSDTS,T1,CONDUIT TO LL SWITCH REPLACE CONDUIT REPAIRED TO CONDSERVATOR LEVEL GAUGE. CPMPLETED BY: W. DOWNING ON 2012-10-25	47825	80
944076	10/25/2012	SSDTS,T1,SS COVERS REPAIR	SSDTS,T1,SS COVERS REPAIR SS TRANSFORMER COVER REMOVED, STRAIGHTENED OUT,	47825	80

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
944076	10/25/2012	SSDTS,T1,SS COVERS REPAIR	REINSTALLED. COMPLETED BY: W. DOWNING ON 2012-10-25	47825	80
944086	10/24/2012	SSDTS,T1 TAP CHANGER PCB TEST	SSDTS,T1 TAP CHANGER PCB TEST OBTAIN OIL SAMPLE(S) FROM TAP CHANGER AND SEND TO LAB ANALYSIS OF PCB CONTENT.PLEASE RECORD THE FOLLOWING ON SAMPLE BOTTLE LABELS: SAMPLE TAKEN AND MADE READY FOR SHIPMENT. COMPLETED BY: P. O'GRADY ON 2012-03-20 OIL SAMPLES TAKEN AND SENT TO LAB FOR TESTING. COMPLETED BY: W. DOWNING & I. ORGAN ON 2012-10-02 OIL SAMPLES TAKEN. COPLETED BY: W. DOWNING ON 2012-10-24	47825	80
1027651	1/22/2014	SSDTS,B1 REMOVE JUMPERS	SSDTS,B1 REMOVE JUMPERS JUMPERS REMOVED. COMPLETED BY: R. DAY ON 2014-01-22	47825	80

AIR BLAST CIRCUIT BREAKER - FORM II

94 Jul 04

Brk. No. B1L03 Brk S/N B142569 Date 2002/12/06 Station 55A

Ambient Temp. [illegible] Type DCVP Mfg. BROWN BOVERI

Before Operating: Pressure [illegible] PSI Counter 900525

Lubricate Control Blocks: Yes ✓ No _____

Coil Resistance: Trip: A 10.7 B 10.6 C 10.6
Close: A 68.2 B 67.3 C 69

DUCTOR TEST: Results (Micro Ohms)
A Phase: Amps 100 Reading 390
B Phase: Amps 100 Reading 422 micro Ω
C Phase: Amps 100 Reading 360

CHECK PRESSURE SWITCHES On Falling Pressure:

Block Reclose:	Found	213	Left	213
Block Trip:	Found	152	Left	156
Block Close:	Found	170	Left	170
Low Pressure Alarm:	Found	195	Left	195

CLEAN AUX.. CONTACTS:
DLF Breakers(Switch # 2610) A Phase _____ B Phase _____ C Phase _____

TIMING TEST:
3 Phase Close: _____
Milliseconds
3 Phase Trip: _____
Milliseconds
Trip Free: _____
Milliseconds
Disagreement: _____
Milliseconds
Open-Close-Open _____
Milliseconds

Check All Connections: _____ 9.4G 7.35GN 2.88G

Megger (5KV) A Phase ~~3~~ B Phase ~~3~~ C Phase ~~3~~

20-Minute Pressure
Drop: 2.28 - 2.27

Heater Amps: Cabinet 1.4 Control Blocks: A .36 B .36 C .38

After Operating: Pressure 2.25 Counter 0539

ONLY IF INSTRUCTED

Clean Intake Filter	Yes _____	
Inspect One Arcing Chamber	Yes _____	Lubrication Required _____
Clean Pressure Reducing Valve	Yes _____	
Lubricate All Arcing Chambers	Yes _____	
Time Individual Heads	Yes _____	
Doble Test	Yes _____	

Remarks: B & Shack Chipped Tank Supports rusted

Test Completed By D Downing C Bradwell

THIS FORM SHOULD BE USED AS A GUIDE IN CARRYING OUT WORK

FORM [illegible] AIR BLAST CIRCUIT BREAKER INSPECTION

384 123

System ID: Station: B1203 Serial No.: 55D B-1425698 584868
Manufacturer: Brown Boveri, Type: 230 KV. Voltage:
Test Date: 2007/06/01 Test Completed By: K.H. W.D. B.W. J.D.E.W/O #:

WEATHER CONDITIONS: (dry) rain humidity temperature 6°C
BEFORE OPERATING: Pressure 230 PSI ~~kPa~~ Counter: 90146
AFTER - 230 PSI 90154

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

DUCTOR (RESISTANCE) READING		
	% CURRENT	MICRO Ω
A ph	100	350
B ph	100	400
C ph	100	360

B1425698

TIMING TEST (milliseconds)			
	A	B	C
3-PH Close	SEE ATTACHED		SHEET 5
3-PH Trip			
Trip Free (dwell)			
Disagreement On Trip			
Resistor Contacts			

Command Current Close 4.86 amps Trip 7.06 amps

NOTE: THE BREAKER (TIMING TEST) PERFORMANCE REPORT INCLUDING ALL MAIN & RESISTOR CONTACTS SHOULD BE ATTACHED TO THE COMPLETED INSPECTION FORM. (If Applicable)

CONTROL CIRCUIT RESISTANCE (Ohms): (Tests to be Completed from Control Cabinet Terminal Board)							
Trip Coil # 1: 11.7	A ph	Ω	B ph	11.7	Ω	C ph	12 Ω
Trip Coil # 2: N/A	A ph	– Ω	B ph	–	Ω	C ph	Ω
Close:	A ph	73 Ω	B ph	74	Ω	C ph	75 Ω

INTERRUPTOR MEGGER TEST 5 KV (Breaker in Open Position) (Test Location Left/Right to be taken from Control Panel)			
A PH	1 LEFT 240 GΩ Mega Ω	2 LEFT Mega Ω	3 LEFT Mega Ω
	RIGHT Mega Ω	RIGHT Mega Ω	RIGHT Mega Ω
B PH	1 LEFT 340 GΩ Mega Ω	2 LEFT Mega Ω	3 LEFT Mega Ω
	RIGHT Mega Ω	RIGHT Megger leads heads to ground Mega Ω	RIGHT Mega Ω
C PH	1 LEFT 250 GΩ Mega Ω	2 LEFT Mega Ω	3 LEFT Mega Ω
	RIGHT Mega Ω	RIGHT Mega Ω	RIGHT Mega Ω

HEATER : AMPS		CABINET HEATER: 1.55 A.	
CONTROL BLOCKS:	A: ON 0.22 A.	B: 0.24 A.	C: 0.22 A.

FORM [illegible] AIR BLAST CIRCUIT BREAKER INSPECTION

System ID: Station:Serial No.: B1L03 55D B1425698
Manufacturer: Type: Voltage:
Test Date: _____ Test Completed By: GH WD BW. J.D.E.W/O #: ___

PRESSURE SETTINGS (kPa)		
	Found	Left
Block Reclose	213	213
Block Trip	156	156
Aux Block Trip		
Block Close	170	170
Low Pressure Alarm	195	195

AFTER OPERATING: Pressure 230 kPa Counter:

CHECKS COMPLETED:

- Air Leaks
- Lubricate Control Blocks
- Check Primary Connections
- 20 Minute Pressure Drop — Start 230. After APP 228.
- _____ Safety Relief valve operation (If Applicable)

ONLY IF INSTRUCTED

- Doble Test
- Clean Air Intake Filters
- Inspect 1 Arcing Chamber
  - Chamber Lubrication Required yes no

COMMENTS:

5994

(2)

AIR BLAST CIRCUIT BREAKER - FORM II

94 Ju

Brk. No. B1L17 Brk S/N 170-73-3/1993 Date 2001/09/12 Station HRD

Ambient Temp. 25°C Type DLF 245 NC 2 Mfg. BROWN/ BOVERI

Before Operating: Pressure _____ Counter 1462

Lubricate Control Blocks: Yes _____ No _____

Coil Resistance: Trip: A 13.2 B 13.4 C 13.2
Close: A 137 B 138 C 135

DUCTOR TEST: Results (Micro Ohms)
A Phase: Amps 100 Reading 174 U ohms
B Phase: Amps 100 Reading 94 U ohms
C Phase: Amps 100 Reading 122 U ohms

CHECK PRESSURE SWITCHES On Falling Pressure:
Block Reclose: Found 400 PSI Left 400 PSI
Block Trip: Found 382 PSI Left 382 PSI
Block Close: Found 370 PSI Left 370 PSI
Low Pressure Alarm: Found 300 PSI Left 300 PSI

CLEAN AUX.. CONTACTS:
DLF Breakers(Switch # 2610) A Phase OK B Phase OK C Phase OK

TIMING TEST:
3 Phase Close: As per test sheets. Milliseconds
3 Phase Trip: _____ Milliseconds
Trip Free: _____ Milliseconds
Disagreement: _____ Milliseconds
Open-Close-Open _____ Milliseconds

Check All Connections: ✓

Megger (5KV) A Phase 1250 mΩ B Phase 1250 mΩ C Phase 1750 mΩ

20-Minute Pressure Drop: _____

Heater Amps: Cabinet ✓ Control Blocks: A ✓ B ✓ C ✓

After Operating: Pressure _____ Counter 1469

ONLY IF INSTRUCTED
Clean Intake Filter Yes _____
Inspect One Arcing Chamber Yes _____ Lubrication Required _____
Clean Pressure Reducing Valve Yes _____
Lubricate All Arcing Chambers Yes _____
Time Individual Heads Yes _____
Doble Test Yes _____

FORM II - AIR BLAST CIRCUIT BREAKER INSPECTION

System ID: B1L17 Station: HRDTS Serial No.: 170-73-37/973
Manufacturer: Brown Boveri Can Ltd Type: AIR BLAST DLF 245 NO2 Voltage: 230 KV
Test Date: 2006-10-10 Test Completed By: B.W G.H. J.D.E.W/O #: 551787

WEATHER CONDITIONS: ✓ dry _____ rain _____ humidity 10°C temperature

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

BEFORE OPERATING: Pressure 426 ~~kPa~~ P.S.I Counter: 1657

DUCTOR (RESISTANCE) READING		
	% CURRENT	MICRO Ω
A ph	100%	165 uΩ
B ph	100%	83 uΩ
C ph	100%	98 uΩ

TIMING TEST (milliseconds)			
	A	B	C
3-PH Close	52.1	53.1	51.2
3-PH Trip	24.3	25.3	24.8
Trip Free (dwell)	56.2	48.6	50.9
Disagreement On Trip	24.7	24.8	1599.9
Resistor Contacts			

Command Current Close _____ amps Trip _____ amps

NOTE: THE BREAKER (TIMING TEST) PERFORMANCE REPORT INCLUDING ALL MAIN CONTACTS SHOULD BE ATTACHED TO THE COMPLETED INSPECTION FORM.

CONTROL CIRCUIT RESISTANCE (Ohms): (test to be completed from the Control Cabinet Terminal Board)								
Trip Coil # 1:	A ph	13.1	Ω	B ph	13	Ω	C ph	13.4 Ω
Trip Coil # 2:	A ph	13	Ω	B ph	13	Ω	C ph	13 Ω
Close:	A ph	45	Ω	B ph	44.8	Ω	C ph	45 Ω

INTERRUPTOR MEGGER TEST 5 KV (Mega Ω) (B1B2 at WAVTS has 2 Interrupters per Phase all other DLF Breakers have 1 per phase)				
A PH	# 1 LEFT 76 GΩ	/ RIGHT	# 2 LEFT 75 GΩ	/ RIGHT
B PH	# 1 LEFT 74 "	/ RIGHT	# 2 LEFT 76 GΩ	/ RIGHT
C PH	# 1 LEFT 76 "	/ RIGHT	# 2 LEFT 74 GΩ	/ RIGHT

HEATER AMPERAGE:			
CABINET HEATER :	4.77 Amps. Total		
CONTROL BLOCKS:	A: 0.58	B: .56	C: .57

FORM II - AIR BLAST CIRCUIT BREAKER INSPECTION

System ID: BIL17 Station: HRD Serial No.: 170-73-3 | 1973
Manufacturer: Brown Boveri Type: DLF 245 n2 Voltage: 230 K.V
Test Date: 2006 | 10 | 11 Test Completed By: GH . B.W. S.T. DH J.D.E.W/O #: _____

PRESSURE SETTINGS (kPa)		
	Found	Left
Block Reclose	400	400
Block Trip	370	370
Aux Block Trip	-	-
Block Close	382	382
Low Pressure Alarm	306	306

CHECKS COMPLETED:
- OK. Air Leaks
- NO Lubricate Control Blocks
- yes Check Primary Connections
- yes 20 Minute Pressure Drop
- ✓ Safety Relief valve operation (If Applicable)

AFTER OPERATING: Pressure 435 ~~kPa~~ psi Counter: 1663

ONLY IF INSTRUCTED
- NO Doble Test
- NO Clean Air Intake Filters
- NO Inspect 1 Arcing Chamber

Chamber Lubrication Required _____ yes ✓ no

COMMENTS:

performed Megger test across contacts on Breaker

Sheet 2 of 2

DOBLE INSULATION TESTS

~~CIRCUIT~~ ~~BREAKER~~ C17

DOBLE ENGINEERING COMPANY
WATERTOWN, MASS.
FORM MH-CB178

COMPANY Hydro
LOCATION OF TESTS White River
CIRCUIT BREAKER
BREAKER MFR. TYPE
BREAKER SERIAL NO. KV AMPS.
DATE LAST INSP. DATE LAST TEST LAST TEST SHEET NO.
BUSHING MFR. BR BUSHING (TYPE-FORM-DWG.NO.)

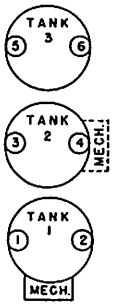
DATE July 7/82
AIR TEMP. 75°F OIL TEMP.
WEATHER % HUM.
AGE
BROWN BOVERI CAPACITORS

	BUSH. NO.	CAPACITOR BUSHING SERIAL NO.	SIDE	PHASE	FEET OF BUS	INS. IN PARLL	TEST KV	EQUIVALENT 10 KV READINGS: MICROAMPERES METER READING	MICROAMPERES MULTIPLIER	MICROAMPERES MICRO-AMPERES	WATTS METER READING	WATTS MULTIPLIER	WATTS WATTS	% POWER FACTOR MEASURED	% POWER FACTOR COR. 20°C	COLLAR TEST (WATTS/CURRENT)	CAP INSULATION RATING
OPEN CIRCUIT BREAKER	1	B1					10	1.6	10uA	660						BAD	
	2	B2					10	45	10	450	43	.002	.096	1.58			114 PF
	3	B3	OVERALL				10	43	10u	430	49	.002	.098	2.32			115 PF
	4	B4					10	46	10u	460	52	.002	.104	2.28			122
	5	B5					10	45	10uA	4.50	44	.002	.088	1.59			121
	6	B6					10	42	10uA	420	48	.002	.096	2.30			112
C.B. CLOSED	TANK 1	B7					10	44	10uA	440	48	.002	.096	2.20			117.2
	TANK 2	B8					10	42	10uA	420	80	.002	.160	3.7			113 G
	TANK 3	B9					10	40	10uA	460	90	.002	.180	4.5			106

OTHER TESTS

LINE NO.																	
1	B10											BAD				BAD	
2	B11							44	10uA	440	62	.002	.124	2.8			115
3	B12							43	10uA	430	47	.002	.094	2.2			114.8
4	B13							43	10uA	430	48	.002	.096	2.2			114.2
5	B14							43	10uA	430	62	.002	.124	2.8			114
6	B15								BAD							BAD	
7	B16															BAD	
8	B17															BAD	
9	B18															BAD	
10		New CAP.						Tested		To Complete		Set.					
11	B1						10	12	10uA	120	11.0	.002	.022	1.8			31.2 G
12	B10						10	12	10uA	120	13.5	.002	.027	2.2			30.6 G
13	B15						10	12	10uA	120	10.5	.002	.021	1.7			30.7 G
14	B16						10	12	10uA	120	11.0	.002	.022	1.8			31.0 G
15	B17						10	11	10uA	110	17	.002	.034	3.1			26.9 G
16	B18						10	12	10uA	120	10.5	.002	.021	1.7			31.2 G

KEY TO BUSHING NO.



REMARKS

KEY TO INSULATION RATING

BUSHINGS-INSULATORS-ETC.	WOOD MEMBERS-OIL-ETC.	WINDINGS
G-GOOD	XG-GOOD	WG-GOOD
D-DETERIORATED	XD-DETERIORATED	WD-DETERIORATED
I-INVESTIGATE	XI-INVESTIGATE	WI-INVESTIGATE
B-BAD (REMOVE OR RECONDITION)	XB-BAD (REMOVE OR RECONDITION)	WB-BAD (REMOVE OR RECONDITION)

TEST SET NO. _____ TEST BY _____ CHECKED BY _____ SHEET NO. _____

D.C.V.F. CAPACITOR TEST SHEET

STATION: SSD

3L203

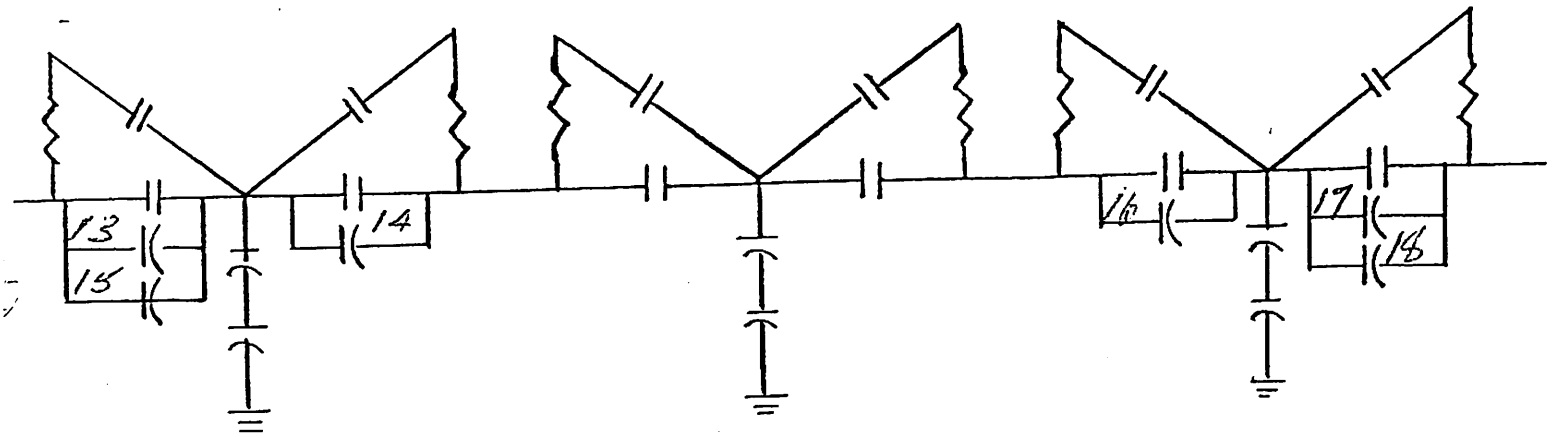
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INSP. BY: C. MERKER

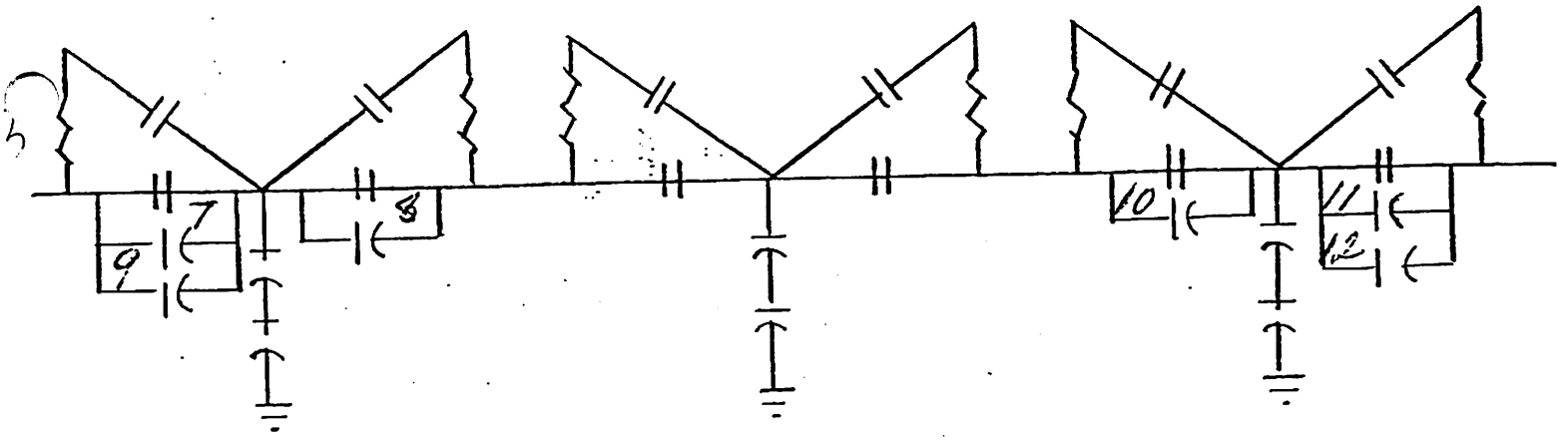
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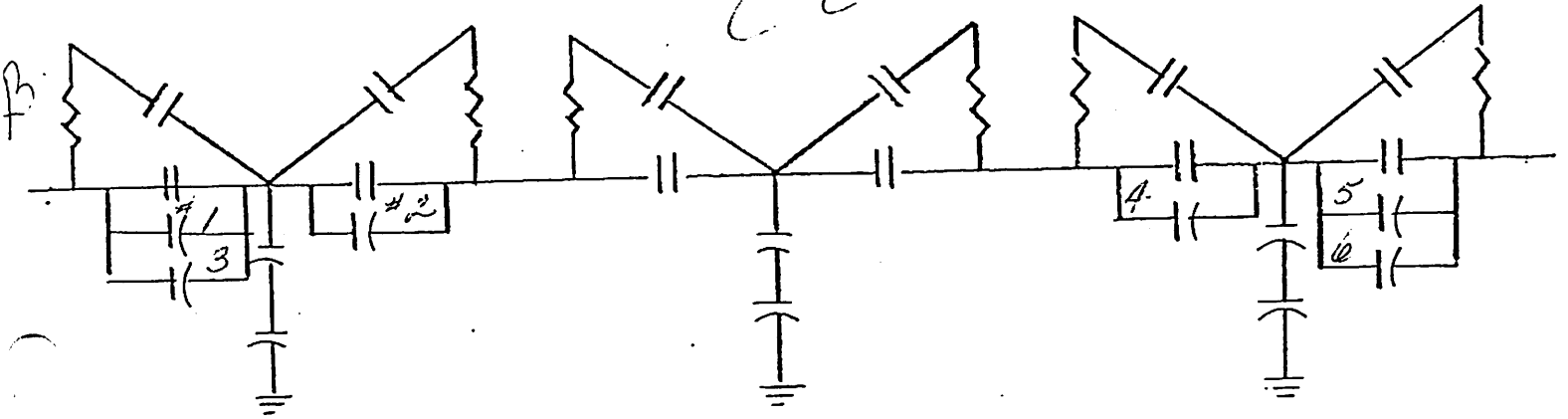
-10



-30



-50



REMARKS: Replaced Caps with ones Tested down, Cleaned Painted & dabbed

MISCELLANEOUS EQUIPMENT

(SPARE BUSHINGS, INSTRUMENT TRANSFORMERS, ETC.)

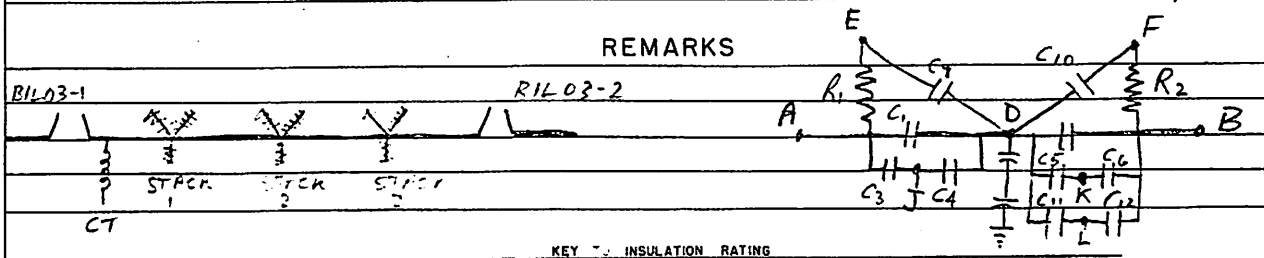
DOBLE ENGINEERING COMPANY
WATERTOWN, MASS.
FORM MH—ME178

COMPANY NFLD HYDRO — DATE 81-08-05
LOCATION OF TESTS SSD TS — AIR TEMP. 25°C — OIL TEMP.
EQUIPMENT TESTED BIL03 (ABCB) — WEATHER cloudy — % HUM. 50
MFG: BROWN BOVERI — DATE LAST TEST
Ser. # 3841 — LAST TEST SHEET NO.

COPIES TO PHASE A

	LINE NO.	STACK # SERIAL NO.	TEST KV	EQUIVALENT 10 KV READINGS MICROAMPERES METER READING	MULTIPLIER	MICROAMPERES	WATTS METER READING	MULTIPLIER	WATTS	% POWER FACTOR MEASURED	COR. 20°C	ENER	GND	Meas.	Cpf	INSULATION RATING
+31,+31	1		10	26	.02	.52	31	.01	.31	5.96		D	A,B	overall	137	G
+20,+18	2	1	10	25	.02	.50	19	.01	.19	3.8		J	A,D	C_3+C_4	134	G
+20,+24	3		10	25	.02	.50	22	.01	.22	4.4		K	D,B	C_5+C_6	128.4	G
+31,+29	4		10	22	.02	.44	30	.01	.30	6.8		L	D,B	$C_{11}+C_{12}$	114	D
+18,+16	5		10	25	.02	.50	17	.2	3.4	29.4 mΩ		A	F	R1	81	G
+17,+23	6		10	24	.02	.48	20	.2	4.0	25 mΩ		B	F	R2	78	G
	7															
	8															
+6,+2	9		10	9	.02	.18	4	.02	.08	4.4		D	A,B	overall	49	G
+33,+36	10	2	10	21	.02	.42	34.5	.1	3.45	29 mΩ		A	E	R1	70	G
+22,+22	11		10	23	.1	2.3	22	1	22	4.55 mΩ		B	F	R2	253	B
	12															
	13															
+34,+34	14		10	51	.02	1.02	34	.2	6.8	66.7		D		overall	158	I
+11,+6	15	3	10	26	.02	.52	8.5	.02	.17	3.27		J		C_3+C_4	141	G
+12,+8	16		10	25	.02	.50	10	.02	.20	4		K		C_5+C_6	128	G
	17		10	21	.1	2.1	no watts reading					L		$C_{11}+C_{12}$	—	B
+18,+20	18		10	22	.02	.44	19	.2	3.8	26.32 mΩ		A		R1	50	G
+21,+19	19		10	25	.02	.50	20	.2	4	25 mΩ		B		R2	102	G
	20															
	21			Standard test not performed, but												
	22			test indicate that												
	23			① A Ø - CENTER STACK - RESISTOR (B TO A) LOW MΩ READING												
	24			② Ø Ø - STACK #3 (NEAR BIL03-2) - BAD CAPACITOR												
	25			DESIGNATED C5 & C6												
	26															
	27															
	28															
	29															

REMARKS



KEY TO INSULATION RATING

BUSHINGS-INSULATORS-ETC.	WOOD MEMBERS-OIL-ETC.	WINDINGS
G=GOOD	XG=GOOD	WG=GOOD
D=DETERIORATED	XD=DETERIORATED	WD=DETERIORATED
I=INVESTIGATE	XI=INVESTIGATE	WI=INVESTIGATE
B=BAD (REMOVE OR RECONDITION)	XB=BAD (REMOVE OR RECONDITION)	WB=BAD (REMOVE OR RECONDITION)

TEST SET NO. M2H-122 TEST BY CA DS CHECKED BY _____ SHEET NO. NLH-SSD-BIL03-B1-1

Case # 25

DOBLE INSULATION TESTS

MISCELLANEOUS EQUIPMENT

(SPARE BUSHINGS, INSTRUMENT TRANSFORMERS, ETC.)

DOBLE ENGINEERING COMPANY
WATERTOWN, MASS
FORM MH–ME178

COMPANY NFLD HYDRO — DATE 81-08-05

LOCATION OF TESTS SSD TS — AIR TEMP. 25°C — OIL TEMP.

EQUIPMENT TESTED BIL03 (ATCB) — WEATHER Cloudy — % HUM. 50%

DATE LAST TEST

Ser# 3842 — LAST TEST SHEET NO.

COPIES TO

PHASE B

LINE NO.	STACK # SERIAL NO.	TEST KV	EQUIVALENT 10 KV READINGS MICROAMPERES METER READING	MULTIPLIER	MICRO-AMPERES	WATTS METER READING	MULTIPLIER	WATTS	% POWER FACTOR MEASURED	COR. 20°C	ENER		Cpf.	INSULATION RATING
+14,+10 — 1		10	25	.02	.50	12	.02	.24	4.8		D		130	G
+8,+8 — 2	1	10	24	.02	.48	8	.02	.16	3.3		J		130	G
+19,+9 — 3		10	20	.02	.40	13	.02	.26	6.5		K		100	D
+5,+7 — 4		10	24	.02	.48	6	.02	.12	2.5		L		128	G
+31,+37 — 5		10	21	.02	.42	34	.1	2.9	34.5	MΩ	A		79	G
+40,+40 — 6		10	24	.02	.48	40	.1	4.0	25	MΩ	B		73	G
7														
8														
+6,+8 — 9		10	9	.02	.18	7	.01	.07	3.9		D		47	G
+37,+37 — 10	2	10	22	.02	.44	37	.1	3.7	27	MΩ	A		62	G
+36,+38 — 11		10	23	.02	.46	37	.1	3.7	27	MΩ	B		58	G
12														
13														
+10,+8 — 14		10	26	.02	.52	9	.02	.18	3.5		D		140	G
+6,+10 — 15	3	10	24	.02	.48	8	.02	.16	3.3		J		130	G
+6,+10 — 16		10	24	.02	.48	8	.02	.16	3.3		K		127	G
+9,+3 — 17		10	24	.02	.48	6	.02	.12	2.5		L		125	G
+40,+40 — 18		10	25	.02	.50	40	.1	4	25	MΩ	A		62	G
+42,+38 — 19		10	24	.02	.48	40	.1	4	25	MΩ	B		65	G
20														
21														
22														
23														
24														
25														
26														
27														
28														
29														

REMARKS

KEY TO INSULATION RATING

BUSHINGS–INSULATORS–ETC.	WOOD MEMBERS–OIL–ETC.	WINDINGS
G=GOOD	XG=GOOD	WG=GOOD
D=DETERIORATED	XD=DETERIORATED	WD=DETERIORATED
I=INVESTIGATE	XI=INVESTIGATE	WI=INVESTIGATE
B=BAD (REMOVE OR RECONDITION)	XB=BAD (REMOVE OR RECONDITION)	WB=BAD (REMOVE OR RECONDITION)

TEST SET NO. _____ TEST BY CO DS CHECKED BY _____ SHEET NO. NLH-SSD-BIL03-BI-2

DOBLE INSULATION TESTS

MISCELLANEOUS EQUIPMENT

(SPARE BUSHINGS, INSTRUMENT TRANSFORMERS, ETC.)

DOBLE ENGINEERING COMPANY
WATERTOWN, MASS.
FORM MH—ME178

COMPANY NFLD HYDRO — DATE 81-08-05

LOCATION OF TESTS SSD-TS — AIR TEMP. 25°C — OIL TEMP.

EQUIPMENT TESTED BIL03 (AB3CB) — WEATHER Cloudy — % HUM. 50%

DATE LAST TEST

Ser # 3843 — LAST TEST SHEET NO.

COPIES TO PHASE C

	LINE NO.	STACK # SERIAL NO.	TEST KV	EQUIVALENT 10 KV READINGS MICROAMPERES METER READING	MULTIPLIER	MICROAMPERES	WATTS METER READING	MULTIPLIER	WATTS	% POWER FACTOR MEASURED	COR. 20°C	ENER		Cpf	INSULATION RATING
+25,+27	1		10	25	.02	.50	26	.01	.26	5.2		D		130	G
+32,+8	2	1	10	25	.02	.50	20	.01	.20	4		J		134	G
+47,+21	3		10	25	.02	.50	34	.01	.34	6.8		K		136	D
+37,+13	4		10	20	.02	.40	25	.01	.25	6.25		L		55	D
+30,+34	5		10	21	.02	.42	32	.1	3.2	31.25 MΩ		A		66	G
+38,+36	6		10	22	.02	.44	37	.1	3.7	27 MΩ		B		76	G
	7														
	8														
+12,+4	9		10	9	.02	.18	8	.01	.08	4.4		D		48	G
+36,+40	10	2	10	24	.02	.48	38	.1	3.8	26.32 MΩ		A		77	G
+39,+31	11		10	22	.02	.44	35	.1	3.5	28.6 MΩ		B		74	G
	12														
	13														
+11,+9	14		10	26	.02	.52	10	.02	.20	3.85		D		140	G
+5,+9	15	3	10	25	.02	.50	7	.02	.14	2.8		J		134	G
+7,+11	16		10	24	.02	.48	9	.02	.18	3.8		K		127	G
+13,+5	17		10	24	.02	.48	9	.02	.18	3.8		L		127	G
+68,+74	18		10	41	.02	.82	71	.1	7.1	14 MΩ		A		100	D
+43,+39	19		10	25	.02	.50	41	.1	4.1	24.4 MΩ		B		69	G
	20														
	21														
	22	[illegible]													
	23														
	24														
	25														
	26														
	27														
	28														
	29														

REMARKS

KEY TO INSULATION RATING

BUSHINGS-INSULATORS-ETC.	WOOD MEMBERS-OIL-ETC.	WINDINGS
G=GOOD	XG=GOOD	WG=GOOD
D=DETERIORATED	XD=DETERIORATED	WD=DETERIORATED
I=INVESTIGATE	XI=INVESTIGATE	WI=INVESTIGATE
B=BAD (REMOVE OR RECONDITION)	XB=BAD (REMOVE OR RECONDITION)	WB=BAD (REMOVE OR RECONDITION)

TEST SET NO. M2H-122 — TEST BY CG, DS — CHECKED BY _____ — SHEET NO. NLH-SSD-BIL03-81-3

Cas: #25

DOBLE INSULATION TESTS

MISCELLANEOUS EQUIPMENT

(SPARE BUSHINGS, INSTRUMENT TRANSFORMERS, ETC.)

DOBLE ENGINEERING COMPANY

FORM MH-ME178

COMPANY HYDRO — DATE 80-10-15

LOCATION OF TESTS SSD — AIR TEMP. 10°C — OIL TEMP.

EQUIPMENT TESTED BIL03 ABCB — WEATHER Sunny — % HUM. 70

TYPE. DCUF. - 230KV 1250 Amps — DATE LAST TEST

MFR. BROWN BOVERI — LAST TEST SHEET NO.

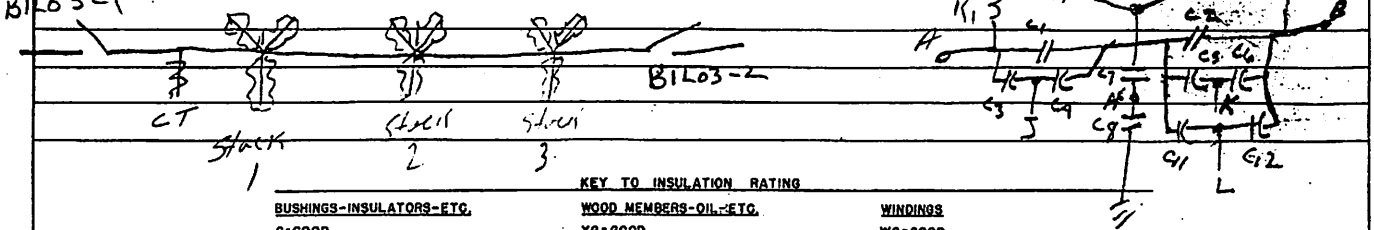
S.N. 3841

COPIES TO A phase

LINE NO.	Stacks ~~SERIAL NO.~~	TEST KV	EQUIVALENT 10 KV READINGS MICROAMPERES METER READING	MULTIPLIER	MICRO-AMPERES	EQUIVALENT 10 KV READINGS WATTS METER READING	MULTIPLIER	WATTS	% POWER FACTOR MEASURED	COR. 20°C	ENER	GND	Measure	INSULATION RATING
1		10	78	10uA	780	35	.1	3.5	45.		D	A, B	Overall	
2		10	57	10uA	570	67	.01	.67	7.3		J	A D	C_3+C_4	
3	1	10	51	10uA	510	41	.01	.41	8.0		K	D, B	C_5+C_6	
4		10	58	.02	1.16	48	.2	9.6	84		L	D, B	$C_{11}+C_{12}$	
5		10	98	10uA	900	65	.10	6.5	11.1	mA	A	E	R_1	
6		10	53	10uA	530	35	.1	3.5	18.9	"	B	F	R_2	
7														
8		10	19	10uA	190	68	.002	.136	7.2		D	AB	Overall	
9	2	10	41	10uA	410	30	.1	3.0	24.4	mA	A	E	R_1	
10		10	58	10uA	580	50	.2	10	17.5	"	B	F	R_2	
11														
12		10	53	10uA	530	58	.01	.58	11.0		D	Same as		
13		10	52	10uA	520	44	.01	.44	9.4		J	above		
14		10	51	10uA	510	58	.01	.50	9.8		K			
15	3	10	45	10uA	450	52	.01	.52	11.2		L			
16		10	42	10uA	420	35	.1	3.5	23.8	mA	A			
17		10	43	10uA	430	31	.1	3.1	22.3	"	B			
18														
19														
20														
21														
22														
23														
24														
25														
26														
27														
28														
29														

+36, +34
+77, +57
+49, +33
+48, +48
+63, +67
+35, +35
+69, +67
+30, +30
+50, +50
+57, +59
+48, +48
+50, +50
+52, +52
+35, +35
+28, +34

REMARKS



KEY TO INSULATION RATING

BUSHINGS-INSULATORS-ETC.	WOOD MEMBERS-OIL-ETC.	WINDINGS
G=GOOD	XG=GOOD	WG=GOOD
D=DETERIORATED	XD=DETERIORATED	WD=DETERIORATED
I=INVESTIGATE	XI=INVESTIGATE	WI=INVESTIGATE
B=BAD (REMOVE OR RECONDITION)	XB=BAD (REMOVE OR RECONDITION)	WB=BAD (REMOVE OR RECONDITION)

TEST SET NO. M12H-129 TEST BY R.R.V.S. CHECKED BY _____ SHEET NO. 193

DOBLE INSULATION TESTS

DOBLE ENGINEERING COMPANY

MISCELLANEOUS EQUIPMENT

FORM MH-ME178

(SPARE BUSHINGS, INSTRUMENT TRANSFORMERS, ETC.)

COMPANY HYDRO — DATE 80-10-15

LOCATION OF TESTS SSD — AIR TEMP. 10°C — OIL TEMP.

EQUIPMENT TESTED BICO 3 — WEATHER Sunny — % HUM. 70

DATE LAST TEST

LAST TEST SHEET NO.

S.N. 3842

COPIES TO B phase

LINE NO.	~~SERIAL NO.~~ stack	TEST KV	EQUIVALENT 10 KV READINGS: MICROAMPERES METER READING	MULTIPLIER	MICROAMPERES	WATTS METER READING	MULTIPLIER	WATTS	% POWER FACTOR: MEASURED	COR. 20°C	ENER.	GND measure	INSULATION RATING
1		10	60	10uA	600	18	.01	.18	3.0		D	Same as	
2		10	48	10uA	480	17	.01	.17	3.6		J	A Phase	
3	1	10	47	10uA	470	17	.01	.17	3.6		K		
4		10	47	10uA	470	15	.01	.15	3.2		L		
5		10	45	10uA	450	35	0.1	3.5	22.2	mv	A		
6		10	45	10uA	450	35	0.1	3.5	22.2	"	B		
7													
8		10	18	10	180	33	.002	.066	3.7		D		
9	2	10	42	10	420	32	.1	3.2	23.8	mv	A		
10		10	42	10	420	33	.1	3.3	23.8	"	B		
11													
12		10	51	10uA	500	39	.01	.39	7.8		D		
13		10	48	10uA	480	23	.01	.23	4.8		J		
14	3	10	41	10uA	410	47	.01	.47	11.5		K		
15		10	48	10uA	480	74	.002	.148	3.2		L		
16		10	43	10uA	430	34	.1	3.4	22.3	mv	A		
17		10	42	10uA	420	29	.1	29	23.8	"	B		
18													
19													
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													

+31, +5
+15, +19
+16, +19
+15, +9
+21
+35, +3.5
+36, +34

+53, +13
+32, +32
+32, +33
+33 +33

+34, +42
+24, +22
+46, +48
+67, +81
+34 +34
+30, +28

14 6

REMARKS

KEY TO INSULATION RATING

BUSHINGS-INSULATORS-ETC.	WOOD MEMBERS-OIL-ETC.	WINDINGS
G=GOOD	XG=GOOD	WG=GOOD
D=DETERIORATED	XD=DETERIORATED	WD=DETERIORATED
I=INVESTIGATE	XI=INVESTIGATE	WI=INVESTIGATE
B=BAD (REMOVE OR RECONDITION)	XB=BAD (REMOVE OR RECONDITION)	WB=BAD (REMOVE OR RECONDITION)

TEST SET NO. M2H-129 TEST BY R.R. D.S. CHECKED BY _____ SHEET NO. 2 of 3

DOBLE INSULATION TESTS

DOBLE ENGINEERING COMPANY

MISCELLANEOUS EQUIPMENT

FORM MH-ME178

(SPARE BUSHINGS, INSTRUMENT TRANSFORMERS, ETC.)

COMPANY HYDRO — DATE 80-10-15

LOCATION OF TESTS SSD — AIR TEMP. 10°C — OIL TEMP.

EQUIPMENT TESTED BIL03 — WEATHER Sunny — % HUM. 70

DATE LAST TEST

LAST TEST SHEET NO.

S.N. 3843

COPIES TO C phase.

LINE NO.	stack SERIAL NO.	TEST KV	EQUIVALENT 10 KV READINGS: MICROAMPERES METER READING	MULTIPLIER	MICROAMPERES	WATTS METER READING	MULTIPLIER	WATTS	% POWER FACTOR MEASURED	COR. 20°C	ENER. GND. measure	INSULATION RATING
1		10	52	10UA	520	21	.01	.21	4.0		D	Same as
2		10	50	10uA	500	20	.01	.20	4.0		J	A phase
3	1	10	57	10uA	570	18	.01	.18	2.3		K	
4		10	49	10uA	490	22	.01	.22	4.6		L	
5		10	52	10uA	520	42	.1	4.2	19.2	mΩ.	A	
6		10	46	10uA	460	37	.1	3.7	21.7	"	B	
7												
8		10	18	10uA	180	28	.002	.056	3.1		D	
9	2	10	41	10uA	410	32	.1	3.2	24.4	mΩ.	~~D~~	
10		10	44	10uA	440	35	.1	3.5	22.7	"	B	
11												
12		10	58	10uA	580	25	.01	.25	4.4		D	
13		10	49	10uA	490	19	.01	.19	3.9		J	
14	3	10	49	10uA	490	21	.01	.21	4.3		K	
15		10	39	10uA	390	18	.01	.18	4.6		L	
16		10	46	10uA	460	33	.1	3.3	21.7	mΩ.	A	
17		10	39	10uA	390	28	.1	2.8	25.6	"	B	
18												
19												
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												

+22, +20
+19, +21
+17, +19
+21, +23
+43 +41
+37
+3
+28, +28
+29, +33
+36, +34

+20, +30
+27, +11
+22, +28
+18, +18
34, 32
+28, +28

REMARKS

KEY TO INSULATION RATING

BUSHINGS-INSULATORS-ETC.	WOOD MEMBERS-OIL-ETC.	WINDINGS
G=GOOD	XG=GOOD	WG=GOOD
D=DETERIORATED	XD=DETERIORATED	WD=DETERIORATED
I=INVESTIGATE	XI=INVESTIGATE	WI=INVESTIGATE
B=BAD (REMOVE OR RECONDITION)	XB=BAD (REMOVE OR RECONDITION)	WB=BAD (REMOVE OR RECONDITION)

TEST SET NO. M2H-129 TEST BY R.R. D.S. CHECKED BY _____ SHEET NO. 3 of 3

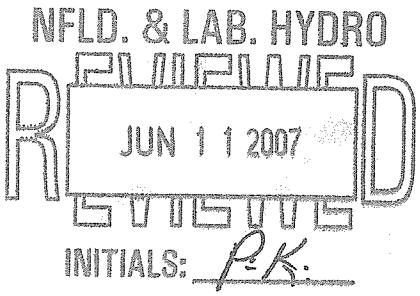
W O P K O R D E R : 3 8 5 2 3 4 SUBSIDIARY: 1 PAGE 1
The Hydro Group Of Companies Date .. 7/05/25

WO TYPE : 1 Corre SSDTS,B1L03,PLC controls,INST PARENT #: 00385234
STATUS : 45 PRIORITY: 4 Requi
ITEM # : 00005814 UNIT #: SSDB1L03 BREAKER,B1L03,SSD TS
PLT COND: B.U. #: 1325 SUPV: WHB Protect & Control Dept
LOCN: SSDTS SSD Term Stn, Sunnyside ORIG: Warren, A Craig
W/H : 1829 Bishop Falls Warehouse PLNR: Lyver, Gerard J.
EMPL: W.O.#: 385234 W.O. SUBCODE: PJC

--- Full Description of Request ----------

Install PLC controls on B1L03
A programmable logic controller to be installed to replace
reclosing control on B1L03
2003 W/O held over til Jan 31/04

---OP#---	----CRAFT----	---DESCRIPTION----------	--SIZE--	-----MHRS----
1.00]	WHBCRTEC]	WHB Tech Services Tech]	2.0]	



-- COMMENTS & WORK DONE ----------

New PLC package wired & tested. old "Cansa" case package removed from Panel 15 & the new PLC installed - wiring changes made & the new recloser was function tested into service Results with Bob Stoyles including any changes needed in logic.

-- ASSET TRACKING INFORMATION ----------

1. List all assets installed (Description and Serial Number):

1.a Provide Nameplate Data for all new assets installed:

2.If an asset was removed, note the Description, Serial# and JDE# if known and where it was transferred. ie. St. Anthony Line Depot, Bishops Falls etc.

3. List all assets disposed or to be disposed (Description, Serial #, and JDE #, if known):

COMPLETED BY: June 2/25 COMPLETED ON: LH / JMcd

-- WORK REMAINING ----------

SUPERVISOR: Bob Stoyles

Work Order # 385234
SSD B1L03

Relay test results for coil resistance and contact resistance. All readings taken with Fluke 76 Meter lead resistance .2 ohms.

Relay	*Coil Ohms*	*Contacts & Resistance*	*Relay Type*
R1	**9.77 Kohms** Coil A & B	**6&4 N/O** .3 ohms energized O.L. de-energized	**KUEP-3D15-110**
R2	**9.71 Kohms** Coil A & B	**6&4 N/O** .3 ohms energized O.L. de-energized	**KUEP-3D15-110**
R3	**9.97 Kohms** Coil A & B	**6&4 N/O** .3 ohms energized O.L. de-energized	**KUEP-3D15-110**
R4	**9.69 Kohms** Coil A & B	**6&4 N/O** .3 ohms energized O.L. de-energized	**KUEP-3D15-110**
R5	**6.32 Kohms** Coil A & B	**Form C**(2 sets) **9&6 open** (.3 ohms relay energized) **9&6 open** (O.L. relay de-energized) **9&3 closed** (.3 ohms relay de-energized) **9&3 closed** (O.L. relay energized) **7&4 open** (.3 ohms relay energized) **7&4 open** (O.L. relay de-energized) **7&1 closed** (.3 ohms relay de-energized) **7&1 closed** (O.L. relay energized)	**KUEP-11D15-110**
R6	**6.27 Kohms** Coil A & B	**Form C**(2 sets) **9&6 open** (.3 ohms relay energized) **9&6 open** (O.L. relay de-energized) **9&3 closed** (.3 ohms relay de-energized) **9&3 closed** (O.L. relay energized) **7&4 open** (.3 ohms relay energized) **7&4 open** (O.L. relay de-energized) **7&1 closed** (.3 ohms relay de-energized) **7&1 closed** (O.L. relay energized)	**KUEP-11D15-110**

R7	**9.92 Kohms** Coil A & B	**6&4 N/O** .3 ohms energized O.L. de-energized	**KUEP-3D15-110**
R8	**9.83 Kohms** Coil 2 & 7	**Form C**(2 sets) **1&3 open** (.3 ohms relay energized) **1&3 open** (O.L. relay de-energized **1&4 closed** (.3 ohms relay de-energized) **1&4 closed** (O.L. relay energized) **8&6 open** (.3 ohms relay energized) **8&6 open** (O.L. relay de-energized) **8&5 closed** (.3 ohms relay de-energized) **8&5 closed** (O.L. relay energized)	**KRP-11DG-110**

Relay	***Coil Ohms***	***Contacts & Resistance***	***Relay Type***
T	**2.62 Kohms** Coil 11& 21	**12&13 N/O** **14&15 N/O** **16&17 N/O** **22&23 N/O** **24&25 N/O** **26&27 N/O**	**RXMS-1** **RK 216 263-AP** **125 VDC**
	All contacts .2 ohms when relay energized and O.L. when de-energized		
BT	**9.67 Kohms** Coil 11& 21	**12&13 N/O** **14&15 N/O** **18&28 N/O** **22&23 N/O** **24&25 N/O** **16&17 N/C** **26&27 N/C**	**RXMA-1** **RK 211 274-AN** **110-125 VDC**
	All open contacts .2 ohms when relay energized and O.L. when de-energized. All closed contacts .2 ohms when relay de-energized and O.L. when relay energized.		

All relays checked against drawings (for contact usage) powered up and operated before installation.

PLC components

RC1	*PC-A984-145*	*Modicon PLC (984-E265)*
RC2	*AS-P120-125*	*Power Supply (P120-125)* *Checked OK*
RC3	*AS-BDAP-253*	*Combined I/O Card (DAP 253)* *All inputs and used outputs checked OK*
RC4	*AS-BDAP-253*	*Combined I/O Card (DAP 253)* *All inputs and used outputs checked OK*
RC5	*AS-BDAP-208*	*Relay Output Card (DAP 208)* *All used outputs checked OK*

The following was done when checking the new PLC recloser into service.

1. *Breaker local close*
2. *Breaker local open*
3. *Breaker remote close*
4. *Breaker remote open*
5. *Reclosing was tried with the following trips*
   a. *21P1 Aph., Bph., and Cph., all reclosed successfully.*
   b. *21P2 Aph., Bph., and Cph., all reclosed successfully.*
   c. *Single ph. trip with reclosing turned off turned into a three ph. Trip*
   d. *BR, BT & F logic was checked.*
   e. *"B" contact to Optimho and other Breaker L03L06 was checked for proper operation.*

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
5126	6/2/2005	SSDTS,B1L03,TERMINAL BOARD	REPLACE DAMAGED PORCELAIN TERMINALS IN CABINET CONTROL CABINET TYPE BD/25 REF DWG TS-10-00 USE SPARE TERMINALS TO REPLACE DAMAGED TERMINALS REPLACED FOUR BROKEN TERMINAL BLOCKS JUNCTION TESTED THE BREAKER. COMPLETED BY: P.O'GRADY ON 2005-06-02 REMOVED SPARE TERMINAL BLOCKS FROM B3B4 AT LHR TO BE INSTALLED IN BREAKER IN SSD. COMPLETED BY: G. HILLER ON 2005-06-02 WORK REMAINING: INSTALL TERMINAL BLOCKS IN B1L03 AT SSD.	47825	90
263859	1/29/2003	SSDTS,B1L03,BREAKER OVERHAUL	SUNNYSIDE TERMINAL STATION - B1L03 COMPLETE THE FOLLOWING ON AIR BLAST CIRCUIT BREAKER 1. REPLACE 9 INTERRUPTORS. 2. REPLACE 3 CONTROL BLOCKS. 3. REPLACE 3 SERVO VALVES. 4. REPLACE 1 SIGNAL DEVICE. 5. OVERHAUL 6 MAIN VALVES. 6. OVERHAUL 1 RETARDING VALVE. REPLACED - 3 SERVO VALVES - 3 CONTROL BLOCKS - 6 MAIN VALVES(FIELD SERVICE) - 1 SIGNALLING DEVICE - 9 INTERRUPTERS BREAKER ALSO MEGGERED DUCTORED AND TIMED. TESTED FOR AIR LEAKS. COMPLETED BY: W. DOWNING, G. HILLIER, P. O'GRADY & G. COMPLETED ON: 2002-12-02 RETARDING VALVE NOT REBUILT. 1 RESISTER CHIPPED ON A 1 STACK CHIPPED ON B PHASE.	47825	90
281652	1/14/2003	SSDTS,B1L03,OVERHAUL(SHOP)	SUNNYSIDE TERMINAL STATION - B1LO3 COMPLETE THE FOLLOWING ON AIR BLAST CIRCUIT BREAKER B1L03 PARTS WHEN RETURNED TO THE SHOP. 1. OVERHAUL 9 INTERRUPTORS.	47804	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
281652	1/14/2003	SSDTS,B1L03,OVERHAUL(SHOP)	2. OVERHAUL 3 CONTROL BLOCKS. 3. OVERHAUL 3 SERVO VALVES. 4. OVERHAUL 1 SIGNAL DEVICE. ALL INTERRUPTERS; SERVO VALVES; CONTROL BLOCKS AND DEVICES OVERHAULED. (TERMINALS CREW)	47804	90
315408	1/29/2003	SSDTS,B1L03,CAPACITOR,REFURB	SSDTS,B1L03,CAPACITOR,REFURBISH CAPACITOR MEGGERED, CLEANED, PRIMED AND PAINTED. COMPLETED BY: P. O'GRADY ON 2003-01-27	47825	90
321854	2/10/2003	SSDTS,VALVE,REPLACE,B1L03	SUNNYSIDE TERMINAL STATION: B1L03 REPLACE VALVE & SEALING DISC. IN SERVO VALVES FOR BREAKER B1L03 AT SSD. (TOTAL 3 PER BREAKER). OUTAGE REQUIRED. DRAIN RECEIVERS. STAMP OUTER CASTING OF EACH VALVE FRONT FACE LEFT CORNER WITH MARKING (P.W.) OUTAGE REQUIRED, DRAIN RECEIVERS. B1L03 SERVO VALVES REMOVED, REFURBISHED, INSTALLED, FOR LEAKS AND RESTORED BACK TO SERVICE. COMPLETED BY: D. BLAKE, G. BRODERICK, P. O'GRADY & S. TUCKER COMPLETED ON: 2003-02-03	47825	90
371613	1/30/2004	SSDTS,B1L03,PLC controls,INST	Install PLC controls on B1L03 A programmable logic controller to be installed to replace reclosing control on B1L03 2003 W/O held over til Jan 31/04 NEW WORK ORDER #371613 COMPLETED BY: J.S. FOLEY ON 2004-01-30	47826	90
371616	1/6/2004	SSDTS,B1L03,INST PLC controls	Install PLC controls on B1L03 Planning Engineer: Craig Warren	47826	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
372957	3/1/2005	SSDTS,B1L03,INDICATION	ECC - Indication for B1L03 at ECC open & close several times, when breaker was opened. CONTACT BOUNCE UNABLE TO DO ANYTHING ABOUT THIS. COMPLETED BY: J.S. FOLEY ON 2005-03-01	47826	90
385234	6/2/2007	SSDTS,B1L03,PLC controls,INST	Install PLC controls on B1L03 A programmable logic controller to be installed to replace reclosing control on B1L03 2003 W/O held over til Jan 31/04 NEW PLC PACKAGE WIRED AND TESTED. OLD "CANSA" CASE PACKAGE REMOVED FROM PANEL 15 AND THE NEW PLC INSTALLED. WIRING CHANGES MADE AND THE NEW RECLOSER WAS FUNTION TESTED INTO SERVICE. RESULTS WITH B. STOYLES INCLUDING ANY CHANGES NEEDED IN LOGIC. COMPLETED BY: L. HOPKINS/J. MCDONALD ON 2007-06-02	47826	80
389723	6/1/2007	SSDTS,BKR B1L03 RE-LUBRICATE	SSDTS,BKR B1L03 RE-LUBRICATE 1. CLEAN COMPONENTS NOW LUBRICATED WITH DOW AND WITH GRAPHITE OIL, RENOLIT & DOW-3451 AS REQUIRED. 2. COMPONENTS TO BE RE-LUBRICATED: 3 CONTROL VALVES 1 SIGNALLING DEVICE 3 SERVO VALVES 9 INTERRUPTERS 3 MAIN VALVES 3. REMOVE STACKS AND INSPECT INTERRIOR GLAZING. 4. INSPECT STACK FLANGE GROUTING. 5. REPLACE ANY DETERIORIATED STACKS AND RECORD. 6. CLEAN STACKS WITH ACETONE PRIOR TO INSTALLATION. 7. USE NEW O-RINGS WHEN REPLACING STACKS. 8. REPLACE VENTILATION CARTRIDGES COMPLETE WITH SEALS ON ALL STACKS. 9. IDENTIFY THE BREAKER FROM WHICH THEY WERE REMOVED RETURN THE USED VENTILATION CARTRIDGES TO A.H.R. NOTE: PART # 68000106 QUANITY MAY HAVE TO BE BY 18 IF THE BREAKER HAS 3 INSULATOR COLUMNS IN THE	47825	80

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
389723	6/1/2007	SSDTS,BKR B1L03 RE-LUBRICATE	STACK. B1L03 RELUBRIACATED AND PM COMPLETED ON BREAKER. FOUND CHIPPED STACK INSULATORS. REPLACEMENT LENGTH. GLYPTOL EXPOSED SURFACE AND RETURNED TO SERVICE. CHIPPED RESISTOR. GLYPOLLED AND RESTORED TO SERVICE. TIMING TEST DONE TO HAVE BASE LINE TECH CHANGED OUT RESTORE AIR TO BREAKER FOUND LEAK IN ONE HEAD. AND REPAIRED LEAK. COMPLETED PM AND FINAL TIMING TESTS. RESTORED TO SERVICE. COMPLETED BY: W. DOWNING ON 2007-06-01	47825	80
393534	4/8/2004	SSD,B1L03,AUX.CONTACTS,CHECK	SSDTS,B1L03,AUX.CONTACTS,CHECK, ALSO SINGLE POLE 1.PHYSICALLY CHECK AUX.CONTACTS FOR TIGHTNESS,NEED RIGHT SIDE PANEL IN ORDER TO CHECK ALL CONTACTS. 2.CHECK SINGLE POLE RECLOSING-INITIATE FROM OUTAGE 1 HR CONTACTS AND RECLOSING CHECKED DURING OUTAGE - OKAY COMPLETED BY: W. DOWNING/J. MCDONALD/L. HOPKINS COMPLETED ON: 2004-04-08	47825	90
417738	7/1/2005	SSDTS,B1L03,CT,SAND & PAINT	SSDTS,B1L03,CT's,SAND & PAINT	47825	90
438274	4/8/2005	SSDTS.B1L03 BT RELAY,REPLACE	Replace SSD B1L03 BT relay Some RXMB1 (BT) relays have faulted. RXMA1 relay on materials work order 439962.	47826	90
439962	4/8/2005	SSDTS.B1L03 BT RELAY,REPLACE	Replace SSD B1L03 BT relay See WO 438274 for labour. This is the work order to purchase the relay. Order stores number 68600952 Qty: 1	47826	90
440828	12/28/2004	SSDTS,B1L03,NOT CLOSING,INVEST	SSDTS,B1L03,NOT CLOSING,INVEST CHECKED FUSES IN BREAKER FRO CONTROL POWER. CHECKED PROTECTION FUSES BEHIND CONTROL PANEL. ECC HAD TROUBLE RECLOSING B1L03	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
440828	12/28/2004	SSDTS,B1L03,NOT CLOSING,INVEST	NO TROUBLE FOUND WEATHER CONDITIONS - SLEET AND ICY. COMPLETED BY: W. WALSH ON 2004-12-28	47825	90
576789	3/6/2007	SSDTS,B1L03,WOULD NOT OPERATE	SSDTS,B1L03,WOULD NOT OPERATE OPERATED BREAKER SEVERAL TIMES LOCALLY WITH OPEN THEN ECC TRIED FROM ST. JOHN'S, STAYED IN SERVICE. LEFT AS IS. BREAKER SEEMS TO OPEN ON DISAGREEMENT. COMPLETED BY: W. DOWNING ON 07-03-06 ---------- WORK REMAINING: COMPLETE TIMING TEST ON BREAKER TO SEE IF OPERATES. REPAIR AS REQUIRED.	47825	90
583884	6/1/2007	SSDTS,B1L03,CONDUIT,REPAIR	SSDTS,B1L03,CONDUIT,REPAIR REPAIR PVC CONDUIT B1L03 P.T. TL203 NEEDS TO BE REGLUED CONDUIT REPAIRED ON P.T. COMPLETED BY: W. DOWNING ON 2007-06-01	47825	90
584868	6/1/2007	SSDTS,B1L03,PVC CONDUIT,REP	SSDTS,B1L03,PVC CONDUIT,REPAIR MAY BE THE SAME AS W/O 584868 COMPLETED.	47825	90
587205	5/10/2007	SSDTS,B1L03,RECLOSER,REPLACE	SSDTS,B1L03,RECLOSER,REPLACE BT RELAY INVESTIGATED ALARM AND FOUND "BT" RELAY P8 IN B1L03 "BURNT OUT" IE THE COIL ISOLATED BREAKER WITH TRADES PERMIT. REPLACED COIL WITH ONE SCAVENGED FROM OLD CHECKED RECLOSING AND DISAFREEMENT VIA SEL RELAY ALL PUT BREAKER BACK IN SERVICE. COMPLETED BY: J. MCDONALD, G. PARSON & P. O'GRADY ON 2007-05-11	47826	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
589257	6/1/2007	SSDTS,B1L03 REPLACE CAPACITORS	SSDTS,B1L03 REPLACE CAPACITORS/VENTILATION PAINT OLD CAPACITORS RETURN OLD VENT. CARTRIDGES TO G.LYVER B.FALLS TO BE ED CAPACITORS REPLACED ON BREAKER COMPLETED BY: W. DOWNING ON 2007-06-01 WORK REMAINING: -CAPACITORS TO BE PAINTED	47825	90
590490	6/1/2007	SSDTS,B1L03 BREAKER PM MTNCE	1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK 2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A DATE. 3.CONSIDER & REPORT ANY SIGNIFICANT ENVIROMENTAL	47825	90
590921	9/22/2007	SSDTS,B1L03,CAP STRAPS,PAINT	SSDTS,B1L03,CAP STRAPS,PAINT (OUTAGE REQUIRED) PAINT CAPACITOR STRAPS, PAINT IN WAREHOUSE. PAINTING NOT REQUIRED STRAPS ARE STAINLESS STEAL	47825	90
623205	1/9/2008	SSDTS,B1L03,FUNCTION TEST TRIP	SSDTS,B1L03,FUNCTION TEST TRIP AND RECLOSING. FUNCTION TEST BREAKER OPERATION AS PER ART BURSEY'S PERFORMED TESTING ON BREAKER (TRIPPING) RECLOSING SINGLE POLE) AS WELL AS THREE PHASE TRIPPING. ALSO CHECKED PNUMATIC DISAGREEMENT ON BREAKER. ALL TESTS WERE OK AND BREAKER OERATED SMOOTHLY. FOUND CONTACT BOUNCE (OPEN AND CLOSE) ON SOE. ELECTRICIANS CLEANED CONTACTS ON BREAKER CAM THAT GIVE BREAKER INDICATION AND SOE TO ECC. OPERATED BREAKER AND NOW INDICATION IS OK. COMPLETED BY: G. PARSONS/L. HOPKINS/J. MCDONALD COMPLETED ON: 2008-01-09	47826	90
790849	7/9/2010	SSDTS,B1L03,ALARM,INVESTIGATE	SSDTS,B1L03,ALARM,INVESTIGATE ANNUNCIATOR ALARM PLC B1L03 FAILURE ECC ALARM AIR ANOMALLY CHECKED AND FOUND CONTROL FUSE NEGATIVE GONE	47826	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
790849	7/9/2010	SSDTS,B1L03,ALARM,INVESTIGATE	REPLACED ALL OK COMPLETED BY: J. MCDONALD ON 2010-07-09	47826	90
838346	4/8/2011	SSDTS,B1LO3,FUNCTION TEST	SSDTS,B1LO3,FUNCTION TEST QUESTIONABLE OPERATIONS OF L01L03 BREAKER DURING TL201 FAULT . CHECK RECLOSING ON ALL THREE PHASES PROTECTION & CLEAN CAMS IN CONTROL CABINET. OPENED BREAKER B1LO3 AND BOTH DISCONNECT. BLOCKED ON P2 TL203 AND USED SEL RELAY TO CHECK RECLOSING ON PHASE. RECORDED TIMES OF BREAKER TRIP AND RECLOSING. ATTACHED READINGS AND TIMES, EVERYTHING OK. ---------- SSD B1LO3 TRIP RECLOSE RECLOSE SETTING ---------- ---------- A2 .119 .692 30 CYCLE B2 .145 .605 C2 .166 .769 L2 .110 ..... DISAGREEEMENT 2.062 COMPLETED BY: G. PARSONS, J. MCDONALD & L. HOPKINS COMPLETED ON: 2011-04-06 BREAKERS B1L03 SSD AND L01L03 WAV FUNCTION TESTED. TEST #1 TRIP RECLOSE ON A, B, C PHASE VIVA THE SEL. TEST #2 3 PHASE TRIP VIVA SEL. TEST #3 DISAGREEMENT WITH RECLOSER OFF VIVA THE SEL. COMPLETED BY: P. O'GRADY & P&C CREW ON 2011-04-08	47826	80

Verbal Safety Talk _____

Appendix 3, Page 58 of 102

THINK SAFETY FIRST

WO TYPE : 2 PM Wo WAVTS,T5,XFMR PM MTNCE PARENT #: 00922301
STATUS : 45 PRIORITY: 3 Plann
ITEM # : 00006412 UNIT #: WAVT5 TRANSFORMER T5,WAV TS
PLT COND: SD BU #: 1325 SUPV: WHB Station Mtce Dept
LOCN: WAVTS WAV Term Stn, Westerm Avalon ORIG: Lyver, Gerard J.
W/H : 1829 Bishop Falls Warehouse PLNR: Lyver, Gerard J.
EMPL: W.O.#: 922301 W.O. SUBCODE: PMN

--- Full Description of Request ----------
1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK SHEET.
2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK ORDER REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A LATER DATE.
3.CONSIDER & REPORT ANY ENVIROMENTAL IMPACTS.

OP#	CRAFT	DESCRIPTION	SIZE	MHRS
1.00	WHBCRSEM	WHB ELEC Term. Stn Mtce. Crew	2.0	
2.00	WHBCRTM	WHB Term. Stn Mtce	1.0	

--- Safety Provisions ----------
1.ENSURE NECESSARY WORK PROTECTION IS IN PLACE BEFORE STARTING WORK.
2.COMPLETE TAILBOARD SAFETY TALK BEFORE BEGINNING WORK.

--- Maintenance Loops ----------
00006412 TRANSFORMER T5,WAV TS Y06A

Keyed.

SCANNED & E-FILED

-- COMMENTS & WORK DONE ----------

PM complete

-- ASSET TRACKING INFORMATION ----------

1. List all assets installed (Description and Serial Number):

1.a Provide Nameplate Data for all new assets installed:

2.If an asset was removed, note the Description, Serial# and JDE# if known and where it was transferred. ie. St. Anthony Line Depot, Bishops Falls etc.

3. List all assets disposed or to be disposed (Description, Serial #, and JDE #, if known):

COMPLETED BY: WD/DH/GT/BW/JH COMPLETED ON: 2012/07/27

-- WORK REMAINING ----------

SUPERVISOR: _____

6 YEAR PM – OLTC TRANSFORMER C/W DIVERTER SWITCHES

System ID: T5 Station: WAVTS Serial No.: 61-00-69167
Manufacturer: Federal Pioneer Type: ONAN ONAF M.V.A: 75/100/125
Test Date: July 16, 2012 Test Completed By: W.D/J.H J.D.E. W/O #: 922301

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

WEATHER CONDITIONS: dry: [X] rain: [ ] humidity [ ] ambient temperature: 20 °C

DIELECTRIC OIL TEST ASTM D-1816 (kV): Conservator Main Tank: 44 Conservator Diverter Switches: 25
Diverter Switch #1 COMMON Diverter Switch #2 35 Diverter switch #3 _____

WINDING TEMP RELAY: (Check if Applicable)					
First Stage Fans: Setting: 80 °C	Found	°C	Left	80	°C
Second Stage Fans: Setting: 85 °C	Found	°C	Left	85	°C
Alarm: Setting: 115 °C	Found	°C	Left	115	°C
Trip: Setting: 125 °C	Found	°C	Left	125	°C

LIQUID TEMP RELAY: (Check if Applicable)					
Alarm: Setting: 90 °C	Found	°C	Left	90°	°C
Trip: Setting: 110 °C	Found	°C	Left	110	°C

FAULT PRESSURE RELAY: (GAS DETECTOR) Main Tank					
Alarm:	Found	200 (cc)	Left	200	(cc)
Trip;	Found	< 3psi (kpa)	Left	< 3psi	(kpa)

FAULT PRESSURE RELAY: (IN LINE GAS DETECTOR) diverter Switches (Check if Applicable)
(Function test Control Circuits) Tested OK ✓ N/A ____

FAULT PRESSURE RELEASE RELAYS: (Function test Control Circuit if Applicable)
Main Tank: Tested Ok ✓ N/A ____

Diverter Sw: A ph: Tested OK ____ N/A ____	Diverter Sw: B ph: Tested OK ____ N/A ____	Diverter Sw: C ph: Tested OK ____ N/A ____

CONSERVATOR MAIN TANK: (Function Test Low level Alarm) OK ✓
CONSERVATOR DIVERTER SWITCHES: (Function Test Low level Alarm) OK ✓

RESISTANCE CHECKS: (including Wiring to Terminal Boards) **500 Volt Test**
Test & record in Mega Ohms or N/A (Acceptable readings > 500 Mega Ohms)

	Line 1 – Line 2	Line 1 / 2 - GND		Line 1 – Line 2	Line 1 / 2 GND
Winding Temp Relay: **Alarm**	∞	∞	**Trip**	∞	∞
Liquid Temp Relay: **Alarm**	∞	∞	**Trip**	∞	∞
Fault Pressure Relay: **Alarm** (Main Tank)	∞ |	∞ |	**Trip**	∞ |	∞ |
Fault Pressure Relay: **Alarm** (In Line Diverter Switches)	∞	∞	**Trip**	∞	∞

6 YEAR PM – OLTC TRANSFORMER C/W DIVERTER SWITCHES

System ID: _____ Station: _____ Serial No.: _____
Manufacturer: _____ Type: _____ M.V.A: _____
Test Date: _____ Test Completed By: _____ J.D.E. W/O #: 922301

RUST/PAINT CONDITION (A - Minor , B – Moderate , C – Severe)

MAIN TANK:	B	RADIATORS:	B
CONTROL CABINET:	B	OTHER:	

CHECKS COMPLETED:

- ✓ Check Explosion Vent
- ✓ Check HV & LV Connections
- ___ Ladder Guards
- ✓ Check porcelain insulators for chips or cracks
- ✓ Manually Operate Fans
- ✓ Silica Gel Checked replace if 50% or more Contaminated
- ✓ Visual Check For Dirty Insulators & Clean if required
- ✓ Check Conservator Tanks For Water, Drain if Necessary
- ___ Check Oil Filtering Unit (type 51) { check Oil Pressure gauge } Replace Filter if Required (Pumps Located on BBKTS T3, HRDTS T8 & WAVTS T5 ONLY)

CHECKS COMPLETED ONLY IF INSTRUCTED:

- _____ Obtain Gas Analysis Sample
- _____ Transformer Ratio Readings
- _____ Capacitive Bridge Testing
- _____ Doble Test

COMMENTS:

NEW SILICA BREATHER
NEW WINDING TEMP GAUGE
1 NEW Pressure SWITCH.
NEW CORDS TO LIQUID & 1 WINDING Temp GAUGE
OIL LEAK REPAIRED ON Xfmer Level GAUGE.
TAP CHANGER OVERHAULED
TAP CHANGER OIL FILTER DIFFERENTIAL ALARM (OK)
OIL FILTER motor AMPS.

6 YEAR PM – OLTC TRANSFORMER C/W DIVERTER SWITCHES

System ID: T5 Station: WAV Serial No.: _____
Manufacturer: T.R. Type: ONAN/ONAF M.V.A: _____
Test Date: 2012/07/16 Test Completed By: _____ J.D.E. W/O #: 922301

RESISTANCE CHECKS: (including Wiring to Terminal Boards) 500 Volt Test

Test & record in Mega Ohms or N/A (Acceptable readings > 500 Mega Ohms)

	Line 1 – Line 2	Line 1 / 2 - GND
Conservator (Main tank) Oil level Gauge: **Alarm**	inf	inf
Conservator (Diverter Sw's) Oil level Gauge: **Alarm**	inf	inf
Fault Pressure Release Relay (Diverter Sw A ph): **Trip**		
Fault Pressure Release Relay (Diverter Sw B ph): **Trip**	inf	inf
Fault Pressure Release Relay (Diverter Sw C ph): **Trip**		

** Caution: Confirm all Primary Protection Circuits are open before Closing Links.

CHECK OIL LEVELS (High , Normal , low)

CONSERVATOR (MAIN TANK)	OK		CONSERVATOR (DIVERTER SWITCHES)	OK	
HV BUSHINGS:	H1 ✓		H2 ✓	H3 ✓	
LV BUSHINGS:	X1 ✓		X2 ✓	X3 ✓	

OPERATING AMPERAGE: (If Applicable)

1 st STAGE FANS 6.9	2 nd STAGE FANS 6.5	MAIN TANK CABINET HEATER 3.5

GROUND CONTINUITY (RESISTANCE): (Micro-Ohms)

NEUTRAL BUSHING:					
HV. ARRESTORS:	H1 877 mΩ		H2 903 μΩ	H3 787 mΩ	
LV. ARRESTORS:	X1 631 μΩ		X2 831 μΩ	X3 1.020 μΩ	

ON LOAD TAP CHANGER

TAP CHANGER COUNTER:	FOUND 54037	LEFT	54112
CHECK LIMITS:	HIGH ✓	LOW	✓
AMPERAGE:	MOTOR 3.2A	CONTROL CABINET HEATER	OK
CHECK GEARS,CHAINS or BELTS:	Checked OK: ✓		
TRANFORMER WINDING RESISTANCE:	Completed Yes: ✓ No: _____		

TAP changer filter motor ~ 3.4A

DIELECTRIC ABSORBTION (5 KV): 10 MIN. ÷ 1 MIN. = INDEX

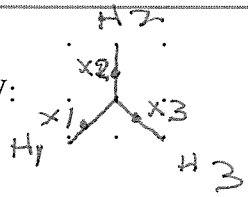
H-LG	1 Min.	Mega Ω	10 Min.	Mega Ω	Index.	%
L-HG	1 Min.	Mega Ω	10 Min.	Mega Ω	Index.	%
HL-G	1 Min. 1.42	Mega Ω	10 Min. 2.54	Mega Ω	Index. 1.62	%

CORE GROUND: (500 Volt test)

Externally Connected Yes ✓ No _____	
RESISTOR: (Ohms) 253.6	CORE GROUND: (Mega Ohms) 500

TRANSFORMER WINDING RESISTANCE TEST FORM

System ID: T 5 Station: WAVES Serial No: 6J-00-69167 Manufacturer: [illegible]
Type: OLTC ✓ TC ____ High voltage 230 Low Voltage 69 Tester Serial No: WDN 0504
Test Date: 2012/07/23 Test Completed By: WD/GT J.D.E. W/O #: 422301

VECTORS: HV: 

LV: . . . TERT: . . .

NOTE: 1. Complete Winding Resistance Test on Tap Position **Found**.
2. Complete Winding Resistance Test on Maximum Tap Position **Raise**.
3. Complete Winding Resistance Test on Maximum Tap Position **Lower**.
4. Confirm Mechanical Center (Off Load Tap Changers).
5. Complete Winding Resistance Test on Tap Position **Left**.

TAP CHANGER LOCATION: HV ✓ LV _____

TAP POSITION	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTANCE DELTA x 1.5
Found 9	H1-X1	500ma	2m	107.1	.277	
Found 9	H2-X2				.277	
Found 9	H3-X3				.276	
Max. Raise ___	H1-X1				.277	
Max. Raise ___	H2-X2				.277	
Max. Raise ___	H3-X3				.276	
Max. Lower 1	H1-X1				.325	
Max. Lower 1	H2-X2				.325	
Max. Lower 1	H3-X3				.325	
Left 1					.325	
Left 1					.325	
Left 1		500ma	2m	107.1	.325	
Non Tap Winding						
Non Tap Winding						
Non Tap Winding						
Tertiary Winding						
Tertiary Winding						
Tertiary Winding						

Note: Observe Indicator Light & Record OHMS or MILLI-OHMS

REMARKS:

	H'-X'	H2 X2	H3-X3	Current. RANGE-500mA % current 107.1	Resistance RANGE 2m
1	.325	.325	.324		
2	.318	.318	.318		
3	.313	.313	.312		
4	.307	.307	.306		
5	.302	.302	.302		
6	.295	.295	.295		
7	.290	.290	.289		
8	.284	.284	.284		
9	.277	.277	.277		
10	.284	.284	.284		
11	.290	.290	.290		
12	.295	.295	.295		
13	.302	.302	.302		
14	.307	.307	.307		
15	.313	.313	.313		
16	.318	.318	.318		
17	.325	.325	.325		

TEMPORARY DE-ENERGIZING DEVICE RECORD	Serial Number	Page Appendix 3, Page 65 of 102

Instructions:

1. This form **must** be kept with the Work Protection and in case of Red Tag or PC17B, a copy will also be kept by the Controlling Authority.
2. Each Holder of Record relying on these grounds **must** apply their own Temporary De-energizing Device tag.
3. Each Work Group relying on the grounds is listed once by the 1st Holder of Record requiring the grounds.
4. Each ground locations requires its own Temporary de-energizing Device Record sheet.
5. Do not remove until all **Work Groups** Listed no longer require use of the Temporary De-energizing Device.

Temporary De-energizing Device	Location: WAVIS 3 GROUNDS ON T5 HIGH SIDE 3 GROUNDS ON T5 LOW SIDE.	PC2/PC17B/PC10A Serial Number 44790

Temporary De-energizing Device Installed by: (print & initial) WD	Work Group	Date:	Time:
Wayne Downing	EM-1	20/2007/04	1130

Holder of Record/Holder Requiring Grounds			Holder of Record/Holder - Grounds no longer Required		
Name (print & initial)	Work Group	Time & Date	Name (print & initial)	Work Group	Time & Date
WAYNE DOWNING WD	EM 1	1230 25/12/07/04	WAYNE DOWNING WD	EM 1	1100 20:2 07 27

Temporary De-Energizing Device Removal for Tests				
PC14/PC17B Test Serial Number	Test - Ground(s) Removed		Return to Pre-test - Grounds Replaced	
	Work Group - Time/Date	HoR Initial	Work Group - Time/Date	HoR Initial

Temporary De-energizing Device Removed by: (print & initial) WD	Work Group	Date:	Time:
Wayne Downing	EM 1	2007/07/27	1105

H-2009-12-1001
MORGAN PRINTING, 709-258-6320

nalcor energy

Holder of Record Check List

Protection Acceptance	PC1 Number	PC2 Number	PC17B Number	PC10A Number	Holder of Record - Time / Date
			44790		2012/07/04
Equipment isolated or isolated & de-energized	T5 AT WAUTS				
Safety Precautions and Instructions					

Holder of Record Worker's List	Worker's Name	Date	Work Group	Time On	Time Off
	G THORNE	2012/07/04	EMI	0907	1535
	D HOSKINS	2012/07/04	EMI	0907	1535
	M AMTHORP.	2012/07/05	EMI	0909	1535
	B WALSH	2012/07/16	EMI	0905	1595
	T HILLIER	2012/07/16	EMI	0920	1530
	G THORNE	2012/07/24	EMI	0830	1530
	R HORLEY	2012/07/25	EMI	0945	1555
	R MORRISEY	2012/07/25	EMI	0945	1555
	G THORNE	2012/07/25	EMI	0945	1555

Holder of Record Test Permission For Workers	Worker's Name	PC14/PC17B PC10A Number	Date	Work Group	Test Permission	Restore to Pretest

Protection Surrendered	Controlling Authority Informed of De-energizing Devise Status?	Work Protection Surrendered Time / Date
✓	☑ Yes	11:11 2012/07/27

H-2009-12-1009-F/B
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Verbal Safety Talk _____
THINK SAFETY FIRST

WO TYPE : 2 PM Wo WAVTS,T5,XFMR PM MTNCE PARENT #: 00678723
STATUS : 48 PRIORITY: 3 Plann
ITEM # : 00006412 UNIT #: WAVT5 TRANSFORMER T5,WAV TS
PLT COND: SD B.U. #: 1325 SUPV: WHB Station Mtce Dept
LOCN: WAVTS WAV Term Stn, Westerm Avalon ORIG: Lyver, Gerard J.
W/H : 1829 Bishop Falls Warehouse PLNR: Lyver, Gerard J.
EMPL: W.O.#: 678723 W.O. SUBCODE: PMN

--- Full Description of Request ----------
1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK SHEET.
2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK ORDER REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A LATER DATE.
3.CONSIDER & REPORT ANY ENVIROMENTAL IMPACTS.

OP#	CRAFT	DESCRIPTION	SIZE	MHRS
1.00	WHBCRSEM	WHB ELEC Term. Stn Mtce. Crew	2.0	
2.00	WHBCRTM	WHB Term. Stn Mtce	1.0	

--- Safety Provisions ----------
1.ENSURE NECESSARY WORK PROTECTION IS IN PLACE BEFORE STARTING WORK.
2.COMPLETE TAILBOARD SAFETY TALK BEFORE BEGINNING WORK.

--- Maintenance Loops ----------
00006412 TRANSFORMER T5,WAV TS Y06A

Glen
Bill
Jeremy
Dan

NFLD. & LAB. HYDRO
RECEIVED
OCT 31 2008
INITIALS:

T A I L B O A R D S A F E T Y T A L K
RISK ASSESSMENT

FORM # 30-0266

REV. DATE 06/05/01

TASK To Isolate TS Tower @ WW.TS for PM

PEOPLE: (Have I/We Considered)

- Crew members know who is in charge?
- How missing crew members will be briefed?
- Workers capabilities adequate?
- Other work groups/general public that may affect this work?
- Personal Protective Equipment?
- Hazards within the work area?

HARDWARE/EQUIP: (Have I/We Considered)

- Safe working loads/rigging?
- Tool conditions/adequacy?
- Climbing hazards?
- Temporary support of structure?
- Equipment pre-use checks?
- Communications?

PROCEDURES: (Have I/We Considered)

- Scope of work?
- The work method?
- Work Protections/Hold-Off/Special Permits?
- Limits of approach? (_____)
- Back feeds?
- Temporary grounding?
- Test for isolation?
- Fall Arrest?
- Controlled products/data sheets?
- Transportation of Dangerous Goods?
- Confined space entry?
- Rescue methods?
- Cover up required?
- Applicable engineering standards?

ENVIRO/OTHER: (Have I/We Considered)

- Overhead power line hazards?
- Underground uitlities?
- Trenching/excavation hazards?
- Traffic control/barricades/signs?
- Weather conditions?
- Hazardous products spills?
- Terrain?
- Deteriorated Plant?
- ENV SOP's?
- Other? _____

PARTICIPANTS:

D Harkins C. Fisher
W Dean
H Moores

HAZARDS IDENTIFIED	CONTROLS
Boom Truck Misuse	beware use Hazard
Bucket Truck	beware use Hazard
working on heights over 10 ft	use fall arrest.
underlying with oil.	Spill Kit on Site.

(use back if necessary)

Supervisor/Lead Hand/Worker

2008 10 17
Date

6 YEAR PM – OLTC TRANSFORMER C/W DIVERTER SWITCHES 6412

System ID: T5-WMR Station: WHV TS Serial No.: 61-00-69167
Manufacturer: F.P.E Type: OLTC M.V.A: 75/100/125
Test Date: 2008 10 14 Test Completed By: BW CH J.D.E. W/O #: C78723

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

WEATHER CONDITIONS: dry: ☑ rain: ☐ humidity ☐ ambient temperature: 12 °C

DIELECTRIC OIL TEST ASTM D-1816 (kV): Conservator Main Tank: 43KV Conservator Diverter Switches: ____
Diverter Switch # 1 ____ Diverter Switch # 2 ____ Diverter switch # 3 ____ TAP CHANGER 41KV
Main Tank 50KV TAP CHANGER Conservator 43

WINDING TEMP RELAY: (Check if Applicable)							
First Stage Fans: Setting: 82 °C	Found	82	°C	Left	82	°C
Second Stage Fans: Setting: 87 °C	Found	87	°C	Left	87	°C
Alarm: Setting: 117 °C	Found	117	°C	Left	117	°C
Trip: Setting: 125 °C	Found	125	°C	Left	125	°C

LIQUID TEMP RELAY: (Check if Applicable)							
Alarm: Setting: 88 °C	Found	~~TAP C~~ 88	°C	Left	88°	°C
Trip: Setting: 105 °C	Found	105°	°C	Left	105°	°C

FAULT PRESSURE RELAY: (GAS DETECTOR) Main Tank							
Alarm:	Found	200	(cc)	Left	200	(cc)
Trip;	Found	400	(kpa)	Left	400	(kpa)

FAULT PRESSURE RELAY: (IN LINE GAS DETECTOR) diverter Switches (Check if Applicable)
(Function test Control Circuits) Tested OK ✓ N/A ____

FAULT PRESSURE RELEASE RELAYS: (Function test Control Circuit if Applicable)
Main Tank: Tested Ok ✓ N/A ____

Diverter Sw: A ph:Tested OK ___ N/A ___	**Diverter Sw: B ph:Tested OK ___ N/A ___**	**Diverter Sw: C ph:Tested OK ___ N/A ___**

CONSERVATOR MAIN TANK: (Function Test Low level Alarm) OK ✓
CONSERVATOR DIVERTER SWITCHES: (Function Test Low level Alarm) OK ✓

RESISTANCE CHECKS: (including Wiring to Terminal Boards) **500 Volt Test**
Test & record in Mega Ohms or N/A (Acceptable readings > 500 Mega Ohms)

	Line 1 – Line 2	Line 1 / 2 - GND		Line 1 – Line 2	Line 1 / 2 GND
Winding Temp Relay: **Alarm**	∞	GR	**Trip**	∞	GR
Liquid Temp Relay: **Alarm**	∞	GR	**Trip**	∞	GR
Fault Pressure Relay: **Alarm** (Main Tank)	∞	GR	**Trip**	∞	GR
Fault Pressure Relay: **Alarm** (In Line Diverter Switches)	∞	GR	**Trip**	∞	GR

6 YEAR PM – OLTC TRANSFORMER C/W DIVERTER SWITCHES

System ID: T5 Station: W.A.V Serial No.: 61-00 69167
Manufacturer: Federal Pioneer Type: _____ M.V.A: 75/100/125
Test Date: 2008/10/14 Test Completed By: GH BW HM DH J.D.E. W/O #: _____

RESISTANCE CHECKS: (including Wiring to Terminal Boards) **500 Volt Test** Test & record in Mega Ohms or N/A (Acceptable readings > 500 Mega Ohms)		
	Line 1 – Line 2	Line 1 / 2 - GND
Conservator (Main tank) Oil level Gauge: **Alarm**	584 mΩ	181mΩ GΩ
Conservator (Diverter Sw's) Oil level Gauge: **Alarm**	∞	156mΩ 1300 mΩ
Fault Pressure Release Relay (Diverter Sw A ph): **Trip**	∞	∞ GΩ
Fault Pressure Release Relay (Diverter Sw B ph): **Trip**	∞	∞ GΩ
Fault Pressure Release Relay (Diverter Sw C ph): **Trip**	∞	∞ GΩ

** Caution: Confirm all Primary Protection Circuits are open before Closing Links.

CHECK OIL LEVELS (High , Normal , low)						
CONSERVATOR (MAIN TANK)			CONSERVATOR (DIVERTER SWITCHES)			
HV BUSHINGS:	H1	Normal	H2	Normal	H3	Normal
LV BUSHINGS:	X1	Normal	X2	Normal	X3	Normal

OPERATING AMPERAGE: (If Applicable)		
1 st STAGE FANS 6.7A.	2 nd STAGE FANS 6.6A.	MAIN TANK CABINET HEATER 3.6

GROUND CONTINUITY (RESISTANCE): (Micro-Ohms)						
NEUTRAL BUSHING:						
HV. ARRESTORS:	H1	647 μΩ	H2	200 μΩ	H3	254 μΩ
LV. ARRESTORS:	X1	611 μΩ	X2	635 μΩ	X3	784 μΩ

ON LOAD TAP CHANGER			
TAP CHANGER COUNTER:	FOUND 38962	LEFT 38983	
CHECK LIMITS: ✓	HIGH OK	LOW OK.	
AMPERAGE: 4.1 A.	MOTOR ✓	CONTROL CABINET HEATER 3.6 A	
CHECK GEARS,CHAINS or BELTS:	Checked OK: ✓		
TRANFORMER WINDING RESISTANCE:	Completed Yes: ✓ No: _____		

DIELECTRIC ABSORBTION (5 KV): 10 MIN. ÷ 1 MIN. = INDEX						
H-LG	1 Min. 1.5 GΩ	Mega Ω	10 Min. 2.14 GΩ	Mega Ω	Index. 1.36	%
L-HG	1 Min. 1.7 GΩ	Mega Ω	10 Min. 2.288 Ω	Mega Ω	Index. 1.38	%
HL-G	1 Min. 1.6 GΩ	Mega Ω	10 Min. 2.36	Mega Ω	Index. 1.45	%

CORE GROUND: (500 Volt test)	
Externally Connected Yes ____ No ____	
RESISTOR: (Ohms)	CORE GROUND: (Mega Ohms)

6 YEAR PM – OLTC TRANSFORMER C/W DIVERTER SWITCHES

System ID: T5 Station: WAV. Serial No.: 61-0069167
Manufacturer: Federal Pioneer Type: _____ M.V.A: 75/100/125
Test Date: 2018 17 Test Completed By: Rudolf/SH/H.M.D4. J.D.E. W/O #: _____

RUST/PAINT CONDITION (A - Minor , B – Moderate , C – Severe)	
MAIN TANK: A	RADIATORS: A
CONTROL CABINET: B	OTHER:

CHECKS COMPLETED:

- ___ Check Explosion Vent
- ___ Check HV & LV Connections
- ___ Ladder Guards
- ___ Check porcelain insulators for chips or cracks
- ___ Manually Operate Fans
- ___ Check Oil Filtering Unit (type 51) { check Oil Pressure gauge } Replace Filter if Required (Pumps Located on BBKTS T3, HRDTS T8 & WAVTS T5 ONLY)
- ___ Silica Gel Checked replace if 50% or more Contaminated
- ___ Visual Check For Dirty Insulators & Clean if required
- ___ Check Conservator Tanks For Water, Drain if Necessary

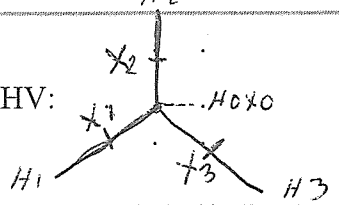
CHECKS COMPLETED ONLY IF INSTRUCTED:

- _____ Obtain Gas Analysis Sample
- _____ Transformer Ratio Readings
- _____ Capacitive Bridge Testing
- _____ Doble Test

COMMENTS: Tank. Conservator Diverter oil Level Gauge Replace. new one ordered & Replaced

TRANSFORMER WINDING RESISTANCE TEST FORM

System ID: T-5 Station: W.A.V. Serial No: 61-00-69167 Manufacture: Federal Pioneer.
Type: OLTC ~ TC ___ High voltage 230 Low Voltage 138 Tester Serial No: ___
Test Date: 2008/10/14 Test Completed By: B.W. MH H.M. D.H. J.D.E. W/O #: 678723

VECTORS: HV: 

LV: . . . TERT: N/A

NOTE: 1. Complete Winding Resistance Test on Tap Position **Found**.
2. Complete Winding Resistance Test on Maximum Tap Position **Raise**.
3. Complete Winding Resistance Test on Maximum Tap Position **Lower**.
4. Confirm Mechanical Center (Off Load Tap Changers).
5. Complete Winding Resistance Test on Tap Position **Left**.

TAP CHANGER LOCATION: HV ✓ LV ___

TAP POSITION	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTANCE DELTA x 1.5
Found 10	H1	500 MA	20	105.3	0.80Ω	
Found 6	" 2	500 MA	20	105.7	.79Ω	
Found 6	" 3	500MA	20	105.6	0.80Ω	
Max. Raise ___	H1	500 mA	20	105.2	.83Ω	
Max. Raise ___	H2	500mA	20	104.3	.82Ω	
Max. Raise ___	H3	500 mA	20	104.1	.83Ω	
Max. Lower ___	H3	500 mA	20	104	.83Ω	
Max. Lower ___	H2	500 mA	20	103	.83Ω	
Max. Lower ___	H1	500 mA	20	105.6	.83	
Left 6	H1	500 mA	20	105.6	.80Ω	
Left 6	H2	500 mA	20	104.9	.80Ω	
Left 6	H3	500 mA	20	103.2	.80Ω	
Non Tap Winding	N/A					
Non Tap Winding	N/A					
Non Tap Winding	N/A					
Tertiary Winding	N/A					
Tertiary Winding	"					
Tertiary Winding	"					

Note: Observe Indicator Light & Record OHMS or MILLI-OHMS

REMARKS:

Nameplate - Autotransformer with Tertiary

Company	Newfoundland & Labrador Hydro	**Serial Number**	61-00-69167
Location	WAV	**Special ID**	
Division	P&C EAST	**Circuit Designation**	T5
Manufacturer	FP	**Configuration**	
Year Manufactured	1989	**Tank Type**	FREE-BREATH
Mfr Location		**Oil Volume**	L
Phases	3	**BIL**	950 kV
Class	ONAN/ONAF/ONAF	**Coolant**	OIL
Weight			
kV	230, 138,	**VA Rating**	75, 100, 125, MVA
Note			

Test Date	8/20/1996	**Test Time**	10:40:55 AM	**Weather**	CLOUDY
Air Temperature	16 °C	**Tank Temperature**	15 °C	**Rel. Humidity**	71 %
Tested by	JM/CQ	**Work Order #**	5552	**Last Test Date**	
Checked by		**Test Set Type**	M4K	**Retest Date**	
Checked Date		**Set Top S/N**	0736	**Reason**	ROUTINE
Last Sheet #		**Set Bottom S/N**	0695	**Travel Time**	
P.O. #		**Ins. Book #**		**Duration**	
Copies		**Sheet #**	1	**Crew Size**	

Arrester Nameplate

Location	Serial #	Mfr	Overall Catalog	Unit Catalog	Type	Rated kV	Order
H1-T	D6418	COB	219652	215920-3008	VN	70	
H1-B	D6419	COB	219652	215920-3013	VN	82	
H2-T	D6420	COB	219652	215920-3008	VN	70	
H2-B	D6417	COB	219652	215920-3013	VN	82	
H3-T	D6424	COB	219652	215920-3008	VN	70	
H3-B	D6425	COB	219652	215920-3013	VN	82	
X1-T	D4666	COB	219598	215920-3001	VN	42	
X1-B	D4667	COB	219598	215920-3005	VN	56	
X2-T	D4668	COB	219598	215920-3001	VN	42	
X2-B	D4669	COB	219598	215920-3005	VN	56	
X3-T	D4670	COB	219598	215920-3001	VN	42	
X3-B	D4671	COB	219598	215920-3005	VN	56	

Bushing Nameplate

Desig.	Serial #	Mfr	Type	C1 % PF	C1 Cap	C2 % PF	C2 Cap	kV	Amps	Year
H1	273414	TTI	U	.33	383		697	300	600	1989

H2	273415	TTI	U	.26	382		712	300	600	1989
H3	273416	TTI	U	.26	379		616	300	600	1989
X1	272494			.26	350		623	145	600	1989
X2	272516			.33	350		609	145	600	1989
X3	272495			.30	356		576	145	600	1989
N	272556			.23	532			15	400	1989

Overall Tests

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10	38.910	1.890		1.19	10321		
CH	10	22.270	1.421	0.76	1.19	5907	G	
CHT(UST)	10	16.620	0.507	0.37	1.19	4410	G	
CHT		16.640	0.469	0.33	1.19	4414		
CT + CHT	2	54.940	1.837		1.19	14573		
CT	2	38.300	1.317	0.40	1.19	10161	G	
CHT(UST)	2	16.630	0.508	0.37	1.19	4411	G	
CHT		16.640	0.520	0.37	1.19	4412		

Bushing C1

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	273414	.33	383	10	1.424	0.036	0.25	1.00	377.60	G	
H2	273415	.26	382	10	1.430	0.028	0.20	1.00	379.30	G	
H3	273416	.26	379	10	1.482	0.033	0.22	1.00	393.10	G	
X1	272494	.26	350	10	1.305	0.033	0.25	1.00	346.10	G	
X2	272516	.33	350	10	1.300	0.042	0.32	1.00	344.90	G	
X3	272495	.30	356	10	1.325	0.038	0.29	1.00	351.50	G	
N	272556	.23	532	10	1.986	0.048	0.24	1.00	526.80	G	

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	273414		697	2	2.929	0.237	0.81	1.00	776.90	I	
H2	273415		712	2	2.947	0.164	0.56	1.00	781.60	I	
H3	273416		616	2	2.615	0.255	0.98	1.00	693.50	I	
X1	272494		623	2	2.499	0.117	0.47	1.00	662.80	I	
X2	272516		609	2	2.441	0.080	0.33	1.00	647.30	I	
X3	272495		576	2	2.344	0.133	0.57	1.00	621.80	I	

Surge Arrester Tests

Location	Test Mode	Test kV	mA	Watts	IR_{auto}	IR_{man}
H1-T	UST RB	10	0.163	0.056	G	

H1-B	GAR RB	10	0.371	0.109	G	
H2-T	UST RB	10	0.160	0.057	G	
H2-B	GAR RB	10	0.375	0.110	G	
H3-T	UST RB	10	0.161	0.058	G	
H3-B	GAR RB	10	0.375	0.114	G	
X1-T	UST RB	10	0.260	0.117	G	
X1-B	GAR RB	10	0.530	0.214	I	
X2-T	UST RB	10	0.258	0.110	G	
X2-B	GAR RB	10	0.531	0.208	I	
X3-T	UST RB	10	0.259	0.114	G	
X3-B	GAR RB	10	0.533	0.206	I	

Exciting Current Tests

	Mfr	Type	Steps	Boost %	Buck %	Position Found	Position Left	Oil Volume
De-Energized Tap Changer								
On-Load Tap Changer	Rein		17			1	1	

			H1 - H0			H2 - H0			H3 - H0				
DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10	14.760	144.30		8.807	85.720		14.100	141		G	
	9	10	17.430	166.90		10.350	103.20		16.240	160.60		G	
	17	10	21.230	200		12.800	127		19.800	192.70		G	

Company : NFLD HYDRO
Division: P & C EAST
Location: WAV Special ID: T5

Test Date: Jul 23 2001 Test Time: 15:14:54

Identification

Mfr: FP Yr Mfr: 1988 Serial #: 61-00-69167
Ph : 3 Cfg: Y-Y CCT Desig: T5

kV : 230 /138 /6.9 MVA:75 / 100 / 125 // Tanktype: OPEN-CONSER
Coolant: OIL

Air temp: 30 deg C App temp: deg C RH: 37% Weather: PTCLDY

Overall Tests

#	Insul.	kV	mA	Watts	%Pwr Factor meas	%Pwr Factor corr	Corr	Cap(pF)
1	CH + CHT	10	38.690	1.244			1.00	10264
2	CH	10	22.040	0.756	0.34	0.34	1.00	5848
3	CHT(UST)	10	16.630	0.505	0.30	0.30	1.00	4413
4	CHT		16.650	0.488	0.29	0.29	1.00	4416
	CT + CHT	2	54.900	1.943			1.00	14564
	CT	2	38.260	1.401	0.37	0.37	1.00	10150
7	CHT(UST)	2	16.640	0.499	0.30	0.30	1.00	4414
8	CHT		16.640	0.542	0.33	0.33	1.00	4414

Bushing Tests

C1

Bush	Nameplate Data Mfr	Type	S/N	Cap(pF)	%PF	Test Results kV	%PF	Cap(pF)
H1	TTI	U	273414	383	.33	10	0.25	378.50
H2	TTI	U	273415	382	.26	10	0.20	378.40
H3	TTI	U	273416	379	.26	10	0.24	392.70
X1	TTI	U	272494	350	.26	10	0.25	345.80
X2	TTI	U	272516	350	.33	10	0.32	347
X3	TTI	U	272495	356	.30	10	0.27	351.50
Y1	TTI	U						
Y2	TTI	U						
Y3	TTI	U						
N	TTI	U	272556	532	.23	10	0.25	527.80

C2

Bush	Nameplate Data Mfr	Type	S/N	Cap(pF)	%PF	Test Results kV	%PF	Cap(pF)
H1	TTI	U	273414	697		2	1.10	752.40
H2	TTI	U	273415	712		2	0.82	755.60
3	TTI	U	273416	616		2	0.70	665.80
X1	TTI	U	272494	623		2	0.99	661.60
X2	TTI	U	272516	609		2	0.77	645.10
X3	TTI	U	272495	576		2	1.17	617.80
Y1	TTI	U						

Company : NFLD HYDRO
Division: P & C EAST
Location: WAV Special ID: T5

Test Date: Jul 23 2001 Test Time: 15:14:54

Y2	TTI	U					
Y3	TTI	U					
N	TTI	U	272556	70	.5	36.44	153.40

Oil Sample Tests

	Sample Location	mA	Watts	%PF
1	MAIN TANK	0.883	0.023	0.26

Surge Arrester Tests

	Location	Mfr	S/N	R-kV	T-kV	mA	Watts
1	H1 TOP	OB	D6418	82.0	10	0.158	0.077
2	H1 BOT	OB	D6419	70.0	10	0.209	0.093
3	H2 TOP	OB	D6420	82.0	10	0.158	0.077
4	H2 BOT	OB	D6417	70.0	10	0.208	0.084
5	H3 TOP	OB	D6424	82.0	10	0.157	0.077
6	H3 BOT	OB	D6425	70.0	10	0.211	0.086
8	X1 TOP	OB	D4666	56.0	10	0.253	0.151
9	X1 BOT	OB	D4667	42.0	10	0.270	0.120
10	X2 TOP	OB	D4668	56.0	10	0.252	0.147
11	X2 BOT	OB	D4669	42.0	10	0.271	0.126
12	X3 TOP	OB	D4670	56.0	10	0.252	0.150
13	X3 BOT	OB	D4671	42.0	10	0.270	0.136

<End of Report>

Verbal Safety Talk _____

THINK SAFETY FIRST

WO TYPE : 5 Capit WAVTS,T5,TAPCHANGER OVERHAUL PARENT #: 00915689
STATUS : 45 PRIORITY: 4 Requi
ITEM # : 00283756 UNIT #: WAVT5-LTC TAP CHANGER,T5 WAV TS
PLT COND: BU #: 13251204 SUPV: WHB Station Mtce Dept
LOCN: WAVTS WAV Term Stn, Westerm Avalon ORIG: Eddy, Brad
W/H : 1829 Bishop Falls Warehouse PLNR: Wellman, Barry F.
EMPL: W.O.#: 915689 W.O. SUBCODE:

--- Full Description of Request ----------
WAVTS,T5,TAPCHANGER OVERHAUL
(PARTS ORDERED BY B EDDY ON PO# 113683, DUE JUNE 27)
(REINHAUSEN TECH SCHEDULED FOR JULY 5)

OP#	CRAFT	DESCRIPTION	SIZE	MHRS
1.00	WHBCRSEM	WHB Stns Elect Maintenanc	1.0	

STOCK NUMBER	DESCRIPTION	UOM	QTY	COST
89400002	OIL,TRANSFORMER (205 L DRUM)	DR	3.00	760.51
88900031	ABSORBENT,OIL PAD	BN	1.00	32.83
58400074	FILTER,CARTRIDGE 12" (ALSOP)	EA	2.00	171.16

Keyed 12-07-06
R.B

-- COMMENTS & WORK DONE ----------

Tap Changer overhauled by Contractor

Tap Changer in good Shape.

-- ASSET TRACKING INFORMATION ----------

1. List all assets installed (Description and Serial Number):

1.a Provide Nameplate Data for all new assets installed:

2. If an asset was removed, note the Description, Serial# and JDE# if known and where it was transferred. ie. St. Anthony Line Depot, Bishops Falls etc.

3. List all assets disposed or to be disposed (Description, Serial #, and JDE #, if known):

COMPLETED BY: W.D. Ball COMPLETED ON: July 7/2012

-- WORK REMAINING ----------

SUPERVISOR: [signature]

EXTRA MATERIAL USED

INVENTORY PART #	DESCRIPTION	UOM	QTY

EXTRA MATERIAL RETURNED

INVENTORY PART #	DESCRIPTION	UOM	QTY

VEHICLE USAGE

VEHICLE #	HOURS USED

TAILBOARD SAFETY TALK FORM (Cont)

Hazards

/ - Risk
X - No Risk

People

_ Adequate PPE Worn
_ Allergies
_ Arc Flash
_ Awkward Positions
_ Chemical Burn
_ Cuts/Abrasions
_ Electrical Shock
_ Falling from Heights
_ Falling Objects
_ Infectious Agents
_ Inhale Hazardous Substances
_ Overexertion
_ Overhead Work
_ Particles in Eye
_ Pinch Points
_ Poisonous Substances
_ Prolonged Positions
_ Respiratory Distress
_ Slips/Trips
_ Sprains/Strains
_ Thermal Burn

Equipment

_ Crane/Lifting Equipment in Operation
_ Damaged/Defective
_ High Voltage
_ Inadequate Guards/ Barriers
_ Moving Equipment Mobile
_ Moving Machinery
_ Poor Ergonomic Design
_ Pressurized Equipment
_ Pressurized Lines
_ Proper Tools not available for Job

Materials

_ Chemical/Other Substance Spills
_ Explosive/Flammable
_ Fibre Optic Cables
_ Hazardous Chemicals
_ Hazardous Waste Present
_ Radioactive Material Present
_ Steam Present

Environment

_ Back Feeds
_ Blind Spots
_ Dangerous Animals
_ Dangerous Flora/Fauna
_ Inadequate Parking Lots
_ Noise
_ Overhead Lines
_ Poor Air Quality
_ Poor Lighting
_ Poor Storage of Materials
_ Poor Weather
_ Poor Workspace Design
_ Public Can Access Area
_ Rough Roads/Terrain
_ Slippery Surfaces
_ Trenches Present
_ Underground Line
_ Vehicle/Machine Traffic
_ Vibration

No.	Hazards	Controls/Barriers
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		

Ensure all crew members complete necessary Step Back 5X5(s).

Person in Control of Work (Print): _____ Date: _____

(Sign): _____

Western Avalon Terminal Station

Service report

MR Order number: _____ Name 1: Michael Arnthor

Service notification: _____ Name 2: _____

Responsible person for order: _____ Work from _____ until 05-07 2012

☒ Maintenance ☐ Repair ☐ Modification ☐ Examination

End customer: Newfoundland & Labrador Hydro Contact person: Reginald Day

Transf. manufacturer: _____ Transformer no.: 61 80 09167

Location-adress: Chapel Arm NL N 47.51568° W53.68537 Year of manuf.: 1989 Transformer load.: _____ %

$P_{nom.}$: 125 MVA $U_{nom.}$: 230 / 138 kV

☐ Indoor ☒ Outdoor Photo: ☐ Yes ☒ No

Tapchanger type: HIETD 400 145 10193W No.: 066205 No. of ops: 56724

Type of motordrive: MA7 No.: 066205 Counter reading: 56724

Transition resistor: R 1: 3,3 Ω ; R 2: _____ Ω Varistors: ☐ yes ☒ no Spark gaps resp.: ☐ U ☐ V ☐ W

Div.-switch no.: 066205 ☒ removed ☒ installed ☒ maintained No. of ops.: 56724

Spare div.-switch no.: _____ ☐ removed ☐ installed ☐ maintained No. of ops.: _____

Oil change: ☒ yes ☐ no Sort: _____ Quantity: ~ 400 liter ☐ TM100 ☐ Tapguard

Contact wear: ☐ single contact wear (mm) ☐ sum contact wear Typ: T,R,G (mm) traces of arcing: ≤ 0,1 mm

SC (fixed)		SC (mov.)		SC (sum)		Contact roller SC Ø	21,8
TC I (fixed)		TC I (mov.)		TC I (sum)		Contact roller TC Ø	21,5
TC II (fixed)		TC II (mov.)		TC II (sum)			

Tap-changer

Function Test: ☒ mech. ☒ Idle ☐ load Switching supervisory device.: ☒ without ☐ checked

Suction pipe: ☐ without bled. ☒ yes ☐ no Insulation parts checked: ☒ Mechanical state checked: ☒

Press. tight: ☒ Yes ☐ no ____ cm / h Identical operating positions MDU/OLTC: ☒ Carbon deposits: ☐ none / _____ mm

Motor drive unit

Mech. state checked: ☒ Electr. devices checked: ☒ Position transmitter checked: ☒ Drive limits test: ☒ mech. ☐ electr.

Drive shafts

☐ Round ____ mm / ☒ square Clearance axial checked: ☒ Mech. state checked: ☒ Cardan joints: ☐ yes ☒ no

Protective relay

Type: ☐ RS1000 ☒ RS2001 ☐ XK ☐ others Cleaning: ☒ Function - Test: ☐ with CB ☒ without CB ☐ no

Oilfilter plant

Type: ☐ OF100 ☒ 51 ☒ others ☐ without Filter cartridge change: ☒ ☐ Carbon filter ☒ Combined filter

Remarks: The OLTC components inspected are in good condition and the results of the test switchings were satisfactory.

The OLTC is ready for service.

City, Date Chapel Arm NL 05 July 2012 20 ____ Signature (MR staff member)

New Foundland & Labrador Hydro
Western Avalon Station

Customer report

MR Order number: _____ Name 1: Michael Amthor

Service notification no.: _____ Name 2: _____

Serialno.: MR 066205 Responsible person for order: _____

Single distance km _____ Total distance km _____ ☐ Car ☐ Van ☐ Lorry

Accessory: ☐ Oil pump: ___day(s) ☐ Lifting device ___day(s) ☐ Tent ___day(s) ☐ Crane ___day(s)

Partnumber:	Description:	Quantity:	Code:	Partnumber:	Description:	Quantity:	Code:
10495700	coupling bracket	2		07134400	locking	5	
05196003	coupling bolt	4		451323	washer 5,3	3	
10018200	o-ring	2		709407 01	small parts DS	2	
12759600	oil filter insert comb.	1		59002102	gasket RS 2001	1	
59057001	gasket	1		59008702	gasket bevel gear	1	
10185200	screw M6×16	6		860258	o-ring cover M.	1	
10180900	screw M6×30	9		16017002	gasket door MA7	4m	
05901105	small parts H	1					
09918501	lead	3					
10104400	screw M5×10	3					
02408498	locking	2					
10155900	screw M6×60	3					
860122	gasket	4					
01528400	washer M5	9					
10104500	screw M5×16	9					

Code: 1 = Technical service canban stock; 2 = already booked items; 3 = from customer (without charging)

Working / travelling hours:

Date	Operation	Start (travel regular)	Finish (travel overtime)	Break from (work regular)	Break to (work overtime)	Duration in hrs	Trip / work	Staff member
04-07-2012	8[00]	2[30]	8,0	6,5			☐ / ☐	Michael Amthor
05-07-2012	7[30]	18[30]			8	2,5	☐ / ☐	Michael Amthor
							☐ / ☐	
							☐ / ☐	
							☐ / ☐	
							☐ / ☐	
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							☐ / ☐	
							☐ / ☐	

Remarks: flight from Moncton to Halifax was delayed. AC changed Moncton – Toronto – St. John's

The signatory confirms the correctness of total hours, materials and accessory data listed in the service report as well as the receipt of a copy of the report.

City, date Chapel Arm 20 12 Signature (Customer) _____

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
400421	5/11/2004	WAV,T5 LTC SCREEN FOR PCB	WESTERN AVALON TERMINAL STATION TEST T5 TAP CHANGER OIL FOR PCB'S NO PCB'S PRESENT. COMPLETED BY: P. O'GRADY & S. TUCKER ON 2004-05-11	47825	90
584743	7/27/2007	WAVTS, T5 TAPCHANGER OIL SAM	WAVTS, T5 TAP CHANGER OIL SAMPLE OBTAIN OIL SAMPLE FOR AS PER T.SHAVE'S INSTRUCTIONS QUOTE WORK ORDER ON INVOICE 1) If oil volume in the equipment is less than 250 gallons (1200 L) flush 1 quart of oil, otherwise flush a gallon into waste oil container. 2) Bottle Samples: rinse bottle by partially filling and gently swirling and emptying the oil into the waste container. Fill bottle to within an inch of the top, to allow for expansion. Visually examine fluid for water droplets or foreign particles. If present, re-sample. If not, attach the cap securely, identify the sampled unit on the bottle's label. Do not tape the cap. 3) Syringe Samples: the plastic stopcock, which comes with the syringe must remain firmly affixed to the syringe to prevent leaks. Flushing the syringe: a) Move the handle toward the sampling valve. b) Open sampling valve and move the handle toward the syringe allowing oil to flush the tube and stopcock. c) Move the handle towards the side port, allowing oil pressure to enter the syringe barrel, forcing the plunger out. Until the inside of the syringe has been wetted with oil, it may be necessary to pull the plunger. d) When oil reaches the 50 cc mark, move the handle towards the sampling valve and eject oil from ssyringe by pushing in the plunger. Catch this ejected oil in waste container Draw the Sample: a) Move the handle towards the side port and allow oil pressure to fill the syringe. DO NOT PULL ON THE PLUNGER When oil reaches the 40-45cc mark, move the handle towards	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
584743	7/27/2007	WAVTS, T5 TAPCHANGER OIL SAM	the syringe. Do not over fill the syringe to avoid gas escape from the plunger side. b) Examine sample to ensure it is free of bubbles and foreign particles. If sample is good, move handle towards the syringe, close drain valve and remove the syringe with stopcock still firmly attached to the syringe. If sample is not clear, repeat sample procedure. c) Record info: on sample bottle check sheet as per enclosed instructions. OIL SAMPLE TAKEN COMPLETED BY: G. HILLIER ON 2007-07-24 --- SYRINGE SAMPLE TAKEN FROM BOTTOM OF TANK. COMPLETED BY: G. HILLIER ON 2007-08-08	47825	90
588492	5/18/2007	WAVTS,T5,SILICA GEL,CHANGE	WAVTS,T5,SILICA GEL,CHANGE SMALL BREATHER INSTALLED T5 BREATHER NOW IN DRYER. COMPLETED BY: W. DOWNING & S. TUCKER ON 2007-05-18 REINSTALL T5 BREATHER WHEN SILICA GEL DRY.	47825	90
589066	9/7/2007	WAVTS,T5,REPLACE TEMP. BREATHE	WAVTS,T5,REPLACE TEMP. BREATHER REPLACE TEMPORARY SILICA GEL BREATHER WHEN DRY. SILICA GEL DRIED AND REPLACED COMPLETED BY: G. HILLIER ON 2007-09-17	47825	90
642725	5/7/2008	WAVTS,T5 OIL SAMPLE TAP CHANGE	WAVTS,T5 OIL SAMPLE TAP CHANGER ONE SAMPLE REQUIRED NO OUTAGE REQUIRED	47825	90
646548	5/22/2008	WAVTS T5 OIL LEAK	WAVTS T5 OIL LEAK	47825	90
658366	9/23/2008	WAVTS,T5,STAIN,OIL,CLEAN UP	SWOP#2008003195 Eastern Terminal Station Equipment WAVTS, T5, Oil stain on Tap changer access door and main TRF. Clean oil stain and repair leak if any	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
658366	9/23/2008	WAVTS,T5,STAIN,OIL,CLEAN UP	CHECKED FOR OIL LEAKS AROUND COVER AND CLEANED UP OIL STAINS. COMPLETED BY: S. TUCKER ON 2008-09-23	47825	90
675991	1/26/2012	WAVTS,T5,WINDING TEMP. GAUGES	WAVTS,T5,WINDING TEMP. GAUGES MOISTURE IN TWO WINDING TEMP. GAUGES, REPLACE	47825	80
678081	10/16/2008	WAVT5 REPLACE RAD VALVES	WAVT5 REPLACE RAD VALVES REPLACE RUSTED RAD DRAIN VALVES WITH STAINLESS. REPLACED TWO VALVES ON T5 RADS COMPLETED BY; W. WALSH/H. MOORES/W. DEAN COMPLETED ON: 2008-10-17	47825	90
678723	10/17/2008	WAVTS,T5,XFMR PM MTNCE	1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK 2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A DATE. 3.CONSIDER & REPORT ANY ENVIROMENTAL IMPACTS. -PM DONE AS PER WORK ORDER -DIVERTER OIL LEVEL GAUGE REPLACED -MAIN TANK OIL LEVEL GAUGE 1 LINE 156 M COMPLETED BY: W. WALSH ON 2008-10-17	47825	90
702663	7/19/2012	WAVTS,T5,MOISTURE IN WD RELAY	WAVTS,T5,MOISTURE IN WD RELAY WINDING TEMPERATURE RELAY REPLACED COMPLETED BY: W. WALSH/G. THORNE ON 2012-07-19	47825	80
702679	5/13/2009	WAVTS,T5,CONSERVATOR TANK,REP	WAVTS,T5,CONSERVATOR TANK,REPLACE LEVEL GAUGE OUTAGE REQUIRED GAUGE REPLACED COMPLETED BY: W. DOWNING ON 2009-05-14	47825	90
710350	5/12/2009	WAVTS,T5,FALL ARREST PLATES	WAVTS,T5,FALL ARREST PLATES,INSTALL THREE FALL ARREST PLATES WELDED ON TRANSFORMER COMPLETED BY: W. DOWNING ON 2009-05-11	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
750012	11/28/2009	WAVTS,T5 TAP CHANGER,FAILURE	WAVTS,T5 TAP CHANGER,FAILURE TIMER REPLACED WITH NEW TEMP ONE. NEW TIMER TO BE (B. STOYLES). COMPLETED BY: W. DOWNING ON 2009-11-28	47825	90
821557	7/20/2012	WAVTS,T5 SELICA GEL CONTAINER	T5 SELICA GEL CONTAINER REPLACE TEMPORARY UNIT NEW SILICA GEL CONTAINER INSTALLED COMPLETED BY: W. WALSH/W. DOWNING ON 12-07-20	47825	80
844084	3/6/2012	WAVTS,T5 TAPCHANGER OIL SAM	WAVTS, T5 TAP CHANGER OIL SAMPLE OBTAIN OIL SAMPLE FOR AS PER T.SHAVE'S INSTRUCTIONS QUOTE WORK ORDER ON INVOICE 1) If oil volume in the equipment is less than 250 gallons (1200 L) flush 1 quart of oil, otherwise flush a gallon into waste oil container. 2) Bottle Samples: rinse bottle by partially filling and gently swirling and emptying the oil into the waste container. Fill bottle to within an inch of the top, to allow for expansion. Visually examine fluid for water droplets or foreign particles. If present, re-sample. If not, attach the cap securely, identify the sampled unit on the bottle's label. Do not tape the cap. 3) Syringe Samples: the plastic stopcock, which comes with the syringe must remain firmly affixed to the syringe to prevent leaks. Flushing the syringe: a) Move the handle toward the sampling valve. b) Open sampling valve and move the handle toward the syringe allowing oil to flush the tube and stopcock. c) Move the handle towards the side port, allowing oil pressure to enter the syringe barrel, forcing the plunger out. Until the inside of the syringe has been wetted with oil, it may be necessary to pull the plunger. d) When oil reaches the 50 cc mark, move the handle towards the sampling valve and eject oil from ssyringe by pushing in the plunger. Catch this ejected oil in waste container	47825	80

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
844084	3/6/2012	WAVTS,T5 TAPCHANGER OIL SAM	Draw the Sample: a) Move the handle towards the side port and allow oil pressure to fill the syringe. DO NOT PULL ON THE PLUNGER When oil reaches the 40-45cc mark, move the handle towards the syringe. Do not over fill the syringe to avoid gas escape from the plunger side. b) Examine sample to ensure it is free of bubbles and foreign particles. If sample is good, move handle towards the syringe, close drain valve and remove the syringe with stopcock still firmly attached to the syringe. If sample is not clear, repeat sample procedure. c) Record info: on sample bottle check sheet as per enclosed instructions. OIL SAMPLE TAKEN COMPLETED BY: G. HILLIER/W. WALSH ON 2012-03-06	47825	80
914315	5/10/2012	WAVTS,T5,TAP CHRANGER OIL SAMP	WAVTS,T5,TAP CHRANGER OIL SAMPLE FOR TASA TESTING OIL SAMPLE FROM PM INDICATED POSSIBLE PROBLEMS SAMPLE TAKEN SENT TO TJH2b IN CALGARY COMPLETED BY: B. TOBIN/W. DOWNING ON 2012-05-10	47825	80
922300	7/25/2012	WAVTS,T5,TRF DOBLE PM	DOBLE TRANSFORMER EVERY 6 YEARS. note sent. 1. CHECK LATEST DOBLE TEST RESULTS TO SEE WHEN LAST TRANSFORMER WAS TESTED. 2. DOBLE TRANSFORMER AS PER CHECK SHEET AND RECORD 3. ANY VARIATIONS FROM INITIAL DOBLE RESULTS SHOULD BE BROUGHT TO THE ATTENTION OF THE P AND C SUPERVISOR. Performed Doble test on T5 at WAVTS on Jy.25th,2012.OK Results sent to all P&C at Whtb. on JY 26...RH. ---- PERFORMED DOBLE TEST - JULY 25 2012 RESULTS SENT TO WHITBOURNE P&C - JULY 26, 2012. (R. HURLEY) ----	47826	80
922301	7/27/2012	WAVTS,T5,XFMR PM MTNCE	1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK	47825	80

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
922301	7/27/2012	WAVTS,T5,XFMR PM MTNCE	2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A DATE. 3.CONSIDER & REPORT ANY ENVIROMENTAL IMPACTS. PM COMPLETED. COMPLETED BY: W. DOWNING, D. HOSKINS, G. THORNE, B. J. HILLIER ON 2012-07-27	47825	80
923911	10/16/2012	WAVTS,T5 REPLACE GAS RELAY	WAVTS,T5 REPLACE GAS RELAY NEW GAS RELAY ORDERED TO REPLACE ONE USED ON T5 PM. MAINTENANCE WO 922301 GAS RELAY ARRIVED AT WBN ON 2012-10-16 COMPLETED BY? R. DAY ON 2012-10-16	47825	80
925139	7/11/2012	WAVTS,T5,RELAY CABLES,REPLACE	WAVTS,T5,RELAY CABLES,REPLACE REPLACE WINDING TEMP, LIQUID LEVEL AND GAS RELAY FOUND TO BE DETERIORATED ON TRANSFORMER PM CABLES SUPPLING TWO TEMP GAUGES AND ONE LIQUID GAUGE WERE REMOVED AND REPLACED ONE WINDING TEMP GAUGE WAS REPLACED CCOMPLETED BY: W. WALSH/J. HILLIER ON 12-07-11	47825	80

Verbal Safety Talk _____

THINK SAFETY FIRST

WO TYPE : 2 PM Wo HRDTS,B1L17 BREAKER PM MTNCE PARENT #: 00963994
STATUS : 45 PRIORITY: 3 Plann
ITEM # : 00005994 UNIT #: HRDB1L17 BREAKER,B1L17,HRD TS
PLT COND: SD BU #: 1325 SUPV: WHB Station Mtce Dept
LOCN: HRDTS HRD Term Stn, Holyrood ORIG: Lyver, Gerard J.
W/H : 1829 Bishop Falls Warehouse PLNR: Lyver, Gerard J.
EMPL: W.O.#: 963994 W.O. SUBCODE: PMN

--- Full Description of Request ----------

1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK SHEET.
2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK ORDER REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A LATER DATE.
3.CONSIDER & REPORT ANY SIGNIFICANT ENVIROMENTAL IMPACTS.

OP#	CRAFT	DESCRIPTION	SIZE	MHRS
1.00	WHBCRSEM	WHB ELEC Term. Stn Mtce. Crew	2.0	
2.00	WHBCRTM	WHB Term. Stn Mtce	1.0	

--- Tools/Materials & Equip Status ----------

1. CHERRY PICKER OR BUCKET TRUCK
2. DOBLE TEST ELECTRONIC TIMING EQUIPMENT
3. DUCTOR TESTER

--- Safety Provisions ----------

1.ENSURE NECESSARY WORK PROTECTION IS IN PLACE BEFORE STARTING WORK.
2.COMPLETE TAILBOARD SAFETY TALK BEFORE BEGINNING WORK.

--- Plan and Drawing Reference ----------

--- Maintenance Loops ----------

00005994	BREAKER,B1L17,HRD TS	Y06A

Keyed 13-04-15
RB

-- COMMENTS & WORK DONE ----------

work done as Per Pm sheets

-- ASSET TRACKING INFORMATION ----------

1. List all assets installed (Description and Serial Number):

1.a Provide Nameplate Data for all new assets installed:

2.If an asset was removed, note the Description, Serial# and JDE# if known and where it was transferred. ie. St. Anthony Line Depot, Bishops Falls etc.

3. List all assets disposed or to be disposed (Description, Serial #, and JDE #, if known):

COMPLETED BY: BW WJ COMPLETED ON: 13 04 07

-- WORK REMAINING ----------

SUPERVISOR: _____

6 Year PM – 230 KV DLF AIR BLAST CIRCUIT BREAKER INSPECTION

System ID: BL17 Station: HRDTS Serial No.: 170 B 3/1873
Manufacturer: Brown Boveri Type: DLF 245 ND 2 Voltage: 245 KV
Test Date: 8/3 04 04 Test Completed By: GW WD. J.D.E.W/O #: 963994

WEATHER CONDITIONS: [ ] dry [ ] rain [ ] humidity [ ] temperature

NOTE: All TESTS MUST BE COMPLETED OR MARKED N/A (unless otherwise Instructed).

BEFORE OPERATING: Pressure 425 PSI kPa Counter: 01859

ACCEPTABLE DUCTOR READINGS < 120 µOhm		
	% CURRENT	µOhm
A ph	100 100	~~252 µΩ~~ 114 µΩ
B ph	100 100	~~233 µΩ~~ 77.8 µΩ
C ph	100	107.8 µΩ

MEGGER TEST 5 KV (PHASE TO GROUND)					
A PH	32 GΩ	Mega Ω	B PH 50 GΩ	Mega Ω	C PH 65 GΩ Mega Ω

TIMING TEST (milliseconds)			
	A	B	C
3-PH Close	54/55	~~53~~ 53	51 51
3-PH Trip	24 24	23 23	24 23
Trip Free (dwell)	54/55	53/53	51/57
Disagreement On Trip	33 32	32 32	1499
Resistor Contacts			

Command Current Close 2.98 amps Trip 4.31 amps

NOTE: THE BREAKER (TIMING TEST) PERFORMANCE REPORT INCLUDING ALL MAIN CONTACTS SHOULD BE ATTACHED TO THE COMPLETED INSPECTION FORM.

CONTROL CIRCUIT RESISTANCE (Ohms): (test to be completed from the Control Cabinet Terminal Board)						
Trip Coil # 1:	A ph 63.7	Ω	B ph 62.2	Ω	C ph 62.2	Ω
Trip Coil # 2:	A ph 87.4 Ω	Ω	B ph	Ω	C ph	Ω
Close:	A ph 42.4	Ω	B ph 42.2	Ω	C ph 42.2	Ω

HEATER AMPERAGE			
CABINET HEATER :	~~5.0 A.~~ 5.1 A.		
CONTROL BLOCKS:	A: R .6 A	B: S .6 A	C: T .3 A.

Phase C indicator linkage is broken control box

Close Tc 3,4 3,6 3,8
R1 R2 R3
1.2 1.2 1.2

6 Year PM – 230 KV DLF AIR BLAST CIRCUIT BREAKER INSPECTION

System ID: BIL17 Station: HRISTS Serial No.: 170-73-3/1973
Manufacturer: Brown Boveri Type: DLF 245 no2 Voltage: 245KV
Test Date: 2013 04 04 Test Completed By: BWJ WD J.D.E.W/O #: _____

PRESSURE SETTINGS (kPa)		
	Found	Left
400 Block Reclose	410	410
373 Block Trip	376	376
Aux Block Trip		
388 Block Close	390	390
Low Pressure Alarm 303	315	315

CHECKS COMPLETED:
- ✓ Air Leaks
- ✓ Lubricate Control Blocks
- ✓ Check Primary Connections
- ✓ 20 Minute Pressure Drop
- ✓ A ph Control Block Aux Contacts
- ✓ B ph Control Block Aux Contacts
- ✓ C ph Control Block Aux Contacts
- ✓ Control Cabinet Aux Contacts

AFTER OPERATING: Pressure 405 psi kPa Counter: 01868

ONLY IF INSTRUCTED
- NA Doble Test
- NA Clean Air Intake Filters
- NA Inspect 1 Arcing Chamber
  Chamber Lubrication Required _____ yes _____ no

COMMENTS:
Phase B & C indicater linkage broken in Control block box

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
925329	8/1/2012	HRDTS,B1L17,CAPACITORS,LEAKING	HRDTS,B1L17,CAPACITORS,LEAKING REPLACE LEAKING CAPACITORS CLEAN UP OIL, REMOVE SOIL ENSURE PAPER WORK COMPLETED BEFOR TRANSPORTING TO SEE ENV-SOP-11 B1L17 AT HRDTS. TWO NEW CAPACITORS INSTALLED. SERIAL # 8402655 TESTED @ 2569 PT SERIAL # 8402646 TESTED @ 2773 PT. COMPLETED BY: P. O'GRADY & CREW ON 2012-08-01	47825	80
946137	11/2/2012	HRDTS,B1L17,CAPACITORS,TEST	HRDTS,B1L17,CAPACITORS,TEST,DISPOSE OF AS PER POLICY AND REGULATIONS. CAPACITORS ARE DISPOSED TWO TESTED LESS THAN 2 PPM AND TWO TESTED AT 29 PPM'S AND 4.5 PPM'S OF PCB. TWO THAT TESTED HIGH ARE IN THEIR DESIGNATED AREA FOR PICK-UP AND OTHER TWO ARE DRAINED. (R. EDISON)	47806	80
497354	12/6/2005	Check Operation of HRD B1L17	Check Operation of HRD B1L17 Reclose on TL217 on Nov 18. Breaker B1L17 at Holyrood was slow in operating. Check operation of breaker. Call Ern Buglar or Art Bursey for further information HRD BREAKER TIMINGS FROM DOBLE TR 3100 --- PHASE A PHASE B PHASE C TRIPS CONTACT 1 25.3 MS 25.2 MS 25.5 MS CONTACT 2 25.1 MS 25.0 MS 25.2 MS --- CLOSES CONTACT 1 53.6 MS 54.1 MS 61.4 MS 53.3 MS 53.8 MS 61.4 MS --- CHECK TRIP/RECLOSING ON B1L17 ********** THE TRIP/RECLOSING WAS INITIATED VIA P2 PROTECTION FOR A B PH, AND C PH. THE FOLLOWING TIMES WERE NOTED FROM (DEC. 6, 2005) ON EMS. THIS WAS DONE TWICE FOR	47826	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
497354	12/6/2005	Check Operation of HRD B1L17	----------	47826	90

A PHASE

TIME
---
94 A TRIP 11.06.40.894
BREAKER OPEN 11.06.40.999
BREAKER CLOSED 11.06.42.634
****

B PHASE

TIME

94B TRIP 11.07.59.658
BREAKER OPEN 11.07.59.728
BREAKER CLOSED 11.08.01.181
****

C PHASE

TIME

94C TRIP 11.08.35.644
BREAKER OPEN 11.08.35.741
BREAKER CLOSED 11.08.37.358

A PHASE

TIME

94A TRIP 11.47.13.748
BREAKER OPEN 11.47.13.853
BREAKER CLOSED 11.47.15.500
****

B PHASE

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
497354	12/6/2005	Check Operation of HRD B1L17	TIME ------ 94B TRIP 11.47.37.117 BREAKER OPEN 11.47.37.186 BREAKER CLOSED 11.47.38.635 ********** C PHASE --------- TIME ------ 94C TRIP 11.47.53.489 BREAKER OPEN 11.47.53.587 BREAKER CLOSED 11.47.55.204 ********** 3 PH OPEN VIA BREAKER OPEN SWITCH VIA T RELAY. ---------- TIME ------ TRIP 13.21.25.499 BREAKER OPEN 13.21.25.573 COMPLETED BY: L. HOPKINS ON 2005-12-06	47826	90
497889	12/6/2005	HRDTS,B1L17,CHECK PROTECTION/T	HRDTS,B1L17,CHECK PROTECTION AND TIME BREAKER IF TESTS REQUIRED AS A RESULT OF SLOW OPERATION ON A Breaker and protection tested ; results in WO # 497354 under actual work done	47826	90
497890	12/7/2005	HRDTS,B1L17,CHECK PROTECTION/T	HRDTS,B1L17,CHECK PROTECTION AND TIME BREAKER IF TESTS REQUIRED AS A RESULT OF SLOW OPERATION ON A P.C. INITATED SINGLE PHASE PROTECTION TRIPS, TIME MEASURED BY SOE TIMING TEST TRIP, CLOSE TRIP FREE. COMPLETED BY: P. O'GRADY ON 2005-12-07	47825	90
547236	9/15/2006	HRDTS,BIL17,TRIPPED ON DISA	HRDTS,BIL17,TRIPPED ON DISAGREEMENT OUTAGE REQUIRED. WORK PROTECTION WAS REQUIRED. OPERATED BREAKER	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
547236	9/15/2006	HRDTS,BIL17,TRIPPED ON DISA	AT BK. CABINET. ALSO OPERATED BK. FROM CONTROL ALSO FROM HRD CONTROL ROOM ELECTRICTY. CHECKED ALL AND "T" RELAY. BREAKER WORKING OK. COMPLETED BY: G. HILLIER, J. MCDONALD & P. O'GRADY COMPLETED ON: 2006-09-14	47825	90
880287	11/3/2011	HRDTS,B1L17,TC INDICATION	HRDTS,B1L17,TC INDICATION TRIP COIL HEALTH LIGHT NOT WORKING FOUND A LOOSE CONNECTION IN THE NEON LIGHT SOCKET COMPLETED BY: P. O'GRADY/W.WALSH ON 2011-11-03	47825	80
880288	11/3/2011	HRDTS,B1L17,TC INDICATION	HRDTS,B1L17,TC INDICATION TRIP COIL HEALTH LIGHT NOT WORKING CHECKED BREAKER PRESSURE SWITCH A CONTACTS AND COIL RESISTANCES PANEL NEON LIGHT SOCKET TIGHTENED, CHECKED APERATION - COMPLETED BY: R. STOYLES/P.O'GRADY/W.WALSH COMPLETRED ON: 11-11-03	47826	80
962976	2/14/2013	HRDTS,B1L17,C-PH ARCING CHAMBE	HRDTS,B1L17,C-PH ARCING CHAMBER OVERHAUL. REMOVE C-PH ARCING CHAMBER, SHIP TO BIF HAVE OVERHAULED AND REINSTALLED WITH NEW HOLLOW CENTRE PHASE HEAD OF B1L17 REMOVED AND SENT TO COMPLETED BY: W. DOWNING ON 2013-02-14	47825	90
523886	2/20/2008	HRD TS B1L17 RTV COATING	HRD TS B1L17 RTV COATING APPLY RTV COATING TO BREAKER GLASS. CONTACT ERNEST BUGLAR (ENGINEERING) FOR DETAILS RTV COATING IS IN WHITBOURNE TWO PHASE DONE OTHER ONE NOT REQUIRED THIS PRODUCT HAS NOT PROVEN TO BE ANY GOOD NOT REQUIRED AS PER H.IRELAND	47825	90
547504	10/11/2006	HRDTS,B1L17,TEST,TIMING	HRDTS,B1L17,TEST,TIMING. ONE PHASE SLOW OPENING SOMETIMES DISAGREEMENT ALARM ANNUNICATES. OUTAGE REQUIRED.	47825	90

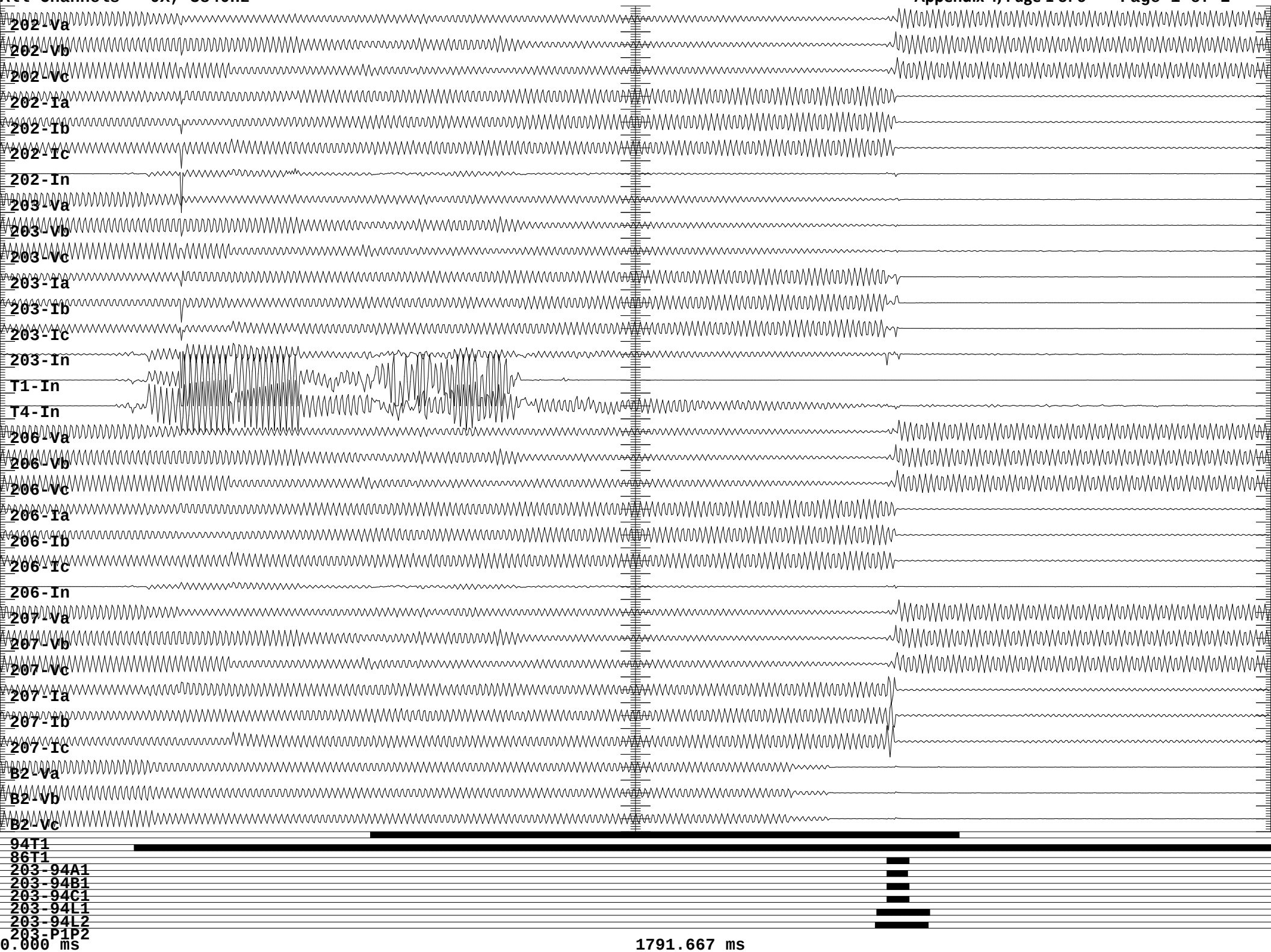
WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
547504	10/11/2006	HRDTS,B1L17,TEST,TIMING	CHECKED ALL 3 PHASES WITH TIMING SET. DISAGREEMENT ON BREAKER WORKING OK. ALARM RESET OK FOR ALL 3 OPERATIONS. COMPLETED BY: G. HILLIER & B. WALSH ON 2006-10-11	47825	90
728010	9/17/2009	HRDTS,B1L17,CHECK AUX.CONTACTS	HRDTS,B1L17,CHECK AUX.CONTACTS BREAKER TRIPPED UNDER DISAGREEMENT. CHECK WO 733227 PERMISSIVE CONTACTS CLEANED AND BREAKER FUNCTION FOUND OK	47825	90
965961	2/28/2013	HRDTS,B1L17,RTV COATING APPLY	RTV COATING APPLY. DISMANTLE COLUMNS AND HEADS, APPLY COATING AND BREAKER. BREAKER HEADS SUPPORT COLUMNS AND CAPICITORS ALL WITH A RTV COATING BY CONTRACTOR. COMPLETED BY: P. O'GRADY ON 2013-02-28 INTERRUPTER HEAD INSTALLED. COMPLETED BY: W. WALSH, I. ORGAN, P. O'GRADY,W. DEAN COMPLETED ON: 2013-03-23	47825	80
676502	7/10/2009	HRDTS,B1L17,RELIEF VALVE,REPLA	HWDTS,B1L17,RELIEF VALVE,REPLACE."B-PH ONLY" valve replaced	47825	90
733227	8/23/2009	HRDTS,B1L17,TRIP/BKR FAIL,INV	HRDTS,B1L17,TRIP/BKR FAIL,INVESTIGATE LIGHTNING STORM CAUSED TL217 PROTECTION TO OPERATE BUT B1L17 WENT INTO LOCKOUT ON THURSDAY, AUG 20, 2009 AT AROUND 7:16 A.M., THERE A LIGHTNING STRIKE ON A PHASE, TL217. THIS CAUSED AN A PHASE TO NEUTRAL FAULT ON OUR PROTECTION. THE FAULT CAUSED OUR PROTECTION TO OPERATE A1 AND A2 RELAYS B1L17 BREAKER DID NOT TRIP. THE PROTECTION ALSO CAUSED TO OPERATE AND BRING IN A BREAKER FAIL 86 TRIP. THE L2 RELAY GOING TO TRIP COIL TWO ACTUALLY CAUSED THE TO TRIP AND WAS THEN LOCKED OUT BECAUSE OF THE 86 TRIP. THE ELECTRICIANS CHECKED BREAKER B1L17 UNDER PERMIT	47826	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
733227	8/23/2009	HRDTS,B1L17,TRIP/BKR FAIL,INV	FOUND THE FOLLOWING: TRIP COIL 1 TRIP COIL 2 3-4 R = 18.2 K OHMS 89 OHMS 3-4 S = 47.1 K OHMS 3-4 T = 29.1 K OHMS THEY DID CLEAN AND BURNISH THE CONTACTS IN THE AND ALSO DID THE SAME ON THE SIGNALING DEVICE AFTER THEY FOUND THE FOLLOWING: TRIP COIL #1 TRIP COIL #2 3-4 R = 61.2 OHMS 90 OHMS 3-4 S = 62.1 OHMS 3-4 T = 64 OHMS WE ALSO CHANGED THE P8 RELAY IN THE BREAKER P8 RESISTANCE 1-2 = .2 OHMS 3-4 = .6 OHMS 5-6 = 1.2 OHMS 7-8 = 1.6 OHMS IT APPEARS THAT THE BREAKER CONTACTS IN OUR TRIP COIL HAD A HIGH RESISTANCE DUE TO THE CONTACTS BEING DIRTY CORRODED. THIS CAUSED THE TRIP COIL ONE NOT TO OPERATE PROPERLY. AFTER THE BREAKER WAS PUT BACK TOGETHER IT TIMING TESTED BY THE ELECTRICIANS. THE BREAKER WAS ALSO FUNCTION TESTED USING THE P1 AND PROTECTION TO TRIP THE BREAKER USING A1, B1, C1 AND A2, B2, C2 RELAYS. THE BREAKER TRIPPED AND RECLOSED PROPERLY ON EACH PHASE. IT ALSO TRIPPED THREE PHASE PROPERLY. COMPLETED BY: G. PARSONS/J. MCDONALD/L. HOPKINS COMPLETED ON: 2009-08-21	47826	90
881761	1/24/2012	HRDTS,AIR SYSTEM ANOMOLY	HRDTS,AIR SYSTEM ANOMOLY B1L17 RESET AIR ON BRAKER B12L18	47825	80

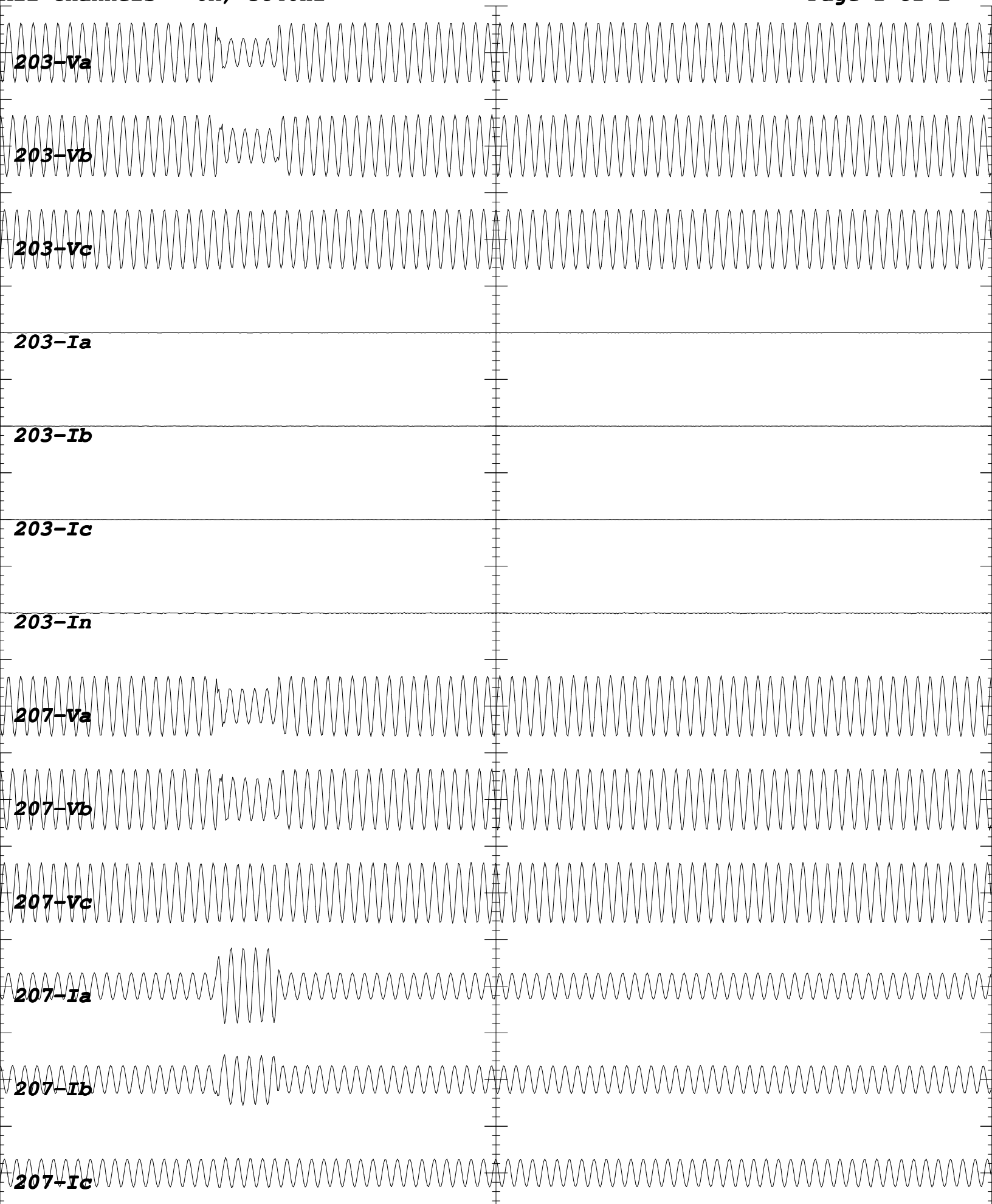
WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
881761	1/24/2012	HRDTS,AIR SYSTEM ANOMOLY	COMPLETED BY: M. PENNEY ON 2011-10-26 COMPLETED	47825	80
976955	4/9/2013	HRDTS,B1L17,AIR PRESS ALARM	HRDTS,B1L17,AIR PRESS ALARM INVESTIGATE ALARM CAUSED BY AIR PRESSURE LOWER THAN 400 PSI RECLOSING SET POINT AIR VALVE ADJUSTED SEVERAL TIMES TO CLEAR ALARM COMPLETED BY: W. DOWNING ON 13-04-09	47825	80
978023	4/7/2013	HRDTS,INVEST.AIR ALARM B1L17	HRDTS,INVEST.AIR ALARM B1L17 AIR ANOMALY BREAKERB1L17 BREAKER INVESTIGATE CHECKED AIR PRESSURE ALARM ON B1L17. ALARM RESET PRESSURE RECOVERED TO 400 PSI. COMPLETED BY: W. DOWNING ON 2013-04-07 AIR ALARM ON B1L17, VALVE STICKING, VALVE ADJUSTED CLEARED. COMPLETED BY: W. DOWNING & B. TOBIN ON 2013-04-10	47825	80
393852	4/8/2004	HRD B1L17 INSULATORS WASH	HRD B1L17 INSULATORS WASH WASH INSULATORS USING KARCHER POWER WASHER (1500 USING WATER ONLY.BREAKER DEENERGIZED FOR WASHING. INSPECT EXISTING RTV COATING AND ADD COMMENTS ON B1L17 PRESSURED WASHED NO VISIBLE SIGN OF ARCING TOP VENT SHROUD RUSTED ON A AND C PHASE COMPLETED BY: P. O'GRADY/W. WALSH/S. TUCKER COMPLETED ON: 2004-04-07	47825	90
326986	6/12/2003	HRDTS,B1L17,AIR LEAK,INVEST*	HRDTS,B1L17,AIR LEAK,REPAIR B PHASE CONTROL BLOCK. SCHEDULE WITH UNIT 1 OUTAGE-AROUND MAY 12TH INVESTIGATED AIR LEAK & FOUND LEAK IN THE CONTROL BLOCK ON B PHASE. NEEDS CONTROL BLOCK TO BE OVERHAULED. COMPLETED BY: G. HILLIER ON 2003-06-12	47825	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
326986	6/12/2003	HRDTS,B1L17,AIR LEAK,INVEST*	TAKE OUTAGE AND DRAIN AIR OF BREAKER AND REPAIR CONTROL BLOCK (DLF 230KV AIR BLAST BK.)	47825	90
333692	6/27/2003	HRDTS,B1L17,PAINT REC. TANKS*	HOLYROOD TERMINAL STATION: BREAKER #B1L17 PAINT RECEIVER TANKS WHITE. PAINT TO BE USED IS AN INDUSTRIAL TYPE WHITE COLOR. BRUCE COLLIER HAS IDENTIFIED THE PAINT AND REQUIRED AMOUNT. THIS WORK CAN BE PERFORMED FROM SCAFFOLD AND OUTAGES WILL NOT BE REQUIRED. NAME PLATES ARE TO BE COVERED DURING THE PAINTING RUST AREAS TO BE SCRAPED AND PRIMED. THE APPLICATION METHOD TO BE WITH BRUSH, ROLLER OR PAD OR A THESE. SPRAY PAINTING METHOD IS NOT TO BE USED. PAINTED AIR RECEIVERS COMPLETED BY: H. MOORES ON 2003-06-27	47825	90
344962	10/9/2003	HRDTS,B1L17,LEAK,REPAIR	HRDTS,B1L17,LEAK,REPAIR DLF 245 NC2 PARTS REQUIRED REPLACED PART #A1-B110 WHICH IS THE PRIMARY CONTROL VALVE SEALING. COMPLETED BY: P.O'GRADY/W.DOWNING ON 2003-10-09	47825	90
398074	12/4/2004	HRDTS.B1L17 INSTALL PLC	HRD 230kV Bkr B1L17 Controls Install Programmable Logic Controller for breaker controls on HRD Bkr B1L17. Remove old relays and case for recloser. Refer to WO #398085 for parts. CHECKED BREAKER FOR PROPER OPERATION BEFORE PROCEEDING WITH JOB. HAD PROBLEM WITH AIR PRESSURE. NEEDED MECHANIC, RESOLVED PROBLEMS CONTINUED WITH REMOVED OLD RECLOSER AND INSTALLED NEW PLC BASED RECLOSER, ASSOCIATED RELAYS AND WIRING. BUZZED OUT CIRCUITS, FUNCTION TESTED AND CHECKED INTO SERVICE. THE BT RELAY SLATED FOR THIS JOB WAS USED AT WAV. C. WARREN REPLACED WITH A DIFFERENT TYPE ABB RXMA1. COMPLETED BY: J. HOPKINS/J.MCDONALD ON 2004-12-04	47826	90

WO#	Comp. Date	Work Description	Detailed Description/Actual Work	Supervisor	St
398085	1/5/2005	HRD 230kV Bkr B1L17 Controls	HRD 230kV Bkr B1L17 Controls Install Programmable Logic Controller for breaker controls on HRD Bkr B1L17. Remove old relays and case for recloser. Refer to WO #398074 for labour. COMPLETED COMPLETED BY: J.S. FOLEY ON 2005-01-05	47826	90
551787	10/20/2006	HRDTS,B1L17 BREAKER PM MTNCE	1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK 2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A DATE. 3.CONSIDER & REPORT ANY SIGNIFICANT ENVIROMENTAL	47825	90
963994	4/7/2013	HRDTS,B1L17 BREAKER PM MTNCE	1.PERFORM PM IN ACCORDANCE WITH APPROPRIATE CHECK 2.RECORD ANY UNCOMPLETED DEFICIENCIES ON A WORK REQUEST IN ORDER TO HAVE THE WORK COMPLETED AT A DATE. 3.CONSIDER & REPORT ANY SIGNIFICANT ENVIROMENTAL WORK DONE AS PER PM SHEETS. COMPLETED BY: B. WALSH & W. DOWNING ON 2013-04-07	47825	80


202-Va
202-Vb
202-Vc
202-Ia
202-Ib
202-Ic
202-In
203-Va
203-Vb
203-Vc
203-Ia
203-Ib
203-Ic
203-In
T1-In
T4-In
206-Va
206-Vb
206-Vc
206-Ia
206-Ib
206-Ic
206-In
207-Va
207-Vb
207-Vc
207-Ia
207-Ib
207-Ic
B2-Va
B2-Vb
B2-Vc
94T1
86T1
203-94A1
203-94B1
203-94C1
203-94L1
203-94L2
203-P1P2
0.000 ms
1791.667 ms

Trace	Label	Name	Scale	Units/Division
1	202-Va	230 KV TL202 A Phase Voltage	1.00	72177.652 V
2	202-Vb	230 KV TL202 B Phase Voltage	1.00	72458.470 V
3	202-Vc	230 KV TL202 C Phase Voltage	1.00	72601.507 V
4	202-Ia	TL202 A Phase Current	5.00	338.114 A
5	202-Ib	TL202 B Phase Current	5.00	338.290 A
6	202-Ic	TL202 C Phase Current	5.00	339.371 A
7	202-In	TL202 Neutral Current	15.00	113.019 A
8	203-Va	230 KV TL203 A Phase Voltage	1.00	72423.934 V
9	203-Vb	230 KV TL203 B Phase Voltage	1.00	72506.562 V
10	203-Vc	230 KV TL203 C Phase Voltage	1.00	72394.188 V
11	203-Ia	TL203 A Phase Current	5.00	337.960 A
12	203-Ib	TL203 B Phase Current	5.00	338.712 A
13	203-Ic	TL203 C Phase Current	5.00	338.641 A
14	203-In	TL203 Neutral Current	15.00	112.692 A
15	T1-In	T1 Neutral Current	2.00	1059.220 A
16	T4-In	T4 Neutral Current	2.00	1059.457 A
17	206-Va	230KV TL206 A Phase Voltage	1.00	72296.314 V
18	206-Vb	230KV TL206 B Phase Voltage	1.00	72600.926 V
19	206-Vc	230KV TL206 C Phase Voltage	1.00	72753.172 V
20	206-Ia	TL206 A Phase Current	5.00	339.398 A
21	206-Ib	TL206 B Phase Current	5.00	338.909 A
22	206-Ic	TL206 C Phase Current	5.00	338.978 A
23	206-In	TL206 Neutral Current	15.00	113.283 A
24	207-Va	230KV TL207 A Phase Voltage	1.00	72562.495 V
25	207-Vb	230KV TL207 B Phase Voltage	1.00	72516.289 V
26	207-Vc	230KV TL207 C Phase Voltage	1.00	72466.927 V
27	207-Ia	TL207 A Phase Current	5.00	339.563 A
28	207-Ib	TL207 B Phase Current	5.00	338.912 A
29	207-Ic	TL207 C Phase Current	5.00	340.012 A
30	B2-Va	138 KV B2 A Phase Voltage	1.00	43573.561 V
31	B2-Vb	138 KV B2 B Phase Voltage	1.00	43518.666 V
32	B2-Vc	138 KV B2 C Phase Voltage	1.00	43444.008 V
33	94T1	94T1	N/A	N/A
34	86T1	86T1(NC)	N/A	N/A
35	203-94A1	TL203 94A1X	N/A	N/A
36	203-94B1	TL203 94B1X	N/A	N/A
37	203-94C1	TL203 94C1X	N/A	N/A
38	203-94L1	TL203 94L1	N/A	N/A
39	203-94L2	TL203 94L2	N/A	N/A
40	203-P1P2	TL203 21P1/P2	N/A	N/A



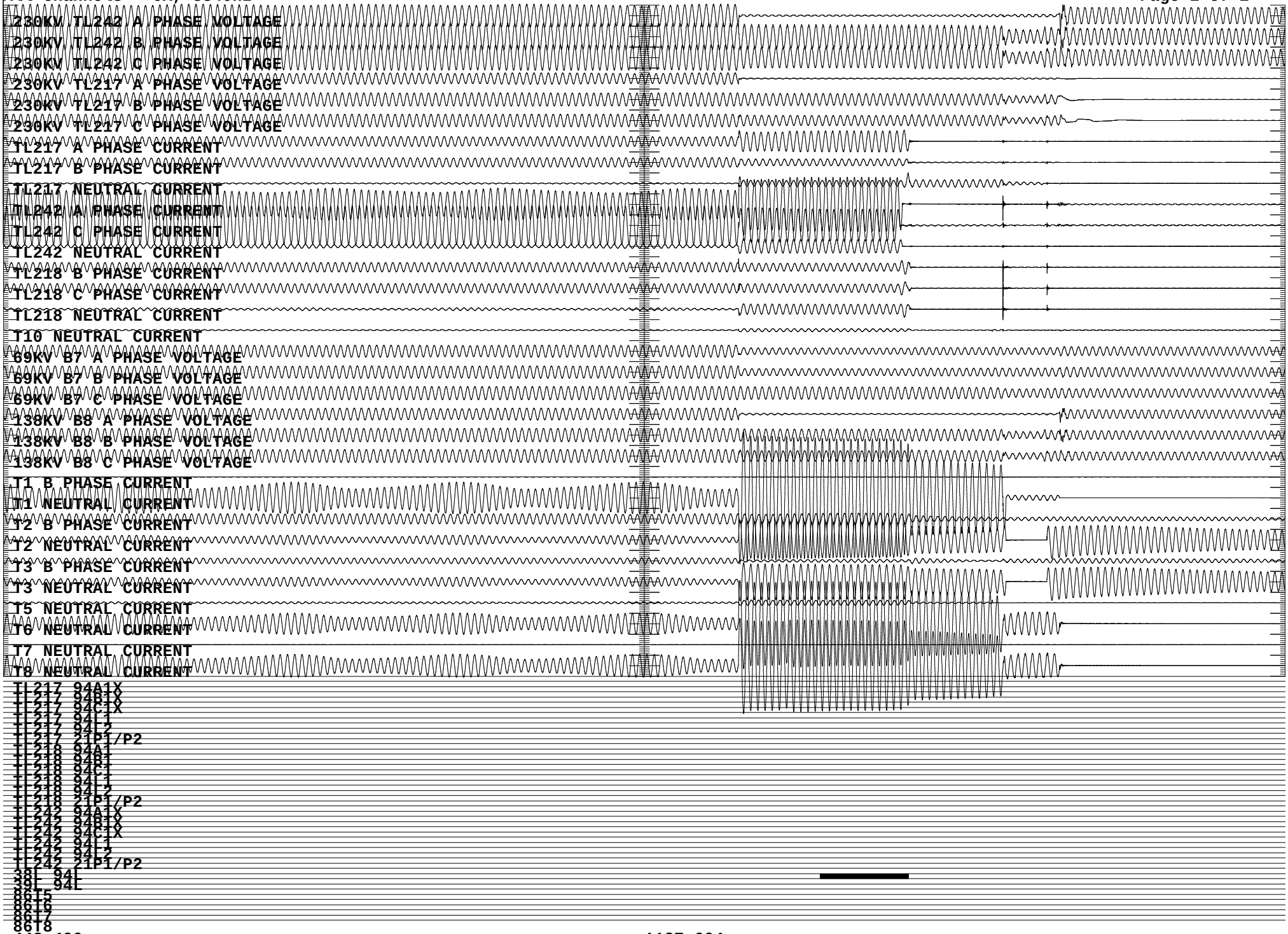
0.000 ms

671.875 ms

Trace	Label	Name	Scale	Units/Division
1	203-Va	230 KV TL203 A Phase Voltage	1.00	72423.934 V
2	203-Vb	230 KV TL203 B Phase Voltage	1.00	72506.562 V
3	203-Vc	230 KV TL203 C Phase Voltage	1.00	72394.188 V
4	203-Ia	TL203 A Phase Current	5.00	337.960 A
5	203-Ib	TL203 B Phase Current	5.00	338.712 A
6	203-Ic	TL203 C Phase Current	5.00	338.641 A
7	203-In	TL203 Neutral Current	15.00	112.692 A
8	207-Va	230KV TL207 A Phase Voltage	1.00	72562.495 V
9	207-Vb	230KV TL207 B Phase Voltage	1.00	72516.289 V
10	207-Vc	230KV TL207 C Phase Voltage	1.00	72466.927 V
11	207-Ia	TL207 A Phase Current	5.00	339.563 A
12	207-Ib	TL207 B Phase Current	5.00	338.912 A
13	207-Ic	TL207 C Phase Current	5.00	340.012 A

Transcan DFR : Holyrood Terminal Station HOLY0FF1.X01 2014/Jan/05 21:27:40 (IRIG-B)

All Channels - 0X, 3840Hz



-443.490 ms 1127.604 ms

Transcan DFR : Holyrood Terminal Station HOLY0FF1.X01 2014/Jan/05 21:27:40 (IRIG-B)
All Channels - 0X, 3840Hz

Trace	Label	Name	Scale	Units/Division
1	242 Va	230KV TL242 A PHASE VOLTAGE	2.00	36484.911 V
2	242 Vb	230KV TL242 B PHASE VOLTAGE	2.00	36668.145 V
3	242 Vc	230KV TL242 C PHASE VOLTAGE	2.00	36558.966 V
4	217 Va	230KV TL217 A PHASE VOLTAGE	1.00	73037.310 V
5	217 Vb	230KV TL217 B PHASE VOLTAGE	1.00	73091.451 V
6	217 Vc	230KV TL217 C PHASE VOLTAGE	1.00	73084.955 V
7	217 Ia	TL217 A PHASE CURRENT	10.00	190.731 A
8	217 Ib	TL217 B PHASE CURRENT	10.00	190.602 A
9	217 In	TL217 NEUTRAL CURRENT	10.00	191.105 A
10	242 Ia	TL242 A PHASE CURRENT	40.00	47.666 A
11	242 Ic	TL242 C PHASE CURRENT	40.00	47.655 A
12	242 In	TL242 NEUTRAL CURRENT	10.00	190.959 A
13	218 Ib	TL218 B PHASE CURRENT	10.00	190.594 A
14	218 Ic	TL218 C PHASE CURRENT	10.00	190.584 A
15	218 In	TL218 NEUTRAL CURRENT	10.00	190.902 A
16	T10 In	T10 NEUTRAL CURRENT	10.00	63.553 A
17	69B7 Va	69KV B7 A PHASE VOLTAGE	1.00	21949.857 V
18	69B7 Vb	69KV B7 B PHASE VOLTAGE	1.00	21892.398 V
19	69B7 Vc	69KV B7 C PHASE VOLTAGE	1.00	21941.347 V
20	138B8 Va	138KV B8 A PHASE VOLTAGE	1.00	43771.399 V
21	138B8 Vb	138KV B8 B PHASE VOLTAGE	1.00	43808.592 V
22	138B8 Vc	138KV B8 C PHASE VOLTAGE	1.00	43804.811 V
23	T1 Ib	T1 B PHASE CURRENT	10.00	190.832 A
24	T1 In	T1 NEUTRAL CURRENT	10.00	190.743 A
25	T2 Ib	T2 B PHASE CURRENT	10.00	190.428 A
26	T2 In	T2 NEUTRAL CURRENT	10.00	190.595 A
27	T3 Ib	T3 B PHASE CURRENT	10.00	189.763 A
28	T3 In	T3 NEUTRAL CURRENT	10.00	190.734 A
29	T5 In	T5 NEUTRAL CURRENT	10.00	47.620 A
30	T6 In	T6 NEUTRAL CURRENT	10.00	63.600 A
31	T7 In	T7 NEUTRAL CURRENT	10.00	63.546 A
32	T8 In	T8 NEUTRAL CURRENT	10.00	158.810 A
33	217 94A1	TL217 94A1X	N/A	N/A
34	217 94B1	TL217 94B1X	N/A	N/A
35	217 94C1	TL217 94C1X	N/A	N/A
36	217 94L1	TL217 94L1	N/A	N/A
37	217 94L2	TL217 94L2	N/A	N/A
38	217 21P	TL217 21P1/P2	N/A	N/A
39	218 94A1	TL218 94A1	N/A	N/A
40	218 94B1	TL218 94B1	N/A	N/A
41	218 94C1	TL218 94C1	N/A	N/A
42	218 94L1	TL218 94L1	N/A	N/A
43	218 94L2	TL218 94L2	N/A	N/A
44	218 21P	TL218 21P1/P2	N/A	N/A
45	242 94A1	TL242 94A1X	N/A	N/A
46	242 94B1	TL242 94B1X	N/A	N/A
47	242 94C1	TL242 94C1X	N/A	N/A
48	242 94L1	TL242 94L1	N/A	N/A
49	242 94L2	TL242 94L2	N/A	N/A
50	242 21P	TL242 21P1/P2	N/A	N/A
51	38L 94L	38L 94L	N/A	N/A

NEWFOUNDLAND AND LABRADOR HYDRO

Sequence of Events
Leading up to Sunnyside Transformer Fault on January 4, 2014

February 2014

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Table 1: Events leading up to Sunnyside Transformer Fault - January 4, 2014

Date	Time	Event
Jun. 1, 2013	**12:00**	The Stephenville Gas Turbine de-rated by 25 MW due to excessive heat build-up in the B turbine module during operation, resulting from the poor condition of the insulating blankets around the turbine and exhaust stack.
Oct. 3, 2013	**08:00**	Hardwoods Gas Turbine removed from service for alternator overhaul. Scheduled completion date was December 19, 2013.
Dec. 11, 2013		During testing at Hardwoods Gas Turbine on December 10, a jacking oil pump failed. The pump on the unit at Stephenville Gas Turbine was temporarily removed and installed at Hardwoods, causing the Stephenville unit to become unavailable while a replacement pump was obtained and installed.
Dec. 14, 2013		A new record system demand of 1,501 MW was supplied.
Dec. 15, 2013	**01:20**	Significant frazil ice accumulation affected the Exploits generation at Grand Falls. Plant production reduced from 63 MW to 38 MW (by 25 MW).
Dec. 16, 2013		Granite Canal Generating Station reduced to 32 MW due to axial vibration.
Dec. 21, 2013	**14:00**	Hardwoods Gas Turbine unavailable, suspected due to the failure of a three-way fuel valve associated with Engine A. The failure occurred during commissioning of the new alternator, following a refurbishment undertaken during the fall.
Dec. 23, 2013	**20:21**	Stephenville Gas Turbine restored to 25 MW with the installation of a new jacking pump to replace the old pump, which was removed on December 11 and sent to Hardwoods. The remaining 25 MW of capacity was pending the delivery of new insulating blankets, scheduled for early January 2014.
Dec. 25, 2013		Holyrood Unit 2 de-rated (by 25 MW) to 142 MW due to a broken control valve.
Dec. 26, 2013	**06:00**	Holyrood Unit 3 de-rated (by 100 MW) to 50 MW due to a failure of a forced draft (FD) fan motor.

Date	Time	Event
		Total unavailable generation at this time is approximately 233 MW. Implemented generation loading sequence generation shortages protocol up to step eight (with the exception of step seven). A copy of this protocol is at the end of this Sequence of Events. Communication continued with Newfoundland Power (NP) as to the status of generation assets, load forecasts, and protocols. Communications occurred internally to ensure awareness of the situation. Supply and demand at peak. Demand: 1385 MW Supply: 1426 MW
Dec. 27, 2013		Generation loading sequence generation shortages protocol was not required. Communication continued with NP as to the status of generation assets, load forecasts and protocols. Supply and Demand at Peak. Demand: 1331 MW Supply: 1456 MW
Dec. 28, 2013	**06:34**	Bay d'Espoir Unit 2 was removed from service due to air supply issue with circuit breaker B1T2. The unit was restored at 1138 hours.
Dec. 28, 2013		Generation loading sequence generation shortages protocol was not required. Forecast peak for December 29 of 1410 MW. This was communicated to NP. Preparations were made between both utilities to prepare, as per shortage protocol. A customer conservation message was discussed as a potential requirement for December 29. The decision was to be made early on December 29. Supply and demand at peak. Demand: 1354 MW Supply: 1456 MW
Dec. 29, 2013		The Stephenville Gas Turbine failed to start initially. The unit was successfully started at 2224 hours. Implemented generation loading sequence generation shortages protocol up to step 13; including asking Corner Brook Pulp and Paper (CBPP) to shed processing load. Continued to discuss the potential of issuing a public conservation message but determined it was not required. Forecast peak for December 30 of 1420 MW. Continued communication with NP regarding the continuing need to implement the Generation

Date	Time	Event
		Loading Sequence Generation Shortages protocol.
	16:35	Implemented the Generation Loading Sequence Generation Shortage Protocol steps to start NP standby generation, implement NP voltage reductions and call on curtailable customer.
	17:08	Received first assistance from CBPP (28 MW)
		Supply and Demand at Peak. Demand: 1425 MW Supply: 1470 MW
		Determined that immediate resolution of Holyrood and Hardwoods generation issues were not possible.
Dec. 30, 2013		Implemented Generation Loading Sequence Generation Shortage protocol up to step 13; This included asking CBPP to shed approximately 30 MW of load in the morning and 52 MW in the evening. There was an internal meeting held to discuss progress on generation and preparations going forward. Discussions were initiated with CBPP regarding a more formal capacity assistance agreement. Forecast peak for December 31 of 1400 MW. Continued communication with NP regarding the continuing need to implement the Generation Loading Sequence Generation Shortage protocol. Supply and Demand at Peak. Demand: 1417 MW (morning) Demand: 1417 MW (evening) Supply: 1458 MW A review of the weather forecasts highlighted that January 2-3 demand levels are were expected to be high. Generation Loading Sequence Generation Shortage protocol not required.
Dec. 31, 2013		A short- term capacity assistance agreement was reached with CBPP for 20, 40 or 60 MW blocks of power. Forecast peak for January 1 of 1450 MW. Continued communication with NP regarding the continuing need to implement the Generation Loading Sequence Generation Shortage protocol.

Date	Time	Event
		The Public Utilities Board was notified of extended capacity issues with the Stephenville Gas Turbine, Hardwoods Gas Turbine and Holyrood Unit 3.
Dec. 31, 2013		Supply and Demand at Peak. Demand: 1393 MW Supply: 1453 MW Implemented Generation Loading Sequence Generation Shortage protocol up to step 13. This included capacity assistance from CBPP for 40 MW during peak.
Jan. 1, 2014		Forecast peak for January 2 of 1500 MW. Continued communication with NP regarding the continuing need to implement the Generation Loading Sequence Generation Shortage protocol. Supply and Demand at Peak. Demand: 1440 MW Supply: 1484 MW
Jan. 2, 2014	**08:00**	A conservation request discussion was initiated with NP in the early morning. The short-term forecast indicated that the evening peak would outstrip available supply.
	14:00	Conservation request issued to all island customers.
	16:13	NP started feeder interruptions. See attached slide for details of the feeder interruptions from January 2 to January 8.
	16:34	Granite Canal unit tripped with a loss of 33 MW.
	16:56	Newfoundland and Labrador Hydro (Hydro) started feeder interruptions. See attached slide for details of the feeder interruptions from January 2 to January 8. Peak Demand supplied 1493 MW at 16:15 hours.
Jan 3, 2014	**12:06**	Unit 2 restored to 165 MW, with only a minor de-rating of 5 MW.

NP – Feeder Interruptions

Date	Time	Feeder Rotations	Average Duration (minutes)
Thursday January 2, 2014	4:13 pm to 10:45 pm	77	88
Friday January 3, 2014	6:57 am to 7:36 pm	141	44
Sunday January 5, 2014	7:23 am to 8:29 pm	158	54
Monday January 6, 2014	5:17 am to 10:48 am	39	47
Wednesday January 8, 2014	3:23 pm to 5:42 pm	32	25

NLH – Feeder Interruptions

Date	Time	Feeder Rotations	Average Duration (minutes)
Thursday January 2, 2014	4:56 pm to 10:50 pm	6	30
Friday January 3, 2014	7:00 am to 7:30 pm	25	30
Sunday January 5, 2014	5:04 pm to 7:03 pm	5	60
Wednesday January 8, 2014	3:32 pm to 4:30 pm	3	30

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES*, **	**Rev. No.**	07
		Page 1	**of** 2

INTRODUCTION

In the event of a system generation shortage, the following guidelines shall be followed in the sequence outlined in order to minimize outages to customers:

PROCEDURE

A. Normal Generation Loading Sequence

1. Bring on line all available Hydro hydroelectric generators and load them to near their full capacity.
2. Request Newfoundland Power to maximize their hydro production.
3. Make a Capacity Request of Deer Lake Power to maximize their hydroelectric generation.
4. Request Non-Utility Generators to maximize their hydro production.
5. Increase Holyrood production to near full capacity.
6. Notify customers taking non-firm power and energy that if they continue to take non-firm power, the energy will be charged at higher standby generation rates.
7. Ask Newfoundland Power to curtail any interruptible loads available.
8. Start and load standby generators, both Hydro and Newfoundland Power units, in order of increasing average energy production cost with due consideration for unit start-up time.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

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SYSTEM OPERATING INSTRUCTION

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		Page 2	**of** 2

PROCEDURE (cont'd.)

9. Cancel all non-firm power delivery to customers and ensure all industrial customers are within contract limits.

If load is still increasing and it is apparent that a generation shortage may occur, proceed as follows:

10. Ensure that steps A1 to A9 above have been followed and implemented.

11. Inform Newfoundland Power of Hydro's need to reduce supply voltage at Hardwoods and Oxen Pond and other delivery points to minimum levels to facilitate load reduction. Begin voltage reduction.

12. Request industrial customers to shed non-essential loads and inform them of system conditions.

13. Request industrial customers to shed additional load.

14. Request Newfoundland Power to shed load by rotating feeders. At the same time, shed load by rotating feeders in Hydro's Rural areas where feeder control exists.

Note:

Generation from Wind Farms may shutdown with little notice.

* Part of the Environmental Plan
** Part of the Emergency Response Plan

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

NEWFOUNDLAND AND LABRADOR HYDRO

Sequence of Events
Following Sunnyside Transformer Fault on January 4, 2014

February 2014

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a nalcor energy company

Events Following SSD Transformer Fault - January 4, 2014

Date	Time	Event
Jan. 4, 2014		Weather forecast for blizzard conditions and heavy snowfall; crews prepared for storm response.
	08:00	Crews dispatched to major terminal stations on the Avalon. Remote hydroelectric plants staffed by operators, and the road to the Upper Salmon plant was maintained open.
	09:05:34	Fault detected in transformer T1 at Sunnyside (SSD). The SSD transformer T1 lockout protection operated resulting in following breaker operations: SSD L109T4 open SSD B3T4 open SSD B1L02 open SSD B2T1 open Four of five breakers for T1 operate, breaker B1L03 failed to open, keeping the 230 kV Bus B1 and transformer T1 energized from TL203. Fault evolved and protection circuits at multiple locations sensed the fault.
	09:05:35	SSD disconnect switch B1T1 in-transit alarm, indicated the disconnect switch had started to open.
	09:05:36	The Paradise River generating unit tripped, with a loss of 8 MW. As a result of the failure of SSD B1L03 to open and clear the T1 fault, the primary one, primary two and backup protection operated on transmission line TL203 at the Western Avalon Terminal Station (WAV). The backup protection also operated for transmission line TL203 at SSD. The following breakers opened for this event: SSD L03L06 open WAV L01L03 open WAV L03L17 open

Date	Time	Event
		TL203 was open at the WAV end and SSD Bus B1 and transformer T1 were de-energized. Backup protection also operated on transmission line TL237 at Come by Chance (CBC) and WAV. The following breakers opened for this event: CBC B1B2 open WAV L01L37 open Circuit breaker B1L37 at WAV appeared to have been delayed in opening by two seconds for the protection trip. **Transmission Lines TL203 (SSD – WAV) and TL237 (CBC – WAV) were out of service and the Avalon was isolated from the rest of the power system. Bus B1 and Transformer T1 at the Come By Chance TS were still energized. The Holyrood Generating Plant remained on-line, momentarily.**
	09:05:37	Normal Newfoundland Power supply to Hydro Place was lost; Hydro's EMS switched to battery power.
	09:05:37	Units at Holyrood cannot supply the load. Holyrood Units 2 and 3 are tripped and isolated from the system by unit breakers. Unit 1 trip is initiated and unit breaker B1B11 opened three phases. Unit breaker B1L17 opened only on two phases during the trip. Backup protection operated on transmission line TL242 at Hardwoods Terminal Station (HWD). Breaker B1L42 opened at HWD. Backup protection operated on transmission line TL218 at Oxen Pond Terminal Station (OPD). Breaker B1L18 opened at OPD. Holyrood Unit 3 was isolated from the system. **Transmission Lines TL203 (SSD – WAV) and TL237 (CBC – WAV) were out of service and the Holyrood Generating Plant was shut down and isolated. The 138 kV and 66 kV transmission had also tripped via NP lines 64L, 86L, 39L from WAV to HRD.**

Date	Time	Event
	09:05:38	Breaker B1L37 at WAV opened, closed and then re-opened in a three second period, an indication that the breaker operated only on two phases.
	09:05:38	Star Lake generating plant tripped with the loss of 18 MW and Stephenville Gas Turbine tripped.
	09:05:41	Cat Arm and Hinds Lake generating plants tripped with a loss of 205 MW of generation.
	09:05:41	SSD disconnect switch B1T1 was fully open, providing full isolation of transformer T1.
	09:05:45	Diesel G1 at Hydro Place on-line, re-storing AC supply.
	09:05:45	Hydro's EMS switched to diesel supply.
	09:09:45	EMS indication for breaker B2L42 at Holyrood toggled between open and closed multiple times, likely making its actual state unclear to the ECC operators.
	09:13	Upper Salmon generating plant tripped with the loss of 88 MW.
	09:27	Breaker B1B2 at Come By Chance closed by the ECC, marking the start of restoration phase and energizing transmission line TL237 to Western Avalon.
	09:41	Attempts to energize Bus B1 at WAV from line TL237. Line breaker B1L37 closed, but tripped again 1.2 seconds later. It was later determined that only two phases of the breaker had closed and there was a phase disagreement trip, momentarily energizing Busses B1 and B3, the WAV transformers, and transmission line TL208 to Vale, all on two phases. A Gas/Oil/Temperature alarm was received for transformer T5. ECC opened WAV breaker B1L08 to isolate TL208 and attempted to close B1L37 again, with the same result. Another Gas/Oil/Temperature alarm is received for T5.
	09:51	WAV circuit breaker L01L37 was closed by ECC, energizing a 230 KV ring Bus section at WAV, transmission line TL201 and the HWD terminal station.

Date	Time	Event
	09:57	Stephenville Gas Turbine in service at 25 MW.
	10:08	Upper Salmon generating plant in service at 88 MW.
	10:14	Granite Canal generating plant in service at 40 MW.
		ECC attempted to close breaker B2L42 at HWD to energize TL242 into Holyrood and restore station service. This energized HRD Bus B12 and, since unit breaker B1L17 had failed during the earlier events and remained closed on one phase, this resulted in a single-phase energizing of Unit 1 transformer T1. Protection circuits for TL242 operated at both HWD and Holyrood. Additional breakers were opened by ECC to provide for further isolation of the HRD TS.
	10:24	Holyrood station service is restored via transmission line TL242 (HWD – HRD) and HRD transformer T10.
	10:26	Holyrood unit disconnect switches B1T1 and B2T2 were opened by the HRD operators.
	10:38	Hydro Place diesel unit G1 tripped offline due to high temperature. There is no power at Hydro Place and EMS switched to battery power.
	10:41	Breaker B1L36 is closed at HWD, restoring transmission line TL236 (HWD – OPD) and OPD TS.
	10:41	ECC closed breaker B3L47 at Deer Lake, energizing transmission line TL247 and starting the process of restoring Cat Arm generating units.
	10:57	Breaker B1L03 at SSD, the breaker that failed to open during the T1 fault, opens un-commanded.
	11:03	The beginning of a 43-minute outage to the ECC, EMS. The outage resulted from a short power interruption (13 seconds), upon the loss of primary supply (Newfoundland Power), the standby diesels and the UPS system. The system was recovered and re-established at 11:46.
	12:00	SSD transformer T1 isolated from the system via disconnect switches. Transformer reported to be still on fire.

Date	Time	Event
	12:13	Three additional, but unsuccessful, attempts to close breaker B1L37 at WAV to restore 230 Busses B1 and B3. Similar to previous attempts the breaker closed only momentarily and at least one T5 transformer Gas/Oil/Temperature alarm was received. At 12:15 the ECC closed WAV breaker B1L17.
	12:18	Cat Arm Unit 2 in service at 65 MW.
	12:22	ECC closed breakers L03L17 and L01L03 at WAV, energizing Busses B1 and B3 from TL237. Due to previous actions this also energized transmission lines TL203 to SSD and TL217 to HRD. WAV transformer T5 lockout protection operated after restoration of Busses B1 and B3, isolating the transformer from the system via WAV breaker B1B3 and transformer disconnects B3T5 and B4T5. It was later determined there was an internal failure of the transformer tap changer. WAV busses B1 (230 KV) and B2 (66 KV) were restored.
	12:23	ECC restores TL217 (WAV - HRD).
	12:30	ECC restores TL218 (HRD - OPD).
	12:56	Cat Arm Unit 1 in service at 65 MW.
	12:57	Bus B1 and Transformer T4 are re-energized at SSD, re-establishing station service and restoring the breaker compressed air system.
	12:58	Switching at SSD to restore the load side of transformer T4 (138 KV). Breaker B3T4 closed by ECC, resulting in the operation of the Bus B1 lockout switch at SSD, initiated by the transformer disconnect switch, B1T4, opening under load and resulted in an arcing fault. Breakers B3T4 and B1L02 tripped. Breaker B1L03 had been previously isolated. Attempt to restore T4 failed. Impact was confined to the Sunnyside Station. Investigation determined the Bus B1 differential protection operated upon closure of B3T4, likely caused by the current transformers and

Date	Time	Event
		wiring on transformer T1 having been destroyed by the transformer fire.
	14:10	Stephenville Gas Turbine off line.
	14:28	Stephenville Gas Turbine in service at 25 MW.
	14:36	After a couple of unsuccessful attempts, the SSD transformer T4 disconnect B1T4 is closed.
	14:37	Circuit breaker B4L64 closed at WAV, restoring 64L and the 138 kV supply to Newfoundland Power on the Avalon.
	14:40	ECC closed breaker L03L06 at SSD, restoring both ends of TL203 (SSD – WAV).
	14:41	The SSD 230 KV Bus B1 was re-energized by ECC via breaker B1L02, which also energized transformer T4. SSD Station service is restored.
	15:12	Hinds Lake unit restarted and loaded to 75 MW. There were considerable issues with the unit breaker B1G1.
	15:25	Circuit breaker B8L39 was closed at HRD, restoring the 138 kV loop from WAV to HRD. **All transmission to the Avalon was restored.**
	15:33:26	A second attempt was made to restore the load side of SSD transformer T4 (138 KV). Breaker B3T4 closed by ECC and again resulted in the opening of the transformer disconnect switch B1T4 under load. The protection at Sunnyside did not operate as expected to clear the arcing fault, which resulted in the operation of the protection on the remote ends of transmission lines TL202 and TL206 at Bay d'Espoir (BDE).
	15:33:32	Breakers B11L06 and L06L34 opened at BDE to trip transmission line TL206 as expected.
	15:33:33	Protection at BDE did not operate to trip transmission line TL202 as expected. Breakers B3B4 and B4B5 would ordinarily trip TL202 at the

Date	Time	Event
		BDE end, but were slow in operating. Lockout protection operated and resulted in a trip of breakers B5B6, B3T5, B3T6, and B2B3. This resulted in a loss of TL204 (BDE – Stoney Brook), and BDE Units 5 and 6 (loss of 150 MW of generation). Breakers L02L07 and B1L02 tripped to isolate TL202 at SSD. **There was a loss of supply from BDE to Sunnyside and the Avalon Peninsula, including Come By Chance. The Auto Restoration Scheme (ARS) was in a disabled state following the return of the EMS at 11:46.**
	15:33:43	Cat Arm Units 1 and 2 tripped off-line with a loss of 130 MW of generation.
	15:37	ECC initiates a close of breaker B11L06 to close TL206 at the BDE end. The line was already closed at the SSD end. This action energized the terminal stations east of SSD.
	15:38	Primary one protection operated on the following transmission lines: TL201 – HWD and WAV TL203 – SSD and WAV TL207 – CBC and SSD TL217 – HRD and WAV TL218 – HRD and OPD TL236 – HWD and OPD TL242 – HRD and HWD Associated line breakers opened for these line protection trips.
	15:39	ECC initiated a breaker group open at WAV. Transmission Line TL206 was restored (BDE – SSD). Power was restored to SSD TS, TL207 and North Atlantic Refining at Come by Chance.
	15:40	Circuit breaker B3T4 was opened at SSD by ECC.
	15:53	Transmission Line TL203 (SSD – WAV) and WAV TS was restored.
	15:54	Transmission Line TL201 (WAV – HWD) and HWD TS was restored.

Date	Time	Event
	16:05	BDE Unit 6 restored at 75 MW. Transmission Line TL236 (HWD – OPD) and OPD TS were restored.
	16:06	BDE Unit 5 restored at 75 MW. Cat Arm Unit 1 restored at 65 MW.
	16:09	Transmission Line TL204 (BDE – Stony Brook) restored.
	16:09	Transmission Line TL242 (HWD – HRD) and HRD TS and station service restored.
	16:10	Transmission Line TL202 (BDE – SSD) restored.
	16:14	Transmission Line TL237 (CBC – WAV) in service.
	16:19	Transmission Line TL217 (WAV – HRD) restored.
	16:26	Cat Arm Unit 2 restored at 65 MW. Granite Canal unit restored to 32 MW.
	16:59	Star Lake generating unit restarted and loaded to 18 MW.
	18:00	Transmission Line TL218 (OPD – HRD) restored.
	18:31	SSD Transformer T4 re-energized, restoring station service.
	20:07	Transmission Line TL219 restored, bringing grid power to Burin Peninsula, which was lost during the initial trip at 09:05.
	21:34	Holyrood Unit 2 back on-line at 165 MW (minor de-rating of 5 MW).
	21:45	The 138 kV loop from Stony Brook to SSD restored.
Jan. 5, 2014	**01:40**	Holyrood Unit 3 on-line at 50 MW. (Holyrood Unit 1 remained down due to vibration issues)

Date	Time	Event
	08:10	ECC closes breaker B1L08 at WAV to energize TL208 to Vale.
	10:40	WAV transformer T3 overload protection trip. Transmission Line 64L tripped at WAV. Outages to Newfoundland Power customers in the Bay Roberts area. Newfoundland Power circuit breaker at Bay Roberts on 39L failed with no supply available from HRD.
	10:44	Transmission Line 64L restored at WAV. Newfoundland Power customers restored.
	11:08	WAV transformer T3 overload protection trip. Outages to Newfoundland Power customers in the Bay Roberts area. Newfoundland Power circuit breaker at Bay Roberts on 39L had failed with no supply available from HRD.
	11:18	Transmission Line 64L restored at WAV. Newfoundland Power customers restored.
	21:27:34	Disconnect switch B1T1 closed at HRD, the first step before the generator is synchronized to the system.
	21:27:41	Disconnect switch B1T1 opened at HRD after the operation of the unit lockout switch on HRD Unit 1. The unit lockout switch operated on HRD Unit 2. Primary protection one and backup protection operated on Transmission Line TL217 at WAV end only. Circuit breakers B1L17 and L03L17 opened. Backup protection operated on transmission line TL218 at OPD end only. Circuit breaker B1L18 opened at OPD.
	21:27:41	Primary protection one operated on transmission line TL242 at HWD end only. Breakers B2L42 at HWD and HRD opened. Protection relay 94TS/T1 operated on transformer T1 at HRD.

Date	Time	Event
		Breaker failure lockout protection operated on the following circuit breakers at HRD. HRD B3L18 HRD B3B130 HRD B1L17 Breaker failure lockout protection operated on circuit breaker B1L17 at WAV and Bus B1 at WAV. The unit lockout switch operated on HRD Unit 3. **The St. John's area was being supplied via TL201 from WAV. Holyrood Units 2 and 3 were off-line (Unit 1 had tripped during the previous day). The 138 kV loop from WAV to HRD was not available.**
	22:19	Transmission Line TL242 (HWD – HRD) restored.
Jan. 6, 2014	**02:02**	Circuit breaker B1L17 was isolated at HRD.
	03:34	Transmission Line TL217 was energized from WAV to HRD to test for line or Bus fault. No fault was found and TL217 was restored.
	05:29	Holyrood Unit 2 back on-line at 165 MW, with a minor de-rating of 5 MW.
	05:46	Transmission Line TL218 (OPD – HRD) restored.
	07:17	HRD Unit 3 on-line at 50 MW.
Jan. 8, 2014	**15:27**	Test performed to energize HRD Bus B1. Disconnect switches B1L17-1 and B1B11-2 were opened. HRD disconnect switch B1T1 was closed. No problems detected and disconnect switch B1B11-2 was closed. Approval given to HRD plant to synchronize Unit 1 to the system.
	15:38	Holyrood Unit 1 on-line at 165 MW, with a minor de-rating of 5 MW.

Alarms from T1 Trip.

TL203 prot trip 1-B

T1 Lock out 5-A

T1 OT, OV, TOOS 5-B

T1 GAS, WT, OL 6-A

T1 prot trip 6-B

7-A Relay inoperative

8-A comp trouble

10-A 125VDC Batt charger
GND./FAIL

11-A T4 OT, OV, TOOS

16-A AIL system
LAP, HAP
DRYER FAIL

13-C BILO2
Block/Trip/Rec'l
& DISAUL

15-C 138KV ABCB DISAGR.
B2T4, L109T4
L100L109, L19L100

16-C 138KV ABCB
L.A.P

17-C 230 KV ABCB
LAP

19-A BILO3 BL TRIP Rec'L
& Disagreement

22-A 138KV ABCB
Heat fail

230KV ABCB
Heat fail

SSD T.S. PNL. NO. 14 TL203 PROT.

Time 11:10 Date JAN 4 20 14 Oper. _____

OPTIMHO (21)

1. RECORD READING _____
2. PRESS " AC/READ" _____
3. PRESS " AC/READ" _____
4. PRESS "RESET".

DATE JAN 4/2014

21/P1

TRIP [X]

ALARM [X]

FLASHED

21/P2

O INST O TIME X COMM O SOTF TRIP	1 X 2 3 4 ZONE

EN X	A X B C G 0 FAULT TYPE	51 50 O/C

SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: _____ TIME: _____

2. PRESS "→"ONCE AND RECORD TYPE: MET

3. PRESS "→"AGAIN AND RECORD DIST: _____

4. PRESS "→"AGAIN AND RECORD GROUP: ____

5. PRESS "EXIT"

SSD T.S. PNL. NO. 15 TL203 PROT.

Time 11:13 Date ____ 20 ___ Oper. _____

I	I	I
50 B AØ	50 B BØ	50 B CØ

3VT

30 ~~Z2~~	30C
30 CL	

TL 203

B1L03 RECL.	AØ	BØ	CØ	3Ø
72	36	39	37	28

DATE Jan 4/2014

T	I
50/51N	

SSD T.S. PNL. NO. 26 TL219 PROT.

Time 11:30 Date ____ 20 ___ Oper. _____

50/51N

- ☐ INST
- ☐ TIME
- ☐ START

50/51L

A	B	C	
☐	☐	☐	INST
☐	☐	☐	TIME
☐	☐	☐	START

79

170

PRI.3PH

110

BV 3PH.

149

DATE JAN 4/2014

OPTIMHO (21)

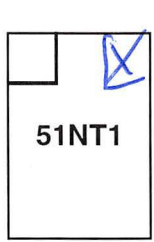
1. RECORD READING _____
2. PRESS "AC/READ" _____
3. PRESS "AC/READ" _____
4. PRESS RESET. _____

21

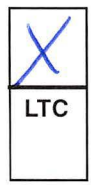
- TRIP ☐
- ALARM ☐

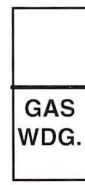
SSD T.S. PNL. 16 TRF.1 PROT.

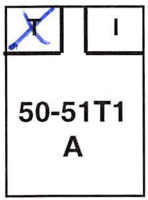
Time 11:32 Date JAN 4 2014 Oper. _____

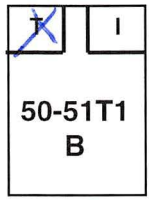


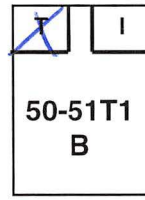


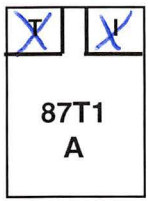


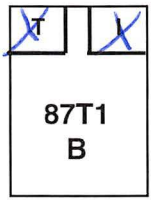


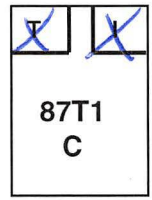








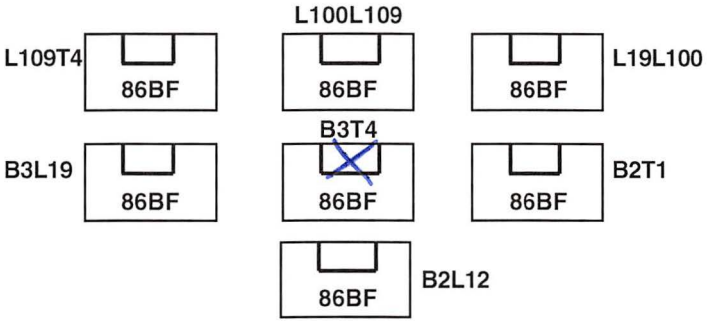




#2

SSD T.S. PNL. NO. 28 138KV BKR. FAIL. PROT.

Time _____ Date _____ 20 ____ Oper. _____



50BF-L09T4&50BF-L100L09

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY O/C CONDITIONS

DISPLAY

DISPLAY

50BF-L19L100&50BF-B3L19

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY O/C CONDITIONS

DISPLAY

DISPLAY

50BF-B3T4&50BF-B2T1

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY O/C CONDITIONS

DISPLAY 86TR-X

DISPLAY

50BF-B2L12

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY O/C CONDITIONS

DISPLAY

DISPLAY

For operated relay(s) push "Events"
Record Date & Time & Push →
for "Type of Fault"

↓ Scrolls to Next Event

Relay _____

Event _____

_____

_____

Relay _____

Event _____

_____

_____

Relay _____

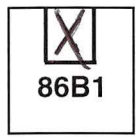
Event _____

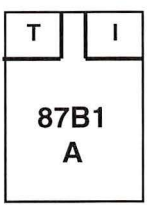
_____

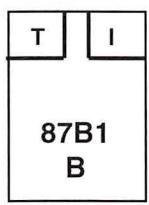
_____

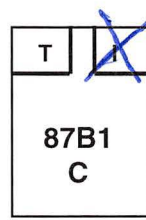
SSD T.S. PNL. 17 230KV BUS. DIFF. & SERV.REST.

Time _____ Date ____ 20 ___ Oper. D.K









Second Ath... TL202 3

SSD T.S. PNL. NO. 13 TL202 PROT.

Time 0959 Date JAN 4 20 14 Oper. DK

I
50 B AØ

I
50 B BØ

I
50 B CØ

30 Z2	~~30C~~
30 CL	

TL 202

B1L02 RECL.	AØ	BØ	CØ	3Ø
52	51	44	39	42
52	52	45	40	43

DATE _____

T	I
50/51N	

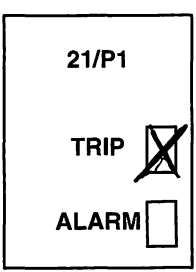
SSD T.S. PNL. NO. 14 TL203 PROT.

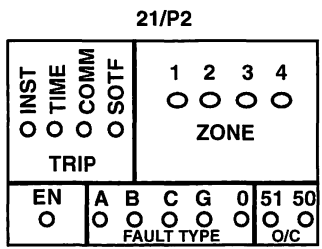
Time 6:59 **Date** JAN 4 **20** 14 **Oper.** DK

OPTIMHO (21)

1. **RECORD READING** SOTF
2. **PRESS " AC/READ"** 2014 JAN 4 15:34:24
3. **PRESS " AC/READ"** SOTF
4. **PRESS "RESET".**

DATE _____





SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: _____ TIME: _____

2. PRESS "→"ONCE AND RECORD TYPE:_____

3. PRESS "→"AGAIN AND RECORD DIST: _____

4. PRESS "→"AGAIN AND RECORD GROUP: ____

5. PRESS "EXIT"

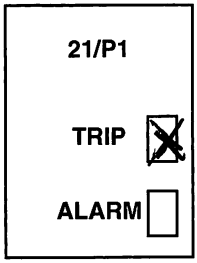
SSD T.S. PNL. NO. 12 TL202 PROT.

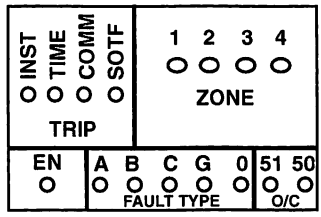
Time 7:01 **Date** JAN 4 **20** 14 **Oper.** D.K

OPTIMHO (21)

1. **RECORD READING** DISTANCE AIDED BC
2. **PRESS " AC/READ"** 2014 JAN 4 16:32:02
3. **PRESS " AC/READ"** LOC -9.4 KM
4. **PRESS "RESET".** 168.8 ms.

DATE _____





SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: _____ TIME: _____

2. PRESS "→"ONCE AND RECORD TYPE:_____

3. PRESS "→"AGAIN AND RECORD DIST: _____

4. PRESS "→"AGAIN AND RECORD GROUP: ____

5. PRESS "EXIT"

7:20

5-B T1 OT, UV, TOUS

6-A T1 GAS, WT, OL

16-A AIR SYSTEM
LAP. HAP
Dryer FAIL

13-C BILOC
BLOCK TRIP/RECL
& DISAGREEMENT

14-C LOC LOT
BLOCK TRIP/RECLOSE
& DISAGREEMENT

16-C 138KV ABCB
LAP

17-C
230KV ABCB LAP

SSD T.S. PNL. NO. 1 L03L06 RECLOSER

Time _____ Date ____ 20 ___ Oper. _____

B1L03 Trip/Reclose & Disallow

20-A L06L07 Block Trip/Reclose & Disallow

B03L06
RECL



DATE _____

(B)

SSD T.S. PNL. NO. 11 TL206 PROT.

Time 708 Date JAN 4 20 14 Oper: D.L

I
50B A

I
50B B

I
50B C

30 Z2	~~30C~~
30 CL	

LO6L17 ← TL206 →

RECL.	A ~~0~~	B ~~0~~	C ~~0~~	3 ~~0~~
177	128	55	48	35
177	127	54	47	34

DATE _____

T
50-51N

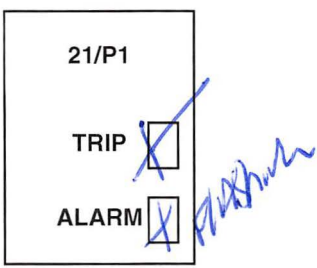
SSD T.S. PNL. NO. 10 TL206 PROT.

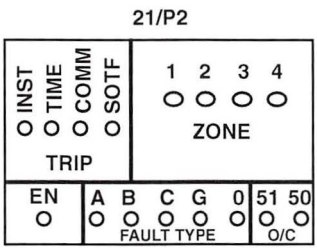
Time 7:10 Date 4 JAN 20 14 Oper: D.K

OPTIMHO (21)

1. RECORD READING SOTF
2. PRESS " AC/READ" 20KM JAN 4 16:35:12
3. PRESS " AC/READ" LOC -95.2 Km
4. PRESS "RESET". 61.67 ms

DATE _____





SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: _____ TIME: _____

2. PRESS "→"ONCE AND RECORD TYPE: _____

3. PRESS "→"AGAIN AND RECORD DIST: _____

4. PRESS "→"AGAIN AND RECORD GROUP: ____

5. PRESS "EXIT"

SSD T.S. PNL. NO. 9 TL207 PROT.

Time ~~JAN 2014~~ 7:20 Date JAN 4 2014 Oper. D.V

LO2L07 3ph. REC.	LO2L07 1ph. REC.
60	75
60	~~73~~ 74

DATE Sept. 22, 2010 → Feb. 10/2013

50/51N

SSD T.S. PNL. NO. 8 TL207 PROT.

Time 4:00 Date ____ 20 ___ Oper. _____

30 C1	30 C2

OPTIMHO (21)

1. RECORD READING SOTF
2. PRESS " AC/READ" 2014 JAN 4 16:39:51
3. PRESS " AC/READ" LOC 215.5Km
4. PRESS "RESET". 60.42mS

DATE 2013/02/10

94L1	94L2
99	20
9F	2D

21/P1

TRIP [X]

ALARM [X]

Flasher

21/P2

O INST O TIME O COMM O SOTF TRIP

1 2 3 4 ZONE

EN | A B C G 0 FAULT TYPE | 51 50 O/C

SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: _____ TIME: _____

2. PRESS "→"ONCE AND RECORD TYPE: _____

3. PRESS "→"AGAIN AND RECORD DIST: _____

4. PRESS "→"AGAIN AND RECORD GROUP: ____

5. PRESS "EXIT"

(3)

SSD T.S. PNL. NO. 28 138KV BKR. FAIL. PROT.

Time 7:00 Date Jan 4 20 2014 Oper. _____

L100L109

L109T4 | 86BF | L19L100

B3T4

B3L19 | B2T1

B2L12

50BF-L09T4&50BF-L100L09

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY | O/C CONDITIONS

DISPLAY

DISPLAY

50BF-L19L100&50BF-B3L19

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY | O/C CONDITIONS

DISPLAY

DISPLAY

50BF-B3T4&50BF-B2T1

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY | O/C CONDITIONS

DISPLAY

DISPLAY

50BF-B2L12

X	Y	INST	A	B	C	Q	N
○	○	○	○	○	○	○	○

RELAY | O/C CONDITIONS

DISPLAY

DISPLAY

For operated relay(s) push "Events"
Record Date & Time & Push →
for "Type of Fault"

↓ Scrolls to Next Event

Relay _____

Event _____

_____

_____

Relay _____

Event _____

_____

_____

Relay _____

Event _____

_____

_____

WAV T.S. **PNL. NO. 5** **TL217 PROT.**

Time 1130 **Date** Jan 5, 2014 **Oper.** SB

OPTIMHO (21)

1. **RECORD READING** Z2 AN Delay
2. **PRESS "AC/READ"** 2014 Jan 5 22:21:33
3. **PRESS "AC/READ"** 208 KM 60 ms
4. **PRESS RESET.**

+91.47

21/P1

TRIP ☑
ALARM ☐

21/ P2

INST ○ TIME ⊘ COMM ○ SOTF ○
TRIP

1 2 3 4
○ ⊘ ○ ○
ZONE

EN ○

A ⊘ B ○ C ○ G ⊘ O ○
FAULT TYPE

51 ○ 50 ○
O/C

SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: _____ TIME: _____

2. PRESS "→" ONCE AND RECORD TYPE: _____

3. PRESS "→" AGAIN AND RECORD DIST: _____

4. PRESS "→" AGAIN AND RECORD GROUP: ____

5. PRESS "EXIT"



WAV T.S. **PNL. NO. 3** **BKR. FAIL PROT.**

Time 1130 **Date** Jan 5, 2016 **Oper.** BA

30 B1L08	30 B1L37

30 L01L03	30 L03L17

✓ 86BF/B1

30 B1L17	30 B1B3

30 B1T1	30 B1T2

30 L01L37

WAV T.S. PNL. NO. 22 TRF. T5 PROT.

Time_____ Date Jan 4 19__ Oper.____

Sat.

30 63	30 49	30 LTC	

86T5

T
51N

T I
50-51 A

T I
50-51 B

T I
50-51 C

A I
87 A

A I
87 B

A I
87 C

WAV T.S. PNL. NO. 11 TL237 PROT.

Time _____ Date Jan 8/ 2021 Oper. _____

30 C1	30 C2

B1L37
RECL.

94LD

94L1

DATE _____

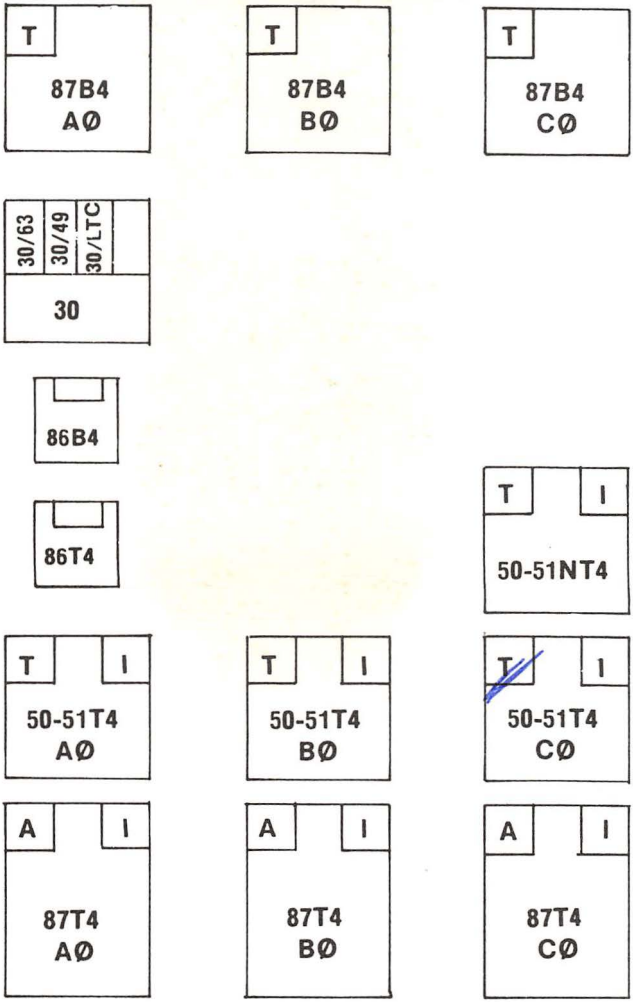
T		I
50-51 N		

50/51 T3B Time.

87 T3 A inst

WAV T.S. _____ HRS. _____ 19____

PNL. No. 20 TRANSFORMER T4 & Bus 4 PROT.

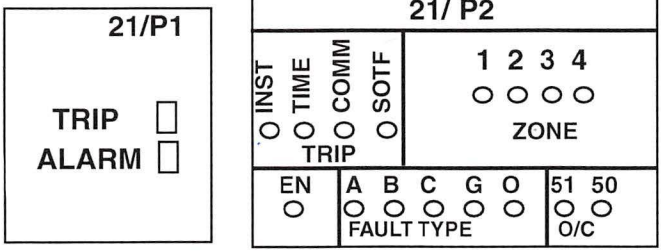


WAV T.S. PNL. NO. 12 TL203 PROT.

Time 1330 Date 2014/01/13 Oper. WD

OPTIMHO (21)

1. RECORD READING Z 1 A N
2. PRESS "AC/READ" 1341- 19
3. PRESS "AC/READ" _____
4. PRESS RESET.



SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: 2014/01/12 TIME: 1243.08 . 076

2. PRESS "→"ONCE AND RECORD TYPE: AG

3. PRESS "→"AGAIN AND RECORD DIST: +3.94

4. PRESS "→"AGAIN AND RECORD GROUP: 1

5. PRESS "EXIT"

WAV T.S. PNL. NO. 14 TL201 PROT.

Time 10:41 Date JAN 15/14 Oper. D. Rich

OPTIMHO (21)

1. RECORD READING _____
2. PRESS "AC/READ" _____
3. PRESS "AC/READ" _____
4. PRESS RESET.

21/P1

TRIP ☐
ALARM ☐

21/P2

INST ○ TIME ⊗ COMM ○ SOTF ○ TRIP

1 2 3 4
○ ○ ○ ○
ZONE

EN ⊗

A B C G O
○ ○ ○ ○ ○
FAULT TYPE

51 50
⊗ ○
O/C

SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: 01/15/14 TIME: 0909:59.770

2. PRESS "→" ONCE AND RECORD TYPE: BG T

3. PRESS "→" AGAIN AND RECORD DIST: +36.02

4. PRESS "→" AGAIN AND RECORD GROUP: 1

5. PRESS "EXIT"

WAV T.S. PNL. NO. 6 TL217 PROT.

Time 10:46 Date Jan 15 2014 19(20) Oper. D.L

A	B	C
50 B		

T	I
50-51N	

30Z2	~~30C~~ 3VT
30CL	

B1L17 RECL.	TL217 AØ	BØ	CØ	3Ø
58	59	34	46	40

DATE _____

3Ø B.U.

WAV T.S. PNL. NO. 11 TL237 PROT.

Time 0:26 Date JAN 15/2014 Oper: D. KING

30 C1	30 C2
	X

B1L37 RECL.

20
19

94LD

93
93

DATE _____

94L1

141
138

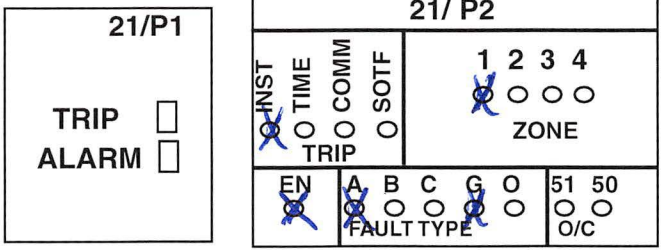
T		I
50-51 N		

WAV T.S. PNL. NO. 12 TL203 PROT.

Time 10:27 Date JAN 15/24 Oper. D. King

OPTIMHO (21)

1. RECORD READING _____
2. PRESS "AC/READ" _____
3. PRESS "AC/READ" _____
4. PRESS RESET.



SEL - 321 (21 P2)

1. PRESS "FAULT" ONCE AND RECORD DATE & TIME

DATE: 2014/01/12 TIME: 1243.08.076

2. PRESS "→"ONCE AND RECORD TYPE: AG

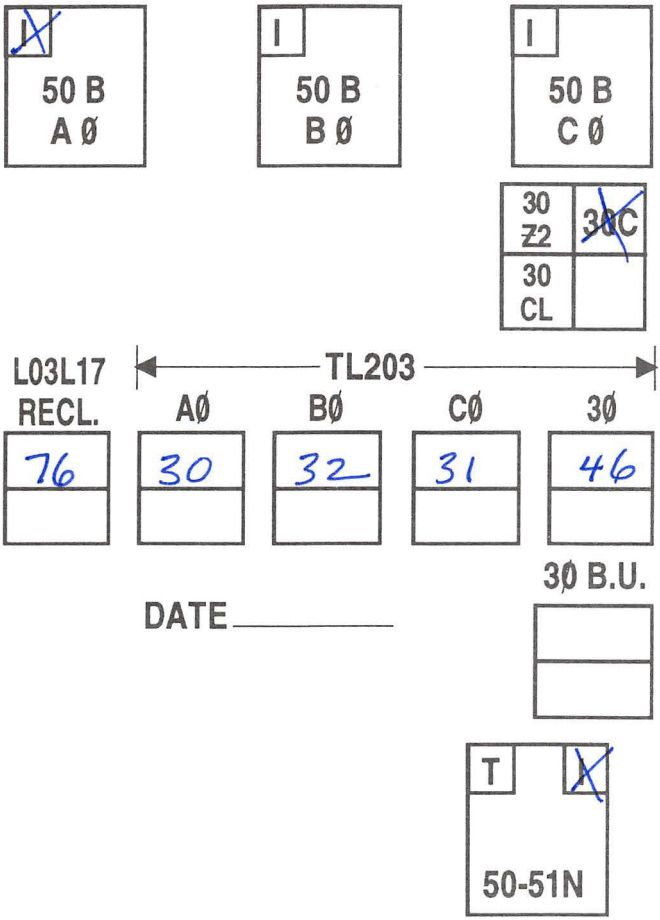
3. PRESS "→"AGAIN AND RECORD DIST: +3.94

4. PRESS "→"AGAIN AND RECORD GROUP: 1

5. PRESS "EXIT"

WAV T.S. PNL. NO. 13 TL203 PROT.

Time 10:30 Date JAN 15 2014 19__ Oper: D.L



SEL. 2411,

→ All Light on

WAV T.S. PNL. NO. 15 TL201 PROT.

Time 10:44 Date JUL 15/2014 Oper. D. KML

30 Z2	30C
30 CL	

LO1L03 ← TL201 →

RECL	A Ø	B Ø	C Ø	3 Ø
88	72	62	60	65
87	70	60	58	63

DATE Jan 11, 2013

X	I
50-51N	

SeL 2411
ALL LIGHTS ON

HRD T.S. Pnl. No. 33 Bkr. Fail. Prot.

Time_____ Date_____19___Oper._____

JAN 4/2014

RELAY CASE - R3

30 13	30 19	30 14	30 15	30 18	30 24	30 17	30 16

RELAY CASE - R4

30 26	30 25

86 BF B3 B13

86 BF B3 L18

30-14 B3 B13

30-15 B2 L42

86 BF B1 L17 FAG 30-3 - 30-4 dida 4 drop

TL 218 P1

SOTF

2014 Jan 4

478.1 KM

70.5 Fault level.

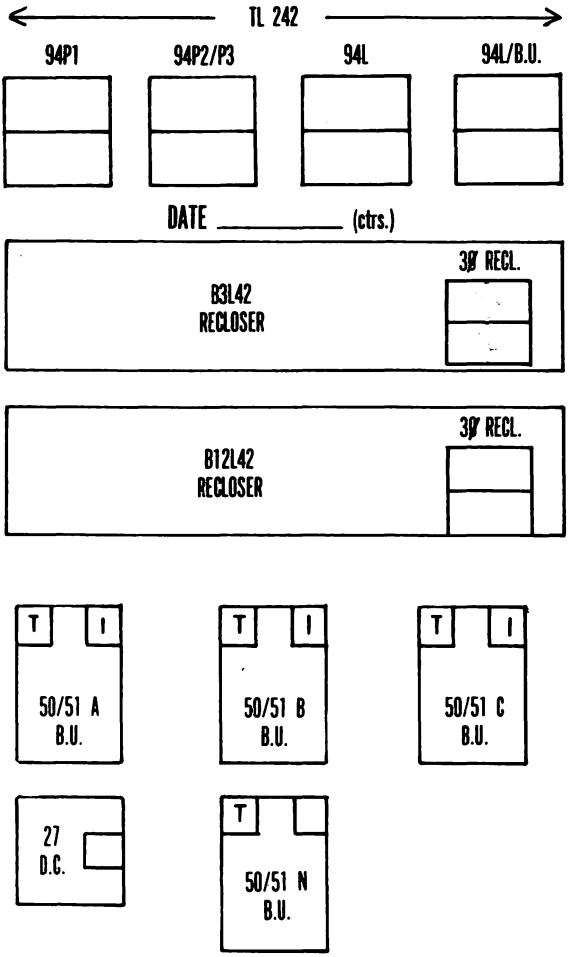
~~Reactor~~

Actual. 12.44 Jan 6

relay shows 2014 Jan 5 23:56:34

HRD T.S. PNL. NO. 27 230KV PROT. - TL 242

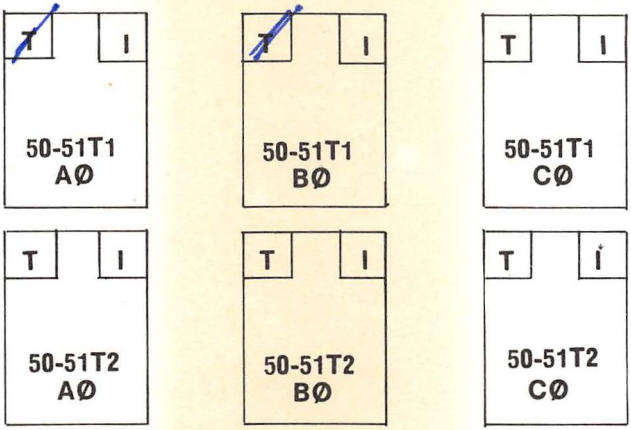
TIME _____ DATE _____ 19 ____ OPERATOR _____



HRD T.S. _____ HRS. _____ 19____

PNL. No. 31 230 KV & TRANSFORMERS

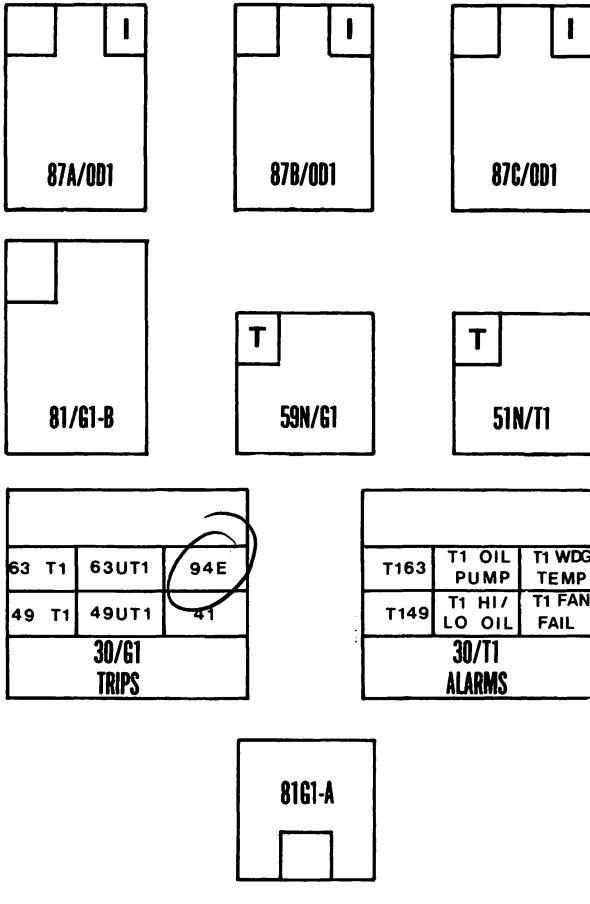
T1 & T2 PROTECTION JAN 4/2014





HRD. G.S. Jan 7, 2014 HRS. 10.30 19 2014

PNL. NO. 2 NO. 1 GEN. & TRF. PROT.



HRD T.S. _____ HRS. _____ 19____

PNL. No 5 ANNUNCIATOR

JAN 4/2014

A

1	2	3	4	5	6	7	8	
9	10	11	12	13	14	15	16	
17	18	19	20	21	22	23	24	
25	26	27	28	29	30	31	32	

B

1	2	3	4	5	6	7	8	
9	10	11	12	13	14	15	16	
17	18	19	20	21	22	23	24	
25	26	27	28	29	30	31	32	

C

1	2	3	4	5	6	7	8	
9	10	11	12	13	14	15	16	
17	18	19	20	21	22	23	24	
25	26	27	28	29	30	31	32	

TL 217

SOTF

Jun 4 16.33.49

Actual time on relay

2014 Jun 6 01.47.49

HRD T.S. Pnl. No. 24 TL217 Prot.

Time_____ Date_____19___Oper._____

30 C	30 CL	30 Z2	

B12L17

A ph.	B ph.	C ph.	Recl.	3 ph.
43	28	40	49	30

~~3 ph. DU~~ B12L17 Reclose

34

Date Jan 16, 2013

Optimho(21)

1. Record reading _____
2. Press "Ac/Read"_____
3. Press Reset

21
trip ☐
alarm ☐

21Z2

TL 242

SO TF

Jan 4 15.58

to

Jan 4.

Relay. time . 2014 Jan 6 00:46:39

HRD T.S. Ph. No. 26 TL218 Prot.

Appendix 16 Page 172 of 187

Time _____ Date _____ 19__ Oper._____

30 C	30 CL	30 Z2	

B2L18

A ph.	B ph.	C ph.	Recl.	3 ph.
22	19	26	28	17

3 ph. BU

Date Sept 11 12

Optimho (21)

1. Record Reading _____
2. Press "Ac/Read" _____
3. Press "Ac/Read" _____
4. Press Reset.

21	21Z2
trip ☐	☐
alarm ☐	

DESIGN STUDY AND FAILURE INVESTIGATION FOR AUTO TRANSFORMER

NALCOR

SERIAL # 289147

CANADIAN GENERAL ELECTRIC

PREPARED BY

ABB Inc.
Transformer Remanufacturing & Engineering Services (TRES)
Brampton, ON Canada

ABB Project Number: xxxxxx

Prepared by: Myra Mikhail, P.Eng
Senior Transformer Design Engineer

James Li, P.Eng
Senior Transformer Design Engineer

Reviewed by: Mustafa Lahloub P.Eng
Engineering Manager, TRES Brampton

Approved by: Ed G. teNyenhuis, M.Eng, P.Eng.
Technical Manager, TRES Canada

February 03, 2014; Draft

Table of Contents

1. INTRODUCTION 4

2. SHORT CIRCUIT STUDY 6

2.1. Procedure 6

2.2. Windings Short Circuit Capability: 6

3. DIELECTRIC STUDY 1

3.1. Procedure 1

3.2. Major Winding insulation 1

4. DISSOLVED GAS IN OIL ANALYSIS (DGA) 1

4.1. SSD T1 - (CGE 289147) 1

4.2. SSD T4 – (CGE 288838) 5

4.3. STB T1 – (CGE 288894) 8

4.4. STB T2 – (CGE 288839) 11

5. GENERAL OIL QUALITY 14

5.1. SSD T1 – (CGE 289147) 14

2.1.1 Main Tank 14

2.1.2 LTC Tank 15

5.2. SSD T4 – (CGE 288838) 16

2.2.1 Main Tank 16

2.2.2 LTC Tank 17

5.3. STB T1 – (CGE 288894) 18

2.3.1 Main Tank 18

2.3.2 LTC Tank 19

5.4. STB T2 – (CGE 288839) 20

2.4.1 Main Tank 20

2.4.2 LTC Tank 21

6. TRANSFORMER POWER FACTOR MEASUREMENT 22

6.1. SSD T1 – (CGE 288147) 22

6.2. SSD T4 – (CGE 288838) 24

6.3. STB T1 – (CGE 288894) 26

6.4. STB T2 – (CGE 288839) 28

7. MAINTENANCE HISTORY 30

7.1. SSD T1 – (CGE 289147) 30

7.2. SSD T4 – (CGE 288838) 32

7.3. STB T1 – (CGE 288894) 33

7.4. STB T2 – (CGE 288839) 34

8. INSPECTION 35

8.1. Findings and Observations 35

9. CONCLUSION 43

10. RECOMMENDATIONS 47

1. Introduction

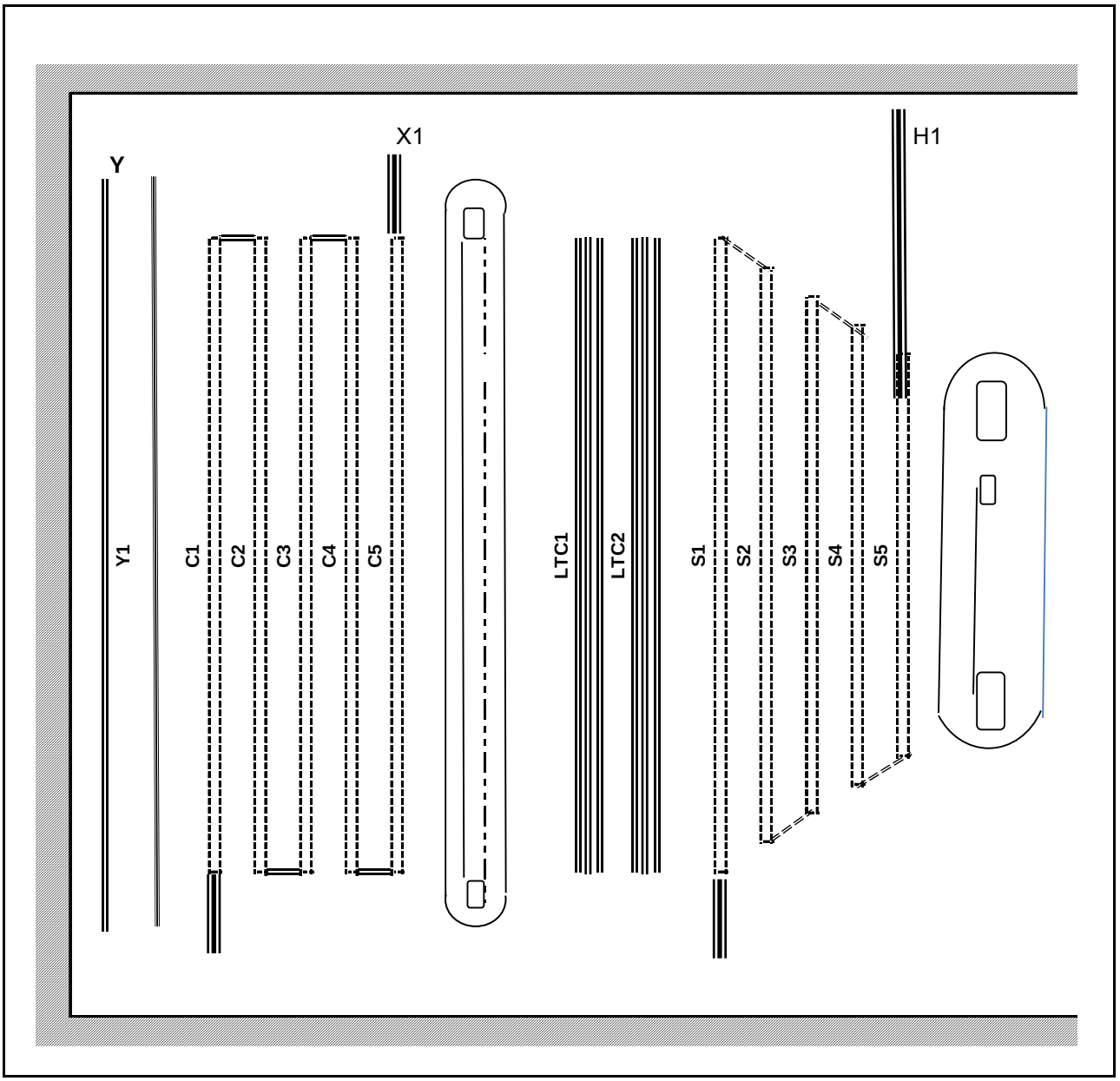
This transformer, sn 289147, failed and caught fire on January 4, 2014. The information available shows that the fault took more cycles than normal to be cleared. The transformer was on fire for about 66 hours. The transformer sustained major damage due to the failure and the fire. The customer requested that ABB inspect the transformer to try and identify the cause of the failure.

Also a comprehensive short circuit and dielectric study of the design is performed. There are four transformers manufactured to the same design. These transformers are built by Canadian General Electric under the Serial Numbers 288838, 288839 & 288894 in 1976 and 289147 in 1978.

Table 1 – Auto Transformer

Identification	Canadian General Electric
Rating	75/100/125 MVA, ONAN/ONAF/ONAF, 65°C Rise, 3Ph, 60Hz
Voltage	HV: 230 kV Grd Y, +5, -15 % ON Load taps LV: 138 KV Grd Y. TV: 6.9 KV Delta.
Lightning Insulation Levels	HV: 900 kV BIL LV: 550 kV BIL HV Neut: 110 kV Bil TV: 95 kV BIL
Core	3 phase unit, 3 legged design.
Windings	On each leg from the core outward: TV: Single layer, copper, MTC conductors. Shield LV : 5 Layers, copper, MTC conductors. Shield RV: 2 layers. Each with 4 multi starts, copper, MTC conductors. HV : 5 Layers, copper, MTC conductors. Shield.
Cooling Equipment	5 Radiators (156 tubes each) 9 Fans 28 In Diam
Manufacturing Date	First 3 units built in 197, the last unit buit in 1978, in Guelph, Ontario.

Figure 1 - Schematic Diagram of the Windings



2. Short Circuit Study

A 3D FEM leakage flux program was used to model this design. This program calculates the flux pattern in the windings as well as the short circuit currents in each winding and the associated forces.

2.1. Procedure

System Impedance:

From the original design, the system available MV is 3000 MVA on 230 KV side and 2000 MVA on the 138 kV side. This will translate in a 4.167% Impedance on the 230 kV side and 6.25% impedance on the 138 kV side on the 125 MVA base. These values are used in the analyses.

Short Circuit Calculation:

The transformer short circuit forces were analyzed with the on load tap changer on Rated, maximum and minimum tap positions.

The transformer core and windings were modeled on a computer program to enable the magnetic field and force calculations to be calculated. Program calculates the winding impedances between pairs of winding and uses the system impedances to calculate the short circuit currents in the transformer windings at the different tap positions. The program then calculates the axial and radial forces on each winding. In this case the forces are calculated on each layer of each winding with more than one layer.

These forces are than used in the design program. From the characteristics of the windings and the type of conductors used, the effect of the forces is derived and the allowable limits are calculated.

2.2. Windings Short Circuit Capability:

From the program results, the forces were calculated and compared with the allowed limits.

Table 2 - Short Circuit Calculations for the TV Winding (single Layer)

TV Winding (Single Layer)		Calculated	Allowed
Average radial inward stress	Psi	19 278	39 347
Dynamic conductor tilting stress	Psi	11249	12000
Axial pressure on end rings	Psi	**10500**	6000

Note:

This winding is failing on axial forces. The winding pressboard end rings are not strong enough to sustain the axial force. The calculated force is higher than the strength of the end ring material.

The other stresses on this winding are within the limits of the design.

Table 3 - Short Circuit Calculations for the Common Winding (Five Layers)

Common Winding (Five Layers)		**Calculated**	**Allowed**
Average radial inward stress	Psi	2899	24183
Dynamic conductor tilting stress	Psi	3779	12000
Axial pressure on end rings	Psi	5750	6000

Note:

This winding is adequately designed for the short forces for all the criteria that needed to be checked.

Table 4 - Short Circuit Calculations for the Tap Winding

Tap Winding (Two Layers)		**Calculated**	**Allowed**
Average radial inward stress	Psi	5805	22489
Dynamic conductor tilting stress	Psi	1432	12000
Axial pressure on end rings	Psi	3000	6000

Note:

This winding is adequately designed for the short forces for all the criteria that needed to be checked.

Table 5 - Short Circuit Calculations for the Series Winding (Five Layers)

Series Winding (Five Layers)		**Calculated**	**Allowed**
Average radial outward stress	Psi	11327	40000
Dynamic conductor tilting stress	Psi	1763	2484
Axial pressure on end rings	Psi	4000	6 000

Note:

This winding is adequately designed for the short forces for all the criteria that needed to be checked.

3. Dielectric Study

The following is an insulation study of the transformer using ABB designs tools and standards.

3.1. Procedure

The design information was obtained from the archives and the transformer insulation clearances were checked against ABB standards.

For the purpose of the study, it was assumed that the quality of the transformer oil and insulation was acceptable for doing full level insulation testing as if the transformer was new.

3.2. Major Winding insulation

Below in

Table to **Error! Reference source not found.**3 are shown actual and allowed calculated electrical clearance values for the major winding insulation. The calculation shows that the insulation arrangement is satisfactory.

Table 6 – Radial Clearances

		Actual	Minimum
Core Leg - TV Winding	mm	9	9
TV Winding - Ground Shield	mm	11	8
Ground Shield - Common Winding	mm	10	10
Common Winding - Tap Winding	mm	11	11
Tap Winding – Series Winding	mm	28	17
Phase – Phase	mm	189	88

Table 7 – Axial Clearances

		Actual	Minimum
TV Winding – Core Yokes	mm	157	33
Common Winding - Core Yokes	mm	152	121
Tap Winding – Core Yokes	mm	152	121
Series Winding – Core Yokes	mm	233	204

All Winding leads, including tap leads, clearances to each other and to ground are within the design allowed rules.

4. Dissolved Gas in Oil Analysis (DGA)

4.1. SSD T1 - (CGE 289147)

Below is the report of the DGA data for the period of 1991 to 2013. The gas signatures for this transformer are shown in **Figure** to **Figure**

The following is noted for the transformer DGA:

- The concentration of Hydrogen (H2) has been well below IEEE C57.104-2008 guide condition level 1 since 1991, the highest level was 49 ppm.
- The concentration of Methane (CH4) and Ethane (C2H6) have been steadily low for the period of the data provided. The Ethylene (C2H4) level is slightly above condition level one of the IEEE C57.104-2008 guide since 1991.
- The concentration of Acetylene (C2H2) has been above IEEE C57.104-2008 guide condition level 2 since 1991. The level went up and down since then but was almost stable around the 10ppm. This could be oil leaking from LTC diverter compartment.
- The carbon dioxide level has been below the IEEE C57.104-2008 guide condition level 2 for the time period provided. The carbon monoxide level is slightly above the IEEE C57.104-2008 guide condition level 1 since 1991. However the ratio of CO2/CO is between 4 and 9. The normal CO2/CO ratios are typically in the range of 5-9. The ratio of the carbon oxides suggests that the concentrations are due to the normal aging process of the transformer.
- Shown below in **Figure 5** is a distribution plot of carbon oxide gas levels taken from a survey by the IEEE Transformer Committee using > 520,000 data records of units in service. This very large quantity of data is being used to revise the gas level limits in C57.104 (the famous Table 1 with condition 1 – 4 levels) – note that the levels will be increased. As can be seen, the 90th percentile levels are 700 ppm and 7500 for CO and CO2 respectively. **Figure 6** shows the CO distribution by age categories and for 30 – 40 years category, the 90th percentile is about 700 ppm. The history gassing on this transformer was around 500 ppm and 3600 ppm for CO and CO2 respectively. Thus these levels are well below the 90th percentile of the IEEE data for the age of this unit.
- The presence of large concentrations of oxygen in the oil can promote the formation of acids in the oil and cellulose and accelerate the aging rate of the cellulose insulation. It is recommended that the concentration of oxygen in the transformer be less than 2000 ppm (Refer to CIGRE report 323 – Aging of Cellulose in Mineral-Oil Insulated Transformers). The transformer maintenance record (09/21/2007) provided by the customer does not mention if the oil had ever been vacuum processed since 1991. The oil samples from this transformer have consistently shown very high oxygen concentrations (>20,000 ppm). The source of this high oxygen is the free-breathing oil conservator. To reduce the oxygen in the transformer oil and eliminate the uncertainty concerning the gas generation.

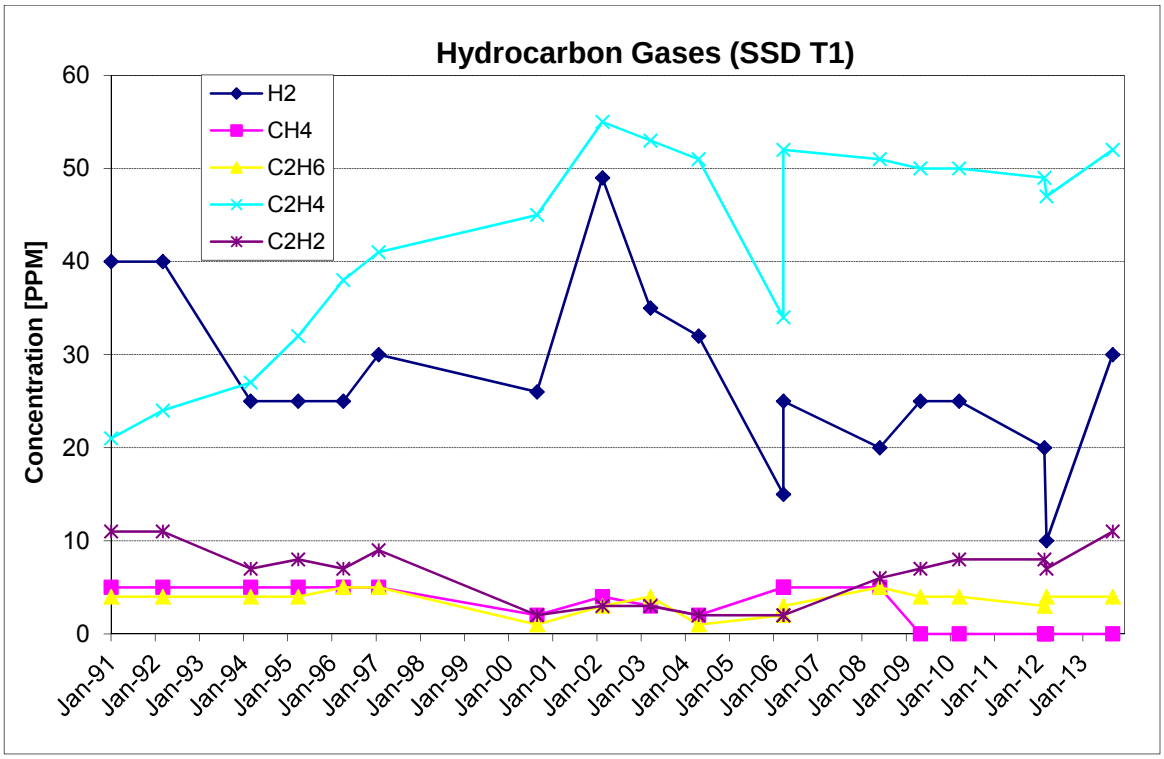


Figure 2 - Hydrocarbon Gas Concentrations

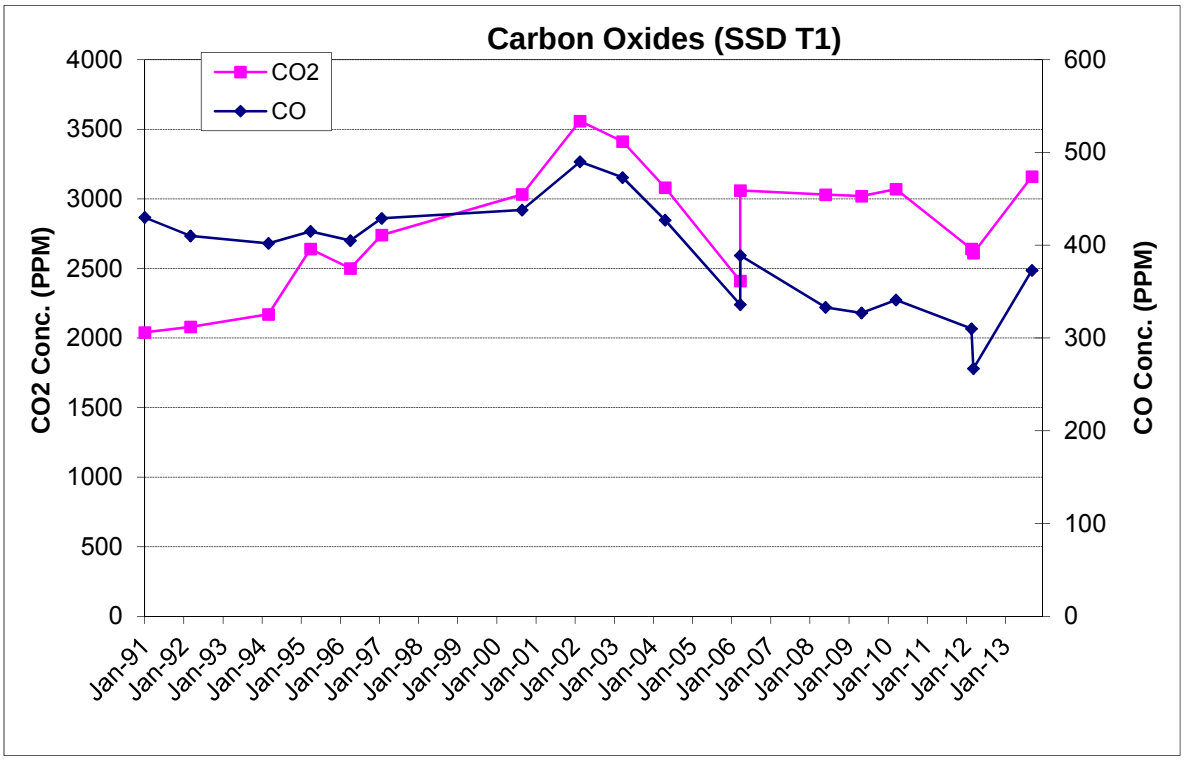


Figure 3 - Carbon Oxides Gas Concentrations

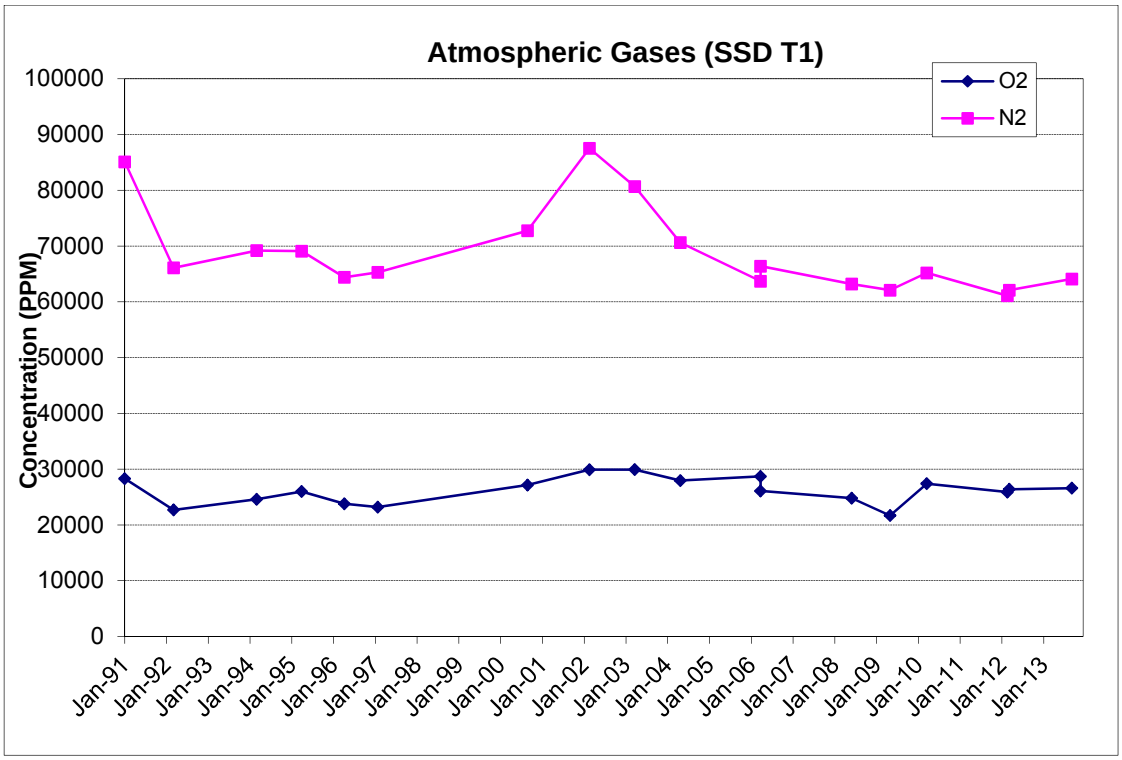


Figure 4 – Atmospheric Gases Concentrations

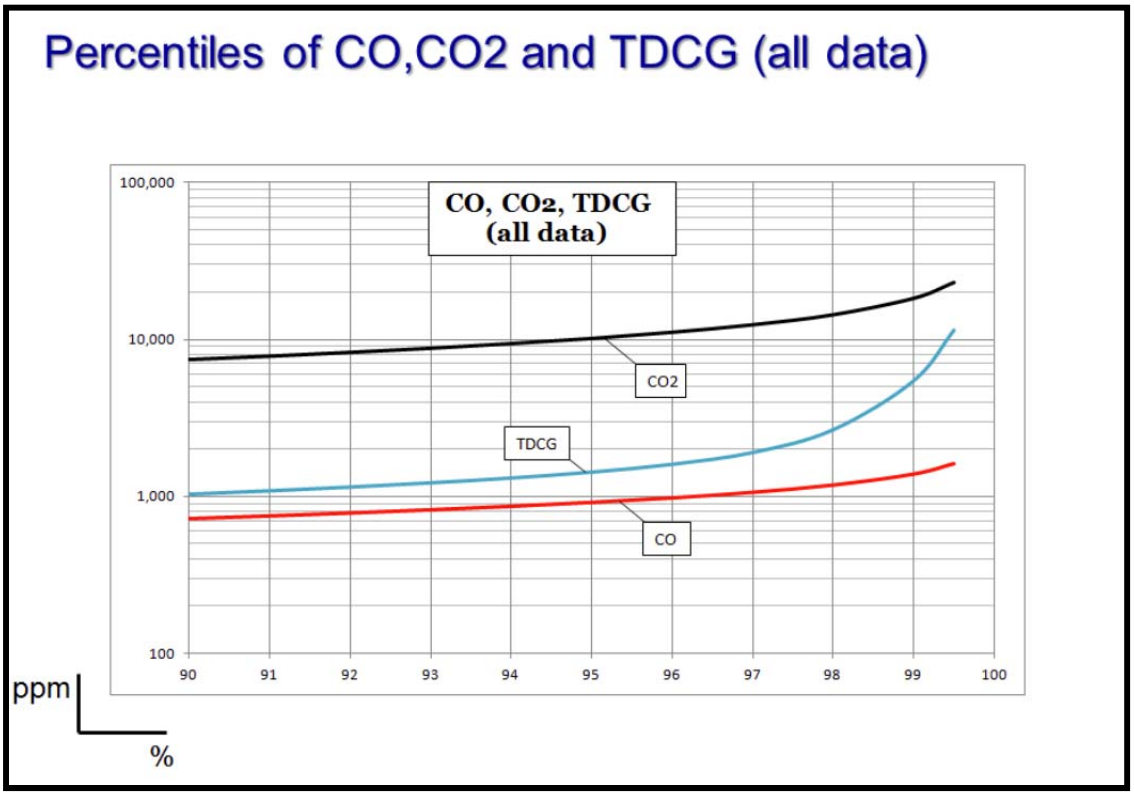


Figure 5 – IEEE Transformer Committee Carbon Oxide Survey Results

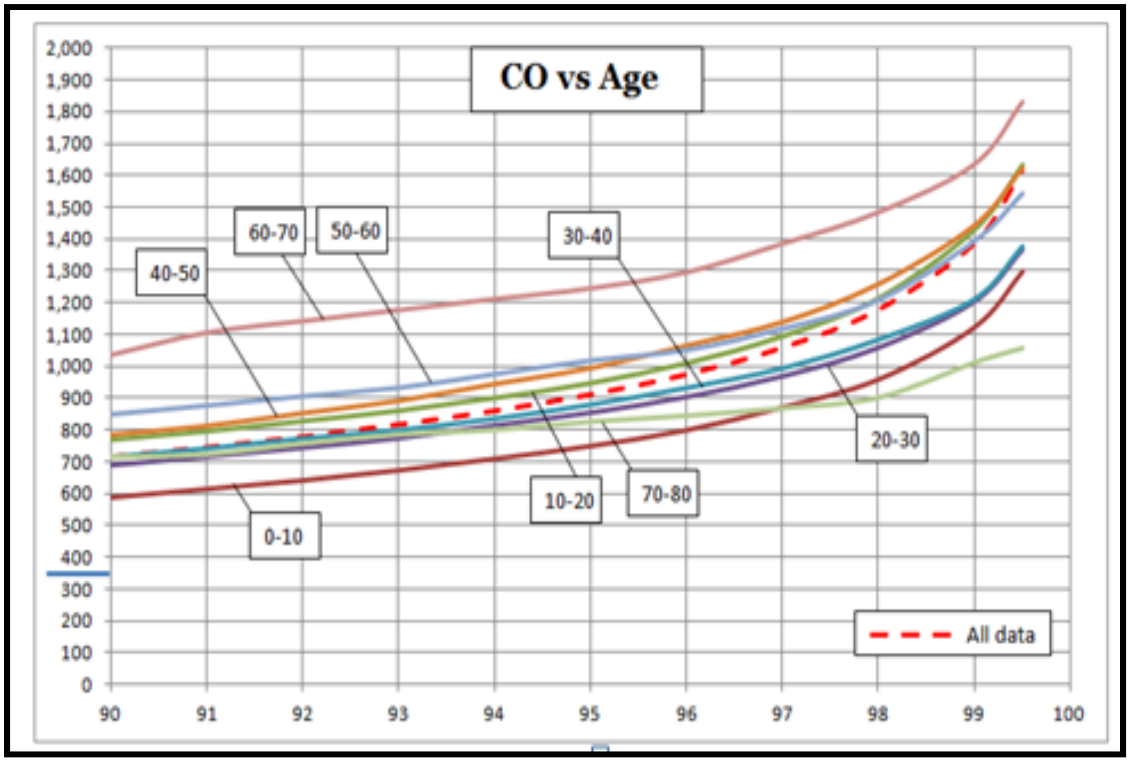


Figure 6 - IEEE Transformer Committee Carbon Oxide Survey Results (CO vs age)

4.2. SSD T4 – (CGE 288838)

Below is the report of the DGA data for the period of 1991 to 2013. The gas signatures for this transformer are shown in **Figure** to **Figure .**

The following is noted for the transformer DGA:

- The concentration of Hydrogen (H2) has been well below IEEE C57.104-2008 guide condition level 1 since 1991, the highest level is 30 ppm.
- The concentration of Methane (CH4) and Ethane (C2H6) have been steadily low for the period of the data provided. The Ethylene (C2H4) level is slightly above condition level one of the IEEE C57.104-2008 guide since 1991.
- The concentration of Acetylene (C2H2) has been above IEEE C57.104-2008 guide condition level 1 since 1991. The level went up and down since then but was almost stable around the 5ppm. This could be oil leaking from LTC diverter compartment.
- The carbon dioxide level has been below the IEEE C57.104-2008 guide condition level 1 for the time period provided. The carbon monoxide level is slightly above the IEEE C57.104-2008 guide condition level 1 between 1996 and 2004, however the level became normal after 2004. The ratio of CO2/CO is between 5 and 10. The normal CO2/CO ratios are typically in the range of 5-9. The ratio of the carbon oxides suggests that the concentrations are due to the normal aging process of the transformer.
- As can be seen from **Figure 5 & 6**, the 90th percentile levels are 700 ppm and 7500 for CO and CO2 respectively. The 90th percentile is about 700 ppm for the CO distribution by age categories and for 30 – 40 years category. The history gassing on this transformer was around 450 ppm and 3000 ppm for CO and CO2 respectively. Thus these levels are below the 90th percentile of the IEEE data for the age of this unit.
- The presence of large concentrations of oxygen in the oil can promote the formation of acids in the oil and cellulose and accelerate the aging rate of the cellulose insulation. It is recommended that the concentration of oxygen in the transformer be less than 2000 ppm (Refer to CIGRE report 323 – Aging of Cellulose in Mineral-Oil Insulated Transformers). The transformer maintenance record (09/06/2012) provided by the customer does not mention if the oil had ever been vacuum processed since 1991. The oil samples from this transformer have consistently shown very high oxygen concentrations (>20,000 ppm) of oxygen. The source of this high oxygen is the free-breathing oil conservator. To reduce the oxygen in the transformer oil and eliminate the uncertainty concerning the gas generation, it is recommended to add a conservator diaphragm. The diaphragm prevents oil from coming in contact with the air. This will prevent moisture, excessive atmospheric gases from dissolving into the oil and it also helps to keep all gases generated by the transformer in oil for more accurate diagnostics.

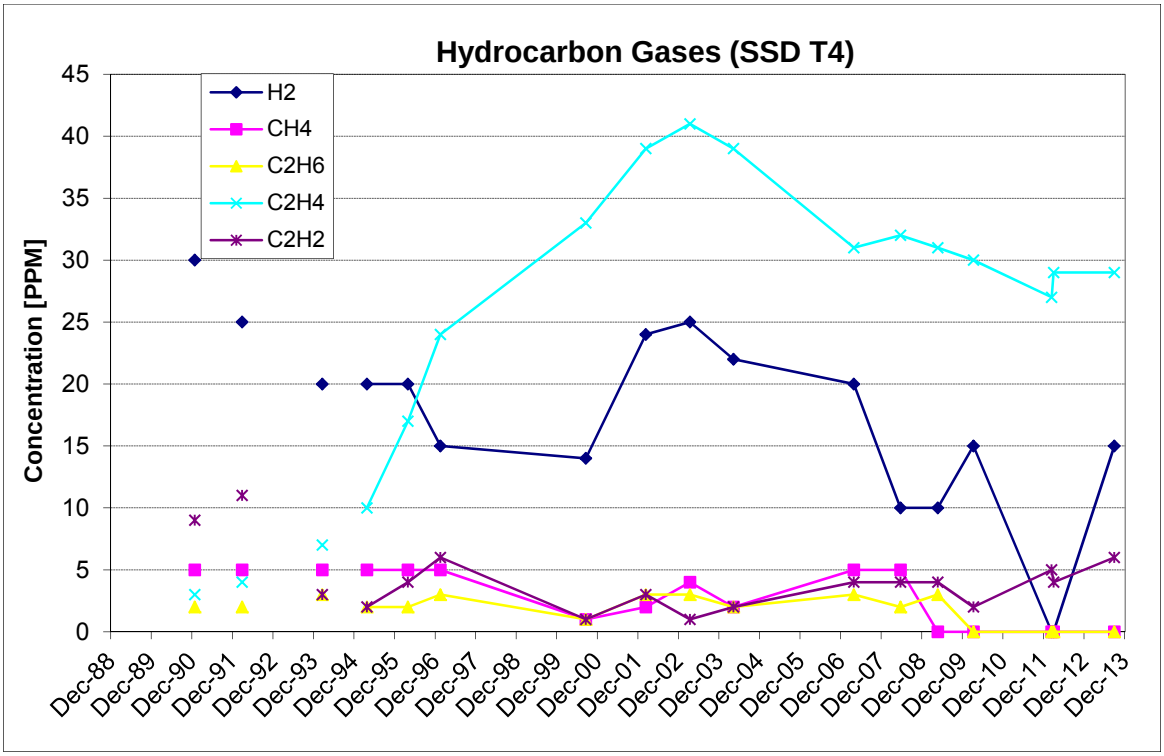


Figure 7 - Hydrocarbon Gas Concentrations

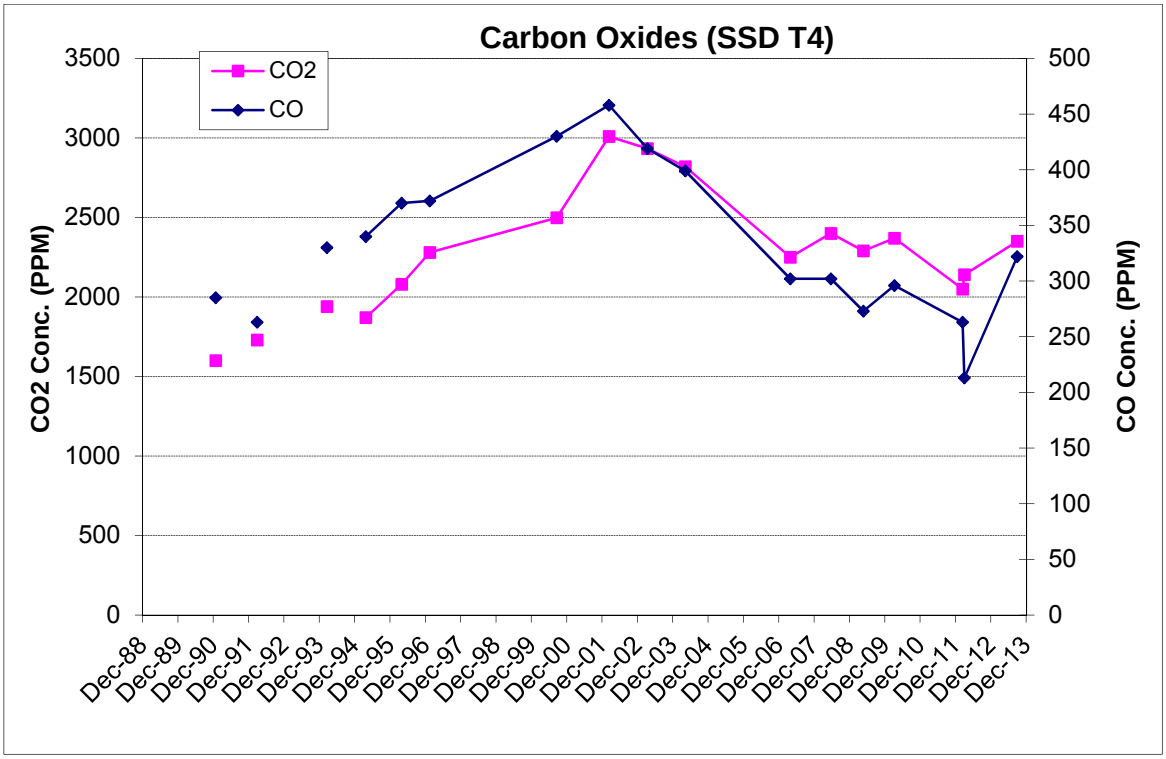


Figure 8 - Carbon Oxides Gas Concentrations

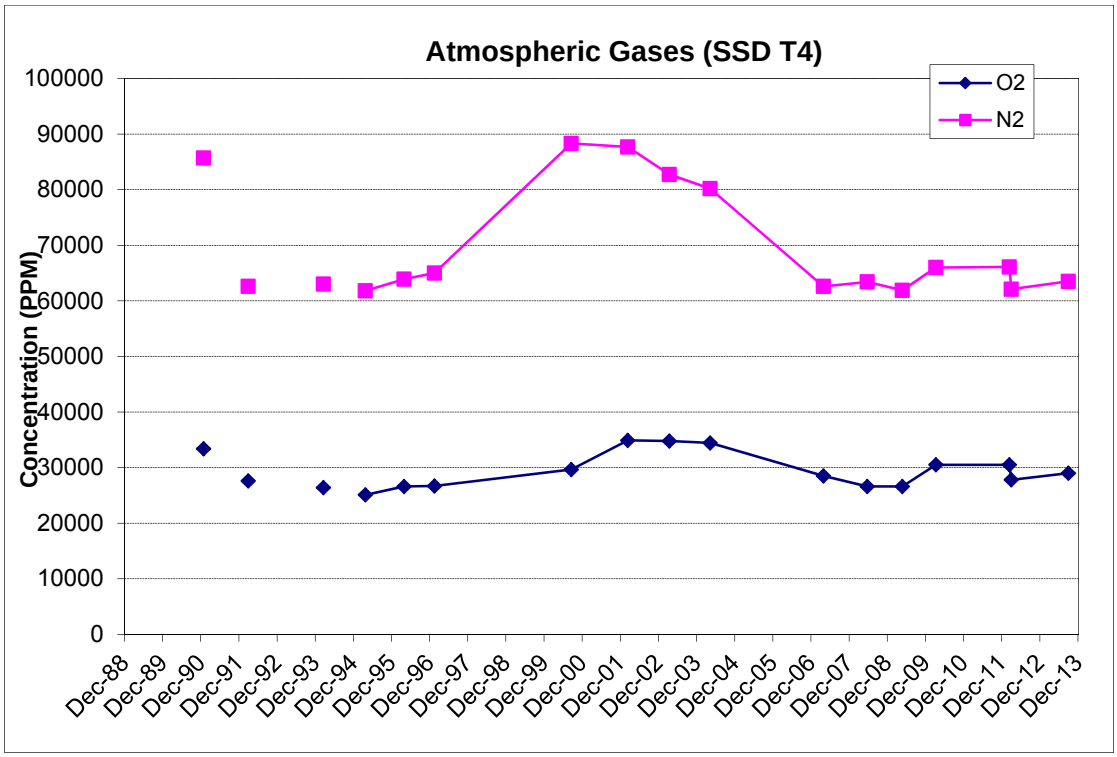


Figure 9 – Atmospheric Gases Concentrations

4.3. STB T1 – (CGE 288894)

Below is the report of the DGA data for the period of 1977 to 2013. The gas signatures for this transformer are shown in **Figure 10** to **Figure 12**.

The following is noted for the transformer DGA:

- The concentration of Hydrogen (H2) has been well below IEEE C57.104-2008 guide condition level 1 since 1977, the highest level is 75 ppm in 1979.
- The concentration of Methane (CH4) and Ethane (C2H6) have been steadily low for the period of the data provided. The Ethylene (C2H4) level has been below condition level 1 of the IEEE C57.104-2008 guide since 1977, except one sample (67 ppm) in 2009.
- The concentration of Acetylene (C2H2) has been below IEEE C57.104-2008 guide condition level 1 since 2009. However the DGA sample for the year 1979 shows high level of C2H2. This could be a bad oil sample.
- The carbon dioxide level has been above the IEEE C57.104-2008 guide condition level 1 for the most of time period provided. The carbon monoxide level is above the IEEE C57.104-2008 guide condition level 1 for most of time as well. However the ratio of CO2/CO is between 4 and 9. The normal CO2/CO ratios are typically in the range of 5-9. The ratio of the carbon oxides suggests that the concentrations are due to the normal aging process of the transformer.
- As can be seen from **Figure 5 & 6**, the 90th percentile levels are 700 ppm and 7500 for CO and CO2 respectively. The 90th percentile is about 700 ppm for the CO distribution by age categories and for 30 – 40 years category. The history gassing on this transformer was around 590 ppm and 4400 ppm for CO and CO2 respectively. Thus these levels are below the 90th percentile of the IEEE data for the age of this unit.
- The presence of large concentrations of oxygen in the oil can promote the formation of acids in the oil and cellulose and accelerate the aging rate of the cellulose insulation. It is recommended that the concentration of oxygen in the transformer be less than 2000 ppm (Refer to CIGRE report 323 – Aging of Cellulose in Mineral-Oil Insulated Transformers). The transformer maintenance record (09/22/2011) provided by the customer does not mention if the oil had ever been vacuum processed since 1991. The oil samples from this transformer have consistently shown very high oxygen concentrations (>20,000 ppm) of oxygen. The source of this high oxygen is the free-breathing oil conservator. To reduce the oxygen in the transformer oil and eliminate the uncertainty concerning the gas generation, it is recommended to add a conservator diaphragm. The diaphragm prevents oil from coming in contact with the air. This will prevent moisture, excessive atmospheric gases from dissolving into the oil and it also helps to keep all gases generated by the transformer in oil for more accurate diagnostics

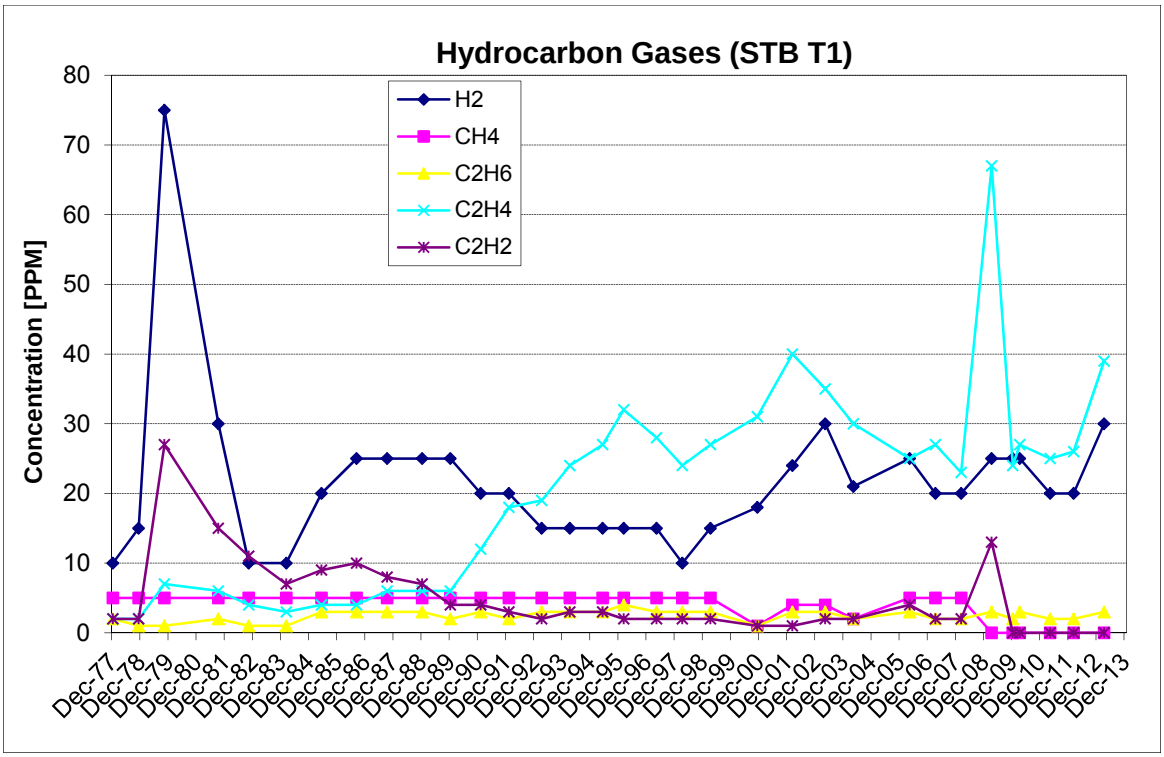


Figure 10 - Hydrocarbon Gas Concentrations

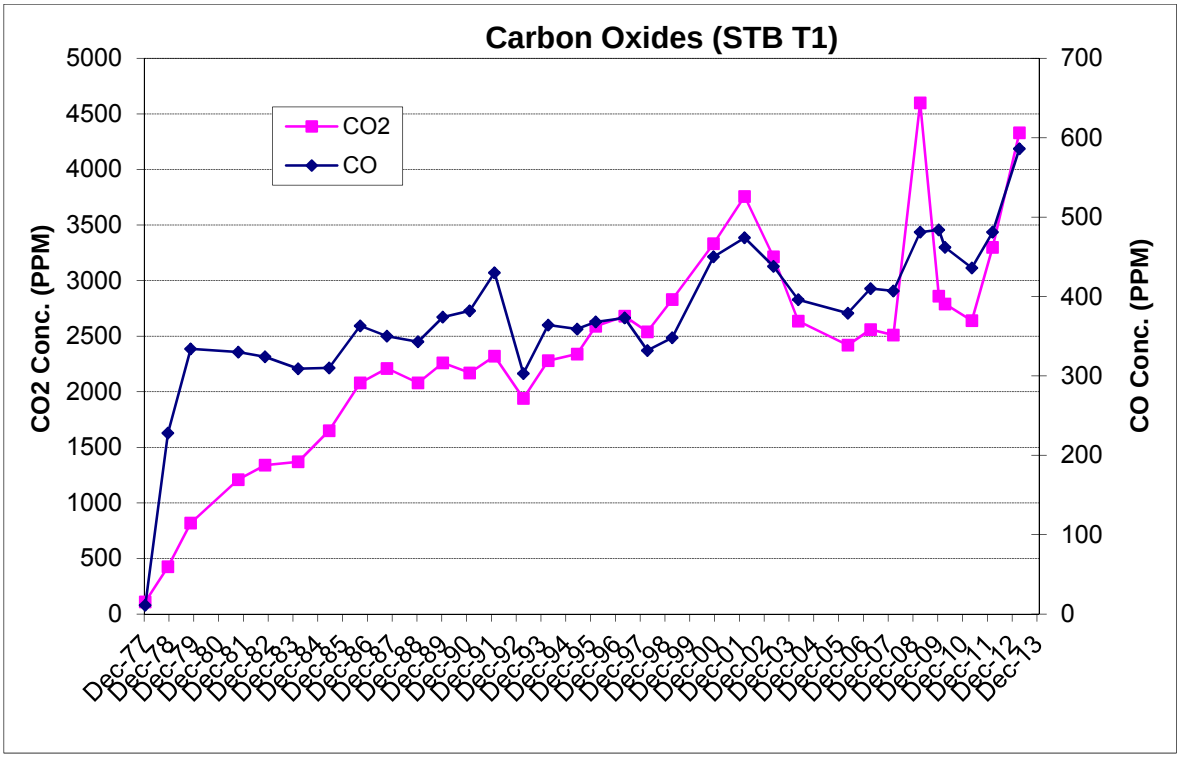


Figure 11 - Carbon Oxides Gas Concentrations

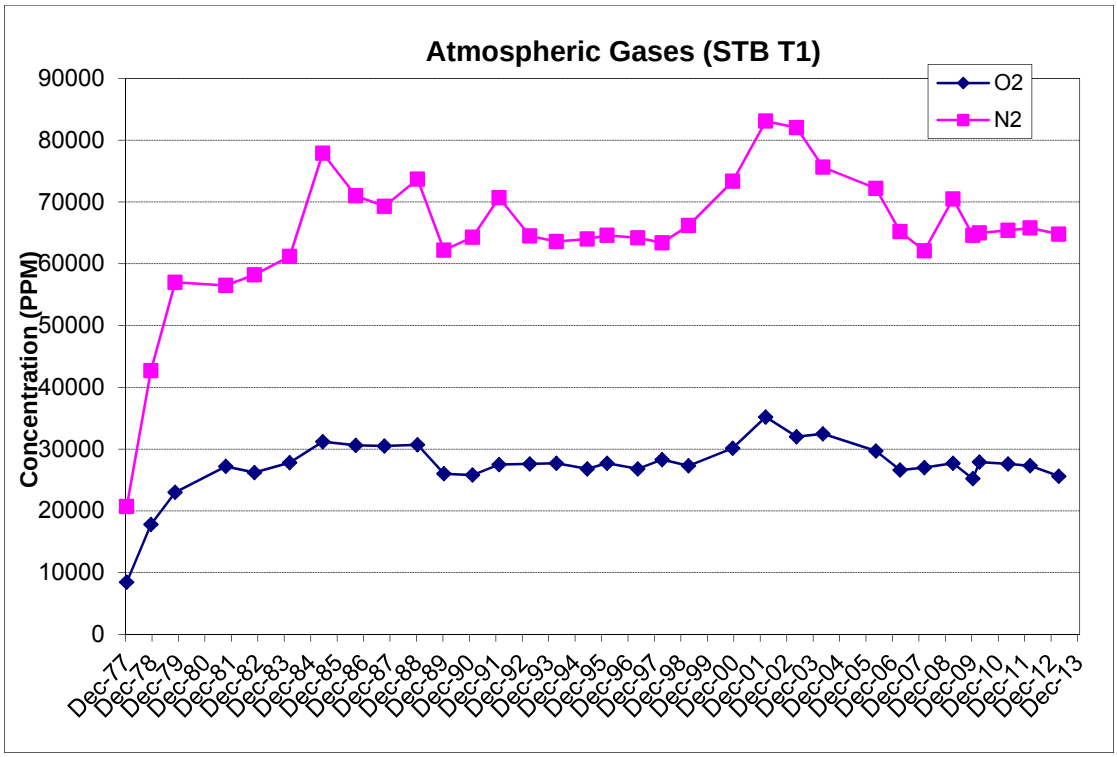


Figure 12 – Atmospheric Gases Concentrations

4.4. STB T2 – (CGE 288839)

Below is the report of the DGA data for the period of 1977 to 2013. The gas signatures for this transformer are shown in **Figure 13** to **Figure 15**.

The following is noted for the transformer DGA:

- The concentration of Hydrogen (H2) has been well below IEEE C57.104-2008 guide condition level 1 since 1977, the highest level is 50 ppm in 1987.
- The concentration of Methane (CH4) and Ethane (C2H6) have been steadily low for the period of the data provided. The Ethylene (C2H4) level has been in condition level 2 of the IEEE C57.104-2008 guide (50 ppm) since 2000.
- The transformer has consistently shown high concentrations (>20 ppm) of Acetylene (C2H2) since 1986, which is far above the IEEE C57.104-2008 guide condition level 2. The high concentration of C2H2 indicates that possible high energy arcing occurred somewhere inside the transformer. The other reason could be oil leaking from LTC diverter compartment. The Acetylene levels are about 10ppm foe few years now. This needs to be monitored closely. Any sudden increase of Acetylene needs to be investigated.
- The carbon dioxide level has been above the IEEE C57.104-2008 guide condition level 1 for the most of time period provided. The carbon monoxide level is above the IEEE C57.104-2008 guide condition level 1 for most of time as well. However the ratio of CO2/CO is between 5 and 10. The normal CO2/CO ratios are typically in the range of 5-9. The ratio of the carbon oxides suggests that the concentrations are due to the normal aging process of the transformer.
- As can be seen from **Figure 5 & 6**, the 90th percentile levels are 700 ppm and 7500 for CO and CO2 respectively. The 90th percentile is about 700 ppm for the CO distribution by age categories and for 30 – 40 years category. The history gassing on this transformer was around 560 ppm and 5500 ppm for CO and CO2 respectively. Thus these levels are below the 90th percentile of the IEEE data for the age of this unit.
- The presence of large concentrations of oxygen in the oil can promote the formation of acids in the oil and cellulose and accelerate the aging rate of the cellulose insulation. It is recommended that the concentration of oxygen in the transformer be less than 2000 ppm (Refer to CIGRE report 323 – Aging of Cellulose in Mineral-Oil Insulated Transformers). It is unknown if the oil had ever been vacuum processed since 1977. The oil samples from this transformer have consistently shown very high oxygen concentrations (>20,000 ppm) of oxygen. The source of this high oxygen is the free-breathing oil conservator. To reduce the oxygen in the transformer oil and eliminate the uncertainty concerning the gas generation, it is recommended to add a conservator diaphragm. The diaphragm prevents oil from coming in contact with the air. This will prevent moisture, excessive atmospheric gases from dissolving into the oil and it also helps to keep all gases generated by the transformer in oil for more accurate diagnostics

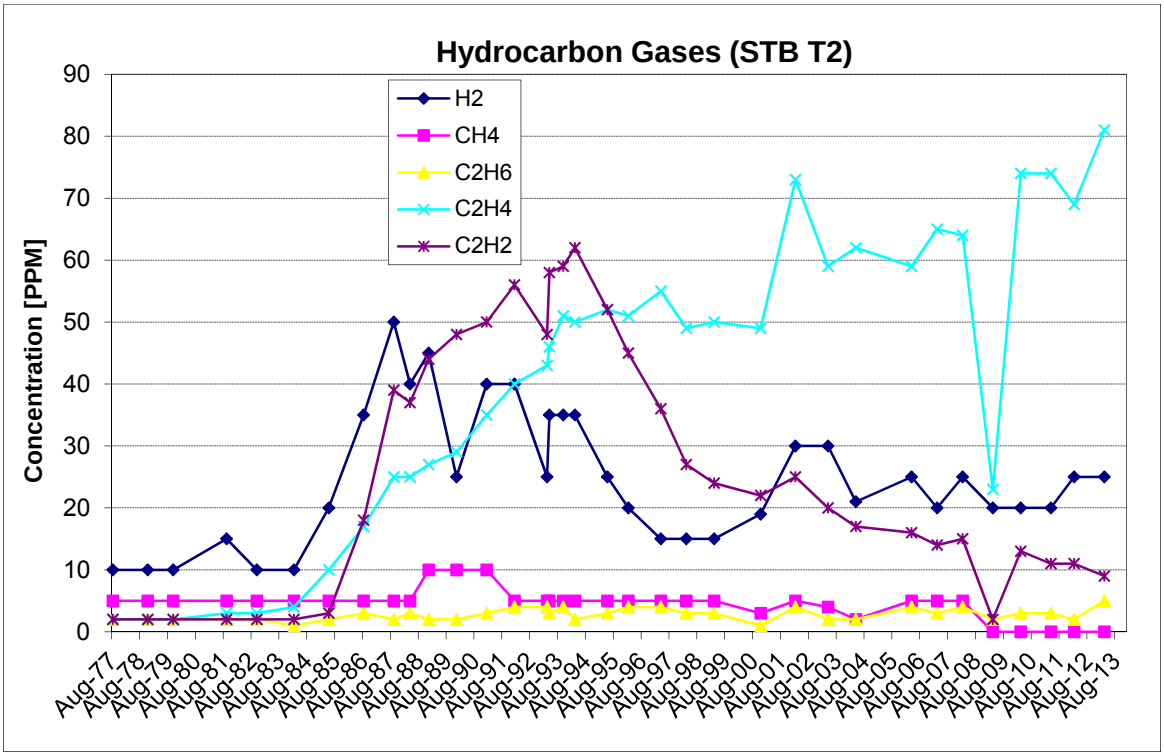


Figure 13 - Hydrocarbon Gas Concentrations

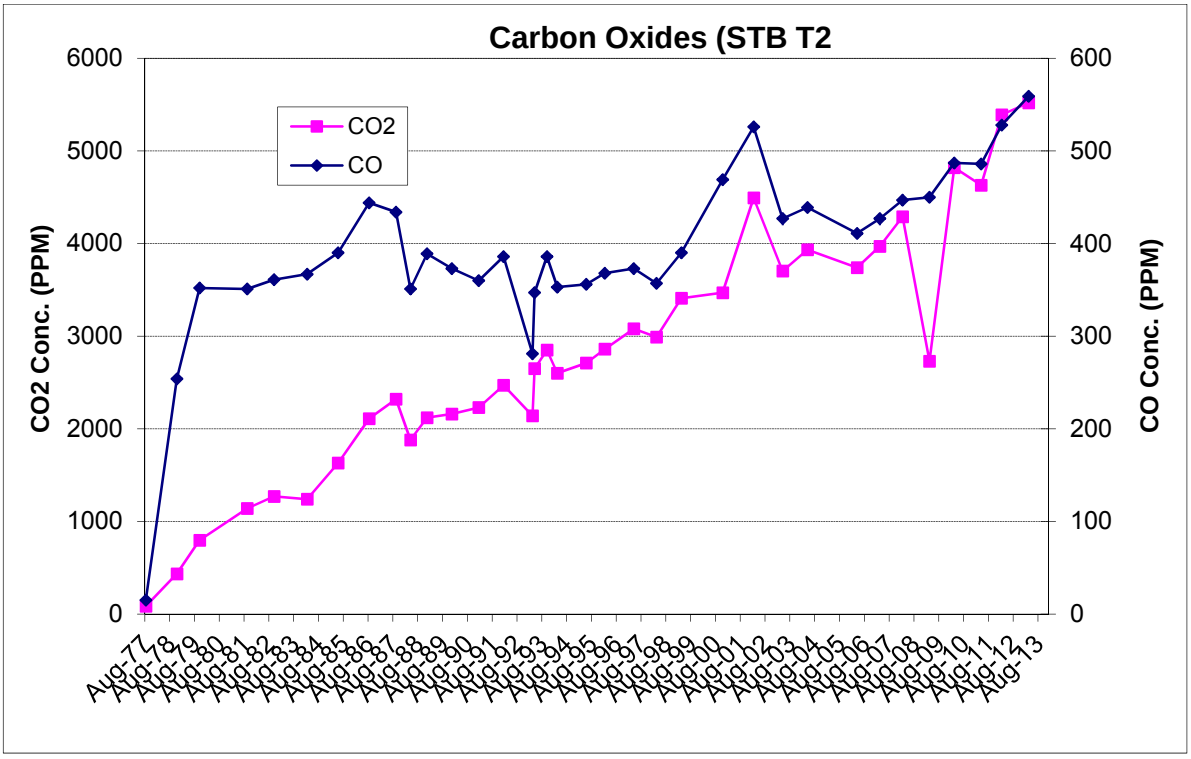


Figure 14 - Carbon Oxides Gas Concentrations

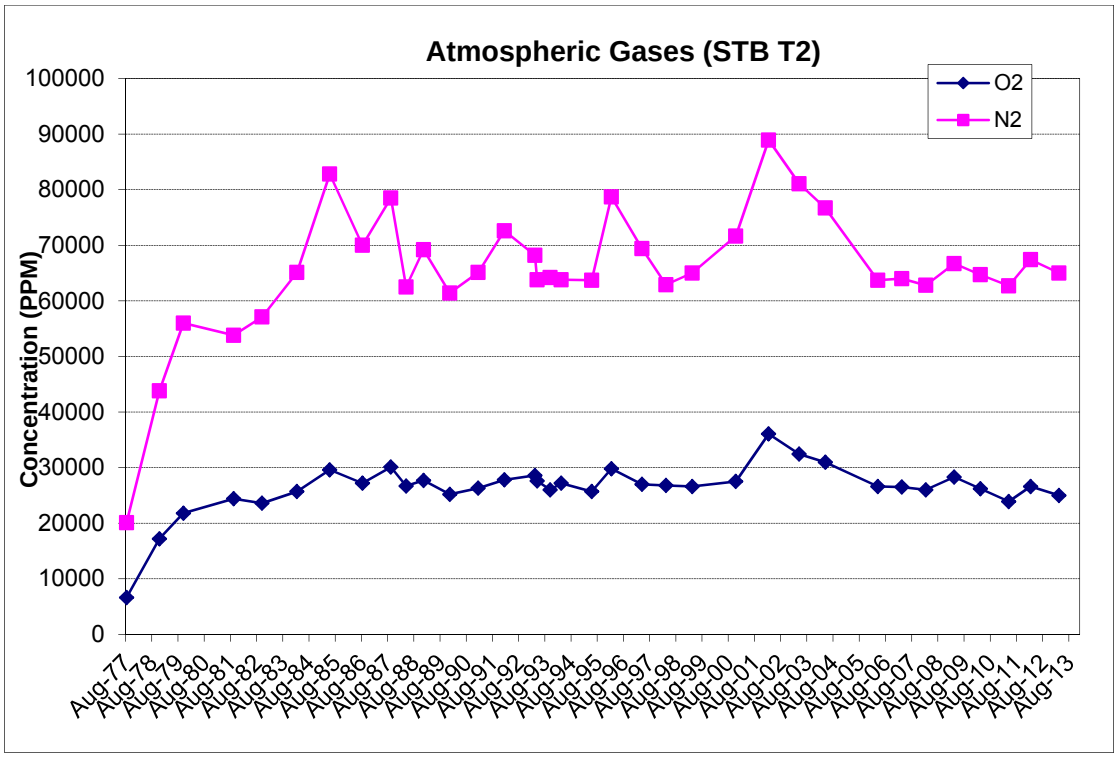


Figure 15 – Atmospheric Gases Concentrations

5. General Oil Quality

5.1. SSD T1 – (CGE 289147)

2.1.1 Main Tank

Below is the report of the oil quality data results from 2009 to 2013. The history of the oil quality data measured for this transformer is shown in **Table** .

The following can be observed:

- The latest measured breakdown voltage (52.0 kV/mm on 09/11/2013) is above the minimum requirement (30kV/mm) as outlined by Doble Engineering for ≥ 230kV transformers with service aged insulating oil based on D877 method. However ASTM D1816-97 is recommended for testing fluid that is being processed into transformers and load tap changers. The gap distance standard settings are 1 mm and 2 mm.

- The interfacial tension values are around 28.0 dynes/cm2 which are below the 32 dynes/cm2 limit recommended by IEEE C57.106-2002 for ≥ 230kV transformers. Lower values may indicate oil soluble contaminants and oxidation products in oil.

- The oxidation inhibitor values were not measured since 2009. The acceptable range is between 0.08 and 0.30%. Oxygen inhibitors are helpful to minimize the effects of oxidation of oil. The first choice of attack by oxygen in the oil is the inhibitor molecules. This keeps the oil free from oxidation and its harmful by-products. As transformer ages, the oxidation inhibitor is used up and need to be replaced.

- The measured Acid Numbers for the oil samples in the past years are all below the recommended limits (0.10 mg KOH/g) by IEEE C57.106-2002 for ≥ 230kV transformers.

- The measured power factor values at 25/100°C are all below the suggested limits as outlined in IEEE C57.106-2002 for continue use of service-aged insulating oil.

- IEEE C57.106-2002 Table 5 recommends that the maximum limit of water content in oil for 230kV transformers is not to exceed 10 ppm or 5% saturation at 50ºC. The oil samples taken from the main tank show moisture content of less than 10 ppm.

Table 8 - Oil Quality Data (Main Tank)

Sample Date	Fluid Temp (°C)	Dielectric Breakdown D877 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Visual Condition D1524	Power Factor D924 (%) 25°C / 100 C		Water (ppm)	% Satur.	Inhibitor (%)
05/05/2009	30	55	0.03	28.6	Clear	0.062	1.38	2	2	-
03/22/2010	25	45	0.03	27.8	Clear	0.035	1.28	5	7	-
02/24/2012	20	59	0.03	26.9	Clear	0.123	2.62	2	4	-
03/13/2012	20	49	0.03	27.5	Clear	0.115	3.28	2	4	-
09/11/2013	35	52	0.03	28.1	Clear	0.166	2.94	3	3	-

2.1.2 LTC Tank

Below is the report of the LTC oil quality data results for 2007, 2008 and 2012. The oil quality test is not available for LTC-B,C in 2007. The history of the oil quality data measured for LTC-A,B,C is shown in **Table** below.

The following can be observed:

- The measured breakdown voltage (around 22.0 kV/mm for LTC-A,B,C) is below the minimum requirement (28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap) as outlined by IEEE C57.106-2002 for LTC mounted at line end with ≥ 69 kV rating and for service aged insulating oil in LTC based on D1816 method. However the oil test reports do not mention gap distance. (1 mm or 2 mm). If the dielectric strength of the oil drops below the suggested values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

- The interfacial tension values are around 36.0 dynes/cm2. However IEEE C57.106-2002 does not specify any IFT limits for continued use of service aged insulating oil for load tap changers.
- The measured Acid Numbers for the oil samples are all below 0.10 mg KOH/g. However IEEE C57.106-2002 does not specify any Acid number limits for load tap changers
- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The oil samples taken from the LTC-A tank does show moisture content of more than 25 ppm. If the water content exceeds the values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

Table 9 - Oil Quality Data (LTC Tank)

Sample Date	LTC ID	Fluid Temp. (°C)	Dielectric Breakdown D1816 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Color # D1500	Water (ppm)
06/27/2007	A	30	14	0.012	35.0	<3.0	43
	B	-	-	-	-	-	-
	C	-	-	-	-	-	-
04/29/2008	A	45	25	0.016	36.3	<2.0	14
	B	35	22	0.014	35.5	<2.5	13
	C	35	22	0.016	36.8	<2.5	9
10/02/2012	A	35	22	0.011	38.7	<4.0	26
	B	35	22	0.015	38.1	<2.5	16
	C	35	23	0.014	38.3	<4.0	18

5.2. SSD T4 – (CGE 288838)

2.2.1 Main Tank

Below is the report of the oil quality data results from 2009 to 2013. The history of the oil quality data measured for this transformer is shown in **Table** .

The following can be observed:

- The latest measured breakdown voltage (52.0 kV/mm on 09/11/2013) is above the minimum requirement (30kV/mm) as outlined by Doble Engineering for 230kV transformers with service aged insulating oil based on D877 method. However ASTM D1816-97 is recommended for testing fluid that is being processed into transformers and load tap changers. The gap distance standard settings are 1 mm and 2 mm.

- The interfacial tension values are around 33.6 dynes/cm2 which is slightly above the 32 dynes/cm2 limit recommended by IEEE C57.106-2002 for 230kV transformers. Lower values may indicate oil soluble contaminants and oxidation products in oil.

- The oxidation inhibitor values were not measured since 2009. The acceptable range is between 0.08 and 0.30%. Oxygen inhibitors are helpful to minimize the effects of oxidation of oil. The first choice of attack by oxygen in the oil is the inhibitor molecules. This keeps the oil free from oxidation and its harmful by-products. As transformer ages, the oxidation inhibitor is used up and need to be replaced. It is highly recommended to add oxidation inhibitor in the oil.

- The measured Acid Numbers for the oil samples in the past years are all below the recommended limits (0.10 mg KOH/g) by IEEE C57.106-2002 for 230kV transformers.

- The measured power factor values at 25/100°C are all below the suggested limits as outlined in IEEE C57.106-2002 for continue use of service-aged insulating oil.

- IEEE C57.106-2002 Table 5 recommends that the maximum limit of water content in oil for 230kV transformers is not to exceed 10 ppm or 5% saturation at 50ºC. The oil samples taken from the main tank show moisture content of less than 10 ppm.

Table 10 - Oil Quality Data (Main Tank)

Sample Date	Fluid Temp (°C)	Dielectric Breakdown D877 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Visual Condition D1524	Power Factor D924 (%) 25°C / 100 C		Water (ppm)	% Satur.	Inhibitor (%)
05/05/2009	34	56	0.01	33.6	Clear	0.066	1.04	2	2	-
03/22/2010	30	36	0.01	31.7	Clear	0.015	0.63	7	8	-
02/24/2012	25	33	0.02	32.0	Clear	0.042	1.24	2	3	-
03/13/2012	25	57	0.02	33.1	Clear	0.054	1.17	2	3	-
09/11/2013	42	52	0.02	33.6	Clear	0.054	1.91	4	3	-

2.2.2 LTC Tank

Below is the report of the LTC oil quality data results for 2008 and 2012. The history of the oil quality data measured for LTC-A,B,C is shown in **Table** below.

The following can be observed:

- The measured breakdown voltage (between 22.0 kV/mm and 29.0 kV/mm for LTC-A,B,C) is below the minimum requirement (28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap) as outlined by IEEE C57.106-2002 for LTC mounted at line end with ≥ 69 kV rating and for service- aged insulating oil in LTC based on D1816 method. However the oil test reports do not mention gap distance. (1 mm or 2 mm?). If the dielectric strength of the oil drops below the suggested values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

- The interfacial tension values are around 39.0 dynes/cm2. However IEEE C57.106-2002 does not specify any IFT limits for continued use of service aged insulating oil for load tap changers.
- The measured Acid Numbers for the oil samples are all below 0.10 mg KOH/g. However IEEE C57.106-2002 does not specify any Acid number limits for load tap changers
- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The oil samples taken from the LTC tank show moisture content of less than 25 ppm. If the water content exceeds the values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

Table 11 - Oil Quality Data (LTC Tank)

Sample Date	LTC ID	Fluid Temp. (°C)	Dielectric Breakdown D1816 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Color # D1500	Water (ppm)
04/29/2008	A	33	-	-	-	-	21
	B	33	21	0.014	37.3	<4.5	18
	C	33	22	0.013	37.9	<4.5	14
08/28/2012	A	45	18	0.011	39.1	<4.0	18
	B	-	-	-	-	-	-
	C	-	-	-	-	-	-
10/02/2012	A	40	22	0.012	39.7	<4.0	11
	B	40	25	0.011	39.4	<4.0	12
	C	40	29	0.014	39.4	<2.5	24

5.3. STB T1 – (CGE 288894)

2.3.1 Main Tank

Below is the report of the oil quality data results from 2009 to 2013. The history of the oil quality data measured for this transformer is shown in **Table** .

The following can be observed:

- The latest measured breakdown voltage (62.0 kV/mm on 03/14/2013) is above the minimum requirement (50kV/mm) as outlined in IEEE C57.106-2002 for 230kV transformers with service aged insulating oil based on D1816-2mm method.
- The interfacial tension values are around 30.4 dynes/cm2 which is below the suggested limits (32 dynes/cm2) recommended by IEEE C57.106-2002 for 230kV transformers. Lower values may indicate oil soluble contaminants and oxidation products in oil.
- The oxidation inhibitor values were not measured since 2009. The acceptable range is between 0.08 and 0.30%. Oxygen inhibitors are helpful to minimize the effects of oxidation of oil. The first choice of attack by oxygen in the oil is the inhibitor molecules. This keeps the oil free from oxidation and its harmful by-products. As transformer ages, the oxidation inhibitor is used up and need to be replaced. It is highly recommended to add oxidation inhibitor in the oil.
- The measured Acid Numbers for the oil samples in the past years are all below the recommended limits (0.10 mg KOH/g) by IEEE C57.106-2002 for 230kV transformers.
- The measured power factor values at 25/100°C are all below the suggested limits as outlined in IEEE C57.106-2002 for continue use of service-aged insulating oil.
- IEEE C57.106-2002 Table 5 recommends that the maximum limit of water content in oil for 230kV transformers is not to exceed 10 ppm or 5% saturation at 50ºC. The oil samples taken from the main tank show moisture content of less than 10 ppm.
- The BDV measurement on 03/14/2012 (in RED) was based on D1816-2mm method.

Table 12 - Oil Quality Data (Main Tank)

Sample Date	Fluid Temp (°C)	Dielectric Breakdown D877 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Visual Condition D1524	Power Factor D924 (%) 25°C / 100 C		Water (ppm)	% Satur.	Inhibitor (%)
03/09/2009	35	53	0.02	32.6	Clear	0.043	0.98	2	2	-
03/15/2010	40	54	0.02	32.0	Clear	0.035	0.98	2	2	-
04/05/2011	40	45	0.02	31.0	Clear	0.065	1.49	4	3	-
02/13/2012	35	52	0.02	30.2	Clear	0.053	2.24	2	2	-
03/14/2013	40	62	0.02	30.4	Clear	0.058	1.39	3	2	-

2.3.2 LTC Tank

Below is the report of the LTC oil quality data results from 2007 to 2010. The history of the oil quality data measured for LTC-A,B,C is shown in **Table** below.

The following can be observed:

- The latest measured breakdown voltage is 30, 31 and 33 kV/mm for LTC-A,B,C. the suggested limits is 28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap as outlined by IEEE C57.106-2002 for LTC mounted at line end with ≥ 69 kV rating and for service- aged insulating oil in LTC based on D1816 method. However the oil test reports do not mention gap distance. (1 mm or 2 mm?). If the dielectric strength of the oil drops below the suggested values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

- The interfacial tension values are around 35.0 dynes/cm2. However IEEE C57.106-2002 does not specify any IFT limits for continued use of service aged insulating oil for load tap changers.
- The measured Acid Numbers for the oil samples are all below 0.10 mg KOH/g. However IEEE C57.106-2002 does not specify any Acid number limits for load tap changers
- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The latest oil samples taken from the LTC tank show moisture content of less than 25 ppm. If the water content exceeds the values given in IEEE C57.106-2002, the oil should be reconditioned or changed.
- Note: The recorded temperature 22°C is much lower than the other phases.

Table 13 - Oil Quality Data (LTC Tank)

Sample Date	LTC ID	Fluid Temp. (°C)	Dielectric Breakdown D1816 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Color # D1500	Water (ppm)
08/06/2007	Left	45	22	0.027	35.6	<3.5	28
	Center	45	18	0.026	35.0	<3.5	29
	Right	45	24	0.026	33.9	<3.5	12
07/18/2008	Left	22	14	0.016	35.1	<2.0	42
	Center	72	14	0.016	34.4	<3.0	40
	Right	72	14	0.015	35.0	<2.5	41
05/27/2010	Left	-	31	0.016	35.5	<3.0	22
	Center	-	30	0.016	35.4	<3.5	15
	Right	-	33	0.016	35.7	<3.0	24

5.4. STB T2 – (CGE 288839)

2.4.1 Main Tank

Below is the report of the oil quality data results from 05/2009 to 09/2013. The history of the oil quality data measured for this transformer is shown in **Table** .

The following can be observed:

- The latest measured breakdown voltage (68.0 kV/mm on 03/14/2013) is above the minimum requirement (50kV/mm) as outlined in IEEE C57.106-2002 for 230kV transformers with service aged insulating oil based on D1816-2mm method.
- The interfacial tension values are around 28.7 dynes/cm2 which is below the suggested limits (32 dynes/cm2) recommended by IEEE C57.106-2002 for 230kV transformers. Lower values may indicate oil soluble contaminants and oxidation products in oil.
- The oxidation inhibitor values were not measured since 2009. The acceptable range is between 0.08 and 0.30%. Oxygen inhibitors are helpful to minimize the effects of oxidation of oil. The first choice of attack by oxygen in the oil is the inhibitor molecules. This keeps the oil free from oxidation and its harmful by-products. As transformer ages, the oxidation inhibitor is used up and need to be replaced. It is highly recommended to add oxidation inhibitor in the oil.
- The measured Acid Numbers for the oil samples in the past years are all below the recommended limits (0.10 mg KOH/g) by IEEE C57.106-2002 for 230kV transformers.
- The measured power factor values at 25/100°C are all below the suggested limits as outlined in IEEE C57.106-2002 for continue use of service-aged insulating oil.
- IEEE C57.106-2002 Table 5 recommends that the maximum limit of water content in oil for 230kV transformers is not to exceed 10 ppm or 5% saturation at 50ºC. The oil samples taken from the main tank show moisture content of less than 10 ppm.
- The BDV measurement on 03/14/2012 (in RED) was based on D1816 method

Table 14 - Oil Quality Data (Main Tank)

Sample Date	Fluid Temp (°C)	Dielectric Breakdown D877 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Visual Condition D1524	Power Factor D924 (%) 25°C / 100 C		Water (ppm)	% Satur.	Inhibitor (%)
03/09/2009	40	56	0.02	29.4	Clear	0.074	1.53	3	2	-
03/15/2010	49	56	0.02	29.4	Clear	0.059	1.59	2	1	-
04/05/2011	48	44	0.02	28.4	Clear	0.132	2.60	6	4	-
02/13/2012	43	45	0.03	27.1	Clear	0.098	2.98	3	2	-
03/14/2013	49	68	0.03	28.7	Clear	0.090	1.86	2	1	-

2.4.2 LTC Tank

Below is the report of the LTC oil quality data results from 2007 to 2011. The history of the oil quality data measured for LTC-A,B,C is shown in **Table** below.

The following can be observed:

- The latest measured breakdown voltage is 17, 21 and 23 kV/mm for LTC-A,B,C. the suggested minimum limits is 28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap as outlined by IEEE C57.106-2002 for LTC mounted at line end with ≥ 69 kV rating and for service- aged insulating oil in LTC based on D1816 method. However the oil test reports do not mention gap distance. (1 mm or 2 mm?). If the dielectric strength of the oil drops below the suggested values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

- The interfacial tension values are around 34.0 dynes/cm2. However IEEE C57.106-2002 does not specify any IFT limits for continued use of service aged insulating oil for load tap changers.

- The measured Acid Numbers for the oil samples are all below 0.10 mg KOH/g. However IEEE C57.106-2002 does not specify any Acid number limits for load tap changers

- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The latest oil samples taken from the LTC tank show moisture content of more than 25 ppm for all three LTCs. If the water content exceeds the values given in IEEE C57.106-2002, the oil should be reconditioned or changed.

Table 15 - Oil Quality Data (LTC Tank)

Sample Date	LTC ID	Fluid Temp. (°C)	Dielectric Breakdown D1816 (kV)	Acid Number D974 (mg KOH/g)	Interfacial Tension D971 (dynes/cm)	Color # D1500	Water (ppm)
08/07/2007	Left	52	25	0.022	34.4	<3.5	16
	Center	52	20	0.024	33.8	<3.5	12
	Right	52	23	0.022	35.0	<3.5	19
07/16/2008	Left	42	17	0.015	35.5	<2.5	44
	Center	42	22	0.015	34.5	<2.5	35
	Right	42	25	0.018	32.6	<2.5	33
08/18/2011	Left	52	23	0.015	33.8	<2.5	34
	Center	52	17	0.016	33.8	<2.5	32
	Right	52	21	0.018	34.1	5.0	42

6. Transformer Power Factor Measurement

6.1. SSD T1 – (CGE 288147)

Doble test was available only for 2007. The overall test and bushings test results for this transformer are shown in **Tables 16** below.

The following is observed:

- The winding power factor values (CH & CT) are below 0.5%. The negative P.F for CHT is most likely because of the ground shield between the LV winding and the TV winding**. Table 16-1**
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable. IEEE Std C57.19.01-2000 specifies a limit of 0.5% for C1 power factor for oil impregnated paper insulated bushings. ABB recommends that the bushings be replaced whenever the power factor is double the nameplate value. **Table 16-2**
- The measured C2 capacitance for HV & LV bushings is higher than the nameplate values by more than 10%. This needs to be compared to initial benchmark test results. **Table 16-3**
- The hot collar tests for TV bushings and neutral bushing are below recommended limit (0.1 W at 10 kV). **Table 16-4**
- The Doble exciting current test are normal. **Table 16-5**

Table 16-1 – Doble Overall Test Results (2007)

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10.016	116.87	3.600	0.31	1.00	31000.6		
CH	10.010	116.15	3.605	0.31	1.00	30808.1	G	
CHT(UST)	10.008	0.7090	-000.02	-0.28	1.00	188.02	I	
CHT		0.720	-0.005	-0.07	1.00	192.500	I	
CT + CHT	5.001	132.63	5.960	0.45	1.00	35180.3		
CT	5.003	131.92	5.973	0.45	1.00	34991.9	G	
CHT(UST)	5.004	0.7070	-000.02	-0.28	1.00	187.58	I	
CHT		0.710	-0.013	-0.18	1.00	188.400	I	

Table 16-2 – Doble Bushing Test Results (2007)

Bushing C1

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	250663	.28	431	10.006	1.599	0.0400	0.25	1.00	424.25	G	
H2	250881	.27	422	10.005	1.571	0.0350	0.22	1.00	416.75	G	
H3	251439	.27	420	10.005	1.564	0.0330	0.21	1.00	414.79	G	
X1	251307	.24	359	10.005	1.348	0.0310	0.23	1.00	357.50	G	
X2	251308	.24	359	10.005	1.350	0.0300	0.22	1.00	358.05	G	
X3	251311	.24	344	10.006	1.295	0.0180	0.14	1.00	343.54	G	

Table 16-3 – Doble Bushing Test Results (2007)

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	250663		379	2.001	1.606	0.0750	0.47	1.00	425.88	I	
H2	250881		384	2.000	1.613	0.0910	0.56	1.00	427.82	I	
H3	251439		390	2.000	1.643	0.0890	0.54	1.00	435.76	I	
X1	251307		339	2.000	1.432	0.0950	0.66	1.00	379.89	I	
X2	251308		341	2.000	1.434	0.0980	0.68	1.00	380.48	I	
X3	251311		366	2.000	1.535	0.1250	0.81	1.00	407.20	I	

Table 16-4 – Bushing Test Results (2007)

Hot Collar Test

Serial #	ID	Test Mode	Skirt #	Test kV	mA	Watts	IR_{auto}	IR_{man}
251458	Y1	GROUND	1	10.003	0.1170	0.0360	G	
251459	Y2	GROUND	1	10.004	0.1210	0.0370	G	
251457	Y3	GROUND	1	10.003	0.1210	0.0450	G	
251456	N	GROUND	1	10.003	0.1180	0.0790	G	

Table 16-5 – Exciting Current Test Results (2007)

Doble Exciting Current Test

			H1 - H0			H2 - H0			H3 - H0				
DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10.018	16.391	160.41	L	10.096	100.62	C	15.702	154.98	L	G	
	5	9.995	17.782	172.67	L	10.996	109.95	C	17.073	167.32	L	G	
	9	10.011	19.436	188.16	L	12.059	120.59	L	18.687	182.66	L	G	
	13	10.011	21.338	205.56	L	13.347	133.12	L	20.553	199.73	L	G	
	17	10.018	23.595	226.91	L	14.837	147.66	L	22.763	220.82	L	G	

6.2. SSD T4 – (CGE 288838)

Doble test was available only for 2012. The overall test and bushings test results for this transformer are shown in **Tables 17** below.

The following is observed:

- The winding power factor value CH is below the allowed limit, but CT is above 0.5%. Please compare to previous results. The negative P.F for CHT is most likely because of the ground shield between the LV winding and the TV winding. **Table 17-1**
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable. IEEE Std C57.19.01-2000 specifies a limit of 0.5% for C1 power factor for oil impregnated paper insulated bushings. ABB recommends that the bushings be replaced whenever the power factor is double the nameplate value. **Table 17-2**
- The measured C2 capacitance for HV & LV bushings is higher than the nameplate values. This needs to be compared to initial benchmark test results. **Table 17-3**
- The hot collar tests for TV bushings and neutral bushing are below recommended limit (0.1 W at 10 kV). **Table 17-4**
- The Doble exciting current test are normal. **Table 17-5**

Table 17-1 – Doble Overall Test Results (2012)

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10.010	121.82	3.893		1.00	32313.1		
CH	10.006	121.09	3.986	0.33	1.00	32119.9	G	
CHT(UST)	10.005	0.7240	-000.07	-0.97	1.00	192.10	I	
CHT		0.730	-0.093	-1.27	1.00	193.200	I	
CT + CHT	5.003	130.06	11.414		1.00	34497.8		
CT	5.002	129.35	11.458	0.89	1.00	34309.3	G	
CHT(UST)	5.003	0.7170	-000.06	-0.84	1.00	190.30	I	
CHT		0.710	-0.044	-0.62	1.00	188.500	I	

Table 17-2 – Doble Bushing Test Results (2012)

Bushing C1

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	245304	.3	416	10.008	1.554	0.0450	0.29	1.00	412.28	G	
H2	245325	.25	421	10.008	1.575	0.0360	0.23	1.00	417.67	G	
H3	245303	.28	420	10.008	1.578	0.0430	0.27	1.00	418.47	G	
X1	245284	.23	353	10.008	1.305	0.0290	0.22	1.00	346.11	G	
X2	245279	.24	370	10.009	1.398	0.0310	0.22	1.00	370.75	G	
X3	245280	.24	359	10.009	1.367	0.0440	0.32	1.00	362.63	G	

Table 17-3 – Doble Bushing Test Results (2012)

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap (pF)	IR_{auto}	IR_{man}
H1	245304		402	2.000	1.640	0.0540	0.33	1.00	434.90	G	
H2	245325		388	2.000	1.578	0.0520	0.33	1.00	418.49	D	
H3	245303		402	2.001	1.626	0.0550	0.34	1.00	431.23	I	
X1	245284		377	2.000	1.716	0.0900	0.52	1.00	455.10	G	
X2	245279		356	2.000	1.439	0.0470	0.33	1.00	381.61	G	
X3	245280		383	2.000	1.526	0.0450	0.29	1.00	404.71	G	

Table 17-4 – Bushing Test Results (2012)

Hot Collar Test

Serial #	ID	Test Mode	Skirt #	Test kV	mA	Watts	IR_{auto}	IR_{man}
244961	Y1	GROUND	1	10.006	0.1250	0.0740	G	
244966	Y2	GROUND	1	10.006	0.1150	0.0230	G	
244962	Y3	GROUND	1	10.007	0.1160	0.0250	G	
244699	N	GROUND	1	10.007	0.1150	0.0630	G	

Table 17-5 – Exciting Current Test Results (2012)

Doble Exciting Current Test

			H1 - H0			H2 - H0			H3 - H0				
DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10.027	14.950	147.67	L	10.418	104.09	L	15.931	152.39	L	G	
	9	10.025	17.799	174.37	L	12.231	121.75	L	19.059	180.30	L	G	
	17	10.035	21.646	210.67	L	15.000	148.47	L	23.184	218.38	L	G	

6.3. STB T1 – (CGE 288894)

Doble test was available only for 2011. The overall test and bushings test results for this transformer are shown in **Tables 18** below.

The following is observed:

- The winding power factor value CH & CT are below the allowed limit. The negative P.F for CHT is most likely because of the ground shield between the LV winding and the TV winding. **Table 18-1**
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable. IEEE Std C57.19.01-2000 specifies a limit of 0.5% for C1 power factor for oil impregnated paper insulated bushings. ABB recommends that the bushings be replaced whenever the power factor is double the nameplate value. **Table 18-2**
- The measured C2 capacitance for HV & LV bushings is higher than the nameplate values. This needs to be compared to initial benchmark test results. **Table 18-3**
- The hot collar tests for TV bushings and neutral bushing are below recommended limit (0.1 W at 10 kV). **Table 18-4**
- The Doble exciting current test are normal. **Table 18-5**

Table 18-1 – Doble Overall Test Results (2011)

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10.008	122.45	3.944		1.00	32481.4		
CH	10.005	121.72	4.017	0.33	1.00	32287.1	G	
CHT(UST)	10.005	0.7200	-000.08	-1.11	1.00	190.92	I	
CHT		0.730	-0.073	-1.00	1.00	194.300	I	
CT + CHT	4.001	129.24	4.660		1.00	34280.1		
CT	4.001	128.52	4.634	0.36	1.00	34090.1	G	
CHT(UST)	4.002	0.7160	0.0060	0.08	1.00	189.87	I	
CHT		0.720	0.026	0.36	1.00	190.000	I	

Table 18-2 – Doble Bushing Test Results (2011)

Bushing C1

ID	Serial	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
H3	247915	.24	417	10.008	1.544	0.0350	0.23	1.00	409.52	G	
X1	246782	.27	353	10.008	1.317	0.0280	0.21	1.00	349.37	G	
X2	246784	.27	353	10.008	1.321	0.0280	0.21	1.00	350.33	G	
X3	246618	.27	352	10.008	1.324	0.0280	0.21	1.00	351.12	G	
H2	248124	.26	415	10.008	1.536	0.0350	0.23	1.00	407.34	G	
H1	246741	.28	409	10.008	1.513	0.0420	0.28	1.00	401.26	G	

Table 18-3 – Doble Bushing Test Results (2011)

Bushing C2

ID	Serial #	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
H1	246741		391	2.001	1.649	0.0640	0.39	1.00	437.49	G	
H2	248124		392	2.000	1.637	0.0640	0.39	1.00	434.34	G	
H3	247915		387	2.001	1.651	0.0690	0.42	1.00	437.87	G	
X1	246782		359	2.000	1.440	0.0390	0.27	1.00	382.06	G	
X2	246784		355	2.001	1.413	0.0390	0.28	1.00	374.81	G	
X3	246618		354	2.000	1.403	0.0380	0.27	1.00	372.23	G	

Table 18-4 – Bushing Test Results (2011)

Hot Collar Test

Serial #	ID	Test Mode	Skirt #	Test kV	mA	Watts	IR_{auto}	IR_{man}
248098	Y1	GROUND	1	10.010	0.1020	0.0220	G	
248096	Y2	GROUND	1	10.009	0.1000	0.0270	G	
248097	Y3	GROUND	1	10.009	0.1030	0.0220	G	
248095	N	GROUND	1	10.006	0.1020	0.0240	G	

Table 18-5 – Exciting Current Test Results (2011)

Doble Exciting Current Test

			H1 - H0			H2 - H0			H3 - H0				
DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10.034	15.894	158.43	L	10.304	102.76	C	16.452	161.67	L	G	
	9	10.037	18.827	186.57	L	12.392	123.86	L	19.367	188.79	L	G	
	17	10.041	22.755	224.48	L	14.900	148.64	L	23.163	224.70	L	G	

6.4. STB T2 – (CGE 288839)

Doble test was available only for 2008. The overall test and bushings test results for this transformer are shown in **Tables 19** below.

The following is observed:

- The winding power factor value CH & CT are below the allowed limit. The negative P.F for CHT is most likely because of the ground shield between the LV winding and the TV winding. **Table 19-1**
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable. IEEE Std C57.19.01-2000 specifies a limit of 0.5% for C1 power factor for oil impregnated paper insulated bushings. ABB recommends that the bushings be replaced whenever the power factor is double the nameplate value. **Table 19-2**
- The measured C2 capacitance for HV bushings is higher than the nameplate values by more than 10%. This needs to be compared to initial benchmark test results and investigated. The measured C2 capacitance for LV bushings is higher than the nameplate values but within 10%. **Table 19-3**
- The hot collar tests for TV bushings and neutral bushing are below recommended limit (0.1 W at 10 kV). **Table 19-4**
- The Doble exciting current test are normal. **Table 19-5**

Table 19-1 – Doble Overall Test Results (2008)

Meas.	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
CH + CHT	10.011	122.14	3.635	0.26	0.88	32399.5		
CH	10.004	121.38	3.650	0.26	0.88	32197.8	G	
CHT(UST)	10.003	0.7200	-000.01	-0.12	0.88	191.08	I	
CHT		0.760	-0.015	-0.18	0.88	201.700	I	
CT + CHT	4.001	132.53	4.722	0.32	0.88	35153.3		
CT	4.001	131.80	4.739	0.32	0.88	34961.5	G	
CHT(UST)	4.001	0.7180	-000.01	-0.12	0.88	190.36	I	
CHT		0.730	-0.017	-0.20	0.88	191.800	I	

Table 19-2 – Doble Bushing Test Results (2008)

Bushing C1

ID	Serial	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
H1	246350	.25	411	10.005	1.525	0.0330	0.21	0.96	404.45	G	
H2	246448	.28	433	10.005	1.611	0.0400	0.24	0.96	427.33	G	
H3	246447	.28	434	10.005	1.620	0.0420	0.25	0.96	429.61	G	
X1	245184	.26	369	10.005	1.386	0.0330	0.23	0.96	367.76	G	
X2	243251	.24	376	10.005	1.403	0.0330	0.23	0.96	372.10	G	
X3	246347	.25	352	10.004	1.322	0.0280	0.20	0.96	350.72	G	

Table 19-3 – Doble Bushing Test Results (2008)

Bushing C2

ID	Serial	NP %PF	NP Cap	Test kV	mA	Watts	%PF corr	Corr Fctr	Cap(pF)	IR_{auto}	IR_{man}
H1	246350		400	2.000	1.701	0.0850	0.50	1.00	451.28	I	
H2	246448		379	2.000	1.608	0.0730	0.45	1.00	426.63	I	
H3	246447		381	2.000	1.602	0.0760	0.47	1.00	424.85	I	
X1	245184		346	2.000	1.404	0.0500	0.36	1.00	372.34	D	
X2	243251		345	2.000	1.422	0.0540	0.38	1.00	377.08	D	
X3	246347		374	2.000	1.501	0.0500	0.33	1.00	398.04	D	

Table 19-4 – Bushing Test Results (2008)

Hot Collar Test

Term ID	ID	Test Mode	Skirt #	Test kV	mA	Watts	IR_{auto}	IR_{man}
244967	Y1	GROUND	1	10.003	0.1160	0.0240	G	
244953	Y2	GROUND	1	10.003	0.1160	0.0240	G	
244959	Y3	GROUND	1	10.003	0.1180	0.0260	G	
244964	N	GROUND	1	10.003	0.1140	0.0260	G	

Table 19-5 – Exciting Current Test Results (2008)

Doble Exciting Current Test

			H1 - H0			H2 - H0			H3 - H0				
DETC	LTC	Test kV	mA	Watts	X	mA	Watts	X	mA	Watts	X	IR_{auto}	IR_{man}
	1	10.017	15.471	153.74	L	9.875	98.173	C	15.410	151.83	L	G	
	9	10.010	18.174	179.19	L	11.737	117.36	C	18.256	178.57	L	G	
	17	10.016	22.002	215.40	L	14.332	142.83	L	22.102	214.90	L	G	

7. Maintenance History

7.1. SSD T1 – (CGE 289147)

Electrical testing was performed in this transformer on 2007. The tests included winding resistance, insulation resistance and polarization index test. The test results are shown in Error! Reference source not found.**20** below.

- The winding resistance test for HV winding is consistent between phases, however the measured resistance is much lower than the other results for the sister units.
- The winding resistance tests for LV & TV windings are consistent between phases, and also very close to the other sister units.
- The ratio test and core Megger test was not performed.
- The insulation resistance test was performed and results look normal in G-ohms, however the polarization index is lower than the ABB suggested value of 2.0 for HV/LV to ground.

Table 20-1 – Insulation Resistance and Polarization Index Test Results

Test Date: 2007/09/05 Test Completed By: GH J.D.E. W/O #:

y - HL Grounded	1 min - 1.84	10 min 5.95	3.18 %
[redacted]	1 min	10 min	
~~LTG~~	1 Min. Mega Ω	10 Min. Mega Ω	Index. %
HL-G y Grounded Tert. - Grounded	1 Min. 2.28 Mega Ω	10 Min. 3.46 Mega Ω	Index. 1.52 %

CORE GROUND: (500 Volt test)	
Externally Connected Yes ____ No ____	
RESISTOR: (Ohms)	CORE GROUND: (Mega Ohms)

Table 20-2 – Winding Resistance Test Results

TAP POSITION	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTANCE DELTA x 1.5
Found 6	6 Ø A	500 mA	2	106.6%	.405	
Found 6	6 Ø B	500mA	2	106.5%	.442	
Found 6	6 Ø C	500mA	2	106.6%	.412	
Max. Raise 17	Ø A	500mA	2	106.4	.485	
Max. Raise 17	Ø B	500 mA	2	106.5%	.461	
Max. Raise 17	Ø C	500mA	2	106.5%	.464	
Max. Lower 1	Ø A	500mA	2	106.4%	.452	
Max. Lower 1	Ø B	500mA	2	106.4%	.458	
Max. Lower 1	Ø C	500 mA	2	106.4%	.458	
Left 6	Ø A	500mA	2	106.5%	.407	
Left 6	Ø B	500mA	2	106.4%	.437	
Left 6	Ø C	500mA	2	106.5%	.401	
Non Tap Winding	Ø A	500mA	2	104%	.570	
Non Tap Winding	Ø B	500mA	2	104.1%	.577	
Non Tap Winding	Ø C	500mA	2	104.1%	.570	
Tertiary Winding	Ø A B and	500mA	200m	107.2	5.7	
Tertiary Winding	Ø B C and	500 mA	200m	107.2	5.5	
Tertiary Winding	Ø A C and	500 mA	200m	107.2	5.3	

Note: Observe Indicator Light & Record OHMS or MILLI-OHMS

7.2. SSD T4 – (CGE 288838)

Electrical testing was performed in 2012 including winding resistance, insulation resistance and polarization index test. The test results are shown in Error! Reference source not found. below.

- The winding resistance test for HV & LV & TV windings is consistent between phases.
- The ratio test was not performed.
- The core Megger test was performed and result looks normal.
- The insulation resistance test was performed and results look normal in G-ohms however the polarization index is lower than the ABB suggested value of 2.0.

Table 21-1 – Insulation Resistance and Polarization Index Test Results

CORE GROUND: (500 Volt test)

Externally Connected Yes ___ No ✓

RESISTOR: (Ohms)		1 min	10 min	CORE GROUND: (Mega Ohms) 720 mega Ω
Auto XFmer	H-Grn.	3.16	4.44	1.14 PI
	L-Grn.	3.60	5.00	1.39 PI
	H-Grn	3.82	5.25	1.37 PI

Sheet 2 of 3

Table 21-2 – Winding Resistance Test Results

TAP POSITION	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTANCE DELTA x 1.5
Found 4	H_1-H_0	500mA	2Ω	105.3%	x1.023	
Found 4	H_2-H_0	500mA	2Ω	105.3%	1.018Ω	
Found 4	H_3-H_0	500mA	2Ω	105.3%	1.018	
Max. Raise 17	H_1-H_0	500mA	2Ω	105.3%	1.083	
Max. Raise 17	H_2-H_0	500mA	2Ω	105.3%	1.054	
Max. Raise 17	H_3-H_0	500mA	2Ω	105.4%	1.052	
Max. Lower 1	H_1-H_0	500mA	2Ω	105.4%	1.053	
Max. Lower 1	H_2-H_0	500mA	2Ω	105.4%	1.049	
Max. Lower 1 x	H_3-H_0	500mA	2Ω	105.4%	1.046	
Left 4	H_1-H_0	500mA	2Ω	105.4%	1.023	
Left 4	H_2-H_0	500mA	2Ω	105.4%	1.019	
Left 4	H_3-H_0	500mA	2Ω	105.4%	1.018	
Non Tap Winding	X_0-X_1	500mA	2Ω	106.3	.592	
Non Tap Winding	X_0-X_2	500mA	2Ω	106.3	.590Ω	
Non Tap Winding	X_0-X_3	500mA	2Ω	106.3	.589Ω	
Tertiary Winding	Y_1-Y_2	5A	200m	99.9%	5.4mΩ	
Tertiary Winding	Y_1-Y_3	5A	200m	99.9%	5.6mΩ	
Tertiary Winding	Y_2-Y_3	5A	200m	100.0%	5.6mΩ	

7.3. STB T1 – (CGE 288894)

Electrical testing was performed in 2011 including winding resistance, insulation resistance and polarization index test. The test results are shown in Error! Reference source not found. below.

- The winding resistance test for HV & LV windings is consistent between phases.
- The deviation of the TV winding resistance between phases is 20%. It is recommended to repeat the TV windings resistance test and compare to the sister units.
- The ratio test was not performed.
- The core Megger test was performed and result looks normal.
- The insulation resistance test was performed and results look normal in G-ohms however the polarization index is lower than the ABB suggested value of 2.0 for HV to ground.

The tap changer inspection was performed on September 23rd, 2011 by GE, the following are found: Both two defects were corrected.

- One end of a resistor was misplaced and came into contact with another resistor.
- A loss bolt was found on resistor.

Other findings:

- One bearing in one of second stage fan motors was found to be broken.

Table 22-1 – Insulation Resistance and Polarization Index Test Results

DIELECTRIC ABSORBTION (5 KV): 10 MIN. ÷ 1 MIN. = INDEX								
HL-TG	1 Min.	4.08	Mega Ω	10 Min.	5.85	Index.	1.44	%
T-HLG	1 Min.	3.18	Mega Ω	10 Min.	13.8	Index.	4.34	%
HLT-G	1 Min.	2.04	Mega Ω	10 Min.	4.5	Index.	2.22	%

CORE GROUND: (500 Volt test)	
Externally Connected Yes ✓ No ____	
RESISTOR: (Ohms) N/A	CORE GROUND: (Mega Ohms) > 999

Table 22-2 – Winding Resistance Test Results

TAP POSITION	WINDING TESTED	CURRENT RANGE	RESISTANCE RANGE	% CURRENT	RESISTANCE	RESISTANCE DELTA x 1.5
Found 1	H_1 - HO	500 MA	2 Ω	105.1	1.035	
Found 1	H_2 - HO	500 MA	2 Ω	104.8	1.036	
Found 1	H_3 - HO	500 ma	2 Ω	105.0	1.031	
Max. Raise 9	H_1 - HO	500 ma	2 Ω	105.3	0.948	
Max. Raise 9	H_2 - HO	500 ma	2 Ω	105.3	0.952	
Max. Raise 9	H_3 - HO	500 ma	2 Ω	105.3	0.952	
Max. Lower 1	H_1 - HO	500 ma	2 Ω	105.2	1.035	
Max. Lower 1	H_2 - HO	500 ma	2 Ω	105.1	1.034	
Max. Lower 1	H_3 - HO	500 ma	2 Ω	105.2	1.035	
Left 1						
Left 1						
Left 1						
Non Tap Winding	X_1 - XO	500 ma	2 Ω	105.9	0.582	
Non Tap Winding	X_2 - XO	500 ma	2 Ω	105.9	0.582	
Non Tap Winding	X_3 - XO	500 ma	2 Ω	105.9	0.582	
Tertiary Winding	Y_1 - Y_2	500 ma	2 Ω	104.6	0.005	0.0075
Tertiary Winding	Y_2 - Y_3	500 ma	2 Ω	104.3	0.006	0.009
Tertiary Winding	Y_1 - Y_3	500 ma	2 Ω	104.4	0.006	0.009

7.4. STB T2 – (CGE 288839)

The maintenance test history is not available for this unit.

8. Inspection

The unit was inspected on January 21, 2014. Entry to the unit was made from the manhole located on the top cover between H2 and H3 bushings. Most of the other man holes and hand holes in the unit were opened also for inspection. It was possible to see and inspect all the active part components.

8.1. Findings and Observations

- Because of risk of broken bushing porcelain falling; H3 and L2 bushing were removed before the inspection. L1 bushing was removed during the inspection.
- Transformer cover was ripped open at the LV side. All the bolts on the LV side and some on the short sides were broken. **See Photos 1&2&3&4**
- All transformer bushings are damaged. The most damaged are the H1, L2 and TV bushings. **See Photos 5&6&7&8**
- The tap changer diverter cylinders of Phases 1 and 3 were separated from their aluminum flanges at the cover. This caused the tap changer assemblies, diverter and selector, to fall. The assemblies were found sitting at the bottom of the tap changer's pocket. No signs of flashover were seen at the selector switches or tap cables. **See Photos 9&10&11&12**
- The fire left indications of burning on the tank wall to a level about a foot above the windings. **See Photo 13**
- No signs of flash over were seen in the cleats and leads including tap leads.
- All windings looked good with no signs of failure within the windings. **See Photos 14&15**
- The L1 & L3 bushing's porcelain inside the transformer were shattered. Also marks of flashover were seen on core clamp just opposite to Phase 1 LV bushing. **See Photos 16&17&18**
- Each of the LV bushings in this transformer has two leads connected to them. One lead is connected to the winding and the other to the tap changer. **See Sketch 1**
- For Phases 1 and 2 the leads connecting the LV bushings to the windings are disconnected. It seems the two leads were mechanically pulled and cur at the crimp during the fault when the cover opened up. The insulation of the leads looks intact with no signs of failure. **See Photos 19&20&21&22**
- Spitting and melting cooper were seen on the LV windings conductor copper strands of phase one. **See Photo 23**



Photo 1 – Cover Open & Broken Bolts



Photo 2 – Cover Open & Broken Bolts



Photo 3 – Cover Open & Broken Bolts



Photo 4 – Cover Open & Broken Bolts



Photo 5 – LV2 Bushing



Photo 6 – LV2 Bushing



Photo 7 – **LV2 Bushing Porcelain**



Photo 8 – **HV1 Bushing Porcelain**



Photo 9 – LTC Compartment (Phases 2 & 3)



Photo 10 – LTC Compartment (Phases 2 & 3)



Photo 11 – LTC Compartment (Phase 3)



Photo 12 – LTC Compartment (Phases 2 & 1)



Photo 13 – Fire Line on Tank Wall & Core Clamp



Photo 14 – Windings



Photo 15 – Windings



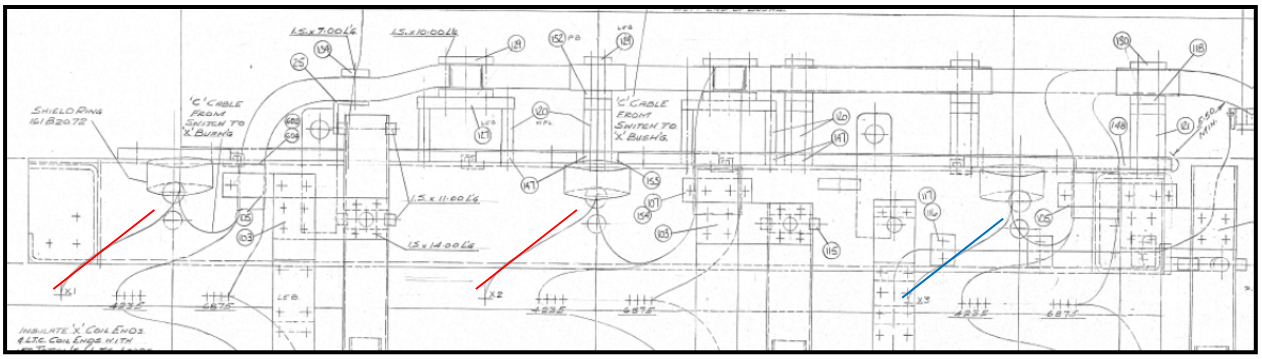
Photo 16 – LV1 Bushing & Flashover marks



Photo 17 – LV1 Bushing



Photo 18 – LV3 Bushing



Sketch 1: LV bushings Connected to the Windings & Tap Changers



Photo 19 – LV2 Winding Lead Broken



Photo 20 – LV2 Bushing Lead Broken at the Crimp



Photo 21 – LV1 Winding Lead Broken



Photo 22 – LV1 Bushing Lead Broken at the Crimp



Photo 23 – LV1 Winding Conductor Strand Copper Spitting

9. Conclusion

Comprehensive short circuit and dielectric study of the design is performed for transformer sn 289147 built in 1978 and failed in 2013. Review of maintenance data and DGA history was completed. Also failure investigation and inspection was performed.

The short circuit design study showed that HV and LV windings are able to withstand short circuit forces while TV winding end rings are not strong enough to withstand the short circuit forces.

The Dielectric study showed that all windings and cable clearances are within the acceptable design levels for the voltage stresses in this transformer.

The DGA, oil quality, transformer power factor and maintenance history of the four transformers were reviewed.

For SSD T1 – CGE 288147

The DGA results showed that:

- The concentration of Acetylene (C2H2) has been above IEEE C57.104-2008 guide condition level 1 (2 ppm) since 1991, The level went up and down since then but was almost stable around the 10ppm. This could be oil leaking from LTC diverter compartment.
- The oil samples from this transformer have consistently shown high oxygen concentrations.

The oil physical results showed that: (Main tank)

- The interfacial tension values are around 28.0 dynes/cm2 which are below the 32 dynes/cm2 limit recommended by IEEE C57.106-2002 for ≥ 230kV transformers.

The oil physical results showed that: (LTC tank)

- The measured breakdown voltage (around 22.0 kV/mm for LTC-A,B,C) is below the minimum requirement (28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap) as outlined by IEEE C57.106-2002.
- The oil samples taken from the LTC-A tank does show moisture content of more than 25 ppm.

The power factor measurements showed that:

- The winding power factor values (CH & CT) are below 0.5%.
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable.
- The measured C2 capacitance for HV & LV bushings is higher than the nameplate values by more than 10%.
- The hot collar tests for TV bushings and neutral bushing are below recommended limit.
- The Doble exciting current test are normal.

The maintenance history showed that:

- The winding resistance test for HV winding is consistent between phases, however the measured resistance is much lower than the other two sister units.
- The winding resistance tests for LV & TV windings are consistent between phases, and also very close to the other two sister units.

- The insulation resistance test was performed and results look normal in G-ohms, however the polarization index is lower than the ABB suggested value of 2.0 for HV/LV to ground.

For SSD T4 – CGE 288838

The DGA results showed that:

- The concentration of Acetylene (C2H2) has been above IEEE C57.104-2008 guide condition level 1 (2 ppm) since 1991, The level went up and down since then but was almost stable around the 5ppm. This could be oil leaking from LTC diverter compartment.
- The oil samples from this transformer have consistently shown high oxygen concentrations.

The oil physical results showed that: (Main tank)

- The latest measured breakdown voltage (52.0kV/mm) is above the minimum requirement (30kV/mm) as outlined by Doble Engineering for 230kV transformers.
- The interfacial tension values are around 33.6 dynes/cm2 which is slightly above the 32 dynes/cm2 limit recommended by IEEE C57.106-2002 for 230kV transformers. Lower values may indicate oil soluble contaminants and oxidation products in oil.
- The measured Acid Numbers for the oil samples are all below the recommended limits.
- The measured power factor values at 25/100°C are all below the suggested limits.
- The moisture in oil is within the acceptable limits.

The oil physical results showed that: (LTC tank)

- The measured breakdown voltage (between 22.0 kV/mm and 29.0 kV/mm for LTC-A,B,C) is below the minimum requirement (28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap).
- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The oil samples taken from the LTC tank show moisture content of less than 25 ppm.

The power factor measurements showed that:

- The winding power factor value CH is below the allowed limit, but CT is above 0.5%.
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable.
- The measured C2 capacitance for HV & LV bushings is higher than the nameplate values. This needs to be compared to initial benchmark test results.
- The hot collar tests for TV bushings and neutral bushing are below recommended limit.
- The Doble exciting current test are normal.

The maintenance history showed that:

- The winding resistance test for HV & LV & TV windings is consistent between phases.
- The ratio test was not performed.
- The core Megger test was performed and result looks normal.
- The insulation resistance test was performed and results look normal in G-ohms however the polarization index is lower than the ABB suggested value of 2.0.

For STB T1 – CGE 288894

The DGA results showed that:

- The concentration of Acetylene (C2H2) has been below IEEE C57.104-2008 guide condition level 1 (2 ppm) since 2009. However the DGA sample for the year 1979 shows high level of C2H2. This could be a bad oil sample.
- The oil samples from this transformer have consistently shown high oxygen concentrations.

The oil physical results showed that: (Main tank)

- The latest measured breakdown voltage (62.0kV/mm) is above the minimum requirement (50kV/mm) as outlined in IEEE C57.106-2002 for 230kV transformers with service aged insulating oil based on D1816-2mm method.
- The interfacial tension values are around 30.4 dynes/cm2 which is below the suggested limits (32 dynes/cm2) recommended by IEEE C57.106-2002 for 230kV transformers. Lower values may indicate oil soluble contaminants and oxidation products in oil.
- The measured Acid Numbers for the oil samples are all below the recommended limits.
- The measured power factor values at 25/100°C are all below the suggested limits.
- The moisture in oil is within the acceptable limits.

The oil physical results showed that: (LTC tank)

- The latest measured breakdown voltage is 30, 31 and 33 kV/mm for LTC-A,B,C. the suggested limits is 28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap as outlined by IEEE C57.106-2002.
- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The latest oil samples taken from the LTC tank show moisture content of less than 25 ppm.

The power factor measurements showed that:

- The winding power factor value CH & CT are below the allowed limit.
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable.
- The measured C2 capacitance for HV & LV bushings is higher than the nameplate values. This needs to be compared to initial benchmark test results.
- The hot collar tests for TV bushings and neutral bushing are below recommended limit
- The Doble exciting current test are normal.

The maintenance history showed that:

- The winding resistance test for HV & LV windings is consistent between phases.
- The deviation of the TV winding resistance between phases is 20%.
- The ratio test was not performed.
- The core Megger test was performed and result looks normal.
- The insulation resistance test was performed and results look normal in G-ohms however the polarization index is lower than the ABB suggested value of 2.0 for HV to ground.

For STB T2 – CGE 288839

The DGA results showed that:

- The transformer has consistently shown very high concentrations (>20 ppm) of Acetylene (C_2H_2) since 1986, which is far above the IEEE C57.104-2008 guide condition level 1 (2 ppm). The high concentration of C_2H_2 indicates that possible high energy arcing occurred somewhere inside the transformer. The other reason could be oil leaking from LTC diverter compartment. The Acetylene levels are about 10ppm foe few years now. This needs to be monitored closely. Any sudden increase of Acetylene needs to be investigated.
- The oil samples from this transformer have consistently shown high oxygen concentrations

The oil physical results showed that: (Main tank)

- The latest measured breakdown voltage (68.0kV/mm) is above the minimum requirement (50kV/mm) as outlined in IEEE C57.106-2002 for 230kV transformers with service aged insulating oil based on D1816-2mm method.
- The interfacial tension values are around 28.7 dynes/cm2 which is below the suggested limits (32 dynes/cm2) recommended by IEEE C57.106-2002 for 230kV transformers.
- The measured Acid Numbers for the oil samples are all below the recommended.
- The measured power factor values at 25/100°C are all below the suggested limits.
- The moisture in oil is within the acceptable limit.

The oil physical results showed that: (LTC tank)

- The latest measured breakdown voltage is 17, 21 and 23 kV/mm for LTC-A,B,C, which is below the suggested minimum limits (28 kV/mm for 1 mm gap and 45 kV/mm for 2 mm gap).
- IEEE C57.106-2002 Table 12 recommends that the maximum limit of water content in oil for LTC is not to exceed 25 ppm. The latest oil samples taken from the LTC tank show moisture content of more than 25 ppm for all three LTCs.

The power factor measurements showed that:

- The winding power factor value CH & CT are below the allowed limit.
- The C1 power factor and capacitance values for HV & LV bushings are all acceptable.
- The measured C2 capacitance for HV bushings is higher than the nameplate values by more than 10%. This needs to be compared to initial benchmark test results and investigated. The measured C2 capacitance for LV bushings is higher than the nameplate values but within 10%.
- The hot collar tests for TV bushings and neutral bushing are below recommended limit.
- The Doble exciting current test are normal.

The failure inspection showed the following:

- All transformer bushings are damaged.
- The tap changer diverter cylinders of Phases 1 and 3 were separated from their aluminum flanges at the cover.
- No signs of flash over were seen in the cleats and leads including tap leads.
- All windings looked good with no signs of failure within the windings. It is not possible to see the internal windings.
- The L1 & L3 bushing's porcelain inside the transformer were shattered. Also marks of flashover were seen on core clamp just opposite to Phase 1 LV bushing.
- For Phases 1 and 2 the leads connecting the LV bushings to the windings are disconnected. It seems the two leads were mechanically pulled and cur at the crimp during the fault when the cover opened up. The insulation of the leads looks intact with no signs of failure.
- Spitting and melting cooper were seen on the LV windings conductor copper strands of phase one.

We still need to review the fault current, voltage and sequence of events but it seems LV1 or LV2 bushing failed first and caused the fire.

10. Recommendations

The following is recommended for all three transformers:

- Comprehensive DGA, oil quality tests and transformer testing is to be planned.
- Consider replacing transformer bushings.
- Add a conservator diaphragm.
- Consider adding oxidation inhibitor to oil.
- Monitor Acetylene (C2H2) closely especially for (STB T2).
- Consider adding online monitor.
- Measure the oil break down voltage per ASTM D1816 (1mm or 2mm) method.
- Repeat the TV windings resistance test (on unit STB T1) and compare to the sister units.
- Repeat the HV resistance test (on unit SSD T1) and compare to the sister unit.
- Perform core Megger test on unit SSD T1.
- Any bushings with higher C2 capacitance need to be compared to initial benchmark test results.
- It is recommended to re-condition of oil in LTC tank or replace with new oil.
- Perform on site drying out on unit SSD T4.

Power Products Service Group

Nalcor order: 20649-000-OB

ABB job number: 557775-10

Breaker ID and Location: B1L03 at Sunnyside Terminal Station

Investigation Location: Nalcor Regional Facility – Bishop's Falls

Breaker type: DCVF245 mc6

Serial number: B142698

Mechanism type: Air Blast

Purpose for visit: Investigate B1L03 Breaker Failed to Trip

On site dates: 2014-02-03 to 2014-02-06

Report presented to: Mr. Hughie Ireland

SCOTT MORRIS
..... Date: February 10, 2014

Scott Morris

ABB **Power Products Service Group**

B1L03 Breaker Data

Type:	DCVF 245mc6
Serial Number	B142698

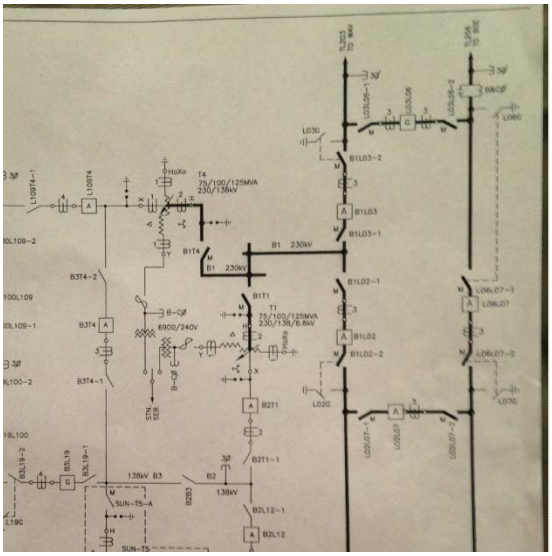
Maintenance History

Below is a summary of maintenance history relevant to the investigation extracted from the maintenance history provided.

Work Order	Date Comp.	Work Done	Investigation Comments
838346	4/8/2011	Function tests done after questionable operations during a fault.	All checked okay.
576789	3/6/2007	Breaker would not operate. Operated locally and ECC. Stayed in service	No cause found.
389723	6/1/2007	Re-lubrication of all interrupters and sub-assemblies	Last time breaker overhauled prior to event
263859	1/29/2003	Breaker overhaul of all interrupters and sub-assemblies	2nd last time breaker overhauled prior to event

Background

On Saturday January, 4 2014 the T1 transformer at Sunnyside Terminal Station faulted. The protections operated to clear the fault. Five breakers were sent trip signals. Three of these were 138 KV ABB DCF 170mc4 air blast breakers. The nomenclatures for these breakers are L109T4, B3T4 and B2T1. The other two breakers were 245 KV ABB DCVF 245mc6 air blast breakers. The nomenclatures for these breakers are B1L02 and B1L03. All indications are that four of the five breakers tripped okay except for the B1L03. With the B1L03 breaker failing to interrupt the next level of protections operated to clear the line. A portion of the station operating diagram showing the affected breakers is below.



The fault on the T1 transformer resulted in a fire which damaged the transformer.

Some field testing was done on the B1L03 breaker after the event. Some odd findings were noted. The breaker would not operate pneumatically. The breaker timing results were not normal or as expected. There was an un-commanded operation of the breaker. These will be discussed further in the investigation.

To ensure the reliability of the B1L03 breaker major work was done. This included the following:

- Removing all the nine interrupters and replacing them with overhauled spares
- Replacing all three servos with three overhauled spares
- Replacing "B" and "C" pole control boxes with rebuilt spares. "A" phase was to be replaced but issues with the overhauled pole box for the "A" phase prevented this. The original "A" phase pole control box was field overhauled at site.
- The main valves on the breaker were field overhauled at site.
- The air receivers were inspected and found to be okay
- The breaker was timed and function tested before being returned to service
- The removed sub-assemblies and interrupters were taken to the Bishop's Falls Regional Facility

The weather data from Environment Canada for Gander Airport was downloaded to get the daily high and low recorded temperatures for six days prior and the day of the event. These are in the table below.

Date	Maximum High Temperature	Minimum Low Temperature
December 29, 2013	-6.6	-15.7
December 30, 2013	-4.1	-15.6
December 31, 2013	-6.6	-16.5
January 1, 2014	-14.4	-19.2
January 2, 2014	-17.0	-22.5
January 3, 2014	-13.4	-22.2
January 4, 2014	-13.6	-18.9

Further detailed investigation on the B1L03 breaker was required to try and determine a cause for not tripping. ABB was contacted to provide support for the investigation. The investigation would take place at the Bishop's Falls Regional Facility.

Chronological Summary of Investigation

Monday February 3, 2014

- 08:30 we had a meeting to discuss the breaker failure to trip, sequence of events, general discussion and next steps.
- We felt we had two options. Nalcor has the capability to function test the servos; pole control boxes and interrupters on their air receiver in the shop. We could try and replicate the failure mode by testing in the shop. The other alternative was to take apart the interrupters and sub-assemblies to look for the problem. It was decided to take the interrupters and sub-assemblies apart for inspection. I felt it may be very difficult to replicate the failure in the shop with so many variables changed from the event.

- Three sets of double interrupter contacts were taken apart and inspected. A micro-ohm reading @ 100 amps was taken on each interrupter prior to dis-assembling. The chart below shows the micro-ohm readings. Some pictures are also inserted below.

Phase	Contacts	Micro-Ohm's
"B"	5 & 6	60.0
"B"	1 & 2	90.8
"C'	3 & 4	63.6

Observations:

1. Interrupter contacts showing no abnormal wear
2. Moving interrupter contacts were moving freely.
3. Micro-ohm readings acceptable.
4. The O-rings and seals showing no abnormal wear.
5. It was noted that some consumable parts and lubricants were not OEM.
6. The main and stationary contacts were lubricated with a thin film of graphite.
7. Renolit HLT2 lubricant was used on dissimilar metals.
8. Dow Corning 55 lubricant was used on static O-rings.

Stationary Contact



Moving Contact Gasket



Moving Contact Transfer Contact



Tuesday February 4, 2014

- Since nothing wrong was found on the three interrupters we decided to inspect the three servos from the breaker. Some pictures are below.

Observations

1. None of the three servos indicated any problems.
2. The parts were showing normal wear and nothing was binding.
3. Non OEM parts were found on the servos.

Servo Gasket



Servo Gasket



- The pole control boxes were the next focus for the investigation. "B" and "C" phase pole control boxes from the B1L03 were at the Bishop's Falls facility. As previously mentioned "A" phase pole control box on the B1L03 breaker was field rebuilt at Sunnyside and is installed on the breaker. "B" and "C" phase pole control boxes were dis-assembled. Prior to starting dis-assembly the trip, close and heater resistor values were recorded.

"B" phase pole control box was dis-assembled first. The table below shows the measured resistance values.

Close coil – terminals 1-2	74.1 ohms
Trip coil – terminals 3-4	11.8 ohms
Heater resistor – terminals 5-6	262 ohms

Observations

1. Lubrication with Dow Corning 55
2. The trip black piston showed signs of corrosion an indication of moisture being present at one time.
3. The housing the black trip piston fit into also showed signs of moisture being present at one time.
4. The linkages and latches for the mechanism were dirty. They did operate freely in the shop environment. In my opinion I felt the latches looked worn and I did not check the mechanism to see if it was properly adjusted. I was not aware of any field checks for the setup of the mechanism being done.
5. Some minor corrosion on parts of the control assembly possibly caused from the salt environment or sulphur from the nearby oil refinery.

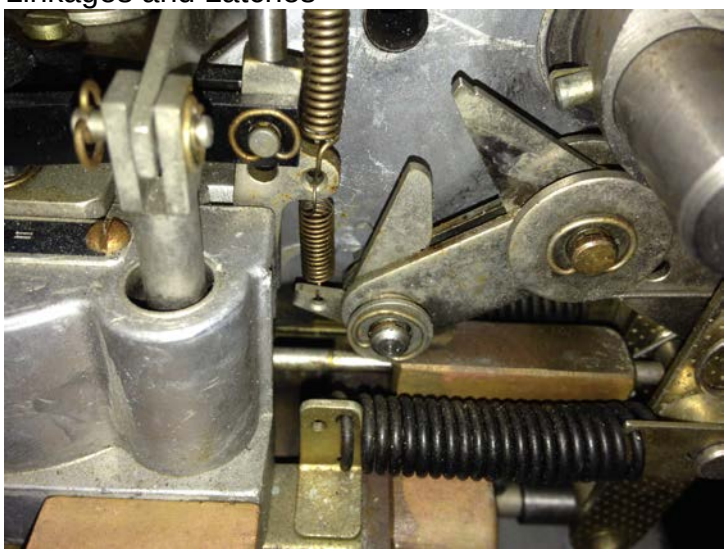
Black Trip Piston



Housing for Black Trip Piston



Linkages and Latches



Linkages and Latches



"C" phase pole control box was dis-assembled next. The table below shows the measured resistance values.

Close coil – terminals 1-2	75.2 ohms
Trip coil – terminals 3-4	11.86 ohms
Heater resistor – terminals 5-6 was not measured	Heater was removed for use on other pole control box

Observations

1. This pole control box was in the same condition as the "B" pole control box with one noticeable difference. There was a wet stain spot on the control box that could not be explained or identified. It had no noticeable smell or taste. It seemed to be some type of solvent or chemical and I found it strange it was still wet. I am not sure if this is of any significance. A picture is below. The right side, a bit darker grey, is wet.

Wet Pole Control Box



- After lunch we had a meeting to discuss the findings to date and next steps. A high level summary of the notes are below. In parallel with this, the crew continued to dismantle the remaining six interrupters and documented the findings.

Meeting Notes

1. The as found timing results on the original B1L03 breaker were very interesting. These readings were done after the event with the TR3100 Doble Timer. The readings were not recorded and are based on memory from the crew.

Close Times "A" phase – 137 ms, "B" phase – 162 ms, "C" phase – 187 ms
These close times are too long and too much delta between phases. A test from 1980 was 116.2 ms

Trip Times "A", "B" & "C" phases all about 50 ms

The trips times are a bit too long compared a test from 1980 of 41.5 ms but with good deltas.

The disagreement times were inconsistent.
"A" phase was normal and cleared at 1599 ms (probably longer since the timer cuts off at 1600 ms)
"B" phase some of the contacts went at 800 ms, 300 ms and the other contact times could not be determined because of lead issues.
The comments for the "C" phase was "not good"

2. It was discussed if P&C could confirm the breaker trip coils did receive the trip command and if so for what duration. The trip coils were all found with good resistance readings. If the trip coils received a command for a long duration the coils would burn out. This was followed up at the meeting with P&C the next day.
3. In parallel with the trip coils not receiving a trip command, the "block trip" circuit was discussed. During the testing of the replacement breaker the block trip pressure switch hung up once. It never acted up again. The block trip relay is energized under normal conditions making it failsafe. If the relay was dropped out it would have alarmed. The relay and circuit was function tested prior the breaker returning to service. Prior to the event there were no alarms at Sunnyside.
4. Another meeting was held the next day to include P&C and maintenance staff to discuss the findings to date.

- The remaining six of double interrupter contacts were taken apart and inspected. A micro-ohm reading @ 100 amps was taken on each interrupter prior to dis-assembling. The chart below shows the micro-ohm readings. The condition of these contacts was found to be the same as the first three inspected.

Phase	Contacts	Micro-Ohm's
"A"	1 & 2	72.9
"A"	3 & 4	79.8
"A'	5 & 6	82.8
"B"	3 & 4	70.3
"C"	1 & 2	69.4
"C"	5 & 6	79.8

Wednesday February 5, 2014

- A meeting with maintenance and P&C was held to review all the details. P&C provided elementary drawings for the breaker and protections. Discussion was recorded into three categories "Confident", "Uncomfortable" and "Follow Up".

Meeting Notes

Confident

- Interrupters removed from B1L03 breaker are not a problem
- The replacement parts of the B1L03 breaker are functioning properly
- Function testing confirmed protection okay
- Protection operated correctly during the event but the B1L03 breaker did not respond
- Air pressure at the B1L03 breaker was normal at the time of T1 failure

- Trip circuit – coils, 52a contacts, resistor, capacitor, control switches, blocked trip relay and "T" relay okay
- No breaker / air system anomaly alarm
- Drained valves to check for moisture
- Dewpoint @ -34 before filling breaker

Uncomfortable

- Is moisture, cold, pollution, lubrication an issue in colder weather for the mechanisms?
- Air system leaks at Sunnyside.
- B1L03 operating times from sequence of events (SOE) seem to show slow operating times. There was a very slow open on January 4, 2014 for the B1L03. This was an un-commanded event.
- Field staff indicated that the breaker would not operate pneumatically from the control cabinet after the event

Follow-up

- Overhaul / re-lube criteria moving forward
- Should the block trip pressure switch be checked or replaced since it was sticky but operated fine during function testing.
- Determine if the historical B1L03 breaker operating times match those for the in service timing to determine if the breaker was slow previous to the event.
- Function test breaker latches in cold weather to see how they perform.
- Are the breakers exercised enough?
- Follow up on the maintenance history for the other breakers that tripped okay for the event.

The forecast for that night was a low of -15 C. I decided to place four pole control boxes outside overnight and test them in the morning. Two pole control boxes were from the "B" and "C" phases of the B1L03 breaker and two were spare boxes from the shop. They had their mechanisms latched.

Thursday February 6, 2014

- The four breaker pole control boxes were tested first thing in the morning. The temperature was -16 C. The test voltage was 90 and 125 volts. P&C's D.C power supply with the current limit at maximum was used. The results were as follows.

1. Both old pole control boxes operated @ 90 volts with no problems
2. "C" phase pole control box did not unlatch @ 90 or 125 volts. The coil was picking up.
3. "B" phase pole control box did not operate the first time @ 90 volts but did unlatch on the second attempt. The mechanism did appear slow to release.

Conclusions:

- The results from the old pole control boxes were not used. It was discovered after they had close coils in the trip coil housing. It was good to see they operated okay.
- "B" phase pole control box did show indications that the mechanism could be affected by cooler temperatures.

- It was discovered after the test that "C" phase pole control box was not latched. This test was not used.
- It was decided to try these tests on the two B1L03 boxes later that day again since it was going to be cold all day.

- The next test on the two pole control boxes was done later that day. The temperature was -14 C. Both pole control boxes tripped @ 90 volts on the first attempt. The mechanisms did not appear slow as the "B" phase the first time.

Conclusions:

- The testing showed indications that the mechanisms could be affected by colder temperatures in the condition they were found. How much is difficult to determine. The exact field conditions of the pole boxes during the event could not be replicated.

- It should be noted that an inspection of the control cabinet of the B1L03 breaker was not done by me for this investigation.

Summary of Findings from the Investigation

Here is the summary of the findings for what I believe happened for this event. This is based on physical evidence from the investigation, discussion with field staff and knowledge of the circuit breaker. There are some things that happened that I can't explain but have offered my opinion and rational. Any of my assumptions are open for discussion any time.

1. I find it interesting that the maintenance records show two previous events that the breaker had operating issues.

Work Order	Date Comp.	Work Done	Investigation Comments
838346	4/8/2011	Function tests done after questionable operations during a fault.	All checked okay.
576789	3/6/2007	Breaker would not operate. Operated locally and ECC. Stayed in service	No cause found.

The temperatures during these events were not cold as the January 4, 2014 event.

2. After dis-assembling the B1L03 breaker and knowing what work was completed at site on the breaker I came to the following conclusions.

1. In my opinion all nine breaker interrupters would have tripped if initiated by the main valves. It should be noted that ABB has never used Renolit as a lubricant on the DCVF breaker and has stopped using this lubricant on other equipment.
2. The main valves on the breaker were field rebuilt at Sunnyside. Indications were that there were no issues found with the original valves. No water or ice was found. I believe that the six main valves would have operated if initiated by the servos. I also believe that if one or up to five of the six main valves did not operate a disagreement would have occurred on the breaker. No disagreement occurred. If no main valves operated a disagreement would not occur.
3. The condition of all three servo valves indicates they would have operated if initiated by their respective pole control boxes. If one or two of the servos did not operate a

disagreement would have occurred. No disagreement occurred. If none of the servos worked a disagreement would not occur.

4. "B" and "C" phase pole control boxes were last maintained in 2007. Both had dirty latches and linkages. They were lubricated with Dow Corning 55 not graphite and showed minor signs of corrosion. "B" trip piston and housing showed signs of moisture and corrosion. "C" phase pole control box had an unexplained wet stain. The cold weather trip testing indicated colder temperatures could have some affect the operation. How much of an effect cannot be determined. In my opinion I believe the pole control boxes in their as found condition should have at least unlatched when called on to trip. The performance of the pole control boxes could be improved with the proper lubrication and confirmation they are properly adjusted. The condition of the pole boxes could possibly cause slow operations.

   If all three pole control boxes were unlatched when initiated by the trip coils the breaker would have attempted a trip. I do not believe the moisture presence found in the "B" phase would prevent an attempt to trip from that pole if the linkage was unlatched. If one or two of the pole control boxes were unlatched a disagreement would have occurred. No disagreement occurred. If none of the pole control boxes unlatched no disagreement would have occurred.

   I am of the opinion that none of the pole control boxes were unlatched when the trip command was sent. Why this occurred I cannot be sure. I am having a difficult time believing that all three pole control boxes would not operate when called upon. This can be caused by an electrical and or mechanical issue.

   A mechanical issue can be caused by many factors such a cold ambient temperatures, lubrication, out of adjustment, dirty latches and linkages, mechanism exercising or moisture in the air system. All these conditions could contribute to the linkage not unlatching or being slow. The condition of the pole control boxes was not determined at the time of the event. It is possible that some of the odd timing results done on the breaker after the event were caused by slow pole control boxes. I am of the opinion that all three pole control boxes would fail not mechanically to not unlatch at least one of the linkages. This would have given a disagreement alarm which we did not receive. The question could be asked why none of the other four breakers experienced any issues. It appears to be something common with the B1L03 breaker.

   The function testing of the rebuilt breaker indicates that no electrical issues existed after the event. There is a possibility that an intermittent electrical issue could have been present prior to the event. Since maintenance records from the two previous events indicate that nothing was found this is remote possibility and a very difficult thing to find.

2. These are the other issues that were discovered during the investigation I would like to discuss.

1. Field staff indicated that the breaker could not be operated pneumatically from the control cabinet. I can provide some reasons why this may have happened.

   The pneumatic trip and close on the breakers require really firm operation to get the breaker to operate. If this was not done the breaker may not operate.

   The other possibility is that the pneumatic control was defective. I have never seen one of these defective before. I believe the condition of the pole control boxes should have allowed the breaker to be operated pneumatically.

2. Historical trip operating times from the SOE for the B1L03 appeared to indicate slow operating times. This required further analysis which was not completed when I left site. If there was no noticeable difference in operating times then this is not significant. If this

does show longer operating times it is an indication the mechanism slowing the breaker down.

3. In conjunction with the slow operating times there was an un-commanded event on January 4th after the event when staff was on site. The timing shows it looks like it went into disagreement on a trip. I can't explain this. It appears the disagreement feature on the breaker was working shortly after the event.
4. The design of the "block trip" circuit is failsafe. If the block trip relay had open circuited or not energized by the breaker pressure switch, an alarm should have been received. There were no alarms at Sunnyside prior to event.

Conclusion

I believe that the three pole control boxes on the B1L03 breakers did not unlatch when the trip command was sent during the event. I believe that the cold temperatures that the breaker was experiencing for days up to the event and the condition of the pole control boxes are factors affecting the breaker operation. The pole control boxes should have operated under these conditions but may be slow.
With all the symptoms I am seeing here I would speculate that there is an intermittent voltage issue in the common part of the trip circuit probably in the form a high resistance connection. This may explain some of the things we have seen. It could explain the two previous issues in the maintenance history. It could explain the odd timing results we saw after the event. It may also explain why the pole control boxes did not unlatch during the event. The trip coils are 11.8 ohms each all in parallel. During the event we would have had fifteen of these coils being energized. This would put a large temporary load on the station battery. If there was a high resistance connection in the trip circuit to the B1L03 breaker there would be less current available for the trip coils with the reduced voltage. The problem is probably intermittent and I also believe temperature related. This would explain why things worked okay after with no problems.

Recommendations

I cannot say I have found the root cause for this event. I am very suspicious of the possible voltage issue with the trip circuit on the B1L03 breaker. I would recommend some follow up testing on the B1L03 breaker to see if this possible problem can be found or replicated again. It would be easier to find when it is colder. I believe it is a terminal connection from the relay to the breaker or it could the D.C. knife switch for the trip close circuits in the breaker control cabinet. I have found the hinge point of similar eight pole switches with high resistance. This was very difficult to find.

In my opinion there could be some improvements made in the lubrication used on certain subassemblies and adjustment checks verified on the pole control boxes.

Power Products Service Group

Nalcor order: 20582-00 OB

ABB job number: 555605-10

Breaker ID: B1L17

Site Location: Holyrood Terminal Station

Breaker type: DLF245 nc2

Serial number: 170-73-3/1973

Mechanism type: Air Blast

Purpose for visit: Investigate “A” Phase Flashover to Ground

On site dates: 2014-01-16 to 2014-01-21

Report presented to: Mr. Hughie Ireland

SCOTT MORRIS ..... Date: January 25, 2014

Scott Morris

B1L17 Breaker Data

Type:	DLF245 nc2
Serial Number	170-73-3/1973
Continuous Current	2000 amps
Maximum Voltage	245 KV
Maximum Voltage Full Wave	1050 KV
Short Circuit Current	12.8 KA symm.
Interrupting Time	2 cycles
Frequency	60 Hz
Operating Pressure: Normal	426 psi
Lockout Pressure: Close	382 psi
Lockout Pressure: Open	370 psi
Lockout Pressure: Reclosing	400 psi
Control Voltage	125 VDC
Customer Purchase Order	15463
As Found Breaker Counter	1885 operations

Background

On January 5, 2014 an “A” phase to ground fault occurred at the Holyrood Terminal Station. The event occurred when the air break switch was being closed on the B1L17 breaker. The sequence of events information indicated the problem to be in the B1L17 breaker zone at Holyrood. It was suspected the “A” phase of the B1L17 breaker was closed when air breaker switch was closed or the breaker flashed. The B1L17 breaker did have open indication when the air breaker switch was closed.

Site inspections by field staff could not find any signs of a flash on the breaker and other equipment in the B1L17 breaker zone.

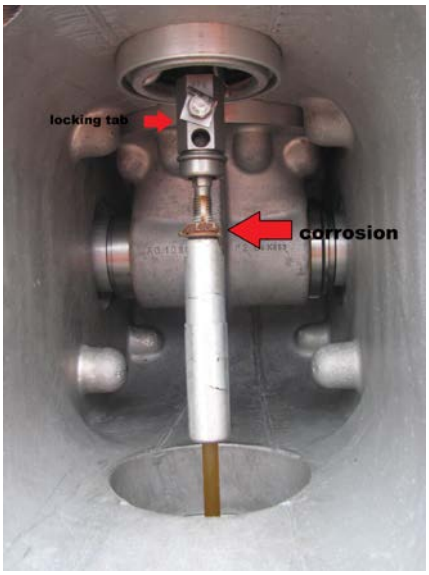
A few days after the event field staff were going establish a work permit on the breaker in the test condition. The intention was to determine if the “A” phase of the breaker was closed. Shortly after starting adding air the breaker the “A” phase interrupter developed a massive air leak. The leak was so loud it startled the worker and they rightfully, briefly exited the area. The worker made an assessment of the situation and returned to the breaker to close of the air supply to the breaker. Eventually all the air drained off the breaker and the all the poles went closed. It was never determined at this time if the “A” phase was actually closed.

Further detailed investigation on the B1L17 breaker was required. ABB was contacted to provide support for the investigation.

Chronological Summary of Investigation

Thursday January 16, 2014

- 09:30 site meeting to discuss breaker failure, sequence of events, general discussion and next steps
- The cover was removed on the “A” phase interrupter to inspect the top of the breaker control rod. The control rod was not under tension as I should be. The control rod adjustment locking tab was in place and one side was bent over the flat on the bolt. The other side of the locking tab was not bent over the hex flat of the control rod. The preferred method is to have both ends of the locking tab secured. Observed that the top nut of the control rod was corroded as shown in the picture below. It is not normal to see corrosion on an air blast breaker using dry air. At this point it was assumed the control rod was broken.



- The inspection cover on the top of the “A” phase air receiver was removed to inspect the breaker control rod drive. The control rod drive bolts were corroded. A picture is below. The control rod drive was not in the position to be expected considering the breaker was suspected of being closed and drained of air. The control rod drive was binding and not able to be moved freely. The bottom of the control rod could not be seen because of the air screen. Not much more could be learned in the tight working space. The control rod and control rod drive needed to be removed for closer inspection.



Friday January 17, 2014

- To remove the control rod the breaker drops were disconnected and the breaker gradient capacitors removed. The interrupters were rigged for lifting and removed. The control rod was disconnected from the control valve and the interrupters removed. After the interrupters were removed we learned that the control rod was not broken.
- The control rod drive was disconnected from the control rod. The control rod and control rod were removed from the breaker.
- Inspection of the control rod confirmed it was not broken. The control rod had signs of tracking near the top of the rod. It was observed that the surface of the control rod had an excessive amount of surface moisture on it considering that the control rod was just removed from a sealed breaker. There were some mechanical marks on the rod probably caused by touching parts of the insulator columns during removal and installation.
- The control rod drive was found seized to the point that it could not be moved at all. See picture below. When the control rod drive was inverted free water came out. The corrosion of the control rod drive was excessive. The screen was in bad shape. This corrosion would not be visible looking in from the bottom inspection cover of the air receiver when the control rod drive was installed.



- There is no indication at this time of a power arc occurring in the “A” phase.
- Suspicious of excessive moisture being present in the air receiver the lower air receiver inspection cover on the “A” phase air receiver was removed. An excessive amount of water was found in the bottom of the air receiver. A picture is below.



- There was discussion on how the water could have entered the breaker. Four breakers in the yard including the B1L17 had silicone put on the columns and interrupters. Two breakers were done consecutively one a time and the other two consecutively one a time too. There was a notable time difference between when the two sets of breakers were done. When this work was performed the breaker control rods were disconnected from the interrupters and left connected at the control rod drive. The control rods were supported on the unused overhead bus, covered up and sealed. It was suspected that water may have entered the B1L17 breaker at this time.
- The other two phases of the B1L17 breaker air receivers were inspected by removing the lower air receiver inspection cover. The "B" phase showed a very small amount of free water. The "C" phase had a moderate amount of water in it. A picture of the "C" phase air receiver is below.



- The next step was discussed. It was decided to check the three air receivers for moisture and one control rod drive for corrosion of another DLF breaker in the yard. The breaker selected was purposely not one of the three breakers that recently had silicone applied. We were trying to determine if the problem could be in all of the breakers.
- The B2L42 breaker was inspected by removing the bottom drain plug on the air receivers. The plugs could be easily resealed. There were no signs of moisture in the air receivers of the B2L42 breaker. The "B" phase control rod drive was inspected for signs of corrosion and showed no signs of corrosion.
- The drain plugs were removed from the B1L17 breakers allowing any water to drain out since colder temperatures were in the forecast.
- There was discussion at the end of the day what was learned so far the next steps.

Saturday January 18, 2014

- The "B" and "C" phases of the B1L17 were disassembled for inspection.
- The control rods of the "B" and "C" phases were found to be in the same condition. There were some marks on the rods that appear to be from scraping or wear. The nuts on the top of the control rod showed signs of corrosion. "C" phase showed the more corrosion compared to "B" phase which is supported by the amount of water in the poles. Pictures of each are below.





- The control rod drive on the “B” phase was tighter than normal to operate by hand. It was operable and not seized like the “A” phase.
- The control rod drive on the “C” phase was quite a bit tighter to operate than the “B” phase but again not seized like the “A” phase.
- In parallel with the B1L17 inspection two more DLF breakers were inspected for moisture in the air receivers. The breakers inspected were the B3B13 and B3L18. The two breakers had silicone installed on them about the same time. Both breakers showed no signs of free water in the air receivers. The control rod drive of the “B” phase on both breakers were inspected and showed no signs of corrosion.
- The control rod drive from the “A” phase was taken apart for inspection. The valve was very badly corroded and completely seized. It was very difficult to get apart. A couple is below.



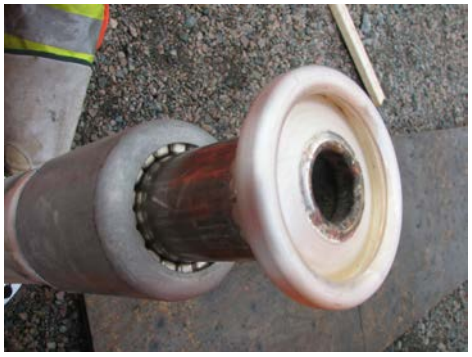
- The “B” and “C” phase control rod drives were also taken apart. Both valves came apart easily and were not seized. The “B” phase valve had some corrosion on the inside but not as bad as the “C” phase. The “C” phase was corroded worse than the “B” phase but not as bad as the “A” phase. The flange bolts on the “C” phase were starting to corrode. This supports the as found condition of the valves being worse when exposed to more water.

Saturday January 18, 2014

- The B2B12 breaker air receivers and the “C” phase control rod drive inspected. There were no signs of moisture in the air receivers and the “C” phase control rod drive showed no signs of corrosion.
- A closer inspection of the “A” phase interrupters and control valve was done.
- The control valve of “A” phase interrupter had signs of water and moisture was present. The percussion gasket showed normal signs of wear and was in good condition. The valve was overhauled about one year ago. In my opinion the control valve would operate properly if properly initiated to do so. A picture is below.



- The blast valve from the “A” phase interrupter was not inspected.
- The two moving interrupter contacts from the “A” phase were removed for inspection.
- Both the main and stationary contacts for both interrupters showed what would be considered to be normal wear. The breaker has 1885 operations. A picture of a moving contact is below.



The tube on each of the moving contacts each showed some signs of heating. I do not believe these were from the recent event. These were not fresh and could not be removed. A picture of a moving contact showing the heating is below.



The stationary contacts looked fine. The inside barrels of the porcelains were cleans and had surface moisture on them.

- I did not see any indications of fault current flowing across an open set of contacts.
- P&C Doble tested the B1L17 oil filled current transformers.
-

- The pole control boxes were inspected. Externally they looked fine. It should be noted that all the linkages in all three pole control boxes were tripped. This is an indication that the air was drained off the breaker while the breaker was open. The inside components of the pole control boxes were not inspected. Considering the age of the breaker they could be overhauled.

Summary of Findings from the Investigation

Here is the summary of the findings for what I believe happened for this event. This is based on the physical evidence from the investigation, discussion with field staff and knowledge of the circuit breaker. There are some parts of the event that I have made some assumptions and I have acknowledged these. Any of my assumptions are open for discussion any time.

1. I believe the "A" phase of the breaker was closed prior to the event happening on January 5, 2014. This begs many questions such as how this can happen and go undetected.

    1. The failure mode of the control rod drive being seized at the time would not allow the "A" pole to operate. The pole control box was operating fine and would have sent a signal to the control drive but the control rod drive would not change state. Since the control box sent its signal to the "A" phase and the other two phases opened, the phase discrepancy feature (disagreement) would be satisfied and no alarm would be received. This failure mode is not sensed by the phase discrepancy.
    2. The other reason I believe the "A" pole did not open is the control rod drive was seized so bad that it would have never been able to complete its operation and the control valve would have developed a major air leak which would have not gone undetected. The "A" phase does develop a major lead post event which will be discussed later.
    3. To support the "A" phase of the B1L17 being closed after it was tripped last I have to assume that the other breakers in the zone had tripped okay. If any of the other breakers were closed the generator would have seen reverse power protections operate from the closed "A" phase on the B1L17. After the zone trip the air break switch to the generator would have been opened. The closed "A" phase on the B1L17 would go undetected until the breaker was energized again by the air break switch. I have not obtained the information if the last trip for the B1L17 was a zone trip.
    4. I believe another factor contributing to the control rod drive not operating was it was frozen in addition to being corroded. The weather historical date from Environment Canada for the St John's airport shows very cold daytime temperatures for the first five days of January.

2. On January 5, 2014 there was an "A" phase to ground fault in the B1L17 breaker zone.

    1. There was no evidence found to locate an "A" phase to ground fault internal to breaker, external to the breaker or in the zone.
    2. Free water was discovered in all three air receivers with the most being in the "A" phase.
    3. The as found condition of the control rod drive on the "A" phase did not make sense to me. If the control rod was in that position a massive air leak would have occurred at the control valve on the interrupter. What happened approximately two days after the event I believe explains the position of the control rod drive.

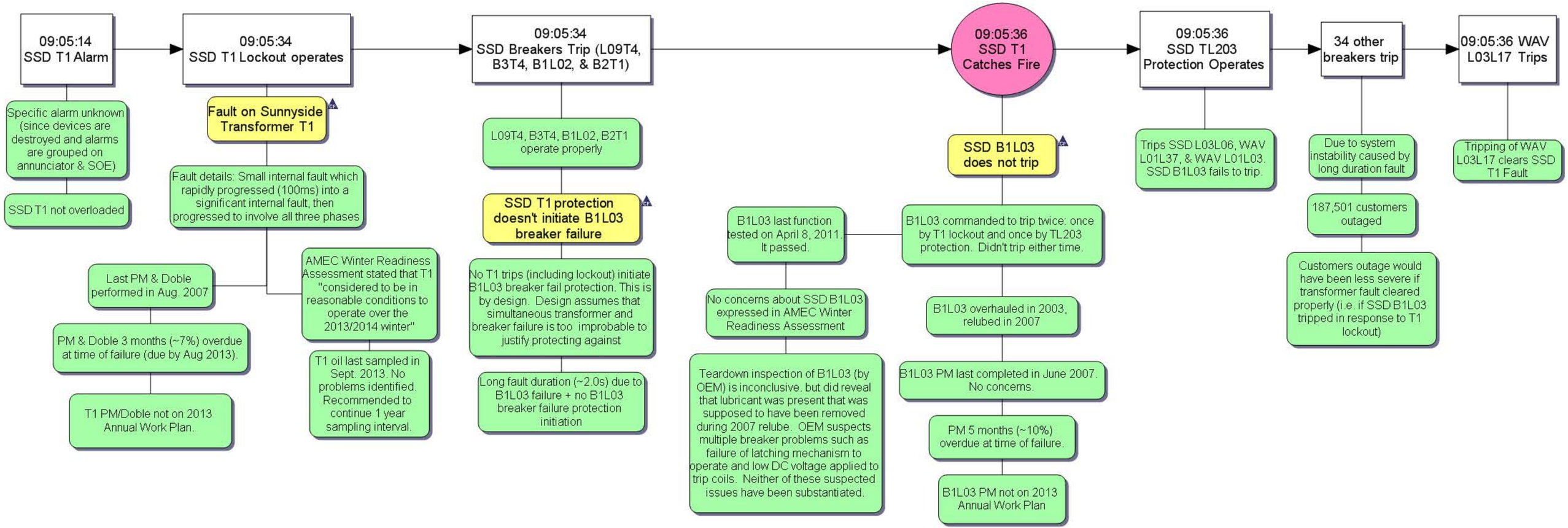
3. Approximately two days after the event when a trades administered work permit in test was being established a massive air leak developed on the “A” phase interrupter when the air pressure was being increased.

    1. I believe that the increase in air pressure caused the control rod to move on the ‘A” phase because the control rod drive had thawed enough for it to move. The weather data as mentioned above shows a high temperature of 9.6 degrees for January 7, 2014.
    2. This would explain why the control rod drive on the “A” phase was found in the position it was in.
    3. The massive air leak caused explains why all the pole control box mechanisms were found tripped. This situation occurs when the air is lost on the breaker with the breaker open. As previously mentioned the pole control box on the “A” phase would still think the breaker was open.

Conclusion

Although no “A” phase to ground path could be found it was quite clear the moisture in “A” phase air receiver was a factor causing the rod control drive to not function properly.

SUNNYSIDE T1 CATCHES FIRE



WESTERN AVALON T5 TAP CHANGER FAILURE

1/4/2014 09:05 AM
09:05:36 WAV T5 Protective Device Alarm Activates
- Occurs during SSD T1 failure.

1/4/2014 09:05 AM
09:05:36 WAV T5 Protective Device Alarm Resets
- WAV T5 de-energized due to additional breakers that tripped to clear SSD T1 fault (due to long duration).

1/4/2014 09:05 AM
09:05:38 WAV T5 Protective Device Alarm Activates

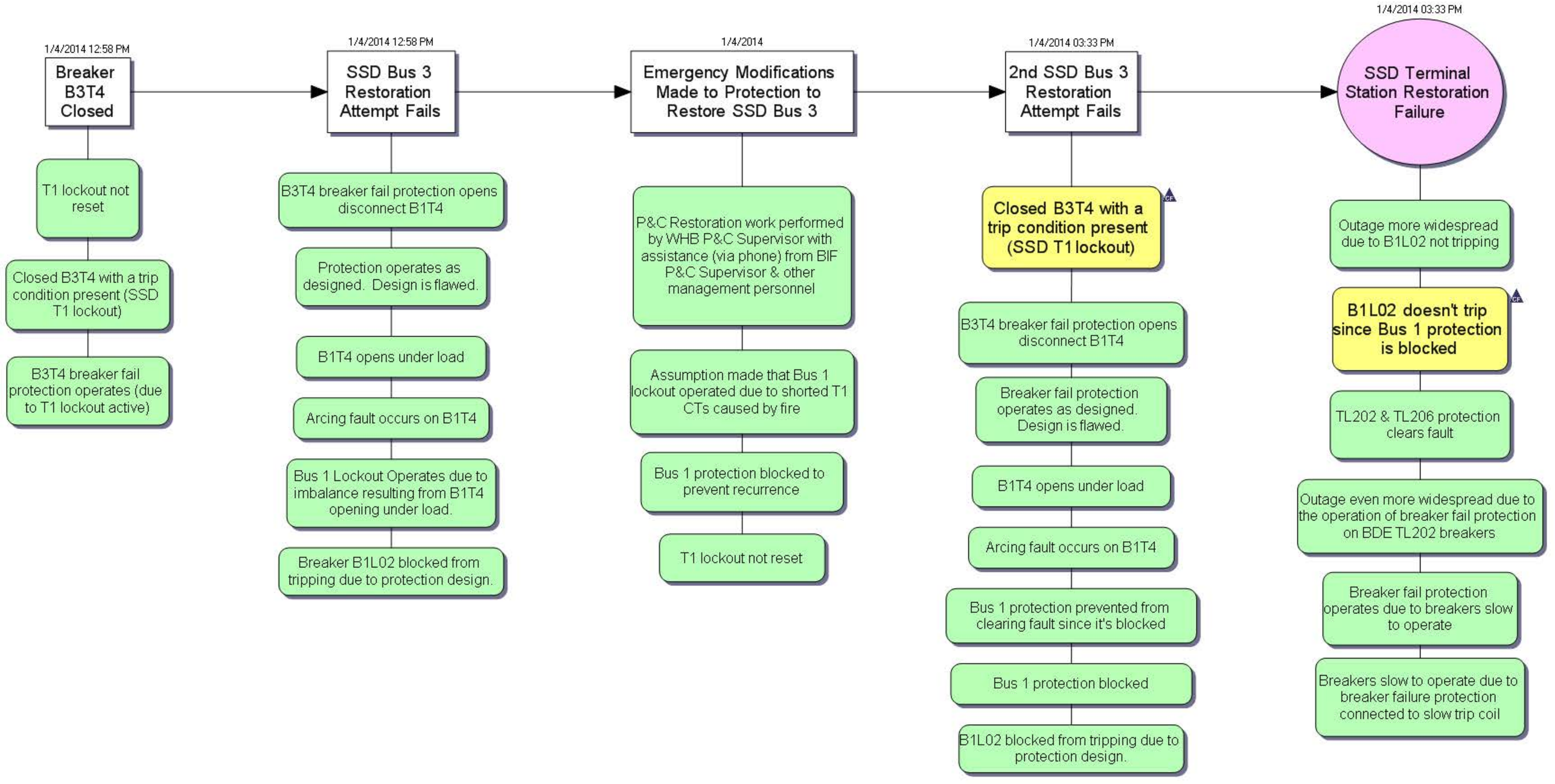
1/4/2014 09:41 AM
09:41:17 WAV T5 Protective Device Alarm Resets
- Operator Closes Breaker WAV B1L37
- WAV T5 Alarm resets, then immediately activates again
- WAV Breaker B1L37 tripped 1.1 sec after closing
- 15% overvoltage (264kV) applied to WAV T5 Phases "A" & "B" for the 1.1s (64 cycles) that B1L37 is closed
- WAV T5 tap changer phase-to-phase insulation 1 minute withstand rating is 285kV
- WAV Breaker B1L37 was not closing on Phase "C"
- Operator tries to close B1L37 two (2) more times and the same sequence of events occur.

1/4/2014 12:22 PM
12:22:15 WAV T5 Transformer Energized
- Energized via closing of WAV L01L03

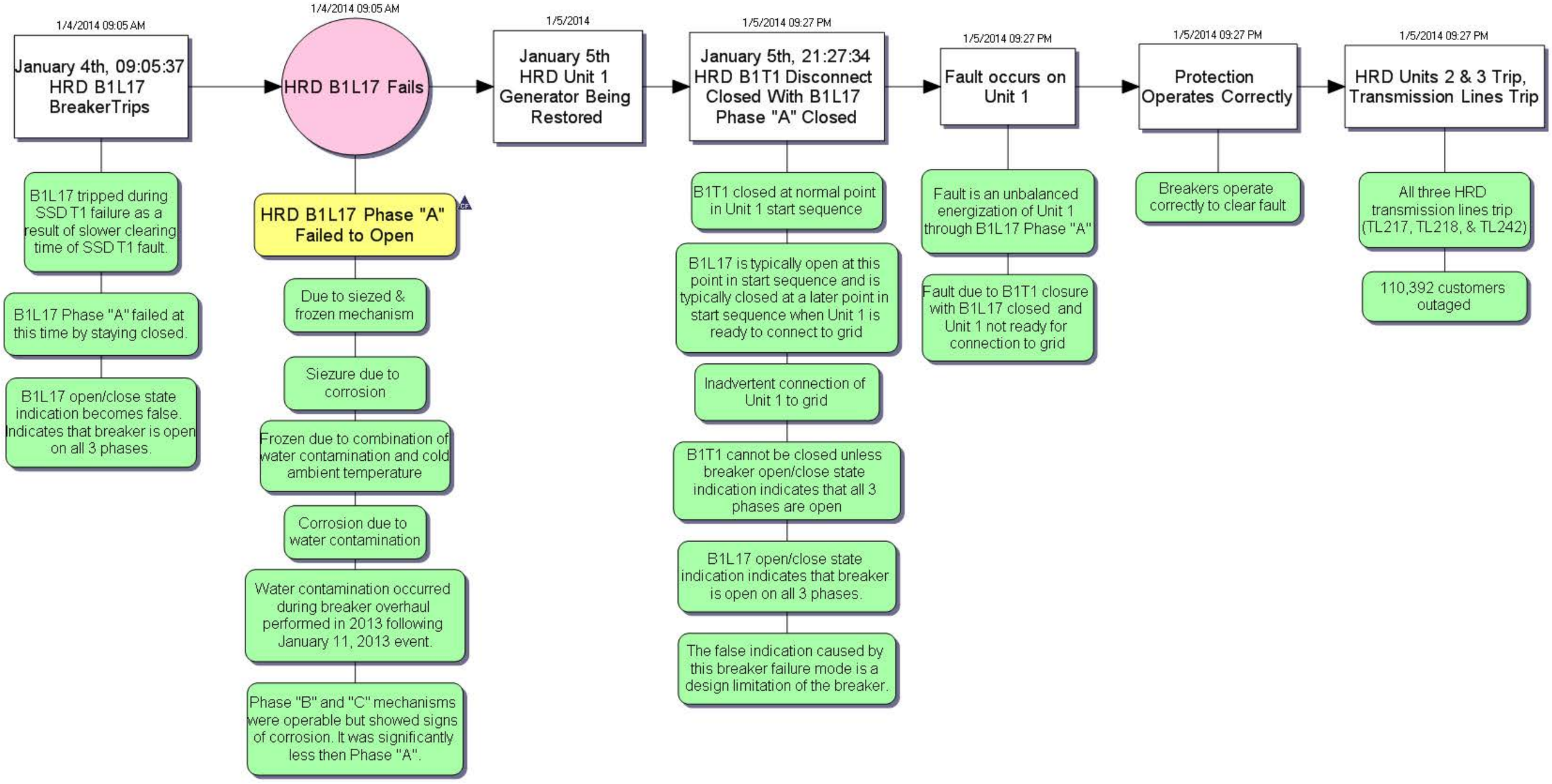
1/4/2014 12:22 PM
WAV T5 Tap Changer Failure
- Line-to-line fault on diverter switch
- WAV T5 fault pressure relay operates
- WAV T5 tap changer fault pressure relay operates

1/4/2014 12:22 PM
12:22:39 WAV T5 Lockout (86T5) Operated
- WAV Breakers B1B3 and B4B5 Operate Correctly to isolate T5
- No customer outages caused by WAV T5 failure

SUNNYSIDE BUS RESTORATION FAILURE



HOLYROOD BREAKER B1L17 FAILURE



ADDITIONAL FINDINGS AND AREAS FOR CONTINUOUS IMPROVEMENTS

In addition to the root causes and corrective actions identified via TapRooT®, several other conditions and their root causes were analyzed and recommendations made. These include areas for continuous improvement in preventative maintenance programs, safety systems, operating procedures, and systems design. Although these conditions did not directly cause the failures, their correction will improve the overall reliability of equipment and the safety of workers at Hydro.

Power Transformer Condition Assessment

Many of Hydro's transformers are original and operate reliably. The transformers reliable operation is credited in part to the current preventative maintenance program, timely corrective maintenance, and sound operating protocol. In addition, Hydro conducts on-going condition assessment of the transformers (which is performed by internal resources utilizing preventative maintenance and corrective maintenance data). An ongoing Power Transformer Upgrades capital program is in place to ensure reliable operation of the transformers over their entire lifecycle.

Finding #1: Condition Assessment Needs Continuous Improvement

The current condition assessments performed on power transformers are not comprehensive life assessments, nor do they include external validation to ensure long term plans are optimized.

Recommendation #1

Commission an engineering consultant to conduct a formal life assessment of Hydro's power transformers and use the results to revise the long-term plans for power transformer upgrades and replacements.

Station Service Transfer Switch Location

The station service transfer switch for the Sunnyside Terminal Station is located adjacent to transformer T1. This made operation of the transfer switch very difficult on January 4, due to the need to mitigate the hazards associated with personnel being in close proximity to the fire on T1. Operation of the transfer switch was needed to allow station service to be quickly restored to the Sunnyside Terminal Station.

Finding #2: Equipment Location Needs Improvement

Recommendation #2

Relocate the Sunnyside Terminal Station's station service transfer switch to the control building.

Recommendation #3

Specify in a Terminals Engineering Standard that the location of the station service transfer switch shall be in the control building in stations that have a control building, or in a location remote to the transformers for those that do not.

Recommendation #4

Review the current location of the station service transfer switches at other terminal station sites similar to Sunnyside to ensure their location is optimal.

Sunnyside Transformer T1 PM

A realignment of PMs on high voltage power transformers occurred in 2010. This caused work on some equipment to be done on a different timeframe than originally planned, meaning the PM on Sunnyside T1, originally intended for 2013, was deferred.

Finding #3: Scheduling Needs Continuous Improvements

Recommendation #5

When practical, complete PMs in accordance to normal scheduling.

Terminal Station Relay Target and Annunciator Cards

Terminal stations have relay target and annunciator cards. These cards are forms that are filled out by terminal maintenance personnel following the operation of protection. During the investigation it was discovered that some of the cards at the Sunnyside/Western Avalon/Holyrood Terminal Stations were incorrect (i.e. do not match the field devices) or unavailable, and also that some of the cards were filled out incorrectly.

Finding #4: Cards are Incorrect or Missing

Recommendation #6
Correct all incorrect cards at terminal stations.

Recommendation #7
Replace all missing cards at terminal stations.

Finding #5: Cards are Incorrectly Filled Out

Recommendation #8
Review and update Operating Instruction 002 as required to ensure relay target cards are completed in a timely manner for all system events and ensure the process for resetting devices is documented. Review the updated operating instruction with all P&C technologists and electricians.

Alarm Naming

Many of the alarms that come back to the ECC for various terminal stations throughout the system are grouped alarms (i.e. multiple devices trigger the same alarm). Some of these grouped alarms are inconsistent in naming, and in some cases, consistently named alarms are triggered by inconsistently grouped devices. These inconsistencies created problems during the investigation, including the inability to identify root causes.

Finding #6: Alarm Naming Needs Improvement

Recommendation #9
Conduct a review of the alarms that are generated from the various stations and, where practical, ensure that alarms from the various stations are consistent in their naming and triggers.

Personnel Availability

In preparation for potential system issues that may arise as a result of the storm that was forecasted for evening of January 3 and early morning of January 4, workers were asked to work on the morning of January 4. As a result of personal commitments and sickness, P&C technologists were not available to work on the day of the incident.

Finding #7: Scheduling Needs Improvement

Recommendation #10

Development of a plan for TRO and PETS personnel availability during emergency situations, which should include but not be limited to the following resources; P&C technologists, Electrical Maintenance A, Terminal Maintenance A, Mechanical Maintenance A, Lineworker A and PCC Engineering.

Sunnyside Terminal Station Air System Leaks

In 2013, a PM was conducted on the air system and identified one air leak in the Sunnyside Terminal Station. In January, while crews were working at the Sunnyside Terminal Station following the breaker B1L03 failure, two air leaks were identified on breaker B1L03 and four other leaks were identified on breakers B1L02, B3T4, L06L07 and L02L06.

Finding #8: Preventative Maintenance Needs Continuous Improvement

The annual air system leak check PM needs improvement to better detect leaks.

Recommendation #11

Conduct a review of the annual air system leak check PM to ensure that it is adequate in both scope and timing of execution to accurately identify leaks at the Sunnyside Terminal Station.

Slow Air Blast Breaker Trips

In reviewing the 100+ air blast breaker trips that occurred as a result of the incidents on January 4 and 5, there were occasions when breakers were slow to trip. The timing test in the air blast breaker PM check sheet does not state a pass/fail criteria. In addition, slow trips of breakers at Bay d'Espoir caused expansion of the outage area during an attempt to reenergize Sunnyside Terminal Station on January 4, 2014.

Finding #9: Preventative Maintenance Needs Improvement

Recommendation #12

State a specific pass/fail criteria for the timing test on the air blast breaker PM check sheet.

Recommendation #13

Check protection connections to all 230 kV breakers ABB type DCVF 245 MC6, in which trip coil No. 2 is not intended to produce the rated interrupting speed performance of the breaker. In cases where protection P2 is connected to a slow trip coil, add an additional P2 trip contact to the trip coil 1 initiation. If additional spare contacts are not available, re-direct the P2 tripping from trip coil No. 2 to trip coil No. 1.

DCF/DCVF Air Blast Breaker Re-lubrication

The task of re-lubricating DCF/DCVF breakers is usually performed in the field where weather conditions can affect the quality of the work. Maintaining a clean environment (with low moisture and free or airborne contaminants such as dirt and dust) during the re-lubrication of the breakers is important. This can become challenging when this task is performed in an outdoor environment. In addition, the work environment can have adverse effects on the quality of the work performed.

Finding# 10: Work Environment Needs Improvement (Cold/Wet)

Recommendation #14

Review the current approach to DCF/DCVF air blast breaker re-lubrication. The review should consider the environment that the lubrication is being performed in and the effects it may have on work comfort and quality control.

DCF/DCVF Air Blast Breaker Re-lubrication

In 2007, breaker B1L03 was re-lubricated to replace DOW 55 grease that was suspected to cause problems during breaker operations in low temperatures. During the inspection of breaker B1L03 in February of 2014, DOW 55 lubricant was found in the interrupters.

Finding #11: Work Execution Needs Continuous Improvement

Recommendation #15

Determine why the DOW 55 grease was not removed during the 2007 re-lubrication and implement the appropriate corrective action.

Sunnyside B1L03 Breaker PM

A realignment of PMs on high voltage breakers occurred in 2010. This caused work on some equipment to be done in a different time frame than originally planned. In result, the PM on Sunnyside B1L03, originally intended for 2013, was deferred.

Finding #12: Scheduling Needs Continuous Improvements

Recommendation #16

When practical, complete PMs in accordance to normal scheduling.

Emergency Backup Station Service Supply

The Sunnyside Terminal Station does not have an emergency backup station service supply (i.e. black start capability). Station service power is required for station equipment to operate properly. During the incidents of January 4, the Sunnyside Terminal Station was without station service power on three occasions for a total outage time of eight hours and two minutes. This both delayed restoration of power to customers, and increased the pressure on personnel to restore station service as soon as possible in order to avoid further delays to customer restoration.

Finding #13: Problem Not Anticipated

The problem that was not anticipated was that both Sunnyside T1 and Sunnyside T4 would be out of service for an extended period of time.

Recommendation #17

Conduct a risk/reward review of the requirements for additional station service

redundancy supply at all 230kV terminal stations and install backup station service supply where recommended by the review.

Breaker Failure Protection Philosophy

Hydro's protection philosophy, which includes the philosophy on breaker failure protection, isn't documented. This increases the risk of designing inconsistent protection schemes.

Finding #14: Protection Philosophy Not Documented

Recommendation #18

Document protection philosophy as a Protection and Control Engineering Standard.

Breaker Replacement Prioritization

Based on the report by ABB of the inspection of B1L03 the findings are not conclusive and point to additional issues such as: some corrosion of components, moisture contamination contributing to failure to operate correctly in low temperatures, and/or dirty linkages. Testing conducted could not repeat the failure mode of the breaker. This non-repeatability of the breaker failure mode and undependability of the breaker to operate correctly, suggests that this breaker is approaching end of life. This breaker was scheduled for replacement in 2015.

Finding #15: Scheduling Needs Continuous Improvement

Recommendation #19

Consider accelerating the replacement of air blast circuit breakers in the existing circuit breaker replacement program. Prioritization criteria of the air blast breakers should include but not be limited to condition assessment and system criticality.



Henville Consulting Inc.

NEWFOUNDLAND AND LABRADOR HYDRO

Protection Systems Impacts on 4 January 2014 Supply Disruptions
– External Protection Review

22 March, 2014

Prepared/Authored by:

Charles Henville
Principal, Henville Consulting Inc.

REGISTERED PROFESSIONAL ENGINEER
PEG
C. HENVILLE
SIGNATURE
22 Mar 2014
DATE
NEWFOUNDLAND & LABRADOR

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Table of Contents

EXECUTIVE SUMMARY 2
1 Introduction 5
2 Review process 5
3 Background 6
4 Sequence of events: relevant time frame 6
The short circuit of T1 at Sunnyside at 9:05 am on 4th February. 6
The first attempt to load T4 at Sunnyside at 12:58 on 4th January 2014 9
The second attempt to load T4 at Sunnyside at 15:33 on 4th January 2014 10
Western Avalon T5 Fault at 12:22 on 4th January 2014 12
5 Key findings and recommendations 14
Transformer protection 14
Role of protection staff during emergencies 15
Transformer breaker failure protection and tripping and isolation logic at Sunnyside 16
Protection System Initiations of Breaker trip coils 18
Protection system settings 19
6 Recommendations status 20
High priority Recommendations 20
Longer term recommendations 20
Appendix 1 22

EXECUTIVE SUMMARY

This focus area contributes the protection systems' impact on the disturbances. This portion of the review is prepared by Henville Consulting Inc, a (British Columbia) corporation specializing in the application and setting of protection systems in large power systems. Recognizing that the vast majority of investigative work has been performed by Newfoundland and Labrador Hydro internal staff, this contribution to the investigation is termed "External Protection Review". It identifies protection issues from a high level.

During the system disturbances on 4th and 5th January 2014, the transmission lines and system transformers were operating in many unusual conditions and with unusual system stress. There were some transformer faults and some slow or failed breakers. Under these conditions, there were many protection operations. Not unexpectedly, given the Newfoundland and Labrador Hydro protection systems are applied according to typical North American best practices, most of the operations were correct, desirable, and easily explained. However in some cases there were protection failures or correct operations that were undesirable. This section is an analysis of the most critical protection operations with a view to fully understanding the relationship of protection operations to the system conditions during the disturbances.

Considering that there were many tens of thousands of individual events (as recorded by sequence of events recorders) on 4th and 5th January, the External Protection Review relied heavily on information and preliminary analysis received from internal staff, specifically, Art Bursey and Alex Lau. The investigation started on 30th January 2014 through telephone discussions and email exchanges between Charles Henville and Art Bursey (Senior System Operations Engineer) and Alex Lau (Supervising Engineer, Protection). The process began with a review of draft 1 of the high level sequence of events report and (through discussion with internal staff) identification of the key protection issues that needed resolution. The investigation continued over the next several days with information exchange, leading up to three days of further analysis at Hydro Place with full access to drawings, detailed relay event records, and digital fault recorder records. Additional information was obtained from the internal review team meetings on 9th and 10th February 2014. This report was drafted during these four days.

The key findings with respect to the impact of protection systems are as follows:

1. Most protection systems responded appropriately to problems with primary equipment during the restoration process.
2. Records available from sequence of event recorders, digital fault recorders and modern

digital protection systems were key enablers to analysis of the primary system events and responses of the protection systems. However, complete analysis of some portions of the disturbance is constrained by limited information availability from several legacy protection systems.

3. On 4th January, there were several instances of breaker failures, and one instance of multiple slow breakers for the same fault. These multiple contingencies may have been related to the severe weather conditions on the day of the disturbances, or may be related to age or condition of equipment. Industry best practices do not apply and design protection systems to handle multiple independent contingencies on power systems. Notwithstanding the events on 4th January 2014, such contingencies are normally considered to be non-credible.
4. The failure of breaker B1L03 at Sunnyside substation to clear a short circuit on Sunnyside Transformer T1, combined with the lack of initiation of breaker failure protection for this type of fault led to the system breakup and initial blackout of the Avalon Peninsula area at 9:05 am.
5. A subsequent fire on T1 damaged some of the secondary wiring used for protection purposes that triggered emergency modifications to the wiring of bus B1 protection. These modifications may have impacted the ability of the 230 kV bus B1 protection to clear a 230 kV fault caused by unexpected opening of Sunnyside 230 kV disconnect switch B1T4 during system restoration. This fault had to be cleared by remote transmission (TL202 and TL206) protection systems at Bay D'Espoir (BDE).
6. One of the two remote transmission (TL202) protection systems did not work as expected and two breakers at the BDE terminal of TL202 opened slowly from the initial protection operation. These breakers plus additional breakers were opened after breaker failure protection at Bay D'Espoir operated. The breaker failure protection operations increased the amount of the system breakup, and delayed restoration.

Key protection system recommendations moving forward

1. Three high priority protection related recommendations have been made.

- **High Priority No. 1**: Check and modify where necessary, trip coil No. 2 connections to all applications on a specific 230 kV breaker type. Until this recommendation is implemented, the integrity of the transmission system may be considered at risk in the event of a transmission system short circuit with a single contingency of a protection failure.
- **High Priority No. 2:** Adjust zone 2 protection timer settings on the TL202 and TL206

terminals at Bay D'Espoir. Previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances. This recommendation has been implemented.

- **High Priority No. 3:** Identify which additional simple relay setting changes or modifications recommended in previous studies may be done in advance of planned upgrades to improve the performance of the transmission system protection. Previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances.

2. Five other recommendations deal with actions that may be considered over a longer term. These recommendations mostly involve risk versus reward or cost benefit analysis decisions, and an action plan will need to be developed to implement each of them.

- **Long Term No. 1:** Consider replacing Sunnyside T1 protection at the same time as T1 is replaced. The decision should be made to allow sufficient time to be in service with the replacement T1.
- **Long Term No. 2:** Consider including a protection technician in emergency response personnel. This recommendation should be implemented in coordination with other emergency response plans.
- **Long Term No. 3:** Review applications of breaker failure protection to ensure all transformer protection systems, initiate breaker failure protection for breakers tripped by the transformer protection. Modify where necessary. This review should be completed within one year and any necessary modifications should be completed in within two years.
- **Long Term No. 4:** Review breaker failure protection applications of all transformer protection designs at stations using the Schweitzer Engineering Laboratories type SEL-501 relay. Modify the scheme if necessary. This review should be completed within one year and any necessary modifications should be completed in within two years. This recommendation would likely be well coordinated with Recommendation LT3 above.
- **Long Term No. 5:** Develop company specific guidelines as to the basic philosophies in the application and design of breaker failure protection systems. This recommendation should be completed before protection design work for Muskrat Falls interconnection project starts.

1 INTRODUCTION

This focus area report is part of an internal report on the Newfoundland and Labrador supply disruptions on 4th January 2014. The main report references this focus area with respect to findings and recommendations concerning protection system performance.

This focus area reviews the protection systems impact on the disturbances. This portion of the review is prepared by Henville Consulting Inc, a (British Columbia) corporation specializing in the application and setting of protection systems in large power systems. Recognizing that the vast majority of investigative work has been performed by Newfoundland and Labrador Hydro internal staff, this contribution to the investigation is termed "External Protection Review". It identifies protection issues from a high level.

In general terms, Newfoundland and Labrador Hydro transmission protection practices conform to typical North American best practices. Redundant protection systems are applied to minimize catastrophic results from protection failure, and breaker failure protection systems are provided for credible single contingencies. In the case of such extreme system stress as occurred on 4th January 2014, it is difficult for protection systems to determine whether conditions should be allowed to persist, or whether automatic operation is desirable to break up the system and allow restoration in an orderly manner. This element of the investigation identifies possible need for further investigation, and revision in protection practices and/or settings in general and specific cases.

The report includes the following main sections:

- The process used to perform the review, including the scope and the gathering and analysis of information received.
- Background as to how the reviewer became involved in this review.
- Sequence of events
- Findings of the review
- Recommendations.

2 REVIEW PROCESS

After identifying the most critical events with respect to protection, the External Protection Review focussed on three events to determine whether protection operations were expected

or if not as expected, what may have gone wrong.

- The short circuit of T1 at Sunnyside at 9:05 am on 4th February.
- The initial attempt to restore power to Sunnyside 138 kV system at 12:58 on 4th January
- The second event to restore power to Sunnyside 138 kV system at 15:33 on 4th January

In addition other major events on 4th January were briefly reviewed.

The External Protection Review relied heavily on information and preliminary analysis received from internal staff, specifically, Art Bursey and Alex Lau. The investigation started on 30th January 2014 through telephone discussions and email exchanges between Charles Henville and Art Bursey and Alex Lau. The External Protection Review process began with a review of Draft 1 of the high level sequence of events report and (through discussion with internal staff) identification of the key protection issues that needed resolution. As the identification process focussed on the three areas mentioned above, the detailed sequence of events report, digital fault records, relays settings files, and relay event reports were exchanged by email and supplemented by telephone conversations to identify key protection issues. On Friday 8th February, Charles Henville started further investigation at Hydro Place using direct access to information stored in Newfoundland and Labrador Hydro files, drawings, and databases. Additional information was obtained from the internal review team meetings on 9th and 10th February, 2014. This report was drafted during 9-12 February 2014.

3 BACKGROUND

The Consultant Henville Consulting Inc. was retained to conduct this review by invitation from Newfoundland and Labrador Hydro. The scope and terms of the review are described in Henville Consulting Inc. quotation QNLH011 part of which is attached as Appendix 1

4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME

The short circuit of T1 at Sunnyside at 9:05 am on 4th February.

A short circuit occurred at 09:05:34.600 inside transformer T1 at Sunnyside. The T1 transformer shares a tripping zone with similar transformer T4; so both transformers needed to be tripped off line by the same circuit breakers. The T1 protection correctly and promptly identified the fault and issued lockout trip signal by 86T1 as shown in Figure 1. Four of the five circuit breakers that needed to open did so promptly. However, 230 kV breaker B1L03 failed to open; so the fault was supplied for an additional extended time. See Figure A1-2 for location of the failed breaker.

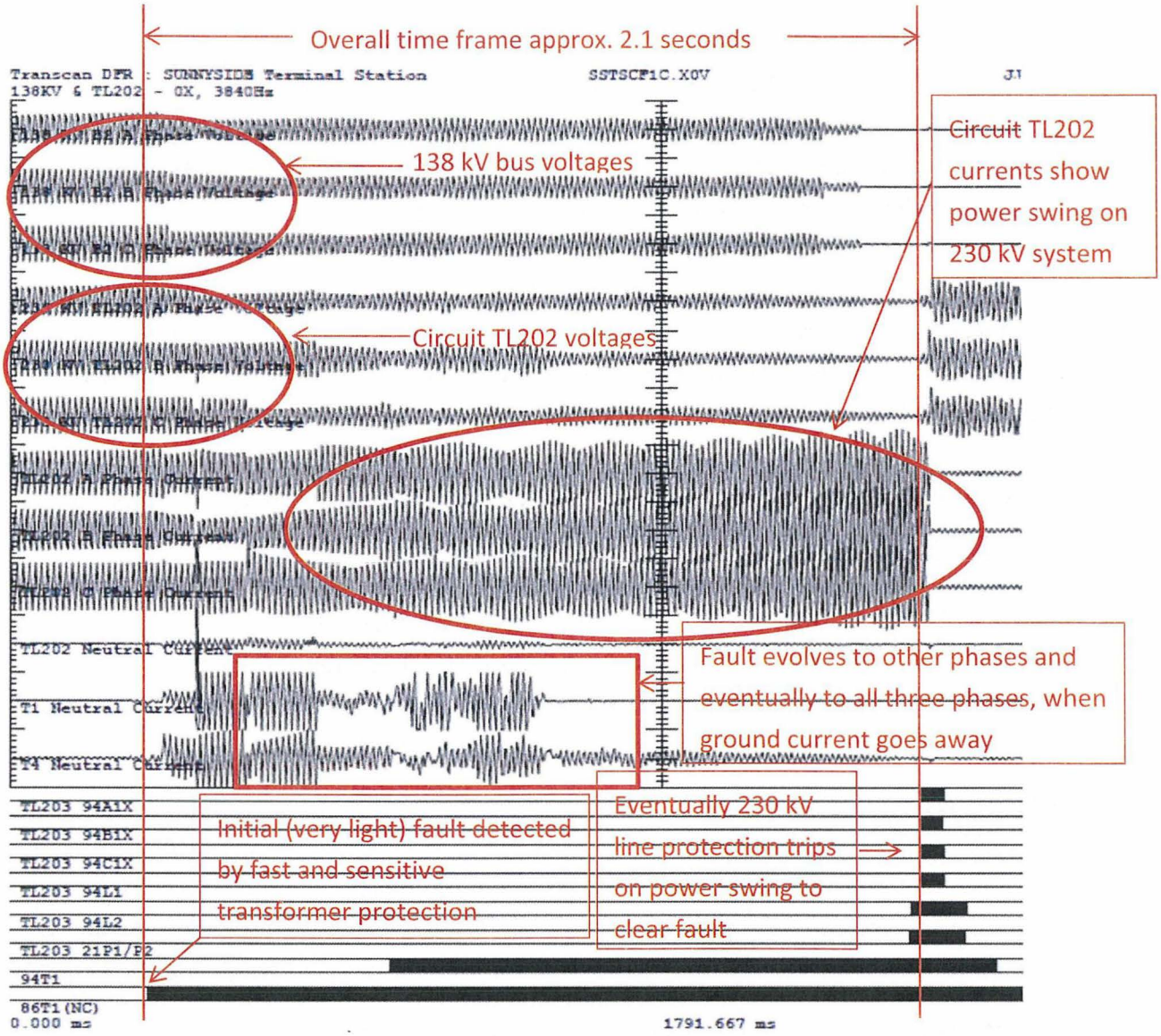


Figure A1-1 Initial (9:05) Sunnyside fault – Digital Fault Recorder Record of Currents, Voltages and Events at Sunnyside Terminal Station

The fifth breaker, B1L03 failed to open. Since clearing was delayed, the T1 fault arc evolved to other phases and eventually created a sustained three phase short circuit that caused the transformer tank to expel oil that caught fire. The extended duration of the short circuit resulted in a power swing that caused TL203 and TL237 to trip in an expected fashion. Tripping of TL203 and TL237 isolated the Avalon Peninsula from the major source of power supply and resulted in a system collapse and blackout.

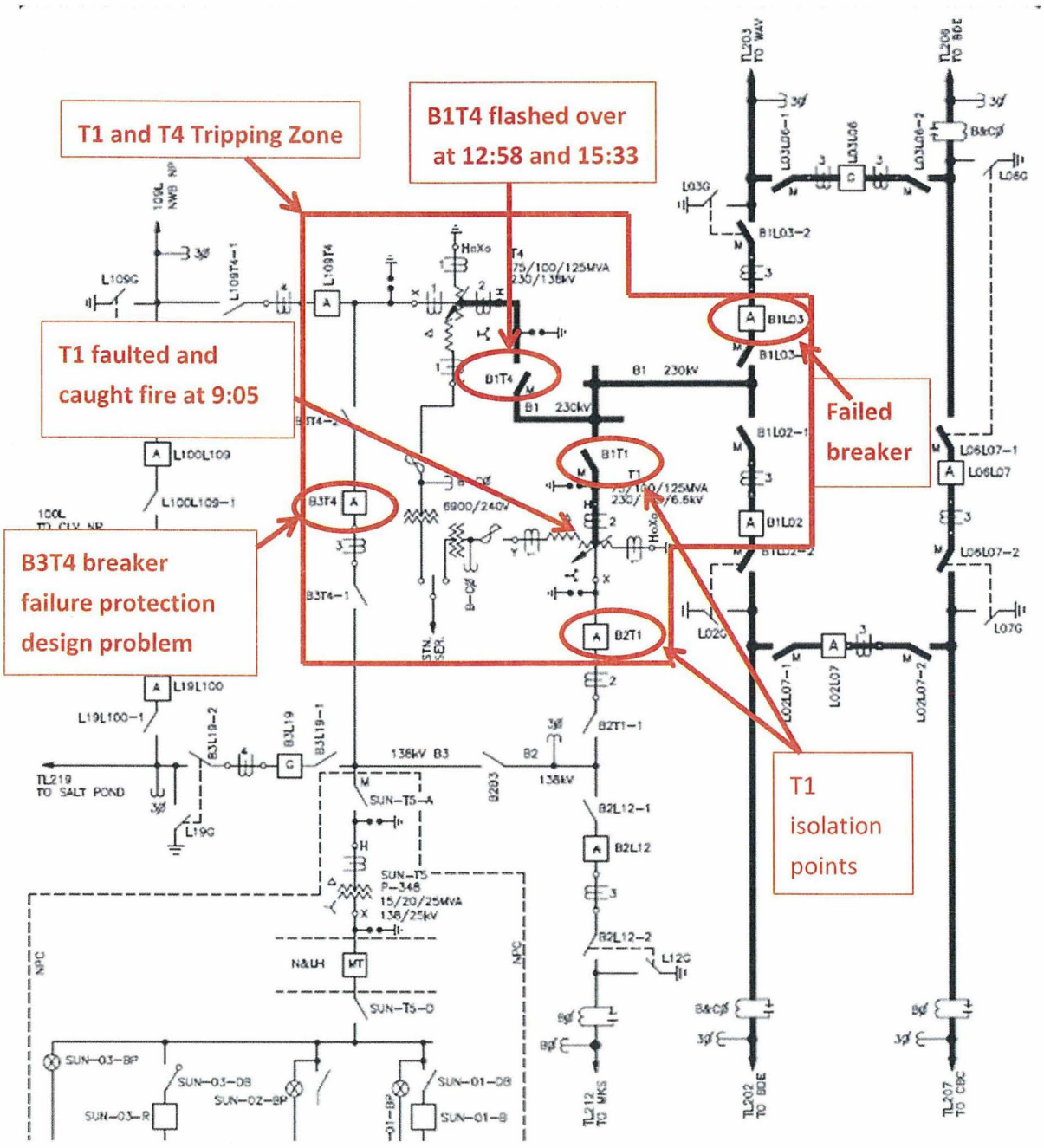


Figure A1-2 Single Line Diagram of Sunnyside Substation

The first attempt to load T4 at Sunnyside at 12:58 on 4th January 2014

At 12:58 after T1 had been electrically isolated, an attempt was made to re-energize the 138 kV side of the station. The 230 kV side was re-energized without incident at 12:56:55.000. Station service was successfully restored at that time. Immediately after 138 kV breaker B3T4 was closed at 12:58:23.928, T4 isolation switch B1T4 started to open, and within a few seconds, Sunnyside 230 kV Bus 1 was tripped by the bus differential protection. It was noticed that the CT secondary wiring on the T1 HV bushing would have been damaged by the fire; so it was disconnected by emergency field modifications. However, analysis during the later investigations showed that it was the opening of disconnect switch B1T4 (see Figure A1-2) under load that caused a fault. Since it is not designed to open under load, an arc was drawn that (approximately five seconds after the switch started to open), flashed over between B and C phases. Figure A1-3 shows the voltages and currents measured at the TL206 terminal at Bay D'Espoir during this event.

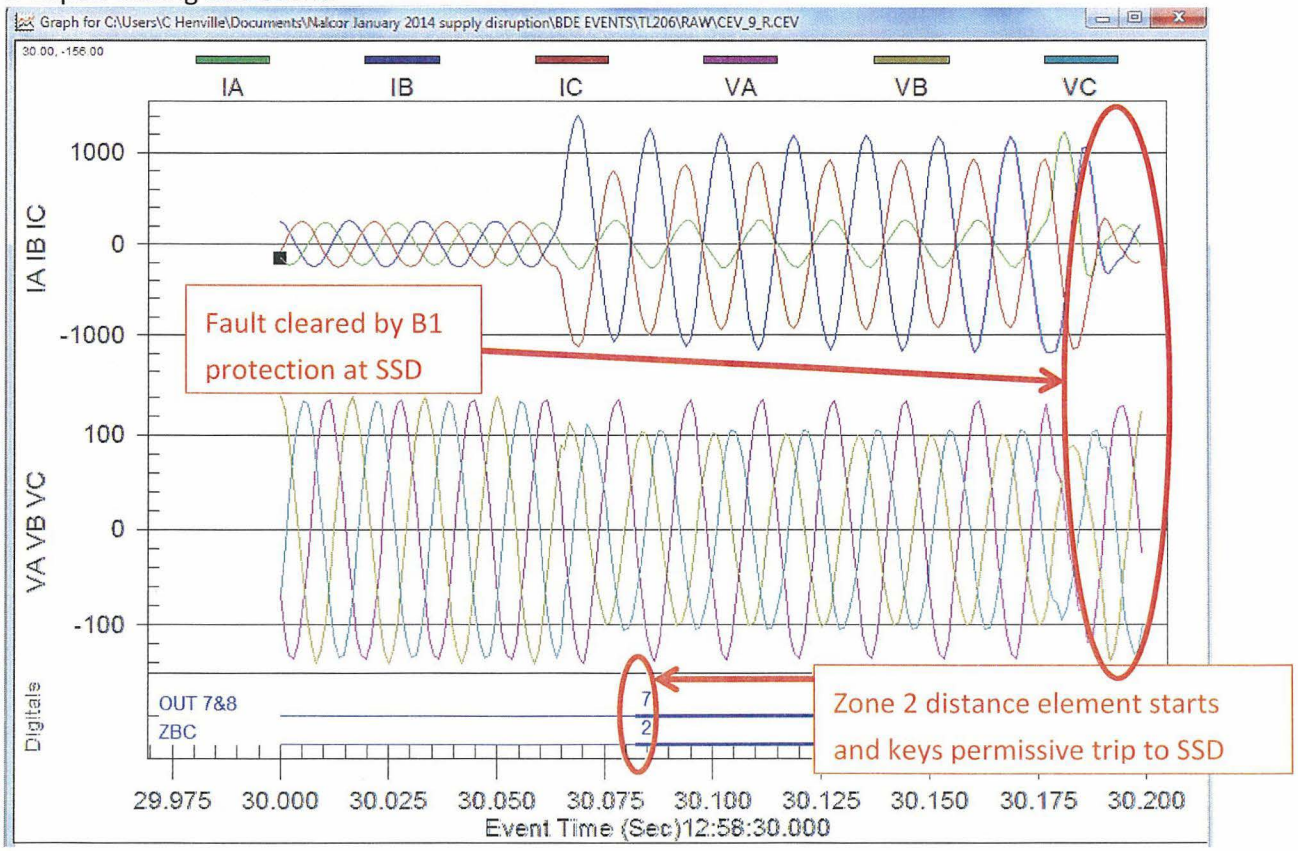


Figure A1-3 Voltages and currents at the BDE terminal of TL206 during the 12:58 event. This is the second fault at Sunnyside on 4th January

The increase in currents and depression in voltages on phases B and C can be seen. Also, the

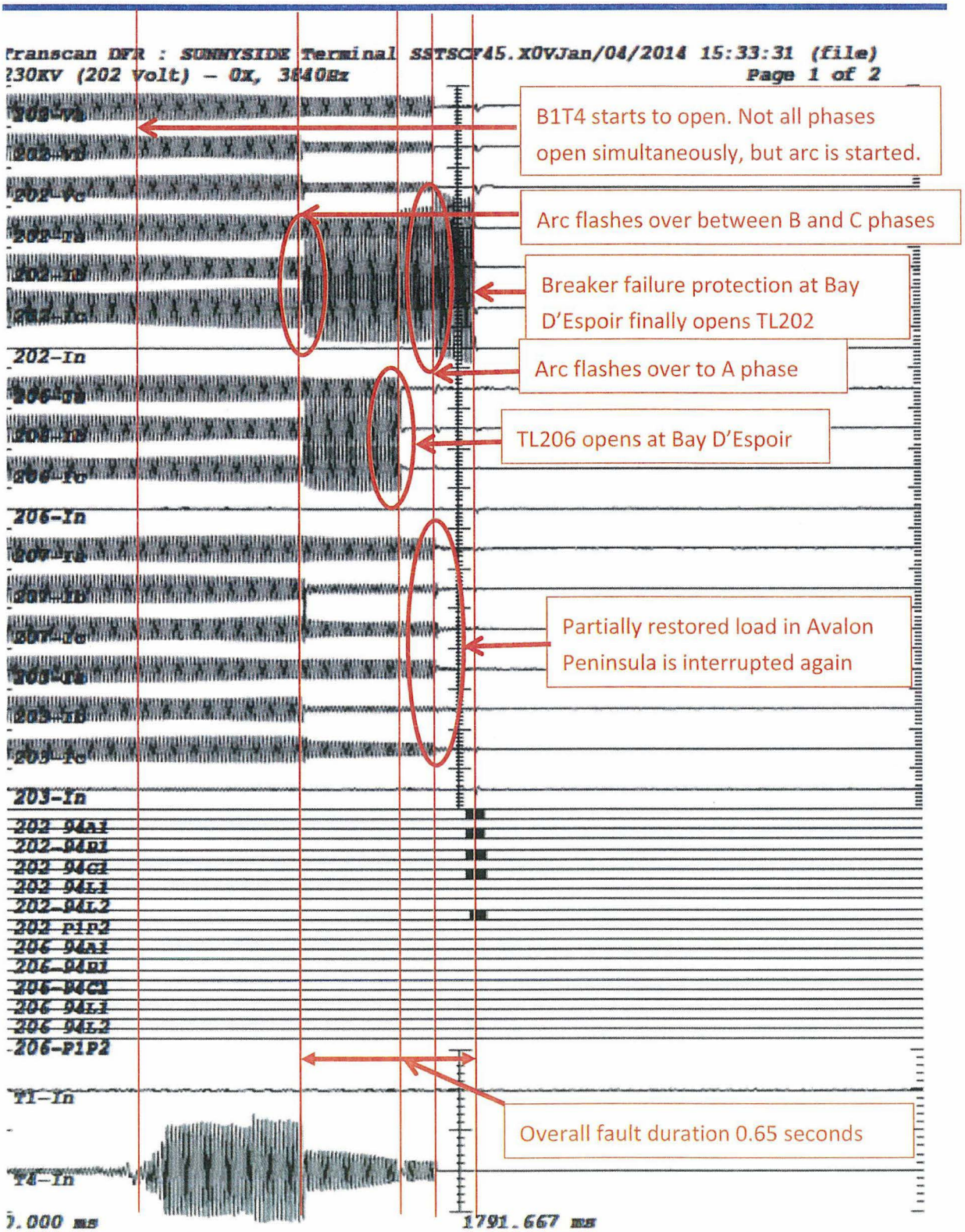
start of the phase BC zone 2 distance element can also be seen. These confirm the presence of a phase B to phase C short circuit at SSD B1 at this time.

The second attempt to load T4 at Sunnyside at 15:33 on 4th January 2014

At 15:33 on 4th January, a second attempt was made to re-energize the 138 kV bus at Sunnyside by closing breaker B3T4 to load T4. In this case the B1 bus protection did not operate, but similar to the 12:58 event, the T4 230 kV isolation disconnect switch B1T4 opened automatically under load. In this case the initial phase to phase fault evolved into a three phase fault. See Figure A1-4 for oscillographic capture of currents and voltages during this incident. The Sunnyside B1 bus protection which should have operated to clear this fault did not do so, and the fault was sustained for approximately 0.6 seconds. See Figure A1-5 for recorded currents and voltages at the Bay D'Espoir terminal of TL206 at the start of this fault.

Remote protection at the TL202 and TL206 terminals at Bay D'Espoir attempted to clear the fault by zone 2 delayed tripping after 0.3 seconds, but breakers at the TL202 terminal were slow to open and an additional delay was incurred until the breaker failure protection for both breakers timed out. The breaker failure protection eventually opened the two slow breakers plus additional breakers at Bay D'Espoir to shed additional generation and trip TL204. Tripping of TL202 and TL206 removed all remaining 230 kV supply to the Avalon Peninsula including St. John's load that had already been restored after the 9:05 incident and Come By Chance refinery.

TL206 tripped approximately 0.3 seconds after fault initiation (as expected for the zone 2 time delay). TL202 tripped approximately 0.35 seconds after TL206 due to the additional delay resulting from slow tripping, of both of its breakers, and waiting for breaker failure protection.



FigureA1-4 Third (15:33) Sunnyside fault – Digital Fault Recorder Record of Currents, Voltages and Events at Sunnyside Terminal Station

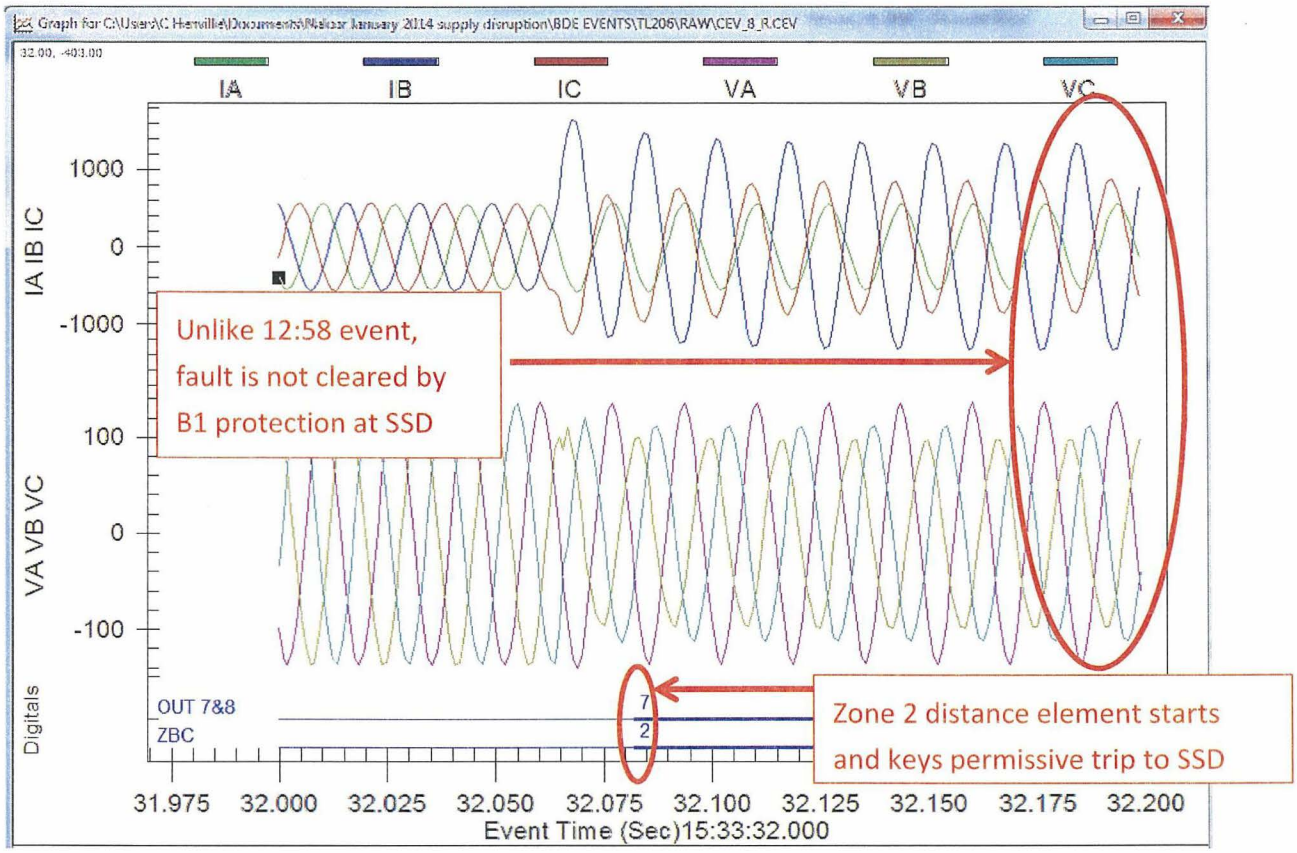


Figure A1-5 Third (15:33) Sunnyside fault – Digital Fault Recorder Record of Currents, and voltages at Bay D'Espoir Terminal of TL206

Western Avalon T5 Fault at 12:22 on 4th January 2014

The failure of Western Avalon T5 during the system restoration process had a negative impact on the restoration. Post mortem investigation of the T5 diverter switch showed evidence of arcing damage on two phases. No digital fault recorder (DFR) record of currents and voltages at Western Avalon was available for this event. The lack of a recording is attributed to a failed hard drive in the Western Avalon fault recorder. Although the recorder kept many records of events on 4th January, they were all stored in random access memory (RAM). The recorder is designed to transfer data from the RAM to a hard drive for storage and eventual retrieval. Records are retrieved by a master station at Hydro Place (once per day) and then archived on the Nalcor information systems network. In this case, with the hard drive failed, when multiple records were triggered on 4th January, the RAM filled up and stopped acquiring any more records until the data had been downloaded automatically to the master station at a much later

time.

Records retrieved from DFRs at nearby stations (Sunnyside and Holyrood) show that the T5 fault was severe, between phase A and phase B, without ground being involved, and was cleared in less than 5 cycles, which is well within expectations for the protection system. See Figure A1-6 for currents and voltages at Sunnyside during the fault at Western Avalon.

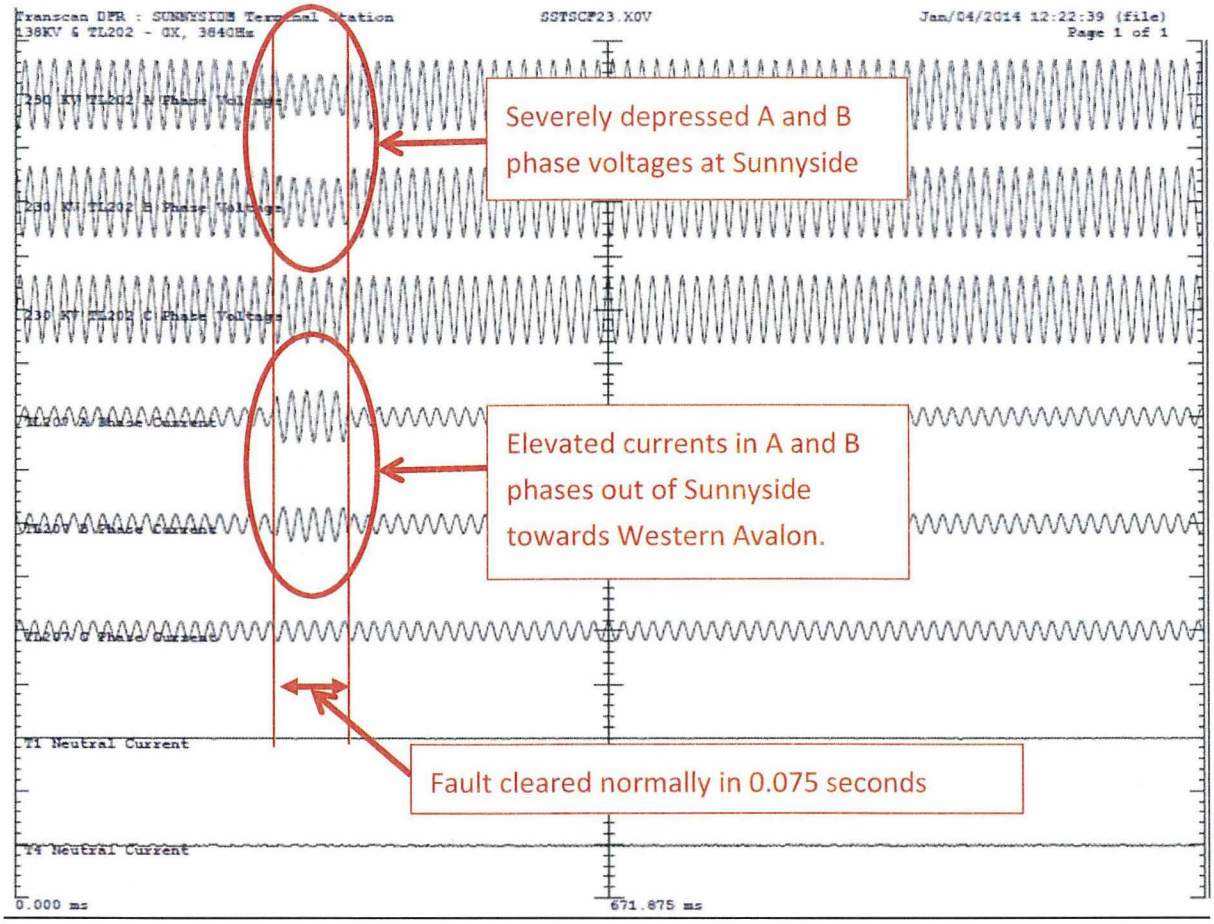


Figure A1-6 Western Avalon T5 fault (12:22) – Digital Fault Recorder Record of Currents, and voltages at Sunnyside

5 KEY FINDINGS AND RECOMMENDATIONS

Transformer protection

For the two transformers that faulted, one at Sunnyside and one at Western Avalon, the transformer protection worked well. In the case of Sunnyside the initial fault was sensed in less than 30 milliseconds, and would have had very little impact on the system if all the breakers had opened within their rated clearing time to clear the fault. In the case of Western Avalon, the protection worked properly and the breakers worked properly so the fault was cleared in less than 80 milliseconds, which is well within the expected maximum time of 100 milliseconds.

It is noted that the existing transformer protection relays for the two transformers that failed

are both electromechanical. Though they worked promptly for the two faults, they provided no more information about what happened than the targets (bright indicating flags) on their front. These targets simply indicate which device operated since the targets were last reset. They provide no information about the time when they operated. Modern computer based relays would have provided detailed sequence of events and recordings of currents and voltages during the fault to give a much richer set of information than was provided by the T1 and T4 neutral currents and lockout relay operating time as recorded by the station DFR and shown in Figure A1-1.

The key recommendation when observing the limited information available about these incidents is that the value of information obtained from modern computer based protection systems should be included in the cost benefits analysis undertaken when considering protection upgrading projects. For instance, in the case of Sunnyside T1 which will have to be replaced, it would seem an appropriate opportunity to also replace the existing transformer protection systems with modern relays at the same time to improve the information available for future events as well as to overcome the design limitations of the existing tripping and isolation logic.

Protection long term recommendation No. 1

Consider upgrading the T1 protection with modern digital protection when T1 is replaced.

Role of protection staff during emergencies

After the failed T1 had been isolated, the (still functional) circuit breakers B1L02 and B3T4 were able to be closed. At 12:58, B1L02 was closed and shortly after, B3T4 was closed. As soon as B3T4 was closed, B1T4 started to open, under load, and within a few seconds flashed over between phases B and C. B1L02 and B3T4 were immediately tripped by Bus B1 protection due to a short circuit on Bus B1 caused by the flashover at disconnect switch B1T4.

Since the T1 HV CT wires for the bus B1 protection had been damaged by the T1 fire, it was assumed that as soon as load current started to flow, the differential protection relay received incorrect information and operated the 86B1 lockout relay to de-energize B1 and T4. When this problem was assumed, emergency modifications to the wiring were made. A protection technologist who would have had experience with the process required to isolate CT wiring was not on site.

Subsequent post mortem analysis revealed that there actually had been a short circuit in the Bus B1 protection zone, and the B1 protection had in fact operated correctly for the 12:58 fault.

The fact that B1 protection failed to operate for a similar (to 12:58) fault at 15:33 confirms the probability that in addition to isolating the faulty CT wiring, the emergency modifications made the complete B1 bus protection inoperative. An inoperative B1 bus protection system contributed to the 15:33 event.

Protection long term recommendation No. 2

Consider including a protection technologist (with appropriate experience) where practical in the personnel who may respond to emergency events.

Transformer breaker failure protection and tripping and isolation logic at Sunnyside

The design of the transformer tripping and isolation scheme resulted in an arcing fault on disconnect switch B1T4 at Sunnyside during the first and second attempts to close B3T4 at that station. When B3T4 was closed at 12:58 and 15:44, the faulted transformer T1 had been isolated, but the lockout relay 86T1 had not been reset. This lockout relay is designed to provide a continuous trip signal to all circuit breakers to prevent them from closing until the transformer has been isolated. In the case of T1, the high voltage side was isolated by opening disconnect switch B1T1 shortly after the fire started. The low voltage side was isolated by circuit breaker B2T1 which had been opened automatically immediately during the T1 fault, and which had been kept open since. Failed circuit breaker B1L03 which also formed part of the tripping zone for T1 and T4 had been isolated by its disconnect switches shortly after the fire started.

T1 and T4 lockout relays are designed to trip all 5 breakers in the tripping zone shown in Figure A1-2, and maintain that tripping signal to the 230 kV breakers until after the faulted transformer has been isolated by its HV disconnect switch. Tripping of 138 kV breakers on the unfaulted transformer is also blocked if the faulted transformer has been isolated by its HV disconnect switch. However, the lockout relays initiate breaker failure protection **only** for 138 kV breakers in the tripping zone, not 230 kV breakers. The reason for not initiating breaker failure protections for the 230 kV breakers is not known, but is a key causal factor in the spread of the impact of the T1 fault beyond Sunnyside Terminal Station. The reason for initiating breaker failure protection through a different logic than initiating tripping is not clear. Newfoundland and Labrador Hydro do not have written guidelines as to the application or

design of breaker failure protection systems.

By design of the tripping scheme, tripping of 230 kV breakers B1L02 and B1L03 is blocked by the B3T4 breaker failure protection through a non conventional application of the breaker failure protection relay retrip function. Non conventional application of the breaker failure protection relay retrip function (during design) was a key causal factor of the opening of disconnect switch B1T4 under load at 15:33 and its subsequent flashover.

Conventional use of the retrip function to trip the protected breaker without delay by the breaker failure protection would also have prevented this undesirable opening of the T4 disconnect switch under load.

Since the Bus B1 protection had been rendered inoperative by the previous emergency modifications, the bus protection was unable to initiate actions to clear the flashover resulting from undesirable automatic opening of the B1T4 switch under load. Disabling of the bus protection during emergency modifications was a key causal factor in persistence of the fault on B1T4.

The fact that two transformers were in the same tripping zone resulted in unusually complex tripping and isolation schemes. However, it is recognized that in substation design there has to be consideration given to the balance between the cost of primary equipment (such as breakers) and complexity of secondary equipment (such as protection).

Protection long term recommendation No. 3

Review breaker failure protection applications on all transformer protection designs at stations similar to Sunnyside to check whether all protection systems on both sides of the transformer initiate breaker failure protection systems for all breakers in the tripping zone. Modify where this does not happen. For instance it is clear that breaker failure protection for Sunnyside B1L02 and B1L03 should be modified. This is considered to be a long term recommendation due to the low probability of simultaneous multiple contingencies (i.e., transformer fault together with breaker failure)

Protection long term recommendation No. 4

Review breaker failure protection applications of all transformer protection designs at stations using the same breaker failure relay (Schweitzer Engineering Laboratories type SEL-501). This review is intended to check whether the breaker failure protection retrip function (if applied in the SEL-501) is being used in a similar non conventional application to that at Sunnyside. If it is, modify the scheme to prevent undesirable or unexpected response from the non conventional application.

Protection long term recommendation No. 5

Develop company specific guidelines as to the basic philosophies in the application and design of breaker failure protection systems for Newfoundland and Labrador Hydro.

Protection System Initiations of Breaker trip coils

Air blast breakers ABB type DCVF 245 MC6 have a second trip coil that is not intended to trip the breaker within its rated fault interruption time. This trip coil is remote from the operating mechanism of the breaker and causes a variable trip time that may in some cases even be longer than the breaker failure timer setting of approximately 0.3 seconds.

Consistent with common industry practice, where two trip coils are provided for breakers, Newfoundland and Labrador Hydro practice is to connect protection system No. 1 to trip coil No. 1 and protection system No. 2 to trip coil No. 2. The two tripping paths are normally kept separate and not cross connected between trip coils. Modern specifications of transmission class breakers require two independent trip coils, either of which will deliver rated breaker performance.

If the breaker is a type for which Trip coil No. 2 may not produce rated performance (such as ABB type DCVF), this seriously affects the redundancy of functionally equivalent redundant protection systems that are expected for HV transmission systems. Expected performance of functionally equivalent protection systems is to provide full backup if one of the protection systems fails. In the case of trip coil No.2 not providing rated performance of the breaker, both protection systems P1 and P2 must be connected to trip the same trip coil. One or the other may also trip the No. 2 trip coil if desired, but P2 must not trip **only** the low performing No. 2 trip coil.

The reason for the seriousness of this finding is that the transmission system is planned to have severe faults cleared in six cycles or less. Functionally equivalent protection systems are applied to ensure that if one protection system fails, the other will still ensure the transmission system meets planned performance in the case of a short circuit. If one of the protections is connected to a poorly performing trip coil, and the other protection fails to operate, one or both of the following undesirable consequence will result.

a) The fault clearing time will be slower than the maximum time for which the transmission system has been planned.
b) The breaker failure protection may operate and clear a larger zone than necessary.

Protection high priority recommendation No. H1

Check protection connections to all 230 kV breakers ABB type DCVF 245 MC6 in which trip coil No. 2 is not intended to produce the rated interrupting speed performance of the breaker. In cases where protection P2 is connected to a slow trip coil, add an additional P2 trip contact to the Trip Coil 1 initiation. If additional spare contacts are not available, re-direct the P2 tripping from trip coil No. 2 to trip coil No. 1. It is recommended that this survey be initiated immediately, and modifications completed where necessary within one year.

Protection system settings

The following comments are not related to the 4th January disturbance. However, they are important for continued reliable operation of the transmission system. It was found during the 15:33 slow fault clearing event that the TL202 and TL206 zone 2 protection systems operated in 0.3 seconds. An earlier study of these protection systems had revealed that a setting of 0.6 seconds was required to coordinate with the communications independent protection on the Sunnyside terminal of TL207. With a setting of 0.3 seconds there is a risk that if the teleprotection systems fail during or before a fault on TL207 the Bay D'Espoir TL202 and TL206 protections may operate simultaneously with the Sunnyside TL207 and cause a serious disruption of supply to the Avalon Peninsula. This adjustment of zone 2 delays at Bay D'Espoir terminals of TL202 and TL206 were included in a series of recommendations regarding settings changes and other modifications from earlier studies of 230kV protection systems East of Bay D'Espoir. It seems that not all of the recommendations from these earlier studies have been implemented. Some of the recommendations were awaiting protection system replacement projects, or other projects. However it is possible that some recommendations may be best implemented independently of other projects, and in view of their importance, should be implemented without undue delay.

Protection high priority recommendation No. H2

Adjust the time delay on the Bay D'Espoir TL202 and TL206 zone 2 elements from 0.3 seconds to 0.6 seconds. Note that previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances. This adjustment has been implemented.

Protection high priority recommendation No. H3

Review the recommendations in the previous two reviews of protection systems for transmission lines protecting the 230 kV lines in the Avalon Peninsula area, and determine if there are recommendations that can be implemented easily and independently of other

projects. Note that previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances. The review should be completed and an action plan developed by 31st December 2014.

6 RECOMMENDATIONS STATUS

High priority Recommendations

H 1. Check and if necessary, modify protection connections to all ABB type DCVF 245 MC6 breakers. It is recommended that this recommendation be completed by July 30th, 2014

H 2. Adjust the zone 2 time delays on Bay D'Espoir TL202 and 206 to 0.6 seconds. This recommendation has been completed.

H 3. Review status of implementation of recommendations in previous 230 kV transmission line protection studies and develop an action plan to implement as many of the recommendations as practical. It is recommended that the action plan be developed by December 31st, 2014

Longer term recommendations

LT 1. Consider replacing Sunnyside T1 protection at the same time as T1 is replaced. The decision should be made to allow sufficient time to be in service with the replacement T1.

LT 2. Consider including a protection technician in emergency response personnel. This recommendation should be implemented in coordination with other emergency response plans.

LT 3. Review applications of breaker failure protection to ensure all transformer protection systems initiate breaker failure protection for breakers tripped by the transformer protection. Modify where necessary. This review should be completed within one year and any necessary modifications should be completed within two years.

LT 4. Review breaker failure protection applications of all transformer protection designs at stations using the Schweitzer Engineering Laboratories type SEL-501 relay. Modify the scheme if necessary. This review should be completed within one year and any necessary modifications should be completed in within two

years. This recommendation would likely be well coordinated with Recommendation LT3 above.

LT 5. Develop company specific guidelines as to the basic philosophies in the application and design of breaker failure protection systems. This recommendation should be completed before protection design work for the Muskrat Falls interconnection project starts.

APPENDIX 1

Proposal for Newfoundland and Labrador Hydro.

Review of Protection Operations on 4 and 5 January 2014

Scope of work:

Review and comment on the most critical or unexplained protection operations on 4 and 5 January 2014.

Background.

During the Newfoundland Island system disturbances on 4th and 5th January 2014, the transmission lines and system transformers were operating in many unusual conditions and with unusual system stress. There were some transformer faults and some slow or failed breakers. Under these conditions, there were many protection operations. Many of the operations were correct and easily explained, however in some cases there were protection operations that have not yet been resolved as of 24th January. It is proposed to assist Newfoundland and Labrador Hydro with analysis of the most critical or unexplained protection operations with a view to fully understanding the relationship of protection operations to the system conditions during the disturbances.

In the case of such extreme system stress, it is difficult for protection systems to determine whether conditions should be allowed to persist, or whether automatic operation is desirable to break up the system and allow restoration in an orderly manner. The proposed services will assist in identifying possible need (if any) for revision in protection practices and/or settings in general or specific cases.

The deliverables are:

1. Assistance with understanding the impact of protection operations on the system performance during the disturbances. This understanding will help determine whether the operations were correct under the circumstances and if correct, whether they were desirable or not under the circumstances.
2. If necessary, recommendations for immediate or longer term modifications to existing protection applications, systems or settings.
3. A verbal report and contribution to the TapRoot analysis meeting on 10th and 11th February 2014.
4. An optional written report to be delivered at a mutually agreeable date in March.

Proposed Approach (work items).

1. Engage in telephone discussions with appropriate NL Hydro engineers during the weeks of 27 January and 3 February.
2. Review preliminary TapRoot Analysis report when available.
3. Identify most critical and/or unexplained protection operations for analysis.
4. Obtain detailed (high resolution) sequence of fault recorder records and protection relay records for operations of highest importance. Obtain drawings and other relevant information by telephone and/or email.
5. Determine preliminary findings.
6. Travel to St. Johns on 6th February for face to face discussion with protection engineers and other staff on 7th February (possibly also 8th or 9th February) before the TapRooT meetings on 10th and 11th February.
7. Participate in TapRooT meeting in St. John's on 10th and 11th February. Provide verbal input.
8. **Optional** – prepare written report of findings if necessary.

NEWFOUNDLAND AND LABRADOR HYDRO

Emergency Response and Restoration

March 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 4
2 REVIEW PROCESS 4
3 BACKGROUND 5
4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME 6
5 KEY FINDINGS AND RECOMMENDATIONS 26

Appendices:

Appendix 1 Sequence of Events Following Sunnyside Transformer Fault
Appendix 2 Sunnyside Terminal Station Single Line
Appendix 3 Holyrood Terminal Station Single Line

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included an investigation of the rotating outages that occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014.

This report provides a detailed description of the events of January 2-8, 2014 from an emergency response and restoration perspective and is followed by key findings and recommendations.

Generally, this review shows that Hydro's personnel responded very well to the events of January 2014. While there are areas for improvement, Hydro was well prepared to address the situation and mobilized its staff effectively and efficiently to deal with the events as they unfolded.

Hydro's planning and preparation prior to the severe weather event was broad and comprehensive. When outages occurred on the morning of January 4, 2014 the local and corporate emergency response plans were utilized and crews responded immediately to the fire at Sunnyside Terminal Station (SSD TS). The safety of the employees and the public remained a top priority through response and restoration activities. The fire was evaluated from a safety and an environmental perspective and a plan was established to manage the situation. In addition to managing the fire, crews also focused on restoring customer power. This involved reconfiguring the station service and re-energizing SSD TS and completing manual switching at various other terminal stations to restore the transmission system. Pre-deployment of staff to plants resulted in fast manual intervention to bring units back in-service,

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

where necessary. A second major disturbance in the afternoon of January 4, 2014 was quickly resolved and the transmission system restored promptly.

Once the transmission system was restored, Units 2 and 3 at the Holyrood Thermal Generating Station were brought back in-service. Unit 1 was delayed due to temporary vibration issues which were investigated and resolved during the incident with the assistance of Alstom, the turbine service contractor.

There was a third major customer disturbance on the evening of January 5, 2014 when attempting to synchronize Holyrood Unit 1 to the system. There was a flash in the Holyrood Terminal Station (Holyrood TS) and all three Holyrood units tripped. Units 2 and 3 were restored early in the morning of January 6, 2014. Additional staff from the Bishop's Falls Office were deployed to relieve and assist local crews on the Avalon. Through a planned and carefully executed investigation the problem was isolated to a failed breaker in the Holyrood TS. This resulted in a safe and uneventful restoration of Holyrood Unit 1 in the afternoon of January 8, 2014 and all customers were restored shortly thereafter.

Based on the findings of this review, the following recommendations are made.

1 Emergency Preparedness

ERR1: Update Severe Weather Preparedness protocol and checklist to capture lessons learned from previous responses and best practices from other utilities.

2 Emergency Response

ERR2: Update emergency response plans with lessons learned from the January 4, 2014 transformer fire and emergency response, including specified methods for dealing with major transformer fires.

ERR3: PCB contents of all oil-filled transformers and equipment should be available in hard copy locally and an alternate location.

3 System Restoration

ERR4: Assess the need and options for additional station service supply for terminal stations in the event of loss of normal supply.

ERR5: Complete lighting improvement plan for the Holyrood plant in 2014.

1 INTRODUCTION

Hydro has completed an internal review of the supply disruptions on the Island Interconnected System for the period January 2 to 8, 2014. This particular report focuses on emergency response and restoration and covers the following areas:

1. Emergency Preparedness;
2. Emergency Response; and
3. System Restoration.

This report reviews how Hydro's emergency response plans were deployed and how decisions were made during the significant equipment outage events. It also looks at how safety and environmental concerns were handled and the effectiveness of Hydro's restoration efforts during challenging times.

2 REVIEW PROCESS

The internal review process was initiated by holding lessons-learned sessions with staff involved in the pre-event preparation, response, and restoration activities during the January 2-8, 2014 supply disruptions. The purpose of the exercise was to review the events to identify things that Hydro did well, in addition to areas to be considered for improvement.

The team also analyzed the sequence of events and emergency preparedness plans. Interviews were conducted with technical and operations personnel to gather additional insights and feedback.

The results of the reviews are mapped out in the Findings and Recommendations section of this report. Immediate concerns were addressed and, where appropriate, implementation status is being documented for longer-term items.

3 BACKGROUND

Hydro has a multifaceted approach to emergency response including corporate emergency response plans and local emergency response plans. Within Hydro, each local area as required, has an Emergency Response Plan (ERP) that describes the roles and responsibilities of personnel involved as they may relate to the various types of emergencies that may occur. A Corporate Emergency Response Plan (CERP) is also in place, which assigns specific responsibilities to individuals within Nalcor Energy's corporate management structure, as needed, during any emergency that may occur (safety, technical, logistic, finance/procurement, employee/family support, environmental, regulatory liaison, media relations, etc.). Within the CERP there are provisions to establish a Corporate Emergency Operations Center (CEOC) at Hydro Place to co-ordinate corporate emergency response activities and support the local response team.

Hydro operates under its documented emergency response plans. These plans include:

1. Local emergency and environmental emergency response plans;
2. Emergency Plans for Generation and Transmission and Rural Operations; and
3. Corporate Emergency Response Plan.

These plans are exercised and regularly reviewed as a function of the requirements of each particular plan.

In addition to a corporate emergency response, Hydro has local on-call[2] personnel, system on-call[3] personnel and an executive on-call[4] (EOC) at all times. These supervisors will co-ordinate response activities to any system or emergency event.

[2] Local On-Call System – Outside of normal operating hours, there is always one person on-call for each division within Hydro. Customer and systems events are channeled through this person from ECC, who then arranges for the dispatch of appropriate response.

[3] System On-Call System – Outside of normal operating hours, there is a manager responsible for coordinating response to broader system issues including generation and transmission system problems.

[4] Executive On-Call System – Outside of normal operating hours, there is an executive member responsible for providing corporate support and determining whether an issue warrants activation of the CERP.

One of the responsibilities of the system on-call person is to contact the EOC and provide information regarding the nature of the incident. The EOC has the authority to activate the CERP and mobilize the CEOC team in full, or in part.

4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME

This section provides an overview of the emergency response and restoration efforts that occurred leading up to and during the outages to the Hydro electrical system during the period January 2 to 8, 2014. It documents a timeline of events and highlights the major incidents and response activities, including:

1. Emergency Preparedness;
2. Emergency Response; and
3. System Restoration.

A more detailed sequence of events is contained in Appendix 1 (Sequence of Events Following Sunnyside Transformer Fault on January 4, 2014).

4.1 Emergency Preparedness

At approximately 09:00 on Friday, January 3, 2014, Hydro's System Operations issued a severe weather warning notice to regional and plant managers for Saturday, January 4. Once the notification had been sent out, System Operations followed up with field operations staff to discuss the need for additional preparations for the pending weather. As part of standing practice, field staff made further coordination calls to secure the resources and vehicles to be on standby and/or report to specific sites.

As well, at 11:00 on January 3, 2014 there was a conference call between senior management, System Operations, Engineering, Transmission and Rural Operations (TRO), Hydro Generation, Corporate Communications and Holyrood Generation. The purpose of this call was to confirm that all groups were aware of the system status and to finalize co-ordinated efforts to respond to the pending severe winter weather. During this call, emphasis was placed on the need to

maintain the continuity of the existing generation infrastructure, and to ensure prompt response to any system issues in order to minimize customer impact.

Hydro deployed work crews in advance of the forecasted severe weather for January 4, 2014 as follows:

- Hydro Generation dispatched resources to various remote plants in preparation of the forecasted storm on January 4, 2014. This included stationing two operators at the Cat Arm plant and one operator and one protection and control technologist at the Granite Canal plant in advance of the storm to avoid potential travel issues during unfavorable weather conditions;
- Holyrood Generation arranged for two electricians and one extra operator to report to work to complement existing staff. As well, an early shift change was arranged in preparation for the pending storm. In addition, Newfoundland Power arranged for staff to operate the gas turbine on January 4, 2014;
- In TRO, it was decided that resources would report to terminal stations on the Avalon Peninsula the following morning. The deployment of resources had one individual covering Sunnyside and Come By Chance, one individual covering Western Avalon, one individual covering Holyrood, and another covering Hardwoods and Oxen Pond terminal stations. In addition, a transmission line crew and an administration officer reported to the Whitbourne office; and
- Hydro's gas turbine generation capacity was not fully available during this period. The Hardwoods and Stephenville gas turbines were either unavailable or de-rated during the January 2014 incident. Hydro secured operators and maintainers around the clock at the Stephenville gas turbine to ensure quick response in the event the gas turbine tripped and had to be restarted. Extra resources were arranged to ensure fuel deliveries for the Stephenville gas turbine, as it was expected to require additional fuel deliveries due to high operational requirements to meet high power system demands.

Hydro completed additional inspections as follows:

- Staff ensured there was full functionality and fuel tanks were full for necessary equipment and vehicles. Having full fuel tanks and fully operational vehicles and equipment ensures no delay in crew mobilization should the need arise; and
- At Holyrood, on-site emergency equipment was checked, operating procedures were reviewed for start-up and shutdown in the event of a power trip, and fuel was ordered to ensure adequate supply for the Newfoundland Power mobile gas turbine located near the plant. The black start plan was discussed with Hydro's Energy Control Centre (ECC).

Hydro arranged extra snow clearing as follows:

- Clearing of Upper Salmon Road to ensure access to Upper Salmon Generating Station;
- Clearing and extra sanding of Hinds Lake Road to ensure access to Hinds Lake Generating Station;
- Request to the City of St. John's to maintain access to Captain Whelan Drive as a priority, to ensure access to Hydro Place;
- Clearing of the main access road to Holyrood Thermal Generating Station and switchyard; and
- Clearing to access the Stephenville gas turbine.

4.2 Emergency Response

On January 4, 2014 at 09:05, Hydro experienced a fault on transformer T1 at the SSD TS, which resulted in a transformer fire. The ECC received several alarms related to breakers and equipment in the SSD TS. One of the breakers in the SSD TS failed to open properly, which created a chain of events resulting in the opening of many other system breakers and the automatic shutdown of generation units on the island power grid. This created an outage mainly in the Burin and Avalon peninsulas. Please refer to Appendix 1 for a more detailed breakdown of the exact sequence of events involving equipment operation.

The advanced deployment of a crew to the SSD TS meant that staff witnessed the catastrophic failure of the transformer (SSD T1) and could expedite response efforts. As per Hydro's local fire response plan, the crew immediately requested emergency support from the local fire department. The Come By Chance fire department responded and arrived at the terminal station shortly after they were notified. Prior to the supervisor arriving on site, the lead hand of the crew took charge and initiated discussions with the fire department. The local crew called ECC and Hydro started mobilizing additional internal resources to assist. Faced with extreme cold temperatures and high winds, the crew then secured the scene for public safety and minimal crew interface. The local on-call person and system on-call person were notified and updated of the situation. The system on-call person notified the EOC who immediately began the mobilization of key resources to the CEOC located in Hydro Place. At approximately 11:00, these resources were in the CEOC representing various corporate functional departments including, System Operations, Supply Chain, Safety, Engineering, Environment, and Corporate Relations. These individuals were available to provide support to the local operational areas and the responding crews if required.

In addition to the corporate support, there was mobilization of additional resources to the Bishop's Falls office to provide support to crews in the field; including senior management, TRO technical support, a safety and environment coordinator, and operations staff.

When the terminals supervisor arrived at SSD TS at approximately 10:30, the crew, terminals supervisor, and the local fire department further assessed the scene and began to formulate an approach forward. Also, the SSD TS was without power due to the both transformers T1 and T4 being out of service.[5]

Immediate areas of focus at that time included:

- The safety of the employees and public;
- Conducting a preliminary assessment of the environmental damage;

[5] The station service power supply is connected to T1 and T4 transformers tertiary windings via transfer switch.

- Conducting an assessment of other potential terminal station equipment damage;
- Achieving SSD T1 transformer isolation and SSD T4 capability to be placed in service to restore service to customers;
- Evaluating options to immediately restore station service. Note that station service is required to provide power to auxiliary equipment and facilities, such as air compressors, control circuitry, battery chargers, and control buildings;
- Evaluation of T1 fire and firefighting plans; and
- Environmental response, due to oil leaks and air emissions.

<u>The safety of the employees and public</u>

The supervisor met with local fire officials and discussed the transformer fire situation and the immediate concern for employee and public safety. The supervisor then consulted with operations support in the Bishop's Falls office, including the TRO safety and environment co-ordinator.

During this initial consultation, it was agreed that there were no immediate public safety concerns because of wind direction, and no immediate threat of the fire spreading to additional areas in the terminal station. Employees at the site followed appropriate safety precautions, such as keeping a safe distance and upwind from the burning transformer fire. The local fire department monitored the situation and performed crowd control.

The exact PCB concentration level in the transformer oil, and the six transformer bushings was unknown. It was agreed to treat the transformer fire as a PCB fire until otherwise confirmed. In order to start restoring power to SSD TS and to facilitate firefighting efforts, SD T1 had to be electrically isolated from the rest of the yard equipment. Utilizing Work Protection methods, SD T1 was safely isolated.

<u>Preliminary assessment of the environmental damage</u>

Once the site was secured, Hydro's environment officials were notified as well as the Canadian

Coast Guard (CCG). The CCG was contacted because of the oil spill as per Hydro`s Environmental Emergency Response Plans.

Initial assessment of the environmental impact showed that there was significant transformer oil sprayed on other terminal station equipment and on the snow covered ground as a result of the initial failure. In particular, there was visible oil on the 138 kV Bus 2 insulators and Bus 2 potential transformers. This would eventually require further testing and cleaning before Bus 2 could be re-energized, but did not impair restoration of service to customers. It was noted that the transformer body was intact and no further oil was being released into the environment. Remediation of the soil around the transformer was not possible due to the active fire on SSD T1. This was further discussed after the SSD T1 fire was extinguished on January 7, 2014. See the upcoming section on "Environmental Response" for details.

<u>Other potential terminal station equipment damage</u>

Station equipment of immediate concern and assessed for damage and contamination:

- 230 kV Disconnect Switch (B1T1): contaminated, deemed operable;
- 230 kV Bus Insulators (Bus 1): contaminated, deemed operable;
- 138kV Air Blast Breaker (B2T1): contaminated;
- 138 kV Bus Insulators (Bus 2): inoperable; and
- 138 kV Potential Transformers on Bus 2: inoperable.

Please refer to Appendix 2 for a single line diagram for SSD TS equipment arrangement.

<u>SSD T1 transformer isolation and SSD T4 restoration</u>

Even though B1T1 Disconnect Switch was contaminated, it was deemed safe to use as an isolation point for SSD T1 on the 230kV high voltage side. In addition, 138 kV Disconnect Switch B2T1-1 was also examined by the crew and was deemed safe to use as an isolation point on the 138kV low voltage side of SSD T1. With these two disconnects opened, SSD T1 was successfully

isolated electrically from Bus B2 and Bus B1 by the crew at approximately 12:00 on January 4, 2014.

The insulators on Bus B1 side, however, had to be monitored once power was restored because of the contamination. To facilitate this, it was decided that the station would be staffed 24-hours a day during the days following the event to monitor the fire and also be available to respond quickly in the event any issues occurred with the insulators and other equipment in the yard.

With SSD T1 isolated, the plan was to restore SSD Bus 1 and energize SSD T4 to restore power to the Burin Peninsula and local area. Through consultation with technical support staff, a review of TRO's emergency plans indicated that, "All transformers within the Stony Brook-Sunnyside Loop have the same rating and can withstand the loss of one unit". This meant that SSD T4 could meet load requirements without SSD T1 in service. This redundancy enabled Hydro to restore customers via SSD T4 and facilitate the supply of station service for the terminal station by manually switching the transfer switch.

<u>Evaluate options to immediately restore station service</u>

With the failure of SSD T1, the station service supply to the station controls was interrupted. The restoration of station service was very important to maintain air supply to air blast circuit breakers. Air blast circuit breakers use compressed air to actuate head mechanisms and extinguish arc in order to interrupt electrical circuits when required. Therefore, the crew established a priority to connect station service through an alternate feed.

It was decided to switch the station service to SSD T4 manually (no automatic transfer switch system) to gain station service supply when SSD T4 was energized. To maintain redundancy, it was decided that a second alternate supply would also be acquired through the means of a portable generator in the event that station service could not be achieved through SSD T4. A portable generator was rented and arranged to be shipped to SSD TS as soon as possible.

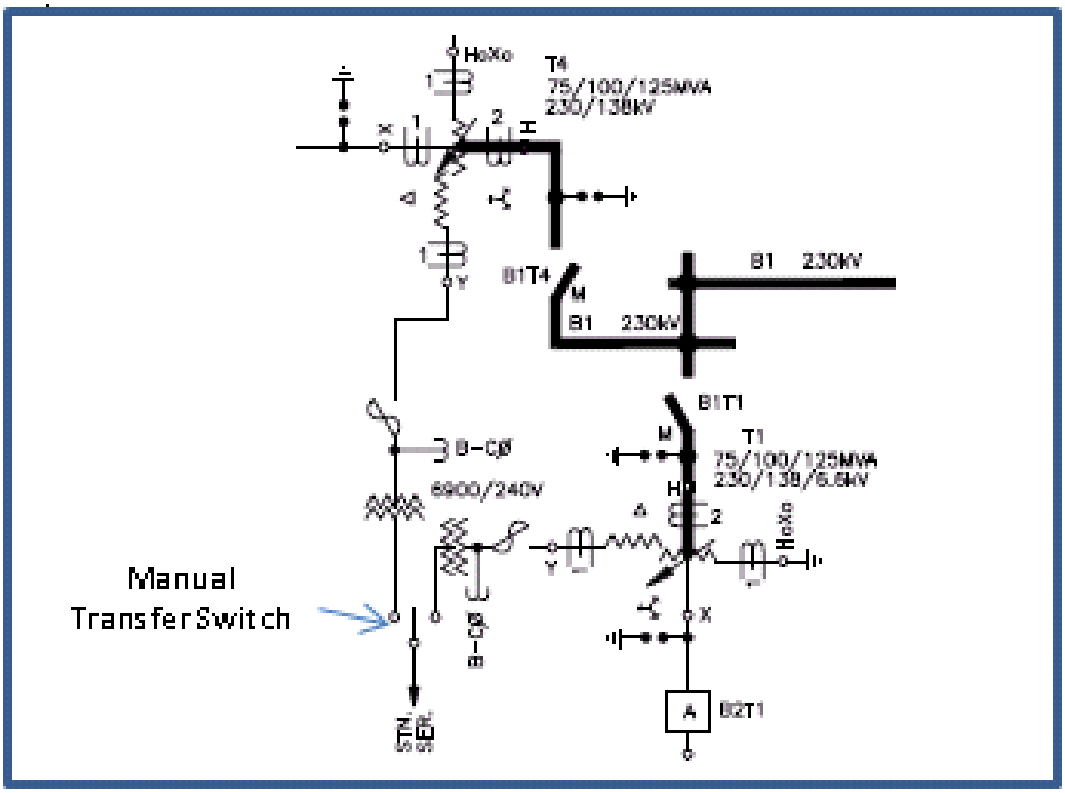


Figure 1: Sunnyside Station Service Supply Arrangement

Evaluation of SSD T1 fire and firefighting plans

Following the initial assessment on January 4, 2014 the Come By Chance volunteer fire department remained on site to assist and monitor. The TRO safety and environment co-ordinator consulted the Churchill Falls fire department mid-afternoon on January 4, 2014 because of their experience in dealing with terminal station transformer fires. They discussed strategies for extinguishing the fire and assessing the situation. It was decided to allow the fire to burn and concentrate efforts on restoring power.

On the morning of January 5, 2015 the TRO safety and environmental co-ordinator met with the Come By Chance and Sunnyside fire departments to tour the site and to discuss the options for extinguishing the fire. The local fire departments raised concerns about a lack of necessary equipment, training, and supplies to fight a transformer terminal station fire. Another concern

identified was the need to install grounds[6] to de-energize (i.e. isolate and ground) transformer SSD T1.

In the afternoon of January 5, 2014 the Emergency Response Team (ERT) co-ordinator in Holyrood was contacted to investigate if they could execute the extinguishing of the fire. They also expressed concern about their limited experience with this type of fire. At this time, it was decided to let the fire continue burning until grounds were in place to ensure the safety of firefighters.

Later in the afternoon, Hydro contacted the Gander fire department and arranged for the Gander fire department to assist and travel to SSD TS the following morning on January 6, 2014. The plan was to let the fire continue burning overnight on January 5, 2014 and in the morning, take a planned outage to Bus 1 to clean the insulators and extinguish the fire. The grounds were installed that night in preparation for firefighting on January 6, 2014. This was to be a joint effort between local fire departments from Sunnyside, Come By Chance and Gander.

However, the plan had to be suspended due to the trip in Holyrood TS during the evening of January 5, 2014. Based on the unfolding situation at Holyrood TS, and a decision to not take a planned outage on SSD Bus 1 due to system security concerns, a new firefighting strategy was implemented.

Arrangements were made to fly in a firefighting crew from Churchill Falls. In co-ordination with the Come By Chance Oil Refinery and the Holyrood Plant staff, the necessary firefighting equipment was obtained to support Churchill Falls and Come By Chance firefighters in extinguishing the fire.

[6] Grounds are electrical cables that connect equipment to the earth in order to protect personnel against the accidental energization of equipment.

The Churchill Falls firefighting crew arrived on site at approximately 18:30 on January 6, 2014. They toured the site and began preparations for extinguishing the fire. A tailboard discussion was held with Hydro personnel, the Churchill Falls, Sunnyside, and Come By Chance firefighters, and the plan was reviewed. The tailboard highlighted concerns of the limits of approach to overhead lines, other live equipment in the yard, as well as the angle of attack to the burning transformer to effectively extinguish the fire.

Firefighting commenced at approximately 23:30 on January 6, 2014 and continued until approximately 02:30 on January 7, 2014 when the fire was extinguished. Personnel remained on site throughout the night to monitor the transformer for possible re-ignition. The next morning, a status of all clear was given.

Throughout this process, the CCG, the provincial government, local fire departments, and Fire and Emergency Services NL received updates from Hydro. The provincial fire commissioner visited the site and provided advice. The Holyrood ERT co-ordinator was on site to witness the fire suppression activities.

Environmental response

When the supervisor arrived at Sunnyside on January 4, 2014 he assumed the responsibility of On-Scene Commander[7] and no environmental remediation measures were undertaken at the time due to the fire. TRO's Safety and Environmental Coordinator was consulted and appropriate agencies were notified. In consultation with Nalcor's Environmental Services Manager, an Environmental and Safety Specialist was scheduled to visit site the next day.

In the afternoon of January 4, 2014 it was confirmed that transformer SSD T1 was <2 mg/kg, which is considered non-PCB, but the PCB content of the transformer bushings remained unknown. However, given that the ratio of the volume of oil in the bushings versus the volume

[7] On-Scene Commander – in the event of an environmental emergency, the On-Scene Commander is a lead person which directs equipment and manpower for containment, cleanup, disposal, restoration and ensures human safety at all times.

of oil in the transformer was low, the PCB exposure risk to the employees and the public was also considered low.

On January 5, 2014 the TRO safety and environment co-ordinator arrived on site and assumed the role of On-Scene Commander. In addition, an Environment and Safety Specialist from Nalcor Energy's Environment department was also on site. Lab samples of the oil were taken from the surrounding area and preparations were initiated to start the remediation clean up when the area was deemed safe.

On January 6, 2014 limited remediation efforts began with Hydro personnel removing oil-contaminated snow. This was performed in an area considered safe from the fire. Also on January 6, 2014 a preliminary site visit was conducted by a remediation consultant, who recommended a soil remediation strategy to be implemented when the fire was extinguished. The soil remediation strategy commenced in full on January 10, 2014.

4.3 System Restoration

4.3.1 Transmission Restoration

This section provides an overview of the power system restoration efforts performed by Hydro following the transformer fire at the SSD TS. As previously noted, on January 4, 2014 at 09:05, the power system experienced an interruption initiated by the failure of SSD T1 at the SSD TS. This resulted in generation outages as well as multiple transmission line outages. This included generating units at Holyrood, Cat Arm, Hinds Lake, Star Lake, Granite Canal and Upper Salmon and transmission line outages localized to the east coast.

Restoration of the island power system was coordinated through ECC, who analyzed incoming alarms, and through discussions with field staff. Where necessary, field staff was dispatched to investigate the alarms prior to restoration of the affected area.

Restoration efforts from 09:05 to 12:58, January 4, 2014

Immediately following the failure of SSD T1, ECC operators performed an overall assessment of the situation to determine the initial cause and the extent of the outage. This included discussions with Hydro field personnel, the Holyrood plant and the Bay d'Espoir (BDE) plant. At 09:27, the ECC operator closed the breaker at Come by Chance to re-energize the line to Western Avalon (TL237) and effectively began the restoration of power to the Avalon Peninsula. The restoration efforts by ECC continued until power was restored to the Holyrood, Hardwoods, and Oxen Pond terminal stations

Restoration efforts were interrupted due to the loss of the Energy Management System (EMS) at ECC from 11:03 to 11:46. During this time ECC did not continue with restoration activities, as maintaining system stability was the first priority. For details of activities related to the EMS disruption, please see Technology and Communications Infrastructure Report.

At 12:22, ECC restored Western Avalon (WAV) Busses B1 and B3. Immediately following restoration, transformer WAV T5 tripped. Personnel were dispatched to investigate and discovered that WAV T5 was in lockout and therefore would have to be isolated until further investigation. WAV T5 was successfully isolated in the mid-afternoon and restoration of Bus 3 and Bus 4 were performed at 14:37. With WAV T5 isolated from the system, the 138 kV loop from Western Avalon to Holyrood was now supported by WAV T3 and T4 only. For more details of activities at the ECC, please see Transmission Availability Report.

In parallel to the transmission restoration, generating units at Cat Arm, Granite Canal and Upper Salmon were also brought back on line, with the last of these units being put on line at 12:56 on January 4, 2014. Restoration efforts in both the Cat Arm and Granite Canal generating plants were expedited by having crews dispatched earlier as per storm preparation plans of January 3, 2014. An operator and a supervisor were dispatched to Hinds Lake to support the restoration activities. During the unit start up they discovered a problem with the unit breaker, which was immediately addressed, and the unit was put in service at 15:14. The other

generating units at Star Lake and Upper Salmon were put back on line without incident. Holyrood generating sequence of restoration is explained in the section titled Holyrood Generation Restoration.

First attempt at Sunnyside restoration (12:58)

At 12:00, after SSD T1 at SSD TS had been electrically isolated by the on-site crew, and in consultation with the TRO technical group in Bishop's Falls and ECC, switching commenced to restore power to SSD T4. When Bus 1 was re-energized by ECC and verified by the on-site crews, and subsequently SSD T4 energized, the station service was restored to the SSD TS, thus providing power for the compressed air system. A few minutes later, ECC operators and on-site crews continued efforts of restoration by attempting to close B3T4 in order to re-energize the 138 kV Bus and TL219 to restore customers on the Burin Peninsula.

Bus 1 immediately tripped on the Bus differential protection lockout. This outage was localized to Sunnyside Bus 1 only. Crews proceeded to re-inspect Bus 1 and surrounding infrastructure to identify any obvious abnormalities. The visual inspection reaffirmed the initial inspection and no obvious defects were identified. Therefore, through consultation with the TRO technical group and System Operations, it was determined that the current transformers located inside of SSD T1 could possibly be damaged by the ongoing fire – triggering the Bus 1 differential protection.

On site crews, with direction from the TRO technical group, made emergency modifications to the wiring of the Bus 1 differential protection to eliminate the damaged current transformers from the protection circuit. The lockout protection was reset and a second restoration attempt was planned.

Second attempt at Sunnyside restoration (15:33)

With this emergency modification to the Bus differential protection circuitry (eliminating SSD T1 current transformers from the circuit), crews planned to reenergize Bus 1 through co-

ordination with ECC. Bus 1 was re-energized at approximately 14:36, thus energizing SSD T4, which feeds power to the station service for the SSD TS.

With SSD T4 energized, it was decided by the crews, and in consultation with the TRO technical staff, to delay further restoration until the compressed air system built up a reserve of air. This was required to ensure the Sunnyside air blast breakers would have enough reserve air to allow multiple operations if needed.

Once the on site crews verified the air system had adequate reserve, restoration continued. At 15:33 when the ECC performed a second attempt to energize the 138 kV bus, there was an immediate trip resulting in the line protection on TL202 and TL206 from Bay d'Espoir to Sunnyside, as well as TL 204 Bay d'Espoir-Stony Brook, and transmission lines to the Avalon Peninsula. This resulted in BDE (Unit 5 and Unit 6) and Cat Arm generating units tripping off line. Again, the supply to the Burin and Avalon peninsulas were cut off and the Sunnyside station service supply was once again disrupted.

A further investigation performed by the on-site crews in discussions with TRO technical staff, and systems operations, identified that the SSD T1 lockout relay was still activated thus triggering additional protection to operate, eventually causing the second major outage.

With an understanding of the cause of the protection operation, ECC commenced system restoration by contacting generating plants and field personnel. Both the generating units at BDE units (Unit 5 and Unit 6) and Cat Arm were restored to service within an hour. In addition, transmission lines were systematically restored to supply key terminal stations on the Avalon Peninsula.

<u>Third attempt at Sunnyside restoration</u>

The on-site crews at Sunnyside reset the SSD T1 lockout, reviewed the alarms now present from the outage, and began planning for a third restoration attempt. When the transformer SSD T1

lockout relay was reset at approximately 17:45, this:

- Enabled station service restoration at Sunnyside at approximately 18:42 through energization of SSD T4;
- Enabled restoration to TL219 and all the customers on the Burin Peninsula; and
- Enabled the restoration of the loop between Sunnyside and Stony Brook.

4.3.2 Holyrood Generation Restoration

This section covers the emergency response and restoration of Holyrood Units 1, 2, and 3 following the system disruptions on January 4 and 5, 2014.

Events of January 4, 2014

At 09:05, when the SSD T1 failed, all three Holyrood units were operating. With the sudden isolation of the Avalon Peninsula from the remainder of the island power system, the Holyrood units were unable to remain on line as the isolated Avalon Peninsula load was more than the plant could carry. All three generating units at Holyrood shutdown and the plant AC station service supply were interrupted. Upon loss of the AC station service supply, the following occurred:

- The DC lube oil pumps automatically started and supplied turbine bearing oil; and
- The two emergency diesel generating units were started to supply essential service power for basic lighting, AC lube oil pumps, battery chargers, turning gear, air heater drives, and power supply to Newfoundland Power's gas turbine for start up.

The manual shutdown of the three units was completed by plant personnel and the Newfoundland Power mobile gas turbine was started to support some of the station service load. This unit is not used to restart the Holyrood units, as it does not have sufficient capacity to start the boiler feed pump motors, essential for unit start up.

At 10:24, the Holyrood plant station service was restored from the grid. With the plant back to normal station service supply the unit start-up process was initiated. The priority was placed on

Unit 1 as it had no known issues and was capable of 170 MW. Unit 2 experienced a turbine rupture disc[8] failure during the sudden shutdown and Unit 3 was limited to 50 MW because of a forced draft fan failure. While restoring Unit 1 to service, repairs were being completed on Unit 2. Three attempts to run-up Unit 1 were unsuccessful due to excessively high vibration preventing the unit from reaching full speed for synchronization. In conjunction with performing repairs on Unit 2, staff attempted to start Unit 3 and it was identified that the auxiliary oil pump[9] was not working. Crews were dispatched to investigate further. The repairs to the turbine rupture disc on Unit 2 were completed at approximately 15:20 and Unit 2 was in start-up mode when the station service supply was lost again at 15:33.

Once again, the two emergency essential service diesels started up and the plant personnel resumed the same process as was completed at 09:05 during the first shutdown. When the normal station service supply was restored at 16:09 the plant staff began the start-up process once again with both Unit 1 and Unit 2 boilers being prepared and repairs to the auxiliary oil pump on Unit 3 continuing. Unit 1 boiler was already pressurized from previous attempts in the day, while Unit 2 was out of service since 09:05. Therefore, Unit 1 started up in a shorter time period and at approximately 19:00, Unit 1, while being brought up to speed, tripped due to high vibration. It was decided to suspend activities on Unit 1 and consult with Alstom[10] for further assistance. In parallel to the work on Unit 1, Unit 2's boiler was being pressurized and the turbine run up to synchronizing speed and at 21:34, Unit 2 was successfully synchronized to the system. In addition, work continued to identify a solution to the auxiliary oil pump system for Unit 3. The team implemented an alternate start-up method and Unit 3 was successfully synchronized to the system at 01:40 on January 5, 2014.

[8] A turbine rupture disc is a mechanical atmospheric protection device used to protect the turbine against backpressure.
[9] Unit 3's auxiliary oil pump supplies oil to the operating header and bearings when the turbine is operating below 3,600 RPM.
[10] Alstom are the service providers for the turbine generators.

Through the evening of January 4, 2014 investigation into the vibration issue on Unit 1 continued. The team speculated that a temporary bow [11] had developed in the turbine shaft that was causing the vibration. A conference call was held in the morning of January 5, 2014 between Holyrood staff, Project Execution and Technical Services (PETS) technical support engineers, and Alstom to discuss the start up approach for Unit 1. It was decided that Unit 1 would be started with a slower than normal process, to allow the bow to run-out. This means that the unit would be held at different speeds to allow the vibration to stabilize to normal operating levels before proceeding to higher speed.

In the afternoon of January 5, 2014 two attempts were made to bring Unit 1 up to synchronizing speed, but the unit tripped due to vibration both times. During the third attempt the unit was brought up to synchronizing speed over a longer period of time than the previous two attempts. For this third attempt, the unit was brought up to synchronizing speed over a period of four hours and the unit was allowed to stabilize at different speeds during the ramp up process. The unit reached synchronizing speed and was ready to be synchronized to the system at 21:27.

Initial response to January 5, 2014 event at 21:27

The Holyrood switchyard was in its normal configuration for bringing Unit 1 into service with both Unit 1 synchronizing breakers, B1L17 and B1B11 in the open position. One of the steps to bringing the unit on line is to close the unit's 230kV disconnect switch B1T1.

[11] A bow in a turbine shaft is caused by a temperature difference across the rotor diameter at zero speed.

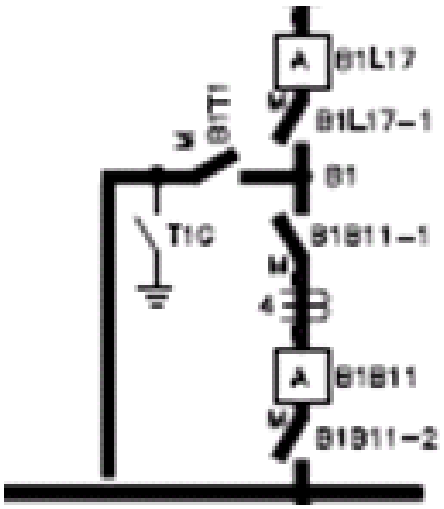


Figure 2 - Holyrood Unit 1 230 kV Connection Arrangement

While closing the Unit 1 disconnect switch B1T1, at 21:27, there was a protection operation resulting in multiple breaker operations in the Holyrood TS thus causing all units at Holyrood to trip offline. This resulted in a loss of service to many customers on the Avalon Peninsula. The process for restoration of essential plant services commenced with the normal start up of the two emergency diesel generators, supplemented by Newfoundland Power's mobile gas turbine.

A very bright flash of light from the Holyrood TS was reported by staff at the Holyrood plant at the time of the disconnect switch operation. It was immediately identified that the cause of the outage was located in the Holyrood TS and required terminal station maintenance staff to respond. TRO crews were dispatched to both the Holyrood and the Western Avalon terminal stations. In addition, TRO technical support and operations staff mobilized to the Bishop's Falls office to help manage and provide technical assistance for the restoration of the station. System operations engineers were also notified and requested to start analyzing data to determine the source of the problem.

In the meantime, the ECC took steps to restore TL-242 to the Holyrood TS to restore the station service to the plant. At approximately 22:20 the line was restored. Subsequently Holyrood

personnel reconfigured the plant for normal station service supply and initiated the restart of the units.

After careful review of the alarms and fault recording data, the source of the problem was identified to be Bus 1 in the Holyrood TS. Therefore, Unit 1 restoration had to be suspended and preparations were made to isolate Bus 1 for further investigation. Bus 1 was successfully isolated at 02:02. In parallel, crews at Western Avalon worked through alarms and the resetting of protective devices in order to facilitate the safe energizing of TL217 (Western Avalon to Holyrood). TL217 was successfully energized at 03:34 on January 6 and normal station service was restored to the Holyrood plant. At 05:29, Unit 2 was back on line and at 07:17, Unit 3 was back on line as well.

Refer to Appendix 3 for a single line diagram of Holyrood.

<u>Emergency response to enable Unit 1 to synchronize to the power grid</u>

In the morning of January 6, 2014 Unit 1 remained in hot stand-by mode and turbine vibration levels were monitored. Meanwhile, crews and technical support investigated the cause of the flash of light seen the previous night near disconnect switch B1T1.

Additional crews were dispatched from Bishop's Falls, while the majority of the Whitbourne based crews were on mandatory rest period. These additional crews helped to continue the fault-finding efforts in the Holyrood TS.

In order to minimize the risk of further interruptions a cautious and thorough examination of the problem was undertaken.

The initial approach to fault-finding and verification of equipment on Bus 1 focused on the following:

1. Visual inspection of B1T1 and Bus 1 from an aerial device;
2. Timing test of 230 kV breaker B1B11, and verification of the control circuits related to B1T1;
3. Determining the air leak location in breaker B1L17;
4. Isolating of breaker B1L17 for testing at a later date;
5. Visually inspecting of the unit step-up transformer T1 and its bushings;
6. Analyzing fault traces and alarms in order to determine a safe and reliable path to bring Unit 1 back online, through either breaker B1L17 or B1B11;
7. Reviewing the interface of the protection and control circuitry between the generating plant and the terminal station; and
8. Engineering analysis of the possible effects of energizing transformer T1 (and consequently Unit 1) from Bus 1 instead of the normal manner.

Regular update meetings were scheduled on January 6, 7, and 8, 2014 for the morning, late afternoon, and late evening to evaluate and discuss the ongoing work, and to decide next steps. Due to the complexity of this event, preserving restored generation and transmission, and not knowing exactly the root cause of the fault, it required a broader team to evaluate the evidence of this event. The meeting participants consisted of field staff, TRO technical support, technical services engineers, PETS, Systems Operations, Holyrood plant personnel, and executive leadership.

Through this iterative testing and consultation process, it was concluded that all equipment connected to Bus 1 including: disconnect switch B1T1, breaker B1B11, and transformer T1, were considered acceptable to energize and synchronize Unit 1 via B1B11. In addition, it was necessary to isolate breaker B1L17 for further investigation at a later date.

As a precaution to ensure there were no unidentified problems with the equipment in and around Bus 1 during the energizing process, a 25-step verification plan was developed to verify Bus 1's integrity before synchronizing to the system. After following this process, Holyrood

Unit 1 was successfully synchronized and put on line through B1B11 breaker at 15:38 on January 8, 2014.

5 KEY FINDINGS AND RECOMMENDATIONS

5.1 Emergency Preparedness

The deployment of crews, the extra snow clearing that was arranged and the emergency preparedness activities which were initiated on January 3, 2014, helped ensure that there was a timely and efficient response to the outages experienced on January 4, 2014. Some examples include:

- By having crews located at Granite Canal and Cat Arm, generation was reinstated at these plants as soon as the transmission system was restored;
- By having crews deployed to terminal stations on the Avalon Peninsula, there was a crew at Sunnyside when the fire started on SSD T1, meaning emergency response to this equipment failure was swift and immediate;
- Due to the extra snow clearing, operations staff were able to access the Holyrood Generating Station and Holyrood TS without issue; and
- Scheduling additional fuel deliveries and operations staff prior to the severe weather event helped ensure the availability of stand-by generation.

The lessons learned from this event, previous events, as well as best practices from other jurisdictions with respect to severe weather preparedness, should be incorporated into a formal protocol.

Recommendation		Status
ERR1	Update Severe Weather Preparedness protocol and checklist to capture lessons learned from previous responses and best practices from other utilities.	In Progress (May 15, 2014)

5.2 Emergency Response

The emergency response to the transformer fire at SSD TS required the co-ordination of many different groups including Hydro personnel, namely: North Atlantic Oil Refining Ltd, Churchill Falls staff, the Fire Commissioners Office, the Come By Chance local fire department, and others. Local fire departments did not have the tools, the training, or the obligation to deal with a transformer fire in a live switchyard. This was overcome by engaging support from other areas of Nalcor Energy and industry. In the end, the planning and execution of extinguishing the transformer fire was done professionally and safely. The learnings from this experience should be documented and emergency plans updated with specific information on methods for dealing with transformer fires.

When the PCB content of the burning transformer was uncertain, and consistent with Hydro's ERP, the first responders treated the fire as though there were PCB's present until they were guaranteed otherwise. This approach was taken to ensure the safety of employees and the public. The local crew were not able to confirm that there were no PCB's in the transformer because the information was not available inside the terminal station building, but only on the side of the burning transformer. In the future, all information about oil contents should be available in hard copy at the site and an alternate location.

Safety is Hydro's number one priority and this was demonstrated through the safe execution of the emergency response and restoration activities. There were no safety incidents during the period of January 2 to January 8 and crews maintained their focus on safety when faced with the challenging circumstances of a transformer fire in a live switchyard, poor weather conditions, cold temperatures, and knowledge of widespread customer power outages. Employees were relentless in their commitment to protecting themselves, their co- workers and the public throughout their restoration and response efforts.

Hydro's local and corporate emergency plans were utilized during the incidents. The local emergency response was co-ordinated from SSD TS under the care and direction of an on scene

commander. This local response was supported by resources in both the Bishop's Falls office and a partial mobilization of the CEOC in St. John's. The local emergency response and fire response were well coordinated and executed. There was no formal activation of the CERP but key functional departmental personnel were contacted individually and were available in the CEOC to provide support to the response and local operational areas. Given the magnitude of the events on January 4, 2014 it would have been appropriate to have had a formal activation of the CERP.

The outage on January 4, 2014 occurred outside normal business hours. Due to the pending weather, some staff were already scheduled to be at work, while additional staff were mobilized through requests made by supervisors on-call.

Recommendation		Status
ERR2	Update emergency response plans with lessons learned from the January 4, 2014 transformer fire and emergency response, including specified methods for dealing with transformer fires.	September 2014
ERR3	PCB contents of all oil-filled transformers and equipment should be available in hard copy locally and an alternate location.	May 2014

5.3 System Restoration

The field response for system restoration activities following the events of the SSD T1 fire on January 4, 2014 were handled well. ECC, system operations, generating plant control rooms, TRO support staff, and on-site crews all worked closely together to bring customers back on line.

ECC operators were faced with a large amount of data and alarms during the initial event, but with a systematic approach, and with the assistance of deployed resources already at key sites,

restoration efforts in both the generating plants, and the terminal stations were improved. Throughout the days of January 4 and 5, 2014 ECC coordinated all the restoration efforts in order to bring customers back online.

Onsite crews played an important role in the restoration efforts in the generating plants and terminal stations. They performed visual inspections of equipment, reset lockouts/alarms, isolated damaged equipment, and verified equipment operations during the restoration efforts. Restoration efforts in SSD TS began once the SSD T1 fire was evaluated and SSD T1 was isolated. In addition, the station service power supply requirements at SSD TS were important to maintain in order to continue the restoration. In general, outages to station service at terminal stations, can affect the ability of crews to restore the power system to normal configuration.

In addition, familiarity with control and protection circuits could improve response time. This was evident in the SSD TS restoration on January 4, 2014. It is important for Hydro to continue the efforts in standardizing control philosophies, and continue to provide avenues for less experienced workers to understand and develop skills.

At the hydroelectric generating plants, there were minimal issues relating to the restoration. In two plants there were operations personnel onsite because of known operational issues. This did result in quicker restoration with coordinated efforts between the ECC and Hydro Generation staff.

Restoration efforts at the Holyrood generating plant were also handled well. During a significant system event which results in a full power outage inside the Holyrood plant, there are a number of different steps to follow to ensure the plant and the units are secure. Plant lighting is limited in certain areas and when planned improvements are completed in 2014, this will aid in the efforts to safely secure the units as well as with the response time of getting units back.

Hydro's restoration of the power system during these challenging times was accomplished through focus and teamwork and without any safety incidents.

Recommendations of the restoration efforts are listed below.

Recommendation		Status
ERR4	Assess the need and options for additional station service supply for terminal stations in the event of loss of normal supply.	In Planning (June 2014)
ERR5	Complete lighting improvement plan at the Holyrood plant in 2014.	In Progress (September 2014)

Appendices

NEWFOUNDLAND AND LABRADOR HYDRO

Sequence of Events
Following Sunnyside Transformer Fault on January 4, 2014

February 2014

newfoundland labrador hydro
a nalcor energy company

Events Following SSD Transformer Fault - January 4, 2014

Date	Time	Event
Jan. 4, 2014		Weather forecast for blizzard conditions and heavy snowfall; crews prepared for storm response.
	08:00	Crews dispatched to major terminal stations on the Avalon. Remote hydroelectric plants staffed by operators, and the road to the Upper Salmon plant was maintained open.
	09:05:34	Fault detected in transformer T1 at Sunnyside (SSD). The SSD transformer T1 lockout protection operated resulting in following breaker operations: SSD L109T4 open SSD B3T4 open SSD B1L02 open SSD B2T1 open Four of five breakers for T1 operate, breaker B1L03 failed to open, keeping the 230 kV Bus B1 and transformer T1 energized from TL203. Fault evolved and protection circuits at multiple locations sensed the fault.
	09:05:35	SSD disconnect switch B1T1 in-transit alarm, indicated the disconnect switch had started to open.
	09:05:36	The Paradise River generating unit tripped, with a loss of 8 MW. As a result of the failure of SSD B1L03 to open and clear the T1 fault, the primary one, primary two and backup protection operated on transmission line TL203 at the Western Avalon Terminal Station (WAV). The backup protection also operated for transmission line TL203 at SSD. The following breakers opened for this event: SSD L03L06 open WAV L01L03 open WAV L03L17 open

Date	Time	Event
		TL203 was open at the WAV end and SSD Bus B1 and transformer T1 were de-energized. Backup protection also operated on transmission line TL237 at Come by Chance (CBC) and WAV. The following breakers opened for this event: CBC B1B2 open WAV L01L37 open Circuit breaker B1L37 at WAV appeared to have been delayed in opening by two seconds for the protection trip. **Transmission Lines TL203 (SSD – WAV) and TL237 (CBC – WAV) were out of service and the Avalon was isolated from the rest of the power system. Bus B1 and Transformer T1 at the Come By Chance TS were still energized. The Holyrood Generating Plant remained on-line, momentarily.**
	09:05:37	Normal Newfoundland Power supply to Hydro Place was lost; Hydro's EMS switched to battery power.
	09:05:37	Units at Holyrood cannot supply the load. Holyrood Units 2 and 3 are tripped and isolated from the system by unit breakers. Unit 1 trip is initiated and unit breaker B1B11 opened three phases. Unit breaker B1L17 opened only on two phases during the trip. Backup protection operated on transmission line TL242 at Hardwoods Terminal Station (HWD). Breaker B1L42 opened at HWD. Backup protection operated on transmission line TL218 at Oxen Pond Terminal Station (OPD). Breaker B1L18 opened at OPD. Holyrood Unit 3 was isolated from the system. **Transmission Lines TL203 (SSD – WAV) and TL237 (CBC – WAV) were out of service and the Holyrood Generating Plant was shut down and isolated. The 138 kV and 66 kV transmission had also tripped via NP lines 64L, 86L, 39L from WAV to HRD.**

Date	Time	Event
	09:05:38	Breaker B1L37 at WAV opened, closed and then re-opened in a three second period, an indication that the breaker operated only on two phases.
	09:05:38	Star Lake generating plant tripped with the loss of 18 MW and Stephenville Gas Turbine tripped.
	09:05:41	Cat Arm and Hinds Lake generating plants tripped with a loss of 205 MW of generation.
	09:05:41	SSD disconnect switch B1T1 was fully open, providing full isolation of transformer T1.
	09:05:45	Diesel G1 at Hydro Place on-line, re-storing AC supply.
	09:05:45	Hydro's EMS switched to diesel supply.
	09:09:45	EMS indication for breaker B2L42 at Holyrood toggled between open and closed multiple times, likely making its actual state unclear to the ECC operators.
	09:13	Upper Salmon generating plant tripped with the loss of 88 MW.
	09:27	Breaker B1B2 at Come By Chance closed by the ECC, marking the start of restoration phase and energizing transmission line TL237 to Western Avalon.
	09:41	Attempts to energize Bus B1 at WAV from line TL237. Line breaker B1L37 closed, but tripped again 1.2 seconds later. It was later determined that only two phases of the breaker had closed and there was a phase disagreement trip, momentarily energizing Busses B1 and B3, the WAV transformers, and transmission line TL208 to Vale, all on two phases. A Gas/Oil/Temperature alarm was received for transformer T5. ECC opened WAV breaker B1L08 to isolate TL208 and attempted to close B1L37 again, with the same result. Another Gas/Oil/Temperature alarm is received for T5.
	09:51	WAV circuit breaker L01L37 was closed by ECC, energizing a 230 KV ring Bus section at WAV, transmission line TL201 and the HWD terminal station.

Date	Time	Event
	09:57	Stephenville Gas Turbine in service at 25 MW.
	10:08	Upper Salmon generating plant in service at 88 MW.
	10:14	Granite Canal generating plant in service at 40 MW.
		ECC attempted to close breaker B2L42 at HWD to energize TL242 into Holyrood and restore station service. This energized HRD Bus B12 and, since unit breaker B1L17 had failed during the earlier events and remained closed on one phase, this resulted in a single-phase energizing of Unit 1 transformer T1. Protection circuits for TL242 operated at both HWD and Holyrood. Additional breakers were opened by ECC to provide for further isolation of the HRD TS.
	10:24	Holyrood station service is restored via transmission line TL242 (HWD – HRD) and HRD transformer T10.
	10:26	Holyrood unit disconnect switches B1T1 and B2T2 were opened by the HRD operators.
	10:38	Hydro Place diesel unit G1 tripped offline due to high temperature. There is no power at Hydro Place and EMS switched to battery power.
	10:41	Breaker B1L36 is closed at HWD, restoring transmission line TL236 (HWD – OPD) and OPD TS.
	10:41	ECC closed breaker B3L47 at Deer Lake, energizing transmission line TL247 and starting the process of restoring Cat Arm generating units.
	10:57	Breaker B1L03 at SSD, the breaker that failed to open during the T1 fault, opens un-commanded.
	11:03	The beginning of a 43-minute outage to the ECC, EMS. The outage resulted from a short power interruption (13 seconds), upon the loss of primary supply (Newfoundland Power), the standby diesels and the UPS system. The system was recovered and re-established at 11:46.
	12:00	SSD transformer T1 isolated from the system via disconnect switches. Transformer reported to be still on fire.

Date	Time	Event
	12:13	Three additional, but unsuccessful, attempts to close breaker B1L37 at WAV to restore 230 Busses B1 and B3. Similar to previous attempts the breaker closed only momentarily and at least one T5 transformer Gas/Oil/Temperature alarm was received. At 12:15 the ECC closed WAV breaker B1L17.
	12:18	Cat Arm Unit 2 in service at 65 MW.
	12:22	ECC closed breakers L03L17 and L01L03 at WAV, energizing Busses B1 and B3 from TL237. Due to previous actions this also energized transmission lines TL203 to SSD and TL217 to HRD. WAV transformer T5 lockout protection operated after restoration of Busses B1 and B3, isolating the transformer from the system via WAV breaker B1B3 and transformer disconnects B3T5 and B4T5. It was later determined there was an internal failure of the transformer tap changer. WAV busses B1 (230 KV) and B2 (66 KV) were restored.
	12:23	ECC restores TL217 (WAV - HRD).
	12:30	ECC restores TL218 (HRD - OPD).
	12:56	Cat Arm Unit 1 in service at 65 MW.
	12:57	Bus B1 and Transformer T4 are re-energized at SSD, re-establishing station service and restoring the breaker compressed air system.
	12:58	Switching at SSD to restore the load side of transformer T4 (138 KV). Breaker B3T4 closed by ECC, resulting in the operation of the Bus B1 lockout switch at SSD, initiated by the transformer disconnect switch, B1T4, opening under load and resulted in an arcing fault. Breakers B3T4 and B1L02 tripped. Breaker B1L03 had been previously isolated. Attempt to restore T4 failed. Impact was confined to the Sunnyside Station. Investigation determined the Bus B1 differential protection operated upon closure of B3T4, likely caused by the current transformers and

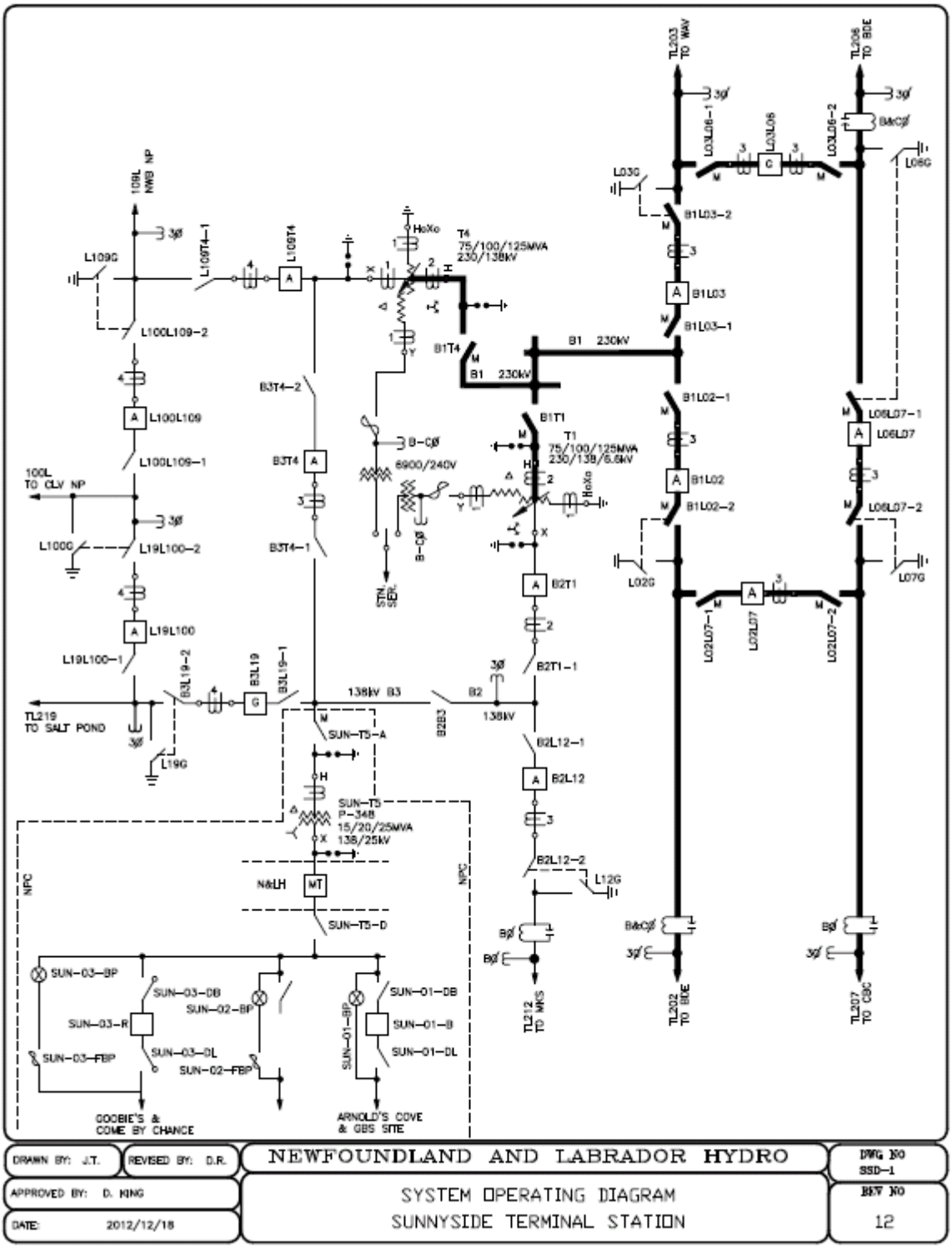
Date	Time	Event
		wiring on transformer T1 having been destroyed by the transformer fire.
	14:10	Stephenville Gas Turbine off line.
	14:28	Stephenville Gas Turbine in service at 25 MW.
	14:36	After a couple of unsuccessful attempts, the SSD transformer T4 disconnect B1T4 is closed.
	14:37	Circuit breaker B4L64 closed at WAV, restoring 64L and the 138 kV supply to Newfoundland Power on the Avalon.
	14:40	ECC closed breaker L03L06 at SSD, restoring both ends of TL203 (SSD – WAV).
	14:41	The SSD 230 KV Bus B1 was re-energized by ECC via breaker B1L02, which also energized transformer T4. SSD Station service is restored.
	15:12	Hinds Lake unit restarted and loaded to 75 MW. There were considerable issues with the unit breaker B1G1.
	15:25	Circuit breaker B8L39 was closed at HRD, restoring the 138 kV loop from WAV to HRD. **All transmission to the Avalon was restored.**
	15:33:26	A second attempt was made to restore the load side of SSD transformer T4 (138 KV). Breaker B3T4 closed by ECC and again resulted in the opening of the transformer disconnect switch B1T4 under load. The protection at Sunnyside did not operate as expected to clear the arcing fault, which resulted in the operation of the protection on the remote ends of transmission lines TL202 and TL206 at Bay d'Espoir (BDE).
	15:33:32	Breakers B11L06 and L06L34 opened at BDE to trip transmission line TL206 as expected.
	15:33:33	Protection at BDE did not operate to trip transmission line TL202 as expected. Breakers B3B4 and B4B5 would ordinarily trip TL202 at the

Date	Time	Event
		BDE end, but were slow in operating. Lockout protection operated and resulted in a trip of breakers B5B6, B3T5, B3T6, and B2B3. This resulted in a loss of TL204 (BDE – Stoney Brook), and BDE Units 5 and 6 (loss of 150 MW of generation). Breakers L02L07 and B1L02 tripped to isolate TL202 at SSD. **There was a loss of supply from BDE to Sunnyside and the Avalon Peninsula, including Come By Chance. The Auto Restoration Scheme (ARS) was in a disabled state following the return of the EMS at 11:46.**
	15:33:43	Cat Arm Units 1 and 2 tripped off-line with a loss of 130 MW of generation.
	15:37	ECC initiates a close of breaker B11L06 to close TL206 at the BDE end. The line was already closed at the SSD end. This action energized the terminal stations east of SSD.
	15:38	Primary one protection operated on the following transmission lines: TL201 – HWD and WAV TL203 – SSD and WAV TL207 – CBC and SSD TL217 – HRD and WAV TL218 – HRD and OPD TL236 – HWD and OPD TL242 – HRD and HWD Associated line breakers opened for these line protection trips.
	15:39	ECC initiated a breaker group open at WAV. Transmission Line TL206 was restored (BDE – SSD). Power was restored to SSD TS, TL207 and North Atlantic Refining at Come by Chance.
	15:40	Circuit breaker B3T4 was opened at SSD by ECC.
	15:53	Transmission Line TL203 (SSD – WAV) and WAV TS was restored.
	15:54	Transmission Line TL201 (WAV – HWD) and HWD TS was restored.

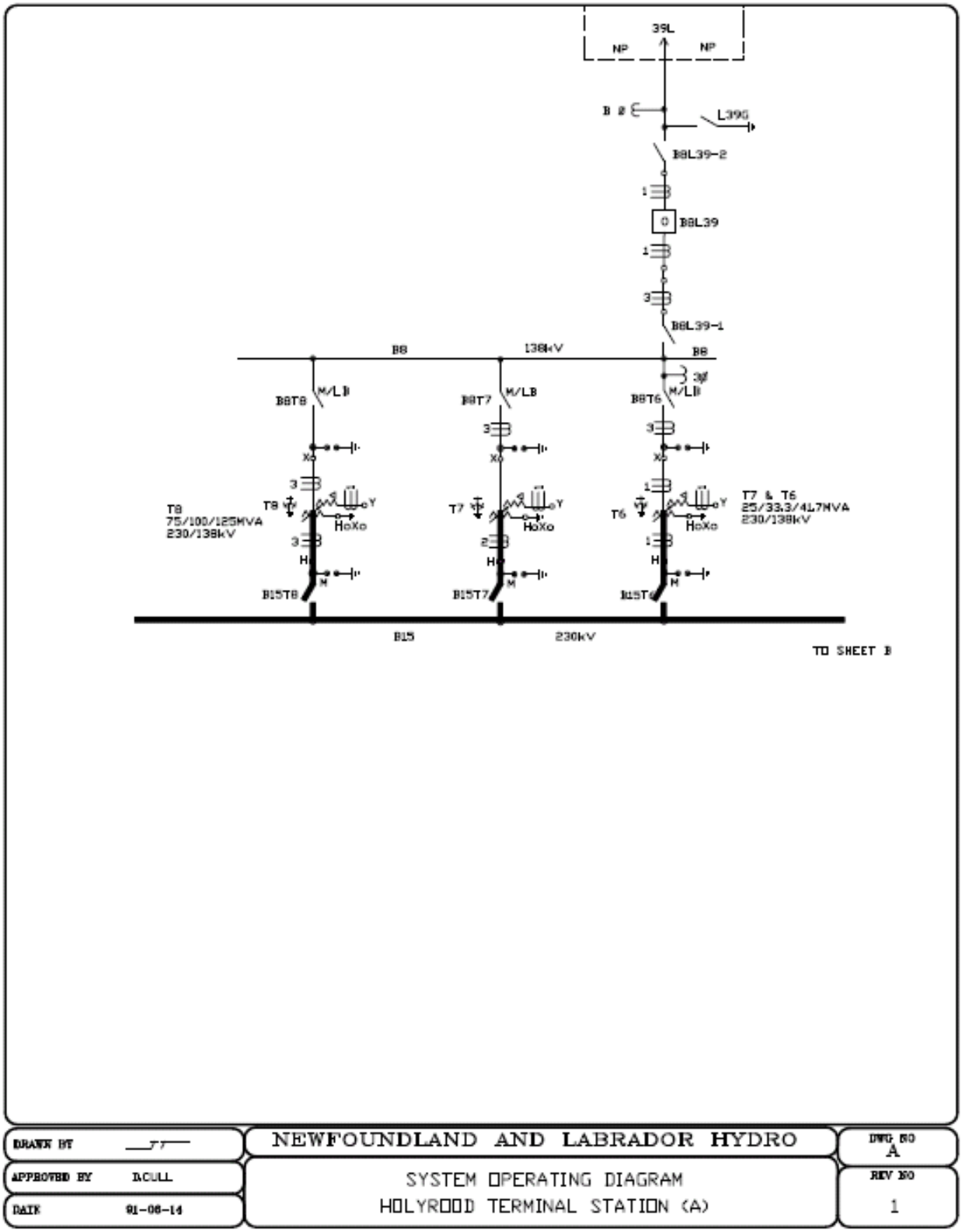
Date	Time	Event
	16:05	BDE Unit 6 restored at 75 MW. Transmission Line TL236 (HWD – OPD) and OPD TS were restored.
	16:06	BDE Unit 5 restored at 75 MW. Cat Arm Unit 1 restored at 65 MW.
	16:09	Transmission Line TL204 (BDE – Stony Brook) restored.
	16:09	Transmission Line TL242 (HWD – HRD) and HRD TS and station service restored.
	16:10	Transmission Line TL202 (BDE – SSD) restored.
	16:14	Transmission Line TL237 (CBC – WAV) in service.
	16:19	Transmission Line TL217 (WAV – HRD) restored.
	16:26	Cat Arm Unit 2 restored at 65 MW. Granite Canal unit restored to 32 MW.
	16:59	Star Lake generating unit restarted and loaded to 18 MW.
	18:00	Transmission Line TL218 (OPD – HRD) restored.
	18:31	SSD Transformer T4 re-energized, restoring station service.
	20:07	Transmission Line TL219 restored, bringing grid power to Burin Peninsula, which was lost during the initial trip at 09:05.
	21:34	Holyrood Unit 2 back on-line at 165 MW (minor de-rating of 5 MW).
	21:45	The 138 kV loop from Stony Brook to SSD restored.
Jan. 5, 2014	**01:40**	Holyrood Unit 3 on-line at 50 MW. (Holyrood Unit 1 remained down due to vibration issues)

Date	Time	Event
	08:10	ECC closes breaker B1L08 at WAV to energize TL208 to Vale.
	10:40	WAV transformer T3 overload protection trip. Transmission Line 64L tripped at WAV. Outages to Newfoundland Power customers in the Bay Roberts area. Newfoundland Power circuit breaker at Bay Roberts on 39L failed with no supply available from HRD.
	10:44	Transmission Line 64L restored at WAV. Newfoundland Power customers restored.
	11:08	WAV transformer T3 overload protection trip. Outages to Newfoundland Power customers in the Bay Roberts area. Newfoundland Power circuit breaker at Bay Roberts on 39L had failed with no supply available from HRD.
	11:18	Transmission Line 64L restored at WAV. Newfoundland Power customers restored.
	21:27:34	Disconnect switch B1T1 closed at HRD, the first step before the generator is synchronized to the system.
	21:27:41	Disconnect switch B1T1 opened at HRD after the operation of the unit lockout switch on HRD Unit 1. The unit lockout switch operated on HRD Unit 2. Primary protection one and backup protection operated on Transmission Line TL217 at WAV end only. Circuit breakers B1L17 and L03L17 opened. Backup protection operated on transmission line TL218 at OPD end only. Circuit breaker B1L18 opened at OPD.
	21:27:41	Primary protection one operated on transmission line TL242 at HWD end only. Breakers B2L42 at HWD and HRD opened. Protection relay 94TS/T1 operated on transformer T1 at HRD.

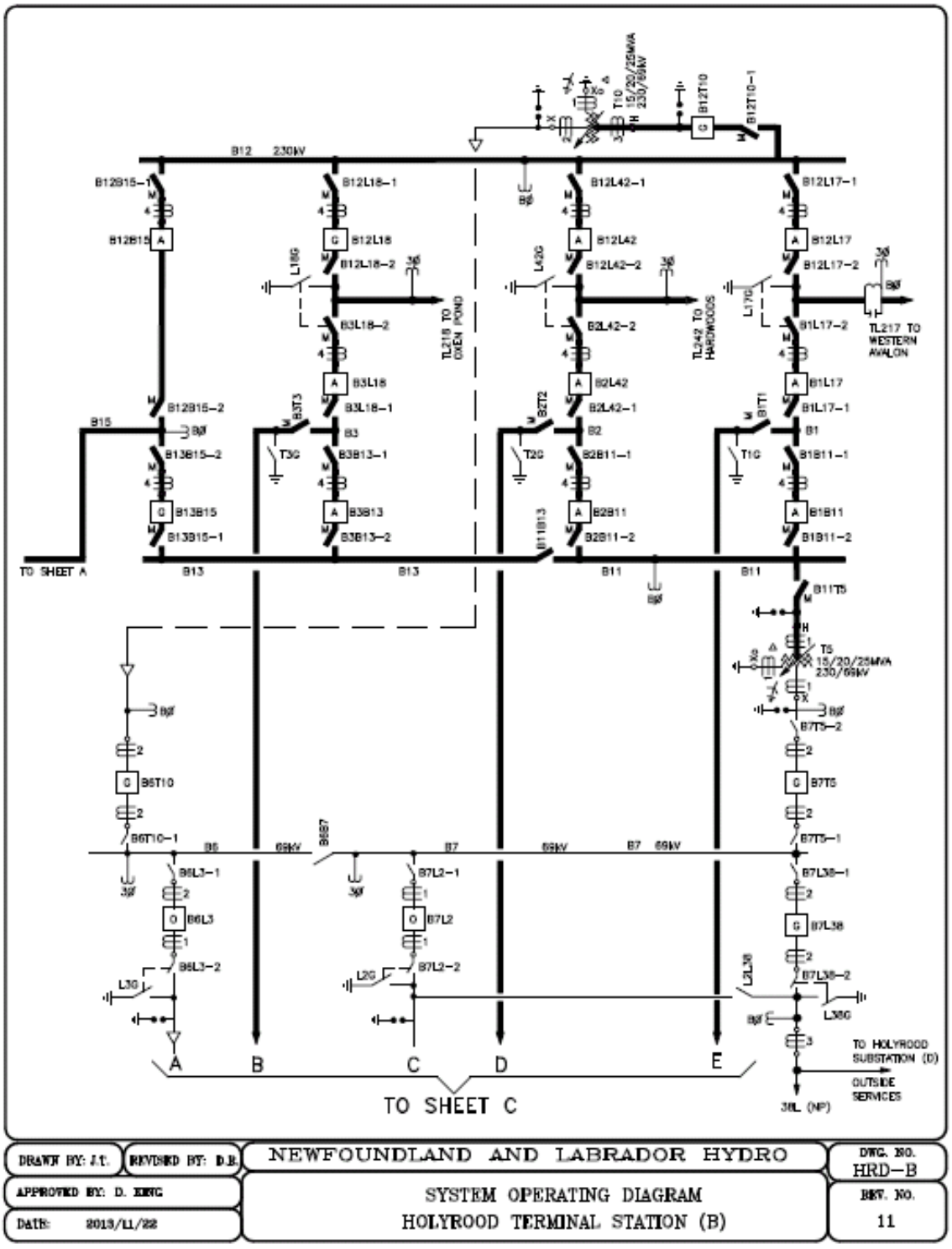
Date	Time	Event
		Breaker failure lockout protection operated on the following circuit breakers at HRD. HRD B3L18 HRD B3B130 HRD B1L17 Breaker failure lockout protection operated on circuit breaker B1L17 at WAV and Bus B1 at WAV. The unit lockout switch operated on HRD Unit 3. **The St. John's area was being supplied via TL201 from WAV. Holyrood Units 2 and 3 were off-line (Unit 1 had tripped during the previous day). The 138 kV loop from WAV to HRD was not available.**
	22:19	Transmission Line TL242 (HWD – HRD) restored.
Jan. 6, 2014	**02:02**	Circuit breaker B1L17 was isolated at HRD.
	03:34	Transmission Line TL217 was energized from WAV to HRD to test for line or Bus fault. No fault was found and TL217 was restored.
	05:29	Holyrood Unit 2 back on-line at 165 MW, with a minor de-rating of 5 MW.
	05:46	Transmission Line TL218 (OPD – HRD) restored.
	07:17	HRD Unit 3 on-line at 50 MW.
Jan. 8, 2014	**15:27**	Test performed to energize HRD Bus B1. Disconnect switches B1L17-1 and B1B11-2 were opened. HRD disconnect switch B1T1 was closed. No problems detected and disconnect switch B1B11-2 was closed. Approval given to HRD plant to synchronize Unit 1 to the system.
	15:38	Holyrood Unit 1 on-line at 165 MW, with a minor de-rating of 5 MW.



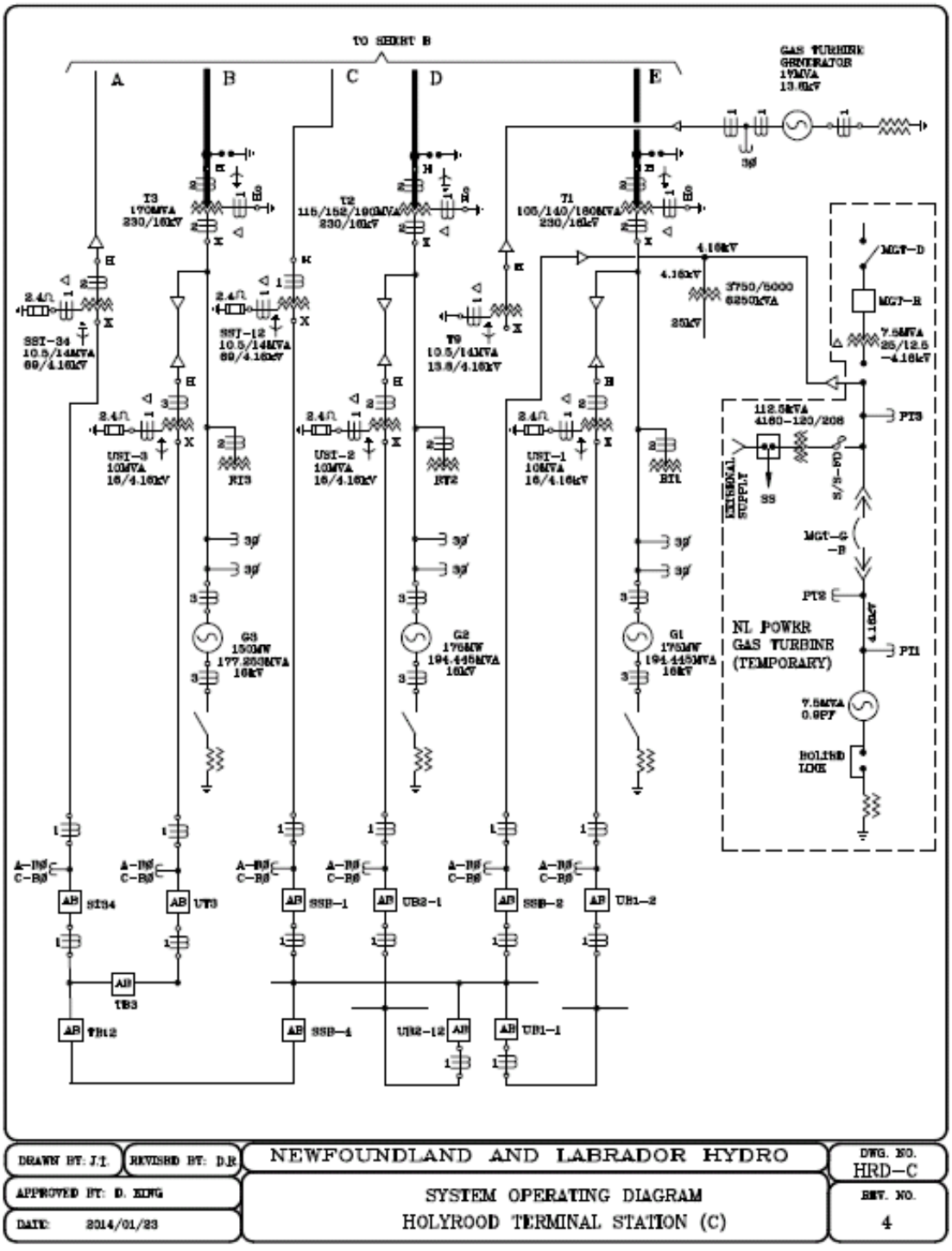
Sunnyside Terminal Station Single Line



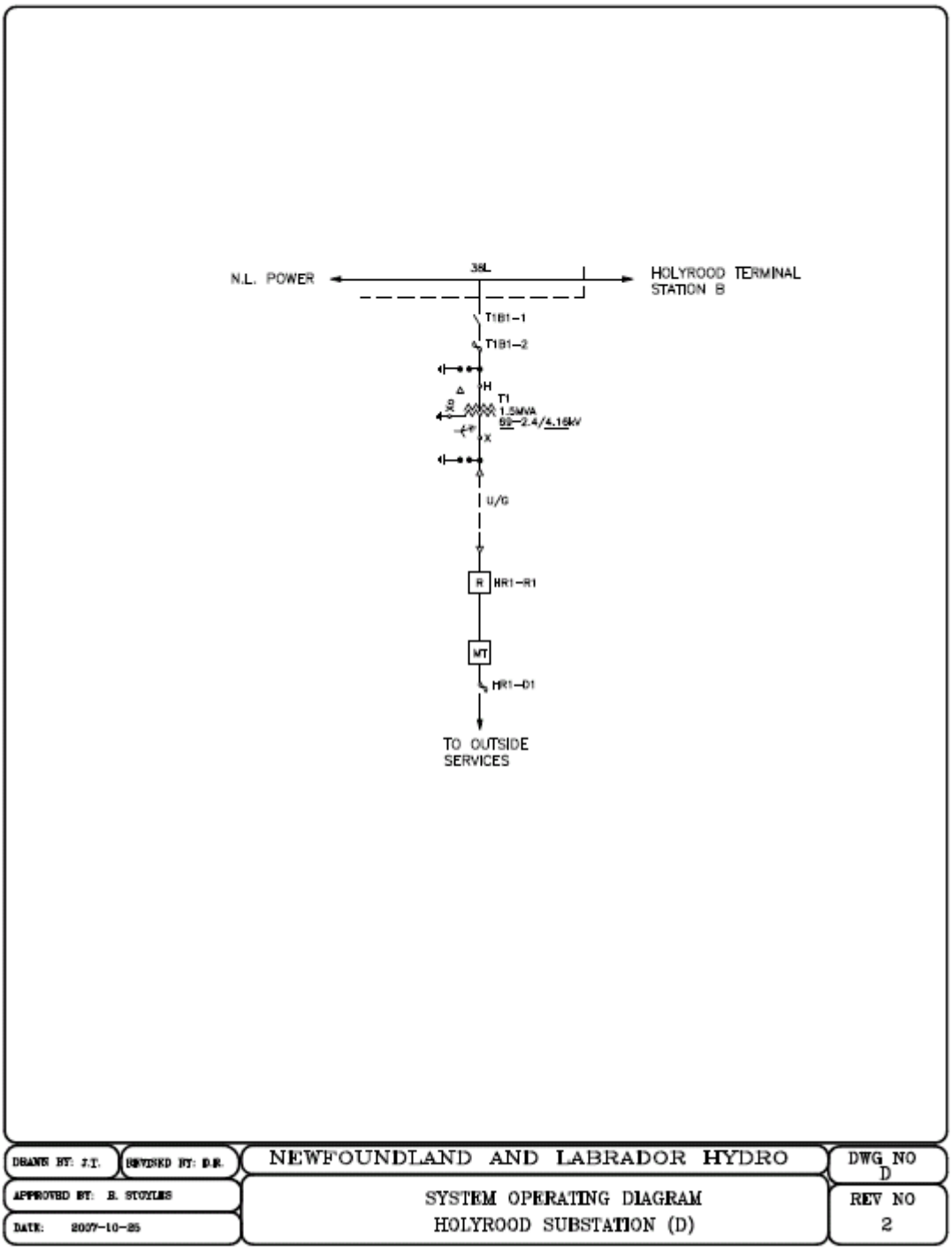
Holyrood Terminal Station Single Line



Holyrood Terminal Station Single Line



Holyrood Terminal Station Single Line



Holyrood Terminal Station Single Line

NEWFOUNDLAND AND LABRADOR HYDRO

Coordination and Communication with Customers

March 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1

1 INTRODUCTION 4

2 REVIEW PROCESS – LESSONS LEARNED 4

3 BACKGROUND 9

4 SEQUENCE OF EVENTS 16

5 KEY FINDINGS AND RECOMMENDATIONS 28

Appendices:

Appendix 1 Power Outage and Emergency Operating Procedures

Appendix 2 Report by MQO Research

Appendix 3 Report by NATIONAL Public Relations

Appendix 4 Report by Cathy Dornan Public Affairs

Appendix 5 010 - System Outages

Appendix 6 A-003 - Notification of Weather Warnings and Lightning Activity

Appendix 7 T-001 - Generation Loading Sequence and Generation Shortages Protocol

Appendix 8 Temporary Revision: T-001 Generation Loading Sequence and Generation Shortages Protocol

Appendix 9 T-007 - Holyrood Black Start Restoration Using Hardwoods Gas Turbine

Appendix 10 T-032 - Restoration Plan for Loss of TL202 and TL206

Appendix 11 T-078 - Hardwoods and Oxen Pond Restoration

Appendix 12 Capacity Assistance Arrangement with Corner Brook Pulp and Paper

Appendix 13 Communications Highlights and System Disruptions

Appendix 14 Conservation News Release

Appendix 15 Joint media campaign initiative sponsored by the Government of Newfoundland and Labrador, Newfoundland and Labrador Hydro and Newfoundland Power

Appendix 16 Information sheet with conservation tips for residential and commercial customers

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included investigation of the rotating outages that occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures that occurred on January 4 and 5, 2014.

This report provides a detailed description of the events of January 2014 from a customer communication and coordination perspective and is followed by key findings and recommendations.

Generally, this review shows that Hydro's personnel responded very well to the events of January 2014. While there are areas for improvement, Hydro was well prepared to address the situation and mobilized its staff effectively and efficiently and dealt with the events as they unfolded.

Hydro's Energy Control Centre (ECC) and Corporate Communications team maintained engagement with Newfoundland Power's control centre and communications team which resulted in coordinated and responsive efforts from the utilities and effective and timely messages to the public. The capacity assistance agreement reached with Corner Brook Pulp and Power (CBPP), one of the four largest Industrial Customers on the island, was effective and enabled Hydro to add generation to the Island Interconnected System. Hydro's Corporate Relations team, including Corporate Communications, Customer Service and Energy Efficiency, provided frequent up-to-date information to the public and key stakeholders through a variety of channels, including traditional and social media, which resulted in key information reaching the public. Customer Service answered calls during the outage and, due to coordinated efforts internally, was able to provide up-to-date information to Hydro's Rural Customers and also

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

assist Newfoundland Power's customers (who phoned Hydro). Information regarding conservation was made available to the public throughout the disruptions which Hydro believes helped reduce load demand.

Based on the findings, the following recommendations are being actioned.

1 Communication and Outage Coordination with Newfoundland Power

CCC1 Review rotating outage process used during the period of January 2-8, 2014, internally and with Newfoundland Power.

CCC2 Review protocol for Hydro's use of Newfoundland Power's hydroelectric and standby generation resources and Newfoundland Power's request for real-time data concerning the status of the Island Interconnected System.

CCC3 Review outage protocol and add a Daily Communications Summary coordinated with Newfoundland Power and the mutual sharing of notices and advisories prior to release.

2 Capacity Assistance from Corner Brook Pulp and Paper

No recommendations identified.

3 Communication with the General Public and Hydro Customers

CCC4 Prepare public advisories templates in advance of potential events to assist with rapid response and customer queries.

CCC5 Streamline internal process for distribution of information from the ECC to Corporate Communications to ensure accurate and timely communication.

CCC6 Develop key customer and power outage stakeholder list.

CCC7 Investigate alternatives for Customer Service calls, including overflow call options and the Interactive Voice Response (IVR) programming at high volume times, to ensure customer calls are answered in a more timely manner.

CCC8 Identify priority feeders in Hydro's service territory and determine which feeders contain sensitive customers to assist in developing a feeder rotation list.

4 Call for Customer Conservation

CCC9 Develop protocol for advising internal and external stakeholders when Hydro's system reserves are within the threshold of the loss of the largest generating unit, and when an energy conservation call is required.

CCC10 Ensure conservation information directed at commercial businesses is prepared and released in addition to conservation information for residents.

1 INTRODUCTION

On January 10, 2014, Newfoundland and Labrador Hydro initiated an internal review of the supply disruptions on the Island Interconnected electricity system in January 2014. This review included investigation of the rotating outages that occurred between January 2-8, 2014 and the transmission/terminal station equipment failure that occurred on January 4 and 5, 2014. The purpose of the review is to analyze and investigate potential contributing factors, determine lessons learned, and to identify immediate and longer-term actions to address opportunities for improving Hydro's performance and preventing similar events in the future. Hydro's review approach emphasized critical self-analysis and captured key items that worked well and areas which can be improved upon.

This report focuses on coordination and communication with customers and covers the following areas:

1) Communication and outage coordination with Newfoundland Power;
2) Capacity assistance from Corner Brook Pulp and Paper;
3) Communication with the general public and Hydro customers; and
4) Call for customer conservation.

In completing the review, employees held lessons learned discussions and reviewed interim findings. Hydro also engaged external consultants where necessary.

2 REVIEW PROCESS – LESSONS LEARNED

One of the key undertakings initiated through the internal review process was a lessons learned exercise which began after the system restoration activities were completed. It included consultations with employees in various areas of Hydro that were involved in the coordination and communication of information during the outages, supply disruptions and restoration efforts. The purpose of the lessons learned exercise was to review the events of January 2014 in

an open and honest manner to identify things that Hydro did well, areas that require improvement and what can be done to initiate those improvements.

The results of the reviews are mapped out in the Findings and Recommendations section. Immediate concerns were addressed and, where appropriate, implementation status is being documented for longer-term items. Hydro also engaged external consultants where necessary to provide analyses and feedback of Hydro's coordination and communication efforts.

2.1 Communication and Outage Coordination with Newfoundland Power

2.1.1 Energy Control Centre

2.1.1.1 January 2-8, 2014

On January 3, 2014, Hydro and Newfoundland Power conducted a review of the coordination process for rotating power outages. This resulted in Hydro's ECC and Newfoundland Power's control centre implementing immediate improvements to the coordination process. For example, during the initial rotating outages on January 2, 2014, each time Newfoundland Power initiated a feeder rotation they would call Hydro's ECC to ensure close coordination and maintain system frequency. When this procedure was reviewed, it was determined that due to the frequency of the rotating outages, this process had the effect of extending Newfoundland Power's customer outages. As a result, it was agreed that while both utilities would maintain contact and continue to monitor the system, Newfoundland Power would monitor system frequency to ensure stability while implementing the rotating outages within an agreed load change threshold.

2.1.1.2 Post January 8, 2014

On January 20, 2014, Hydro's System Operations division commenced a lessons learned exercise, which included, amongst other things, a review of Hydro's ECC's coordination efforts with Newfoundland Power's control centre. Present at this meeting were responsible parties from System Operations, including the ECC, Energy Systems and Supply Chain Management.

Specifically, in relation to Newfoundland Power, the following items were discussed:

- coordination and communication with Newfoundland Power;
    - coordination of feeder rotation;
    - level of communication;
    - power system restoration;
- communications with Corporate Relations;
    - routing of customer calls to the ECC after hours;
- Hydro's Generation Loading Sequence and Generation Shortages protocol;
- Hydro's rotating outage procedure, generally; and
- internal documentation of the events.

2.1.2 Corporate Relations – Corporate Communications

On January 20, 2014, Hydro's Corporate Relations division conducted an initial lessons learned exercise. Included in this exercise were members from Hydro's Corporate Communications team, Customer Service team and Energy Efficiency team. This review included, amongst other things, a review of Hydro's communications efforts with Newfoundland Power. Specifically, relating to communication with Newfoundland Power, the following items were discussed:

- communication and coordination between utilities;
    - preparation and release of information to the public;
    - media relations;
- communication and coordination with System Operations; and
- communication planning.

Hydro plans to share its findings with Newfoundland Power to determine if further improvements can be made to the coordination and communication process between the two utilities.

2.2 Capacity Assistance from Corner Brook Pulp and Paper

Hydro's System Operations also conducted a lessons learned exercise regarding Hydro's coordination efforts with CBPP. Specifically, the following items were discussed:

- coordination and communication with CBPP; and
- temporary addition of the CBPP capacity arrangement to the Generation Loading Sequence and Generation Shortages protocol.

2.3 Communication with the General Public and Hydro Customers

2.3.1 Internal

In relation to communications and customer service with the general public and customers, the following items were discussed as part of the internal lessons learned exercise:

- media relations;
- social/digital media;
    - outage takeover website;
    - use of Twitter, Facebook;
- communication and coordination with System Operations;
- customer service;
    - accountabilities for Customer Call Centre with the ECC;
    - overflow call options and IVR programming at high volume times;
- information flow to government officials;
    - coordination with government on communication and campaign work;
- stakeholder communication; and
- communication planning.

2.3.2 External

Following the outages, Hydro's Communications team engaged external consultants to: i) conduct a public survey to determine the power outages impact on customers and provide customers' opinion on Hydro's performance during the outages; ii) review Hydro's usage of

social media during the disruptions; and iii) review Hydro's management of the initial communication response and provide post event analysis.

a) MQO Research

MQO Research was engaged to conduct a telephone survey with randomly selected individuals on the island portion of the province to determine the power outages' impact on individuals and review of Hydro's performance during the disruptions. A copy of this report is located at Appendix 2.

b) NATIONAL Public Relations

NATIONAL Public Relations was engaged to provide a review of Hydro's use of social media from January 2-12, 2014. This included a review of Twitter, Instagram and on-line mentions. A copy of this report is located at Appendix 3.

c) Cathy Dornan Public Affairs

On January 4, 2014, Cathy Dornan Public Affairs was engaged to provide communication assistance to Hydro's Corporate Relations division throughout the supply disruptions. They were subsequently engaged to provide a post event analysis of Hydro's response efforts and compare it to accepted communication principles. A copy of this report is located at Appendix 4.

2.4 Call for Customer Conservation

In terms of customer conservation, the following items were discussed as part of the lessons learned exercise:

- call for conservation;
    - effectiveness of efforts;
    - continued use of customer conservation for 2014;
- integration and coordination between the ECC and the Energy Efficiency team;

- conservation messages and approach;
    - timing of conservation request; and
    - content for demand related messages.

3 BACKGROUND

3.1 Communication and Outage Coordination with Newfoundland Power

3.1.1 System Operations and Energy Control Centre

Hydro and Newfoundland Power coordinate many activities in the areas of forecasting, planning and operations. There is no single overarching document that outlines the coordination processes that exists between the two utilities. For particular activities, Hydro maintains documented procedures that are used to guide the coordination between the two utilities. The following list identifies the procedures, or instructions, maintained and used by Hydro that involve coordination with Newfoundland Power:

- 010 - System Outages;
- A-003 - Notification of Weather Warnings and Lightning Activity;
- T-001 - Generation Loading Sequence and Generation Shortages[2];
- T-007 - Holyrood Black Start Restoration Using Hardwoods Gas Turbine;
- T-032 - Restoration Plan for Loss of TL202 and TL206; and
- T-078 - Hardwoods and Oxen Pond Restoration.

These instructions are attached as Appendices 5 to 11.

Discussions and communications occur on an ongoing basis between personnel at various levels of the utilities. These activities, and the coordination that exists, have developed over time and through particular oversight of the Inter-Utility System Planning and Reliability Committee, with representation by both utilities. The committee includes senior operations and engineering

[2] T-001 does not reference the temporary arrangement with Corner Brook Pulp and Paper. T-001 has been temporarily revised to reflect the capacity assistance agreement with Corner Brook Pulp and Paper and is attached at Appendix 8.

management from Hydro and Newfoundland Power and meets twice a year to consider matters relating to load forecasting, system reliability, generation availability and peak load management preparedness. The intent of these discussions is to share observations with respect to historical and forecast loads. Hydro uses Newfoundland Power's forecast, together with forecasts for Hydro's Industrial and Rural Customers, to develop a five-year forecast, by month, of the Island Interconnected System energy and peak demands. As well, each year Hydro and Newfoundland Power discuss and coordinate the performance of Newfoundland Power's generation to prove the availability of their generation plants for the winter period.

Subsequent to the receipt of Newfoundland Power's five-year forecast and the completion of Hydro's long-term planning forecast, which includes Hydro's forecast of Newfoundland Power's energy and peak demand requirements, Hydro and Newfoundland Power communicate and discuss each other's forecast results.

Monthly, Hydro issues a report to its control room operators regarding the cost and start up times associated with all standby resources, including gas turbines and diesels owned by Newfoundland Power. This report presents the status of all standby generation and the start up time of each resource. Daily, Hydro and Newfoundland Power communicate and coordinate generation resources in order to meet system demands. Newfoundland Power reports to Hydro on the availability of their generating units. As required, Hydro's ECC discusses with Newfoundland Power's control centre the availability of water resources in their small hydroelectric facilities to ensure timely use of their generation and to maximize the benefits in maintaining customer supply. Hydro also makes requests to Newfoundland Power, as required, to change the level of production output of their hydroelectric units. In addition, Hydro and Newfoundland Power coordinate planned equipment outages to minimize the impact on customers and ensure power system security.

During periods when the system demand is expected to be high or when system generation

reserves are at risk, Hydro and Newfoundland Power coordinate additional activities:

- When cold weather and high system demands are on the forecast horizon, hourly forecasts of system demand are shared with Newfoundland Power.
- Hydro may request Newfoundland Power curtail their interruptible customers and request Newfoundland Power place in service their standby gas turbine and diesel units to help meet system demand. Hydro and Newfoundland Power discuss the appropriate timing associated with each of these requests to ensure maximum benefit to the system and minimize impacts to customers.
- Hydro and Newfoundland Power coordinate to ensure a balance between system supply and demand.
- Hydro and Newfoundland Power coordinate delivery point voltage reduction strategies by reducing the voltage on certain power system elements to reduce the system demand.
- Hydro and Newfoundland Power also coordinate public conservation requests, using a consistent message.

Prior to January 2, 2014, Hydro had never had to engage in rotating outages on the broad Island Interconnected System. In this situation, demand went beyond available supply and Hydro determined it was unable to maintain system frequency (60 Hz). Hydro's ECC and Newfoundland Power's control centre coordinated the rotating outage process to ensure the reliability and integrity of the power system. This is to maintain a balance between supply and demand to minimize the impact to customers. When load shedding was required, Hydro tried to proportionately balance the number of Hydro's customers affected with the number of Newfoundland Power customers affected.

3.1.2 Corporate Communications

Hydro maintained communication dialogue with Newfoundland Power and coordinated the release of information as required. Normally, when there is a routine power outage, Hydro

follows its Power Outage and Emergency Operating Procedures (Appendix 1) which provides a communications plan for Hydro to follow during a routine power outage. During an outage, Hydro will work with Newfoundland Power's communications representatives to relay and receive information about outages affecting Newfoundland Power's customers (when required).

3.2 Capacity Assistance from Corner Brook Pulp and Paper

Hydro and CBPP have a Service Agreement, approved by the Board of Commissioners of Public Utilities (PUB), which sets out the terms and conditions under which Hydro provides service to CBPP. CBPP owns and operates approximately 137 MW of hydroelectric generating capacity that provides 50 and 60 Hz power to its paper mill. CBPP has 81 MW of 60 Hz generation capacity and 56 MW of 50Hz capacity. Of the 56 MW (50Hz), 32 MW is used; 20 MW through a frequency converter and 12 MW used for mill load. The remainder is not used due to CBPP system constraints. To supplement their power requirements, CBPP purchases firm and non-firm power and energy from Hydro under the Service Agreement. Under the Service Agreement, by October 1 of each year, CBPP is required to declare the amount of firm power that it intends to purchase from Hydro the following year. Based on the amount of firm power required, CBPP is also entitled to a certain amount of non-firm (interruptible) power. Since 2009, CBPP has operated under a pilot program which enables a demand credit rate structure to facilitate the more efficient use of CBPP's hydraulic generating resources and permits lower energy production from Hydro's Holyrood Thermal Generating Station.

While extremely rare, due to high demand and supply concerns, Hydro will investigate opportunities with its Industrial Customers, such as CBPP, to enter into a short-term capacity assistance arrangement. Such an arrangement with CBPP was finalized on December 31, 2013. The arrangement allows for Hydro to call on progressively increasing blocks of capacity from CBPP's 60 Hz generation (20 MW, 40 MW and 60 MW). These blocks are made available in four-hour periods through load curtailment at the Corner Brook paper mill. The arrangement

with CBPP for capacity assistance has since been extended through the remainder of the winter period (to March 31, 2014). The details of the arrangement are attached at Appendix 11.

When system demand is expected to be high, Hydro will engage its Generation Loading Sequence and Generation Shortages protocol (Appendix 7). Under the steps in this protocol, as it pertains to CBPP, Hydro will first request that CBPP (through Deer Lake Power) maximize its hydroelectric generation (step 3) and will cancel all non-firm power delivery (step 9). If load is still increasing and it is apparent that a generation shortage may occur, Hydro will ask its Industrial Customers (which includes CBPP) to shed non-essential loads and inform them of system conditions (step 12). Hydro will then make a capacity assistance request to CBPP (step 13) and request they, and other Industrial Customers, shed additional load (step 14). Step 13 of this protocol was added, on an interim basis, in December 2013 to incorporate the capacity assistance agreement with CBPP (Appendix 8).

3.3 Communication with the General Public and Hydro Customers

Hydro will make provincial electricity consumers aware that they may be affected by a generation shortage using both traditional and social media. For Hydro's Rural Customers, in the case that customer demand exceeds generation supply, Hydro will develop a feeder rotation list of its customers and provide notice to customers when possible. The outage rotation list serves as a guideline to indicate which customers will be affected, the time of the outage and the approximate outage duration. Depending on system conditions, the feeder rotation list may have to be modified or revised. The notice provided to the public and customers consists of general information regarding the approximate length and general timing of the outage. The exact numbers of customers affected can vary upon implementation based on the load reduction required.

Hydro's customer rotation and notification process is generally as follows:

1. The ECC provides a feeder rotation list to Customer Service and Corporate

Communications. This identifies the communities and feeders that will be subject to an outage, the approximate time and the approximate duration;

2. Customer Service updates the outage notification database with the information;
3. Corporate Communications issues an advisory and distributes the advisory through media, its website and social media;
4. The ECC provides any further updates regarding changes in the rotation list or issues with the rotations; and
5. The ECC advises Customer Service and Corporate Communications when overall customer rotation has ended.

During a power outage, Hydro's Corporate Communications team relays timely and accurate information to the public and the media. Information is communicated through a variety of channels: social media (Twitter and Facebook); Public Service Announcement on Hydro's website and via traditional media. Hydro works with regional representatives to develop and deliver information to key customers and the general public in the affected areas. The Corporate Communications team also ensures key stakeholders are advised.

Hydro's Customer Service Call Centre is open Monday-Friday from 08:00 to 16:00 to serve Hydro's customers, and Hydro provides an automated 24-hour power outage and emergency service to its customers. Outside of regular call centre hours, emergency and outage calls are routed through an IVR system to the ECC. If the ECC receives a high volume of calls, it will contact Customer Service and make a decision to call in Customer Service Representatives (CSR) and open the Call Centre after hours.

Customers may use either of Hydro's Customer Service toll-free numbers to access the Power Outage and Emergency System (POES). Once contact is made with the POES, customers can obtain the following information:

- Dates and times of scheduled outages for specified communities; and

- Updates on current unscheduled outages for specified communities.

Callers to the POES have the option to press zero to speak to a CSR. During normal work hours, calls are directed to Hydro's Call Centre. After hours, calls are directed to the ECC. CSRs have been coached to provide as much detail as possible. At minimum, the CSR provides the following information:

- the time the outage started;
- if crews are on-site or en route;
- if a helicopter patrol is in progress;
- that Hydro has availed of social media as a tool to provide outage update;
- that Hydro expects a minimum of four hours to complete an assessment of the power outage (dependent upon weather conditions that can slow the assessment/patrol);
- that Hydro will continue to update its automated telephone system as further information is available;
- that customers can access information via Hydro's website at www.nlh.nl.ca and that Hydro will continue to update its online outage takeover website as further information is available;
- that Hydro will provide updates through the news media (VOCM, CBC radio, depending on the magnitude of the situation); and
- ask the customer to call back if other concerns arise.

3.4 Call for Customer Conservation

Hydro monitors the projected reserve using the seven-day load forecast and projected capacity availability. System Operations also monitors the system on a day forward basis. Due to the range of variability in the short-term forecasts, Hydro assesses the likelihood of load on the power system approaching the available capacity to determine when conservation may provide a benefit. When Hydro determines that conservation may benefit the system, it initiates a discussion with Newfoundland Power and then a discussion with internal stakeholders. The

focus of the discussions is on the need for the request, the appropriate timing for the request to be most effective to avoid rotating outages and the need to balance public confidence in the power system. In determining if the conservation request is needed, Hydro reviews the load forecast for the period in question, available or unavailability of generation, including wind generation, and weather forecasts.

If Hydro determines that a conservation request is required, Hydro's Corporate Communications team and Energy Efficiency team will work closely with Newfoundland Power to coordinate messaging and ensure the information is released to the public and key stakeholders.

4 SEQUENCE OF EVENTS

4.1 Communication and Outage Coordination with Newfoundland Power

At various times in December, Hydro was actively managing the system supply and load using its regular planning process and tools and the Generation Load Sequence and Generation Shortage protocol as required. There were a number of circumstances in December which prompted the Systems Operations team to actively and closely monitor both forecast load and supply including discussions with Newfoundland Power.

With respect to outage coordination, Hydro realized that it would likely not meet the forecast load on January 2, 2014. At that time, it enacted the final steps in its Generation Load Sequence and Generation Shortage protocol and planned for a customer conservation request and probable rotating outages. That morning, Hydro's ECC contacted Newfoundland Power's control centre to discuss the forecast and the need for a conservation request. Hydro's ECC also notified Corporate Communications and internal stakeholders. Internal discussions occurred between Hydro's operations and communications team via teleconference at 11:00 to discuss the details of the supply and load parameters and the required conservation request. Following the meeting, conservation messages were coordinated with Newfoundland Power and after

several discussions, it was agreed that Hydro would take the lead on releasing the conservation advisory. Following the discussions with Newfoundland Power, Hydro drafted the advisory. Once the advisory was drafted and internally approved, it was sent to media in the early afternoon and released to the public (posted on Hydro's website and social media sites.) Following release of the advisory, key messages were sent to Newfoundland Power.[3] Subsequent media interviews were conducted.

With increasing system load and rapidly declining operating reserves, Hydro's ECC requested Newfoundland Power's control centre to commence rotating outages at 16:13 on January 2, 2014. At this point, there were a number of key elements that were monitored to support the decisions on the timing and the amount of load to interrupt. These elements were: 1) amount of remaining generation reserve; 2) system frequency; and 3) system voltages. System frequency, total generation and system voltage data were shared between the utilities in real time. The determining factor for rotating outages was the system frequency. Once Hydro determined it was unable to maintain system frequency (60 Hz), rotating outages were implemented.

On January 2, 2014, as Newfoundland Power was implementing rotating outages, they called Hydro's Energy Control Centre each time. This was to ensure close coordination when shedding and restoring customer load to maintain system frequency. The process was reviewed on January 3, 2014 and it was agreed that while both utilities would maintain contact, the number of the coordination calls relating to the rotating outages would be reduced. Both utilities continued to monitor the system to ensure the system frequency was stable while rotating the outages.

From January 2 to January 8, 2014, Hydro and Newfoundland Power's control centre maintained communications. At the end of each day, Hydro and Newfoundland Power engaged

[3] A more detailed account of the sequence of events for Corporate Relations is shown in Table 2.

in a discussion about the day's events and prepared for the following day. This included a review of the load forecast, weather forecast, and potential for rotating outages. Each morning, Hydro contacted Newfoundland Power to confirm load forecast for the day and the likelihood for rotating outages. From January 2 to January 8, 2014, notice to Newfoundland Power to begin rotating outages was given to their control center in real time which resulted in the requests being implemented very quickly. It should be noted that there were times, due to system voltage constraints, that Hydro specifically requested that customers on the Avalon Peninsula be chosen for outages.

For its direct Rural Customers, Hydro established an outage rotation schedule, using 30 – 60 minute intervals. This included the Northern Peninsula, the Connaigre Peninsula, Burgeo and South Brook areas. The Customer Service and Corporate Communications teams were updated by the ECC on January 5 and 8, 2014, regarding the outages affecting Hydro's customers. Customer Service and Corporate Communications were provided a list of communities and approximate times for the rotating outages. The customer outage database was updated with timely information. Social and digital media (Hydro website, twitter, Facebook) were also used to communicate outages.

4.2 Capacity Assistance from Corner Brook Pulp and Paper

During the disruptions, Hydro's ECC maintained communication and coordination with CBPP. When Hydro determined that capacity assistance was required, the ECC contacted CBPP (via Deer Lake Power) and requested the required block of load for the four-hour period. CBPP was also informed when capacity assistance was no longer required.

A summary of when Hydro relied on the capacity assistance agreement with CBPP from January 2-8, 2014, is detailed below in Table 1.

Table 1: Corner Brook Pulp and Paper Capacity Request Summary

Starting Date and Time	Capacity Delivered (MW)	Number of Four-Hour Periods
January 2 (06:45) to January 3, 2014 (22:45)	60	10
January 4 (07:55) to January 6, 2014 (20:00)	60	15
January 6, 2014 (20:00-23:59)	40	1
January 8, 2014 (07:00-19:40)	60	3
January 8, 2014 (19:40-22:16)	40	1

4.3 Communication with the General Public and Hydro Customers

4.3.1 Corporate Communications

On January 2, 2014, Hydro generally followed its routine Power Outage and Emergency Operating Procedures (a description of the events regarding the call for customer conservation is described in the next section). At approximately 13:50 on January 2, 2014, Hydro made provincial electricity customers aware that conservation was required using traditional, social and digital media. At 16:13, Hydro communicated to the public that generation supply would not meet customer demand and rotating outages were required. The focus of the information was outage details, conservation and safety.

The Corporate Communications team was accessible to the media throughout the January supply disruptions. Hydro participated in more than 100 media stories and held seven media briefings. Hydro posted a high volume of information via social media, which included 350+ Twitter posts, 60+ Facebook posts, and more than 49,000 social media mentions. Hydro experienced an increase in its Twitter followers from 3,000 to approximately 9,000 and its Facebook followers increased by 1400 over the outage period to approximately 8,800. Three Corporate Communications team members managed public responses and social media messages.

Hydro's Vice President of Corporate Relations tweeted directly from her account. Hydro also retweeted and posted information relating to Newfoundland Power. An account of the events and actions from Hydro's Communications team is fully outlined in Table 2.

On January 4, 2014, Hydro engaged Cathy Dornan Public Affairs to assist Hydro in its communications response efforts, as per the Outage and Emergency Operating Procedures.

On January 5, 2014, Hydro launched an "outage takeover website" to temporarily replace Hydro's website. The purpose of the outage takeover website was to create a one-stop place where advisories, important links and key contact information could be housed and easily accessed by the public. This site was the first thing that a visitor to www.nlh.nl.ca or someone searching for Hydro through a search engine would see. The following information was included: latest Public Safety Advisory; link to Hydro's outage information page; Hydro's customer inquiry number; media contact; link to Newfoundland Power's outage information page and customer inquiry number; and safety information. The outage takeover website also featured a live twitter feed.

During the rotating outages on January 5 and 8, 2014, a list of outages was communicated to Hydro customers through media advisories, an update to the outage information page on the Hydro website, and posts on social media sites, Twitter and Facebook.

Table 2: Timeline of Communication Activities

Date	Time	Action
January 2, 2014	08:00	Call from operations confirmed peak load may exceed capacity
	11:30 – 12:30	Several discussions with Newfoundland Power communications team on advisory and messaging — Decision that Hydro would take lead on releasing

Date	Time	Action
		advisory — Decision to release conservation request had to be balanced against maintaining public confidence. i.e. important to ensure it was absolutely necessary before releasing.
	12:30	Advisory and messages drafted
	13:00	Update provided to Government
	13:30	Advisory distributed for internal approval
	13:51	Advisory sent to media/public – posted to website and social media
	14:30	Key messages sent to Newfoundland Power communications
	15:00	Confirmed media interviews with NTV, VOCM, CBC, Telegram, CBC National
	15:12	Information sent to all employees – conservation messages
	16:13	Rotating outages began, regular updates through social media
	~21:30-23:30	Updated advisory sent to media/public, social media rotations stopped for the night
January 3, 2014	07:00	Updated Newfoundland Power communications on loads and messages for the day Social media updates continued with safety and conservation messages throughout day and into evening
		Media interviews with CBC morning shows, VOCM and Telegram
	12:21	Requested Newfoundland Power join Hydro for joint

Date	Time	Action
		media brief
	13:15	Advisory for media briefing sent to Newfoundland Power communications for approval
	13:37	Media advisory distributed
	14:30	Joint media briefing at Hydro Place
	16:30	Dawn Dalley, Vice President of Corporate Relations - interview with CBC Here and Now
	16:30	Updated advisory sent to media/public on rotating outages
	18:00	Rob Henderson, Vice President of Hydro - interview with VOCM
	19:36	Rotating outages end, information updated on social media
January 4, 2014	09:00	Social posts indicating outages likely result of severe weather, investigating
	10:00	Began media interviews and social posts indicating investigation into incident at Sunnyside terminal station
	Ongoing	Liaison and dialogue with Newfoundland Power Communications team
	13:00	Prepared messages with Newfoundland Power at Hydro Place
	14:00	Joint media briefing – Hydro, Newfoundland Power, Fire and Emergency Services NL (FESNL) Continued constant feed of real-time updates, Q&A on social media
	16:40	Information on outage sent to media/public and posted on website

Date	Time	Action
	17:30	Prepared key messages with Newfoundland Power at Hydro Place
	18:00	Joint media briefing – Hydro, Newfoundland Power, FESNL Continued real-time updates and frequent messages about conservation and safety
January 5, 2014		Frequent messages on social media about conservation and safety on outage takeover website
	11:00	Launched takeover website – contained links to important information, advisories and contact numbers
	11:30	Briefing at Government with stakeholders
	13:30	Joint media briefing with Premier, Hydro and Newfoundland Power
	~14:30	Ed Martin, President and CEO, on VOCM open line show
		Started work on joint media campaign sponsored by Government, Hydro and Newfoundland Power Hydro communications and Hydro takeCHARGE team – worked with Government to develop messages and collateral. Newfoundland Power provided input.
	17:30	Hydro advised its customers of rotating outages – schedule posted online
	21:40	Trip at Holyrood
	21:50	Dawn Dalley updated VOCM and CBC on Holyrood incident
	21:50-23:00	Real-time information distributed on social media until all customers restored
January 6, 2014	05:17-22:48	Rotating outages to Newfoundland Power customers

Date	Time	Action
		Ed Martin - interview with CBC morning show
		Continued posting information on social media with real-time updates and responding to questions
		Government joint conservation advertisements began running, included posting conservation info to Government website and used hashtag #conserveNL
		Joint media briefing Premier, Hydro
	13:30	Hydro continued frequent conservation messages on social media
		No planned rotating outages
January 7, 2014		Conservation and safety messages continued via social media
		Continued answering questions about generation and load on social media
		Joint briefing with Premier, Newfoundland Power and Hydro
	13:00	Posted update on Hydro takeover website and on social media
	16:40	Updated Hydro takeover/front website
January 8, 2014	10:30	Government shared top ten conservation tips – Hydro re-tweeted
		New peak load reached – conservation messages continued on social media
		Rotating outages resumed. Hydro posted lists of communities and times on website for outages in Hydro distribution service territory
	15:23	Rotating outages to Newfoundland Power and Hydro

Date	Time	Action
		customers begin
	~15:30	Media advisory issued on rotating outages and posted on Hydro takeover website online
	16:00	Joint briefing, Premier, Hydro and Newfoundland Power
		Rotating outages ended and public notified
	17:42	Advisory posted on Hydro takeover website that Unit 1 at Holyrood back online
	18:30	Ed Martin interviewed with CBC On the Go, NTV Evening News and CBC Here and Now
January 9, 2014		Hydro communications team continued to answer questions and provide social media updates
January 10 – 14, 2014		Preparation for PUB reporting
		Prepared public advertisement and stakeholder outreach apologizing to customers for impact of outages and to make it clear that Hydro is in full support of review processes
		Prepared post outage survey with general public to assess communication and impact including conservation measures

4.3.2 Customer Service

After 16:13 on January 2, 2014, following the start of Newfoundland Power's rotating outages, Hydro's ECC received calls from Newfoundland Power's customers asking about the outages. At that time, Customer Service and the ECC decided to reopen Hydro's Call Centre if the call activity continued or increased. The ECC monitored the volume of calls and determined that the Call Centre did not need to reopen that evening.

With the continued calls for conservation and potential for rotating outages, Hydro's Call Centre opened early at 07:00 on January 3, 2014. Two CSRs and a supervisor were present. The Call Centre answered four calls between 07:00 and 08:00 and thirty-seven calls between 16:00 and 20:00. After 20:00, calls slowed considerably and Customer Service decided to close the Call Centre and calls were transferred back to the ECC.

Following the system events of the morning of January 4, 2014, due to the volume of calls coming in, the ECC requested Call Centre support. The Call Centre was opened from noon to 18:30 with two CSRs and one supervisor on site. Fifty calls were answered during that time with approximately 80% of the calls from Newfoundland Power customers. Call volume dropped considerably after the provision of public outage updates by Hydro's Corporate Communications team (via media and social media). Customer calls were transferred to the ECC at 18:30.

Call Centre support was not required on January 5, 2014, however, two CSRs were on standby in case they were needed. The Call Centre Supervisor maintained frequent contact with the ECC to monitor the situation and volume of calls. The Call Centre operated normally on January 6 and 7, 2014. During this timeframe, Hydro received some calls from Newfoundland Power residential customers seeking damage compensation. All calls from Newfoundland Power customers were directed to contact Newfoundland Power with their concerns as per normal process.

Rotating outages began at 15:23 on January 8, 2014 and Hydro decided to keep the Call Centre open after 16:00. While rotating outages ceased prior to 18:00 that evening, the public was informed of the possibly of outages recommencing, depending on customer demand. As such, the Call Centre remained open until 19:30. Thirty-three calls were answered between 16:00 and 19:30 and customer calls were transferred back to the ECC at 19:30.

4.4 Call for Customer Conservation

A decision to issue a conservation request to customers was made during the morning of January 2, 2014 as there was an anticipated shortage in generation capacity to meet the customer demand expected during the evening peak period. At 08:00 on January 2, 2014, the available system supply, including purchases, was 1,497 MW; at that time the system demand was 1,450 MW, with a reserve of 47 MW.

On January 1, the mean temperature for the day was -13 C[4] and the system peak demand was 1,436 MW. The forecast temperatures for January 2, 2014 were in the range of -13 C to -18 C[4]. With a reduced system reserve; a weather forecast indicating extremely cold temperatures for the day; and Hydro's experience with system demands in the period leading up to January 2, 2014 Hydro felt that a conservation request was required to deal with a potential generation capacity shortage. Thus, at 08:00, Hydro's ECC initiated discussions with Newfoundland Power's control centre regarding a conservation request. Also, at that time, the ECC contacted Corporate Communications. Discussions were held between System Operations and Corporate Relations via teleconference at 11:00 to brief on the details of the supply and load parameters and the required conservation request.

Following the meeting, messages were coordinated with Newfoundland Power and it was determined that the conservation request should come from Hydro. Hydro drafted a press advisory and appropriate social media messages and, upon internal approval, the release was issued to local media. Interviews were arranged with local media proactively and prior to the press advisory being released to expedite the public release of information. Social media posts on Twitter and Facebook were made just after the press advisory was issued. Hydro formally issued the conservation request to the public at approximately 14:00 via traditional and social media. The news release (Appendix 14) defined a series of short-term conservation measures customers were asked to make.

[4] Source: Environment Canada for the City of St. John's.

Subsequently, a joint media campaign initiative sponsored by the Government of Newfoundland and Labrador, Hydro and Newfoundland Power was initiated. The campaign included radio and print ads (Appendix 15) and web based initiatives. An information sheet with conservation tips for residential and commercial customers was also promoted through social media and was posted on the Government's website (Appendix 16). Both utilities and government in media interviews also promoted the same targeted conservation measures to customers which asked customers to: 1) reduce electric heat by a few degrees; 2) conserve hot water by not running dishwashers, washers and showers; 3) avoid using clothes dryers; and 4) turn off Christmas lights.

5 KEY FINDINGS AND RECOMMENDATIONS

5.1 Coordination and Communication with Newfoundland Power

Power system restoration communication and coordination with Newfoundland Power went well. Resources in Hydro's System Operations were present to help operators in the ECC and conduct was professional and calm in the control room. The communication between Hydro and Newfoundland Power control centres worked well with real-time improvements to the rotating outage process that resulted in a reduction in the average outage duration experienced by Newfoundland Power's customers. Newfoundland Power and Hydro rotated feeders and monitored a common frequency source which permitted Hydro to maintain system reliability. The Generation Load Sequence and Generation Shortage Protocol was followed and ensured that the ECC maintained system reliability.

The dialogue between Hydro's Corporate Communications teams and Newfoundland Power's communications team ensured the public was kept aware of the situation by the best possible means and helped ensure consistent messaging. Hydro's Corporate Communications team was accessible to Newfoundland Power's communication team throughout the disruptions and shared information in an open manner. Hydro also shared Newfoundland Power's contact information on its website, subsequent outage takeover website and through social media. The

effort was generally coordinated and efficient and overall resulted in a timely exchange of information to each other and to the public. Where there were gaps during the events, feedback was provided and changes were made.

The rotating outage process, including the changes incorporated on January 3, 2014, worked well, however, a review of the process, both internally and with Newfoundland Power's control centre, should be conducted to ensure best practices are used in future events.

In addition to reviewing the rotating power outage process, Hydro and Newfoundland Power have agreed to develop a protocol to address Hydro's use of Newfoundland Power's hydroelectric and standby generation resources. Hydro is also reviewing Newfoundland Power's request, received in February 2014, that originated from the inter-utility meeting held in May 2013, for real-time data relating to the status of the Island Interconnected System.

While Newfoundland Power was consulted during the decision to issue the initial conservation advisory, the advisory itself was not provided to Newfoundland Power prior to its release. Hydro has reviewed this process and even though Hydro is satisfied that Newfoundland Power was fully aware of the contents of the advisory, courtesy dictates that Hydro should have provided a copy to Newfoundland Power prior to releasing the advisory to the public.

It was also noted that a daily summary of events would assist in supplementing the communication between the utilities, in terms of reviewing the events that occurred, during the outages and looking back from a lessons learned perspective and should be incorporated into Hydro's Power Outage and Emergency Operating Procedure.

Recommendation		Status (Timing)
CCC1	Review rotating outage process used during the period of January 2-8, 2014, internally and with	In Progress (May 15, 2014)

Recommendation		Status (Timing)
	Newfoundland Power.	
CCC2	Review protocol for Hydro's use of Newfoundland Power's hydroelectric and standby generation resources and Newfoundland Power's request for real-time data concerning the status of the Island Interconnected System.	In Progress (May 15, 2014)
CCC3	Review outage protocol and add a Daily Communications Summary coordinated with Newfoundland Power and the mutual sharing of notices and advisories prior to release.	In Progress (April 30, 2014)

5.2 Capacity Assistance from Corner Brook Pulp and Paper

The coordination and communication efforts between Hydro and CBPP worked well. Upon determining that capacity assistance was required, Hydro contacted CBPP, who were receptive to a solution and a short-term capacity assistance agreement was achieved in short order. These types of arrangements are normal for utility operations and provided Hydro with additional generation. The arrangement was also more cost effective than other alternatives, such as renting a gas turbine, and was an appropriate solution for the time frame required. This arrangement is in place until March 31, 2014**.**

5.3 Communication with the General Public and Hydro's Customers

5.3.1 External Review

Hydro's Corporate Communications team engaged external consultants, MQO Research, NATIONAL Public Relations and Cathy Dornan Public Affairs to review Hydro's performance during the outages. The telephone survey conducted by MQO Research showed that 62% of the people surveyed gave Hydro a rating of seven or higher (out of ten) when asked if Hydro provided information that was easy to understand. Over 50% of people surveyed provided a

rating of seven or higher on Hydro's provision of up-to-date and reliable information. While respondents indicated that Hydro could have provided more information and updates during the outages, respondents also indicated that Hydro's communication with the public was one of the top things that Hydro did well during the events. The report by NATIONAL Public Relations also shows that Hydro had a significant presence on social media. It demonstrates that social media was an effective means of sharing information and that Hydro was successful in reaching its target audience: customers and members of the general public. The report by Cathy Dornan Public Affairs indicates that Hydro did a very good job of communicating to the public and ensured that the public had reliable information.

5.3.2 Internal Review

The Corporate Communications team engaged in frequent distribution of information through a variety of channels, including traditional and social media. The team was accessible to the media throughout the disruptions and responded to social media questions efficiently and effectively. Hydro posted a high volume of information via social media and shared information in real time, for example, the Vice President of Corporate Relations was on air with VOCM and CBC within ten minutes following the January 5 Holyrood event. To assist with the provision of information to the public in the future, advisory templates should be prepared in advance.

During the outages, Hydro created an outage takeover website during the outages that took priority over Hydro's website such that all advisories, important links and key information was housed in one place and accessible by the public. It has been determined that the outage takeover website worked very well during the disruptions and Hydro has created an outage takeover website which can be deployed immediately by Corporate Communications during future events. The website will also have mobile functionality such that the public can access it through mobile devices.

Corporate Communications and the ECC maintained good dialogue and contact throughout the events, however, there were a few instances where information on system events was not provided to Corporate Communications in a timely manner. This resulted in the inaccurate provision of information to stakeholders and customers. Where there were gaps during the events, feedback was provided and changes were made.

Hydro communicated with key stakeholders during the disruptions. Regular updates were sent to Government by the Vice President of Corporate Relations. Both Hydro and Government participated in joint media briefings and participated in a joint energy conservation campaign. As well, new stakeholders were identified during the outages, such as the Canadian Federation of Independent Businesses. However, a broader key customer account and power outage stakeholder list would assist and expedite this process in the future.

Following the outages in January 2014, Hydro has continued to provide information to, and answer questions from, the public through email and social media. A public advertisement and stakeholder outreach plan was prepared and issued publicly, apologizing to customers for the events and their impact.

Hydro also held follow-up meetings with large institutions, including Memorial University and College of the North Atlantic, and has had discussions with the school district, the St. John's Board of Trade and the Canadian Federation of Independent Businesses.

On January 29, 2014, Hydro started posting its daily supply and demand reports, which it provides to the PUB, on Hydro's website. On February 17, 2014, Hydro posted a blog post explaining peak demand and generation and a live feed of Hydro System generation and Island System generation on its website, in response to customer feedback and requests.

Recommendation		Status (Timing)
CCC4	Prepare public advisories templates in advance of potential events to assist with rapid response and customer queries.	In Progress (May 15, 2014)
CCC5	Streamline internal process for distribution of information from the ECC to Corporate Communications to ensure accurate and timely communication.	In Progress (May 15, 2014)
CCC6	Develop key customer and power outage stakeholder list.	In Progress (May 15, 2014)

Customer Service received a number of calls during the outages from Newfoundland Power customers, seeking information on the duration of outage rotations and when generation supply would return to normal. The overall customer tone was good; while some customers were frustrated, few were really upset. A lack of information on restoration times and uncertainty with supply were the common concerns expressed by callers. Some businesses expressed concern with the economic impact on their business. The provision of news updates and media briefings by the Corporate Communications team appeared to ease the call volume into Hydro's Call Centre. It was noted that there were only two CSRs available to take calls at a time, meaning that if more than two people called at the same time, a queue was created and people had to wait until a CSR was available. Customer Service is already investigating overflow call options and the IVR programming at high volume times and potential alternatives.

If the Call Centre was not open, calls were directed to the ECC. While coordination between the ECC and Customer Service worked well and the ECC determined it was capable of answering Customer Service calls while the Call Centre was closed, to ensure that the ECC can focus on system operations, the process of routing calls to the ECC after hours should be reviewed by

the ECC and Customer Service to determine if a better alternative exists.

During the outages, it was discovered that each Transmission & Rural Operations (TRO) region maintained its own key customer contact list and these lists are not centralized and coordinated with Hydro's Customer Service. While Hydro was able to provide its customers with up-to-date information in an effective manner, it was determined that the key customer contact list for each TRO region should be centralized and a process put in place for ongoing management of the list.

	Recommendation	Status (Timing)
CCC7	Investigate alternatives for Customer Service calls, including overflow call options and the IVR programming at high volume times, to ensure customer calls are answered in a more timely manner.	In Progress (April 30, 2014)
CCC8	Identify priority feeders in Hydro's service territory and determine which feeders contain sensitive customers to assist in developing a feeder rotation list.	In Progress (April 30, 2014)

5.4 Call for Customer Conservation

Hydro is of the opinion that the conservation measures had an impact in reducing customer demand, although the specific impact of the conservation measures cannot be measured. Through monitoring of social and traditional media, it was apparent that people were taking steps to conserve energy in both their homes and businesses. At the beginning of the rotating outages, in particular, people posted about observing homes without their holiday lights on and discussed measures they were taking inside their homes and businesses, such as turning down their heat and turning off commercial lighting and heat.

The survey conducted by MQO Research post-outage, indicates that 86% of respondents practiced energy conservation measures during the outages and most had continued with these measures up to the time of the survey. Most respondents indicated that they turned off outdoor Christmas lights (83%) and turned down the heat (51%). As well, through coordination with the Government of Newfoundland and Labrador, Memorial University of Newfoundland, the College of the North Atlantic and grade schools remained closed removing considerable load from the electrical system. As well, we recognize that commercial customers were also assisting. Within Hydro offices, for example, adjustments were made to heating systems to enable demand savings within the peak periods. Changes in total system load pattern due to conservation, weather variables, and regular dynamic behaviour of load, however, make it difficult to discern the specific and measureable impact of conservation. Regardless, such requests are worthwhile and should be maintained.

Hydro and Newfoundland Power promote energy conservation initiatives and programs through the joint utility program, takeCHARGE. The internal review determined that additional broad conservation programs related to demand reductions are not necessary during the 2014 winter period. There are two primary reasons for this assessment. First, the marginal cost of generation is driven by Holyrood Thermal Generating Station fuel which is an energy related cost. This has resulted in a focus on energy conservation in joint utility programming as a cost effective alternative to the burning of fuel at Holyrood. The short-term calls for conservation in January were targeting demand reductions. The establishment of demand management programs would require further study of the longer-term marginal costs of the system to provide economic basis for their implementation. Secondly, at this time Hydro's generation is projected to meet the forecast load for the remaining 2014 winter period so an extended demand management program is not required.

Following the January 2014 supply disruptions, the ECC requires a formal protocol for advising internal and external stakeholders to determine if a conservations request is necessary.

Corporate Communications also requires a clear protocol for advising the public of the conservation request.

The conservation requests and public releases were prepared very quickly. When the initial conservation request was made on January 2, 2014, it focused solely on conservation and what the public could do to conserve. This is consistent with the approach taken by utilities in other jurisdictions, however, the conservation information provided to the public was primarily directed at residential customers initially, but should be broadened to include commercial customers.

The Corporate Communications team and Energy Efficiency team worked well together to develop the messaging surrounding energy conservation and this practise should be continued.

Recommendation		**Status (Timing)**
CCC9	Develop protocol for advising internal and external stakeholders when Hydro's system reserves are within the threshold of the loss of the largest generating unit, and when an energy conservation call is required.	In Progress (April 30, 2014)
CCC10	Ensure conservation information directed at commercial businesses is prepared and released in addition to conservation information for residents.	In Progress (April 30, 2014)

Appendices

Appendix 1

POWER OUTAGE AND EMERGENCY OPERATING PROCEDURES

Revision: 5
Updated: March 21, 2011

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

PURPOSE 1
GENERAL 1
GUIDELINES 2
RESPONSIBILITIES 2
Customer Service Manager 2
Regional Manager or Designate 3
Communications Centre Designate 3
Corporate Communications & Shareholder Relations (CC&SR) Designate 3
System Operations and Customer Services (SO&CS) Administrative Assistant 4
OUTAGE PROTOCOL DURING REGULAR BUSINESS HOURS: (8:00 AM to 4:00 PM WEEKDAYS) 5
Customer Service Representatives (CSRs) 5
Communications Centre Designate 5
Regional and Area Office Personnel 6
Regional Designate 6
ECC Operator 6
ECC Shift Supervisor 7
OUTAGE PROTOCOL AFTER REGULAR BUSINESS HOURS (FROM 4:00 PM to 8:00 AM AND WEEKENDS) 8
ECC Operator 8
ECC Shift Supervisor 8
Customer Services On Call Person 8
Region On Call Person 9
Customer Service Representatives 9
PROCEDURES 10
Section 1 - Procedures for Responding to a Power Outage or Emergency Call 10
Section 2 - Procedures for Managing a Power Outage or Emergency 13

Appendix A

PURPOSE

The purpose of this document is to provide a clear communications plan for Newfoundland and Labrador Hydro (Hydro) during a power outage or emergency, to better service our customers. The document outlines the roles and responsibilities of departments and designated individuals during customer outages and emergencies, as well as the procedures to follow during these situations.

GENERAL

Hydro provides a 24-hour power outage and emergency service to its customers in Newfoundland and Labrador. Customers may use either of Hydro's Customer Service toll-free numbers to access the on-line Power Outage and Emergency System (POES). Once contact is made with the POES, customers can acquire the following information:

- Dates and times of scheduled outages for specified telephone exchanges.
- Updates on current unscheduled outages for specified telephone exchanges.

While in the POES customers have the option to "zero out" to speak with a Hydro Representative. Calls are directed to Hydro's Communications Centre during normal work hours and to the Energy Control Centre (ECC) after hours. If a customer accesses the POES and no outages are recorded for the exchange they selected, then they are immediately given the option to "zero out" to report an outage to a Hydro representative.

In addition to the POES, customers can access outage information via Hydro's website at www.nlh.nl.ca.

The procedures and responsibilities outlined in this document are designed to insure all reported power outages and emergencies are documented and responded to in a timely and effective manner. In addition, customers affected by a power outage or emergency are kept up-to-date on the status of the outage affecting them. This will occur either through the POES or through information provided by Corporate Communications & Shareholder Relations to the media.

These procedures are divided into two sections. *Section 1 - Procedures for Responding to a Power Outage or Emergency Call*, outlines the process to be followed from the time notification of a power outage or emergency is received until it is responded to in the field. *Section 2 - Procedures for Managing a Power Outage or Emergency*, outlines the process to be followed from the initial assessment of the event until power is restored or the emergency is over and the POES is back to normal mode.

GUIDELINES

Power outage and emergency calls from customers during regular work hours will be handled through Hydro's Communications Centre.

Power outage and emergency calls from customers after regular work hours will be handled through Hydro's ECC, unless the Communications Centre has been activated because the volume of customer calls can not be handled through the ECC.

Three or more calls to the Communications Centre, or to ECC or the Region reporting an outage in a similar location triggers the immediate standard outage notification message to be placed on POES. The standard outage notification will include basic information about the areas affected, if there is a known reason for the outage and an approximate restoration time. If the reason for the outage is unknown, then no reason will be given for the outage. If the restoration time is unknown the initial message will inform the customer of this. If the restoration time is unknown after 1 hour a new message will be recorded indicating an estimated restoration time of 3 hours. If there is a delay in getting to the site the initial message will indicate a restoration time of 4 hours.

Single Points of Contact (SPOC) have been identified for: Communications Centre, Corporate Communications and Shareholder Relations (CC&SR) and the Region impacted by the outage or emergency. A list of SPOC designates and contact information is attached in Appendix A to this document

RESPONSIBILITIES

Customer Service Manager

1. Will ensure Hydro's POES is functioning as required and changes and upgrades are identified and carried out in a timely manner.
2. Will ensure customer concerns with respect to the system are recorded and responded to.
3. Will ensure user suggestions and concerns are recorded and addressed.
4. Will co-ordinate all changes and updates with the Service Provider.
5. Will ensure all users of the POES receive sufficient and up-to-date training.
6. Will ensure that the power outage procedures outlined in this document are provided to all staff involved in the power outage process.
7. Will ensure the power outage procedure is regularly reviewed and updated as necessary and communicated to all involved.
8. Will monitor the effectiveness of this power outage procedure and report deficiencies to appropriate staff to address the shortcomings.

Regional Manager or Designate

1. The Regional Manager will be the SPOC for the Region affected by the power outage or emergency.
2. The Regional Manager may designate a Regional designate to handle power outages or emergencies and act as the SPOC.
3. Will designate two or more employees in each of the following locations to handle power outage and emergency calls from the Communications Centre: Wabush, Happy Valley-Goose Bay, St. Anthony, Port Saunders and Bishop's Falls.
4. Will be responsible for establishing a VIP contact list of customers for their Region and ensuring this list is kept up-to-date.
5. Will ensure that customers on the VIP contact list are contacted when any of the conditions exist in Table 1: Power Outage or Emergency Severity Table.
6. Will work with Corporate Communication & Shareholder Relations (CC&SR) designate to prepare information for release to stakeholders and the media.
7. Will ensure that employees in the areas affected by the power outage or emergency know the proper protocol for handling calls from the public and the media.
8. Will maintain contact with the field crew and provide the Communications Centre designate with all pertinent information as early as possible.

Communications Centre Designate

1. Will be the SPOC for System Operations & Customer Service (SO&CS) Department during regular business hours and when the Communications Centre is activated after regular business hours.
2. Will communicate with the ECC, and Regional and CC&SR designate to relay and receive information about the outage.
3. Will maintain regular contact with the ECC designate to obtain updates when required.
4. Will provide information to the CSRs for updating the standard outage notification and ensure the POES is accurate and up-to-date.
5. Will make the appropriate arrangements to staff the Communications Centre to handle power outages that will continue after 4:00PM.
6. Will provide notice of any temporary closure of the Communications Centre to the ECC and will provide contact information in case of emergency during the closure.
7. Will co-odinate with all parties to implement a contingency plan if and when a problem should occur with any of the communications networking (ie. Communications Centre telephones not functioning)
8. Will set up Holiday Call Routing at the beginning of each year for Billing and Outages.

Corporate Communications & Shareholder Relations (CC&SR) Designate

1. Will be the SPOC for CC&SR Department.
2. Will relay timely and accurate information to the media during power outages.

3. Will work with NF Power's Communications representatives to relay and receive information about outages affecting NF Power customers (when required).
4. Will work with a Regional Representative to help develop and deliver information to VIP customers and the general public in the affected areas.
5. Will develop and maintain a VIP list for key shareholders & customers (i.e. Premiers office, MHA's, PUB, Mayors).

System Operations and Customer Services (SO&CS) Administrative Assistant

1. Will maintain a list of all (SPOC) and designates, all On-call Personnel throughout the System and Regional and area office personnel. This information will be kept on a common drive available to all users and will be attached as an appendix to this document.
2. Will maintain an up-to-date list of employees in each region and area office who are designated to handle power outage and emergency calls received from the Communications Centre during regular work hours.

Responsibilities for CSRs, ECC Operators, ECC Shift Supervisor, Regional and Area Office Personnel, Customer Services and Region On Call are outlined in the following pages under Outage Protocol.

OUTAGE PROTOCOL DURING REGULAR BUSINESS HOURS: (8:00 AM to 4:00 PM NST WEEKDAYS)

Customer Service Representatives (CSRs)

1. Will answer calls to the power outage line on a priority 1 basis.
2. Will open the CIS Emergency Calls Database in Lotus Notes and document all pertinent information on the power outage or emergency. (This information may be received directly from the customer or may be passed on by an ECC Operator or the Region.)
3. The CIS Emergency Call file is automatically forwarded to a group of individuals in one of three regional offices, depending on the area selected by the CSR when the file is created. As the note is opened by individuals in the regional office group, a return notification is sent to the originator.
4. If a return notification is not received immediately **OR** if the power outage or emergency is deemed by the CSR to be of an extreme nature (i.e. life threatening, major property damage, fire) will immediately follow up the Lotus Note with a telephone call to the designated person(s) in the affected regional or area office and confirm the Lotus Note was received. If it was not received will pass the information on verbally.
5. Will notify the Communications Centre designate if Lotus Notes is not operating.
6. Will contact the Communications Centre designate if contact cannot be made with personnel in the affected regional or area office.
7. Will immediately place a standard outage notification message on the POES, if any of these conditions exist:
   - A third call is received for the same power outage or emergency.
   - ECC has identified the outage as a system problem affecting multiple customers.
   - The Region has identified the outage as a system problem affecting multiple customers.
8. Will notify the Communications Centre designate when the standard notification is established.
9. Will continue to update the outage notification with information provided by the Communications Centre designate.
10. Will forward all calls from the media to the CC&SR designate.

Communications Centre Designate

1. Will receive information from the Regional designate once the situation is assessed by the field crew on site.
2. Will determine the severity of the outage per Table 1: Power Outage or Emergency Severity Table in consultation with the Regional Designate and will contact the CC&SR designate if one of the conditions exist as described in Table 1.
3. Will maintain contact with the CC&SR designate for the purpose of providing updated information on the power outage or emergency.
4. Will maintain contact with the affected area Regional Designate to obtain

updates on the outage or emergency.

5. Will maintain regular contact with the ECC Operator to obtain updates when required.
6. Will provide information to the CSRs for updating the standard outage notification.
7. Will relay information to the ECC and to the Customer Services On Call person by 3:30 PM of any power outages or emergencies that will extend beyond 4:00 PM.

Regional and Area Office Personnel

1. The designated employees will handle power outage and emergency calls received from the Communications Centre, system information received from the ECC and calls from the public regarding a power outage or emergency. One of the employees or a designate will be available at all times to receive and process transactions.
2. Will immediately open and read Lotus Notes on power outages and emergencies received from the Communications Centre.
3. If Lotus Notes is not operating or if information is received from the ECC, will manually record the outage information from the CSR or ECC Operator and pass it onto the Regional designate for immediate action.
4. Will manually record outage information received directly from the public, pass the information onto the Regional designate for immediate action and call the Communications Centre for information purpose. (The Power Outage and Emergency phone number will also be passed onto the public for future reference - 1-888-737-1296.)
5. Will forward all calls from the media to the CC&SR designate.

Regional Designate

1. Will maintain regular contact with the field crew and provide the Communications Centre designate with the following pertinent information as early as possible:
   - Cause of the outage or emergency
   - Location and number of communities and customers affected
   - Estimated restoration time
   - Changes to initial information
   - Number of crews working on the problem
2. Will provide updates to the Communication Centre designate on the status of the power outage and emergency.
3. Will relay information to the Region On Call person by 4:00 PM of any ongoing power outages.
4. Will forward all calls from the media to the CC&SR designate.

ECC Operator

1. Will make contact with the Regional and Area Office Personnel and pass along the power outage or emergency information in cases when immediate contact cannot be made with the Communications Centre during regular business hours.

2. If the Communications Centre is closed during regular business hours, calls taken by the ECC Operator will be immediately forwarded to the Regional and area office personnel.
3. Will receive information from the Communications Centre designate by 3:30PM on any ongoing outages or emergencies.

ECC Shift Supervisor

1. Will contact a CSR in the Communications Centre if two or more power outage or emergency calls are received in the ECC.
2. Will contact a CSR in the Communications Centre immediately if a system event occurs that results in a power outage to Hydro customers.
3. Will provide an update to the Communications Centre designate, if the Communications Centre is reopened during an ongoing outage.

OUTAGE PROTOCOL AFTER REGULAR BUSINESS HOURS (FROM 4:00 PM to 8:00 AM NST AND WEEKENDS)

ECC Operator

1. Will review the CIS Emergency Calls Database in Lotus Notes for details on all power outage and emergency activity that occurred that day and will review any on line messages currently active in the POES.
2. Will note the details of the outage and contact the Region On Call person upon notification of a power outage or emergency.
3. Will immediately place a standard outage notification message on the POES, if any of these conditions exist:
   - A third call is received for the same power outage or emergency.
   - ECC has identified the outage as a system problem affecting multiple customers.
   - The Region has identified the outage as a system problem affecting multiple customers.
4. Will update the standard outage notification on the POES as information is received from the field.
5. Will forward all calls from the media to the CC&SR designate.
6. Will continue to answer power outages and emergency calls from all areas that have not been transferred to the Communications Centre.
7. Prior to shift change will relay information to the Communications Centre designate of any ongoing power outages.

ECC Shift Supervisor

1. Will be the SPOC for the ECC.
2. Will determine the severity of the outage per Table 1: Power Outage or Emergency Severity Table in consultation with the Region On Call person and will contact the CC&SR designate if one of the conditions exist as describe in Table 1.
3. Will make the decision to contact the Customer Services On Call person to request that the Communications Centre be opened to accept trouble calls.
4. Following activation of the Communications Centre will provide any available update information to the Communications Centre designate concerning the ongoing outage or emergency.

Customer Services On Call Person

1. When contacted by ECC or the Communications Centre will confirm the location and extent of the outage and will then proceed directly to the Communications Centre. (This may occur prior to 4PM if an ongoing power outage or emergency is expected to extend beyond 4PM).
2. Will contact the CSRs to work as per the latest callback schedule.
3. Will reroute all telephone exchanges in the outage area from the ECC to the Communications Centre when a CSR(s) is set up to take calls.

4. Will maintain hourly contact with the Region On Call person to obtain regular updates on the outage.
5. Will keep CSR informed of the latest information for the purpose of keeping POES updated.
6. Will maintain hourly contact with the CC&SR designate for the purpose of providing updated information on the outage or emergency.
7. Will keep the Region On Call person informed of any pertinent information provided by customers.
8. In consultation with the Region On Call person, will deem the power outage or emergency over and will restore the call rerouting to its normal status.
9. Will relay information to the Communications Centre designate by 8:00 AM of any ongoing power outages.

Region On Call Person

1. When notified by ECC of a power or emergency will immediately make the necessary arrangements for a timely response.
2. Will provide updates to the ECC each hour on the hour until the power outage or emergency is over, or more frequently if the situation worsens or ends.
3. If the Communications Centre is activated, will provide updates to the Customer Service On Call person each hour on the hour until the power outage or emergency is over, or more frequently if the situation worsens or ends.
4. Will arrange a designate to provide information to ECC or the Communications Centre and /or process information received from ECC or the Communications Centre if, due to the severity of the outage or emergency is unable to perform these duties in an effective manner.
5. Will relay information to the Regional designate by 8:00 AM of any ongoing power outages.

Customer Service Representatives

1. Will report to the Communications Centre when called. Recall will be on a rotation basis.

PROCEDURES

Section 1 - Procedures for Responding to a Power Outage or Emergency Call

1.1 Power outage or emergency calls will be answered and processed by the Communications Centre, Energy Control Centre (ECC) and Regional and Area Office Personnel. Calls received at any other Hydro location will be directed to Hydro's Power Outage Line 1-888-737-1296.

1.2 Calls received at the Communications Centre, ECC and Regional and Area Office will be processed as follows:

1.2.1 **Communications Centre**

1.2.1.1 Calls will be answered by first available Customer Services Representative (CSR).

1.2.1.2 Only power outage and emergency calls will be accepted on the 1-888-737-1296 line. A CSR should transfer all other calls received on this line to Hydro's Customer Service line.

1.2.1.3 When the call is answered, the CSR will immediately open the CIS Emergency Calls Database and document all pertinent information on the outage or emergency.

1.2.1.4 The CSR will confirm receipt of return notification from the regional office personnel.

1.2.1.5 If a return notification is not received immediately **OR** if the power outage or emergency is deemed by the CSR to be of an extreme nature (i.e. life threatening, major property damage, fire) will immediately follow up the Lotus Note with a telephone call to the designated person(s) in the affected regional or area office and confirm the Lotus Note was received. If it was not received will pass the information on verbally.

1.2.1.6 Should Lotus Notes not be operating, the CSR will manually record the pertinent information and immediately call the Regional and Area Office Personnel in the affected regional or area office.

1.2.1.7 All CSR's will immediately read a Lotus Note received from the emergency database that was processed by another CSR.

1.2.1.8 Should two or more power outage or emergency calls be received at or around the same time, the CSRs taking the calls will communicate with the other CSRs through Lotus Notes Instant Messaging, where possible, to avoid a duplicate message being sent to the affected regional or area office.

1.2.1.9 All calls from the media will be forwarded to the Corporate Communication & Shareholder Relations (CC&SR) designate.

1.2.2 **Energy Control Centre**

1.2.2.1 Calls will be answered by the first available System Operator.

1.2.2.2 Power outage and emergency calls received during **regular business hours** will be handled as follows:

1.2.2.2.1 The ECC Operator will record the information from the customer and immediately call a CSR in the Communications Centre with the information. If immediate contact cannot be made with a CSR, the ECC Operator will make contact with the Regional or Area Office Personnel and pass along the power outage or emergency information. The ECC Shift Supervisor will contact the Communications Centre designate and inform them of the situation as soon as possible.

1.2.2.2.2 If a System event occurs that results in a power outage, the ECC Operator will contact a CSR in the Communications Centre immediately and pass along the pertinent information pertaining to the outage.

1.2.2.2.3 If the Communications Centre is closed during regular business hours the ECC Operator will handle the calls the same as those received after regular business hours. The call shall be made to the Regional Office (general number) as the on call person may not be available during regular work hours.

1.2.2.3 Power outage and emergency calls received **after regular business hours (4PM – 8AM, weekends and holidays)** will be handled as follows:

1.2.2.3.1 The ECC Operator will record the information from the customer and immediately call the Region On Call Person with the information.

1.2.2.4 All calls from the media will be forwarded to the CC&SR designate.

1.2.3 **Regional and Area Office**

1.2.3.1 Calls made directly to the office will be handled by the employee who answers the phone.

1.2.3.2 The employee will manually record the pertinent information and immediately notify the Regional designate in the affected regional or area office and a CSR in the Communications Centre (8AM to 4PM weekdays) or the ECC (4PM to 8AM, weekends & holidays) and pass along the information.

1.2.3.3 The employee receiving the call will provide the customer with Hydro's Emergency Power Outage Number 1-888-737-1296.

1.2.3.4 All calls from the media will be forwarded to the CC&SR designate.

1.3 If contact cannot be made by the CSR or ECC with the Region and Area Office Personnel in the affected area, the CSR or ECC Operator will immediately contact the Communications Centre designate (during regular business hours) or ECC Shift Supervisor (after regular business hours) who will assume responsibility for making contact with the Regional designate or Region On Call Person and pass along the outage information.

1.4 **Proceed to Step 1.5 only if one of the following events occur:**

1.4.1 A third call is received for the same power outage or emergency.
1.4.2 ECC has identified the outage as a system problem affecting multiple customers.
1.4.3 The Region has identified the outage as a system problem affecting multiple customers.

1.5 When initial contact has been made with the Regional and Area Office Personnel, the CSR (during regular business hours) or ECC Operator (after regular business hours) will place a standard outage notification message on the Power Outage and Emergency System (POES).

The standard outage notification will include basic information about the area(s) affected, if there is a known reason for the outage and an approximate restoration time. If the reason for the outage is unknown, then no reason will be given for the outage. If the restoration time is unknown the initial message will inform the customer of this. If the restoration time is unknown after 1 hour a new message will be recorded indicating a restoration time of 3 hours. If there is a delay in getting to the site the initial message will indicate a restoration time of 4 hours.

1.6 When the recorded message has been completed the CSR or ECC Operator will notify the Communications Centre designate (during regular business hours) or ECC Shift Supervisor (after regular business hours).

1.7 The Communications Centre designate or ECC Shift Supervisor in conjunction with the Regional designate or Region On Call Person will use the following table to determine the severity of the power outage or emergency. If any one of these conditions is met, then notify the CC&SR designate immediately.

Table 1: Power Outage or Emergency Severity Table
▪ Power disturbances affecting a significant number of customers and/or occurring over a significant period of time. The threshold for reporting an incident in this category is any power disturbance causing 1,000 or greater customer-hours of interruption (e.g., one hour outage affecting 1,000 customers or a 15 minute outage affecting 4,000 customers).
▪ Power disturbances affecting an entire diesel system, regardless of the number of customers, when the duration of the outage is four hours or more.
▪ Any intermittent power disturbances that occur frequently over a period of four hours or more and affect a specific geographic area.
▪ Any other power disturbance or incident that, in the judgment of the utility, ought to be reported to the PUB.

Section 2 - Procedures for Managing a Power Outage or Emergency

2.1 When the standard outage notification message is in place and the severity of the power outage or emergency is determined, the following steps shall be taken to manage the event.

1.1.1 **<u>Regular business hours – 8AM to 4PM Monday to Friday</u>**

1.1.1.1 When the initial assessment is completed by the field crew on site, the Regional designate will provide an update to the Communication Centre designate and pass along the following outage information: time, location and cause of the outage, number of communities and customer impacted and estimated restoration time.

1.1.1.2 If the severity of the outage or emergency falls in one of the categories in Table 1: Power Outage or Emergency Severity Table, the Communications Centre designate will contact the Corporate Communication & Shareholder Relations (CC&SR) designate to pass along the following outage information: time, location and cause of the outage, number of communities and customers impacted and estimated restoration time. The Communications Centre designate will provide the CC&SR designate with hourly updates, or more frequently if the condition worsens, until the outage is over.

1.1.1.3 If the severity of the outage or emergency falls in one of the categories in Table 1: Power Outage or Emergency Severity Table, the Regional designate will contact VIP customers in their region affected by the outage or emergency.

1.1.1.4 The Regional designate will provide employees in the areas

affected by the power outage or emergency accurate and up-to-date information. This is important for employees in Hydro's diesel plants who may receive calls from the public regarding an outage or emergency.

1.1.1.5 The Regional designate will provide updates to the Communications Centre designate each hour at the top of the hour until the power outage or emergency is over, or more frequently if new information becomes available or if the outage worsens.

1.1.1.6 As each update is received from the Regional designate, the Communications Centre designate will assign a CSR to update the IVR message, even if no new information is provided.

1.1.1.7 The SPOC for Customer Services will also maintain regular contact with the ECC to obtain updates when required.

1.1.1.8 Should it appear that an ongoing power outage or emergency will extend beyond 4PM the Regional and Communication Centre designates will arrange transition of responsibilities by 3:30PM and relay information about the outage to Region On Call person and ECC personnel respectively. The following information will be provided: time, location and cause of the outage, number of communities and customer impacted, estimated restoration time, number of crews on site and work to be completed.

2.2.1 **4PM to 8AM and on weekends & holidays (Communication Centre Closed)**

2.2.1.1 When the initial assessment is complete by the field crew on site, the Region On Call person or designate will provide an update to the ECC Shift Supervisor and pass along the following outage information: time, location and cause of the outage, number of communities and customer impacted and estimated restoration time.

2.2.1.2 If the severity of the outage or emergency falls in one of the categories in Table 1: Power Outage or Emergency Severity Table, the ECC Shift Supervisor will contact the CC&SR designate to pass along the following outage information: time, location and cause of the outage, number of communities and customers impacted and estimated restoration time. The ECC Shift Supervisor will provide the CC&SR designate with an update if the outage worsens.

2.2.1.3 The Region On Call person or designate will contact VIP customers in their region affected by the outage or emergency, if necessary.

2.2.1.4 The Region On Call person or designate will provide employees in the areas affected by the power outage or emergency accurate and up-to-date information. This is important for employees in

Hydro's diesel plants who may receive calls from the public regarding an outage or emergency.

2.2.1.5 The Region On Call or designate person will provide updates to the ECC Shift Supervisor each hour at the top of the hour until the power outage or emergency is over, or more frequently if new information becomes available or if the outage worsens.

2.2.1.6 As each update is received, the ECC Shift Supervisor will assign an ECC Operator to update the IVR message even if no new information is received.

2.2.1.7 Should it appear that an ongoing power outage or emergency will extend beyond 8:00AM, the Region On Call person or designate and the ECC Shift Supervisor will arrange transition of responsibilities by 8:00AM and relay information about the outage to Regional designate and Communications Centre designate respectively. The following information will be provided: time, location and cause of the outage, number of communities and customers impacted, estimated restoration time, number of crews on site and work to be completed.

2.3.1 **4PM to 8AM and on weekends & holidays (Communication Centre Opened)**

2.3.1.1 If the power outage or emergency occurs after normal hours or on weekends or holidays and the ECC Shift Supervisor determines the severity of the incident requires the Communications Centre to be opened he/she will contact the Customer Services On Call person and request the Communications Centre be opened.

2.3.1.2 The Customer Services On Call person will immediately arrange the Communications Centre to be opened.

2.3.1.3 When a CSR(s) is set up to take calls, the Customer Services On Call person will reroute all telephone exchanges in the outage area from the ECC to the Communications Centre.

2.3.1.4 The ECC Operator will continue to answer power outages and emergency calls from all areas that have not been transferred to the Communications Centre.

2.3.1.5 The Customer Services On Call person will contact the ECC Shift Supervisor and the Region On Call person for an update on the outage and will obtain the following information: time, location and cause of the outage, number of communities and customers impacted and estimated restoration time.

2.3.1.6 As each update is received the Customer Services On Call person will assign a CSR to update the IVR message, even if no new information is provided.

2.3.1.7 The Customer Services On Call person will provide the CC&SR designate with an update if the outage worsens.

2.3.1.8 Should the Customer Services On Call person decide to close the Communications Centre before the power outage or emergency is over he/she will contact the ECC Shift Supervisor to arrange transition of responsibilities and notify the Region On Call person or designate and the CC&SR designate of the transfer of responsibilities.

2.3.1.9 In consultation with the Region On Call person or designate, the Customer Service On Call person will deem the power outage or emergency over and will restore the call rerouting to its normal status.

1.2 **Planned Outages that extend beyond the original work**

Whenever a planned outage is deemed to extend for more than 30 minutes beyond the original planned outage, the field crew shall notify the Regional On Call. At this point, employees will follow Step 2 of these procedures.

1.3 When a power outage or emergency is over the Communications Centre designate (during regular business hours) or the ECC Shift Supervisor (after regular business hours) will ensure the POES is restored to normal operating status.

1.4 Whenever a major outage or emergency occurs the Customer Services Manager will arrange a “lessons learned” meeting at the earliest opportunity but not more then 5 working days following the outage.

APPENDIX A

Power Outage and Emergency Contact List			
On Call Listing			
	Work Number	Home Number	Cell Number
System Operations & Customer Services			
Robert Henderson			
Bob Butler			
Terry LeDrew			
Art Bursey			
David Harris			
Rob Cater			
Al Ballard			
Sonya Duggan			
Central Region			
Mike Churchill			
Gary Broderick			
Hughie Ireland			
Kenny Lush			
Darren Moore			
Jim Sceviour			
Scott Slade			
Paul Smith			
Joe Walsh			
Jim Wheeler			
Northern Region			
Bill Nippard			
Roger Hynes			
Ivan Parrill			
Tony Walker			
Dean Smith			
Kirby Spence			
Wade Hillier			
Clarence Way			
Roger Smith			
Jeff Rumbolt			
Clem Richards			
Larry Brown			
Ron Smith			
Labrador Region			
Harold Kean			
Anthony O'Brien			
Ken Lyall			
Rod Cabot			
Tom Sheppard			
Gerard Gould			
Phil Goudie			
Corporate Communications and Shareholder Relations			
Karen O'Neil			
Merissa Wiseman			

Single Points of Contact (Regular Work Hours)			
	Work Number	Home Number	Cell Number
System Operations & Customer Services			
Sonya Duggan			
Al Ballard			
Rob Henderson			
Bob Butler			
Sandra Sheppard			
Central Region			
Darlene Hancock			
Donna Bursey			
Lisa LeDrew			
Lois Dalley			
Kay Curtis			
Cathy Penney			
Lillian Hunt			
Northern Region			
Lousie Sinnicks			
Mary Lowe			
Darlene Genneaux			
Debbie Calloway			
Labrador Region			
April Pike			
Wayne Hoskins			
Charles Strowbridge			
Corina Ralph			
Corporate Communications and Shareholder Relations			
Karen O'Neil			
Merissa Wiseman			

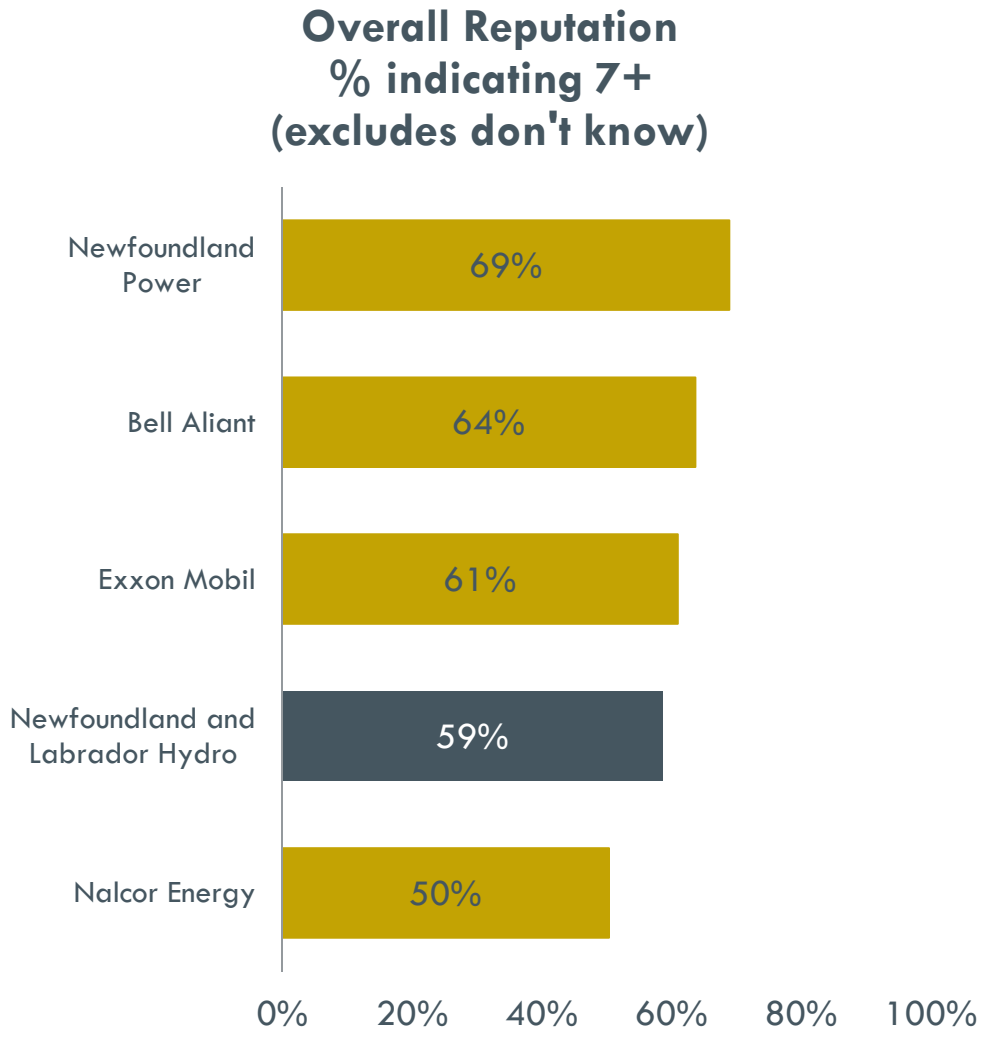
Newfoundland and Labrador Hydro
Power Outage Follow Up February 2014

Background and Methodology

- This project is based on telephone interviews completed with randomly selected individuals, 18 years of age and older, throughout Newfoundland and Labrador.
- Data collection took place from Jan 29th to Feb 4th 2014. Of note, data collection was taken after the major storm that caused wide spread planned and unplanned power outages.
- A total of 400 interviews were completed, which gives a margin of error of ± 4.9%, at the 95% confidence level.

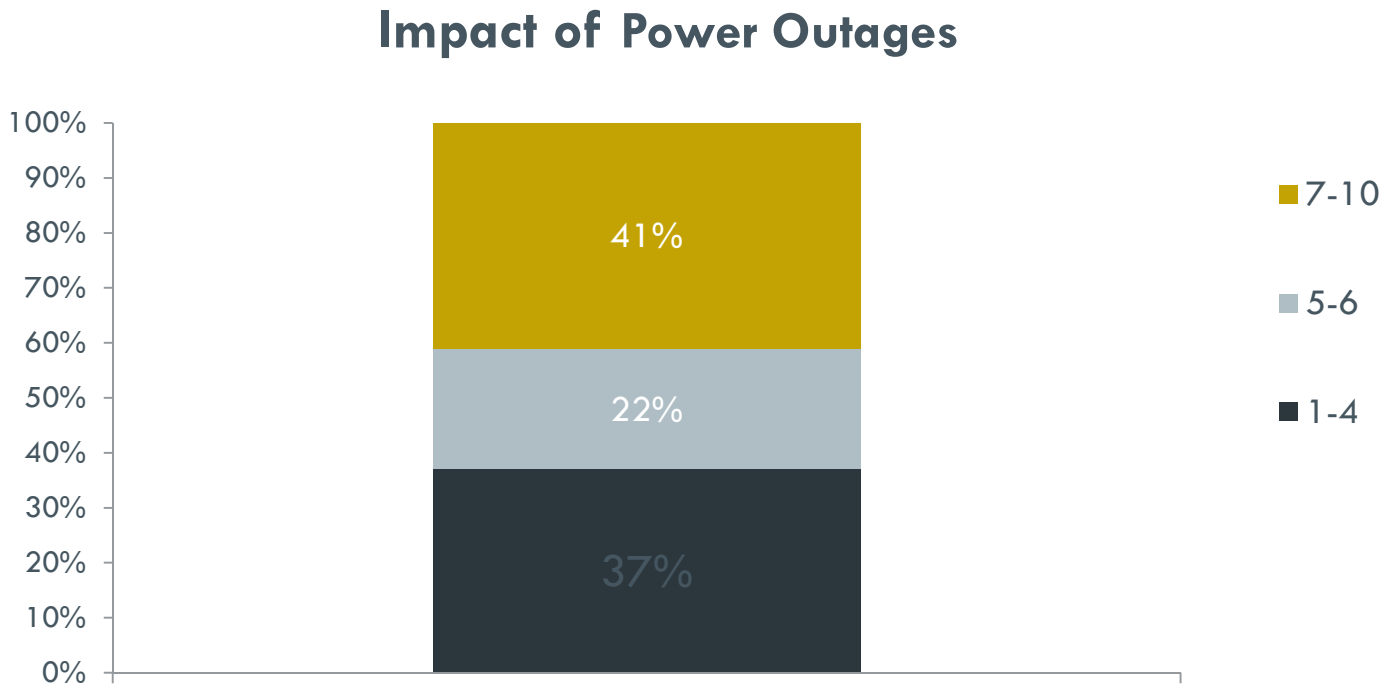
Benchmark Measures

- The survey began by asking respondents to assess the overall reputation of several prominent companies.
- A scale of 1 to 10 was used, where 1 is “a very bad reputation” and 10 is “a very good reputation”.
- The % indicating 7+ are shown. 59% gave Newfoundland and Labrador Hydro a score of 7 or higher.



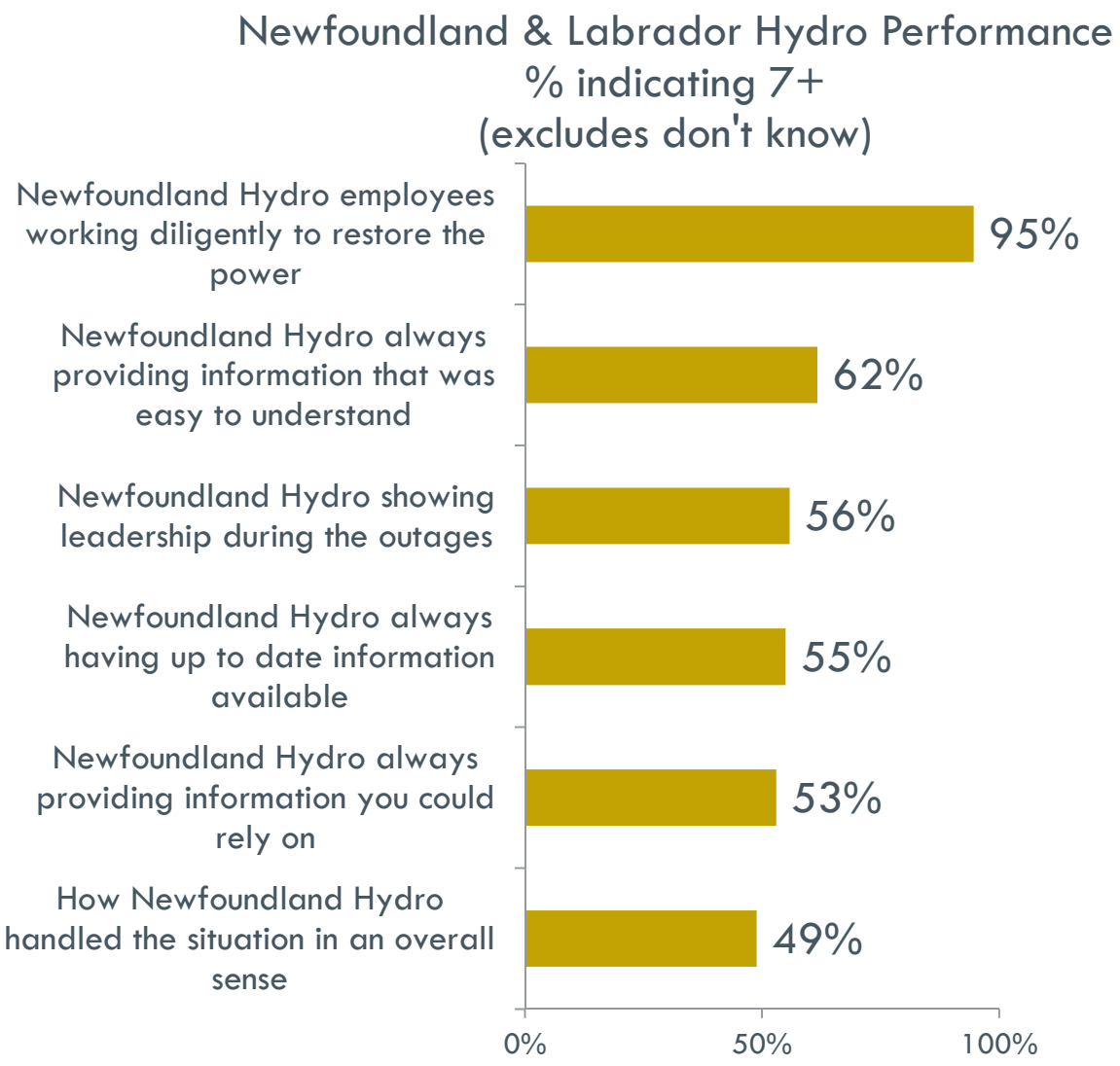
Impact of Recent Power Outages

- Respondents were asked to rate from a scale of 1 to 10, where 1 is "no impact at all" and 10 is "a very serious impact", the impact that the recent power outages had on them.
- For only 13%, the recent power outages had no impact at all (score of 1) on them.



NL Hydro Performance

- There is no negative perception of the employees trying to restore power. 95% gave a rating of 7 or higher and only 1% gave a 4 or less.
- Almost 50% gave a rating of 7 or higher on Hydro's overall handling of the situation.



Excludes "Don't Know"

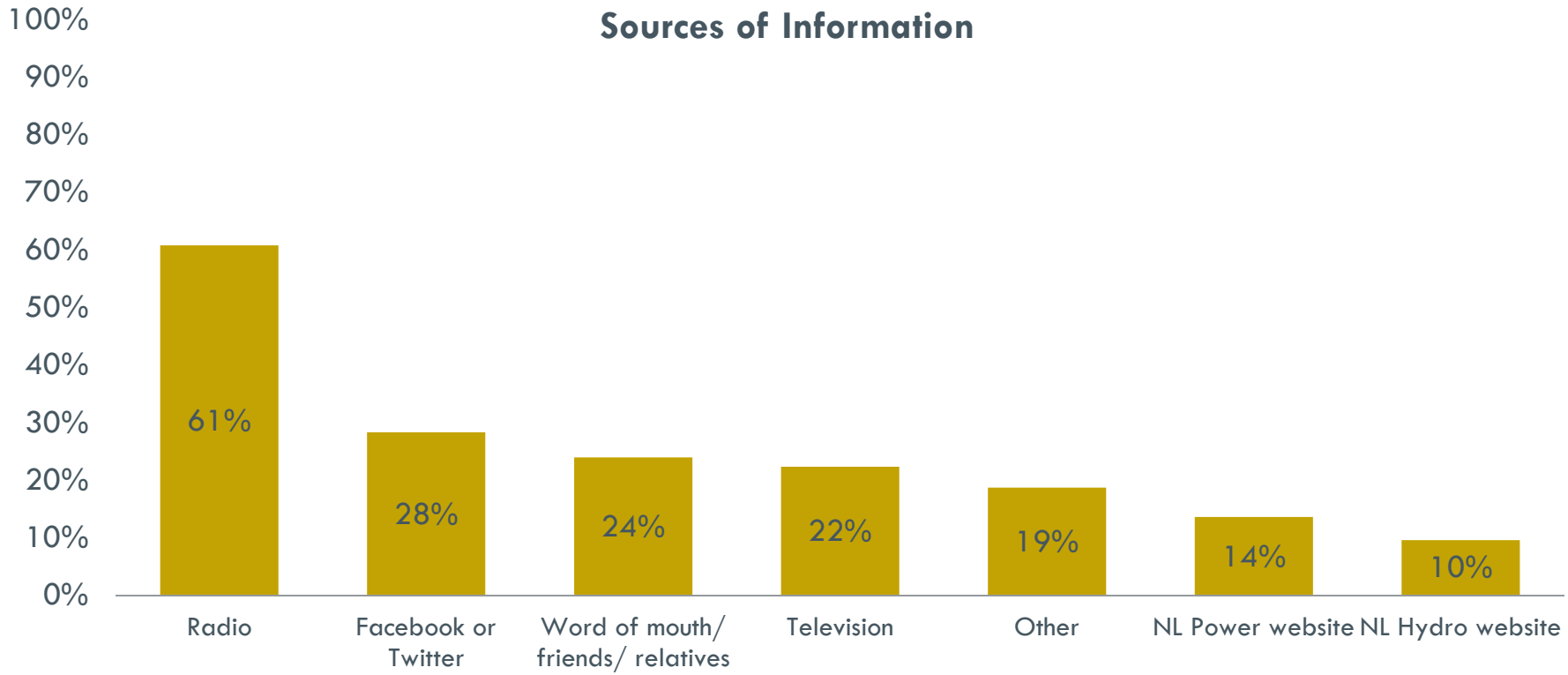
Open-ended questions

- Respondents were asked what they think Newfoundland & Labrador Hydro could have done better during the power outages. The top mentions were:
  - To be better prepared for power outages
  - To give more information/updates during the power outages

- Respondents were asked what were the specific things they felt Newfoundland & Labrador Hydro did well during the outages. The top mentions are below and the apparent contradiction between information and updates being on both lists can be explained by the comments coming from two different groups of people:
  - The dedication of the workers
  - They tried their best to get the power back as quickly as possible
  - Communication delivered to the public

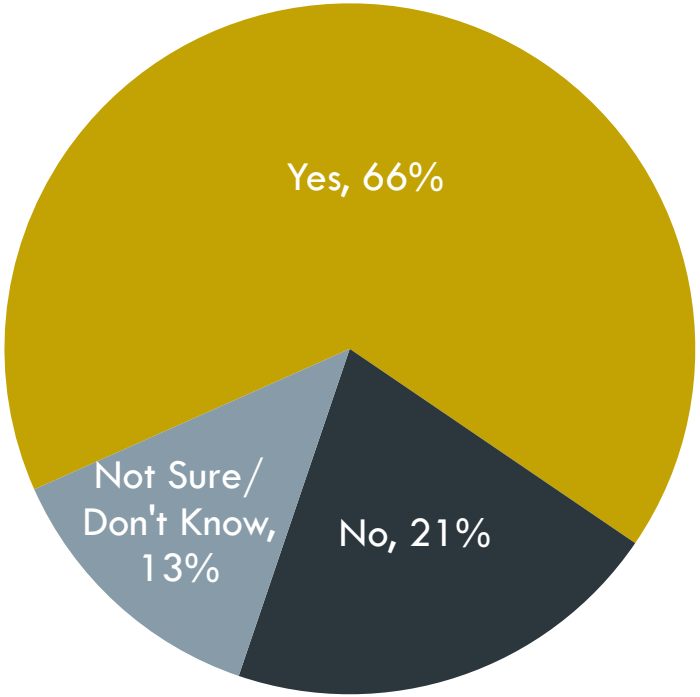
Sources of Information

- The respondents were asked what sources of information did they rely on the most during the power outages.
- The most common is radio at 61%



Information Available

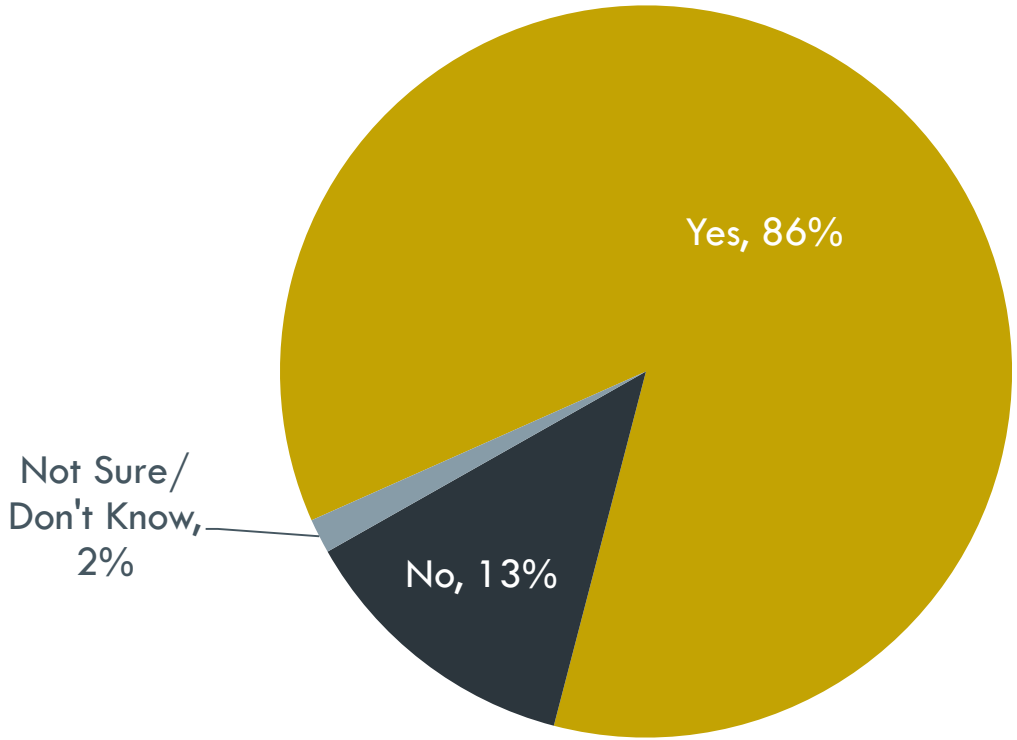
Did you feel that Newfoundland & Labrador Hydro provided information in enough places?



- Those that answered no were asked where else should the information have been. Most answered that they wanted more information available on the radio and that they wanted information available on the telephone (hotline).

Energy Conservation Measures

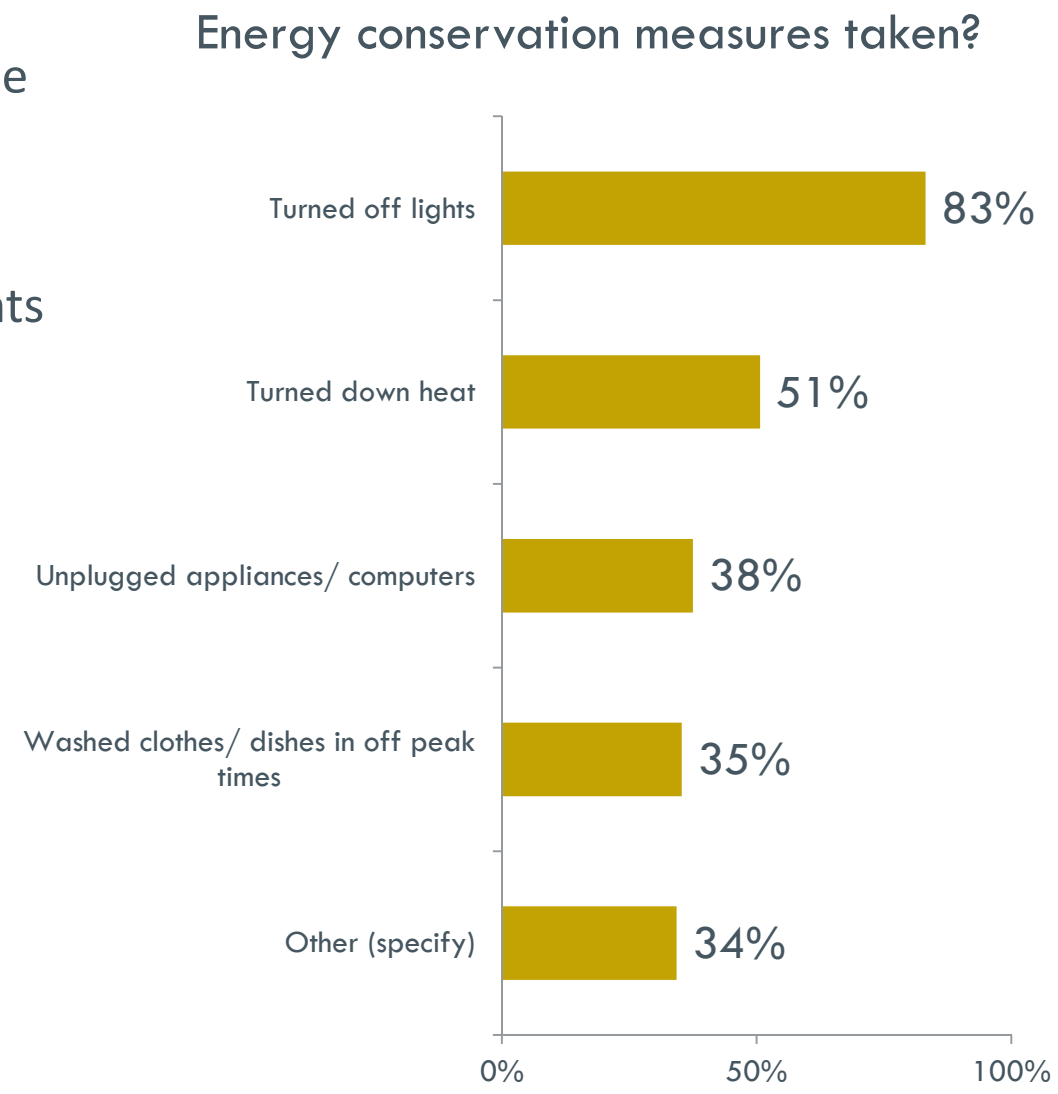
Did you and your family practice any energy conservation measures around the time of the outages that you would not normally have done?



Energy Conservation Measures

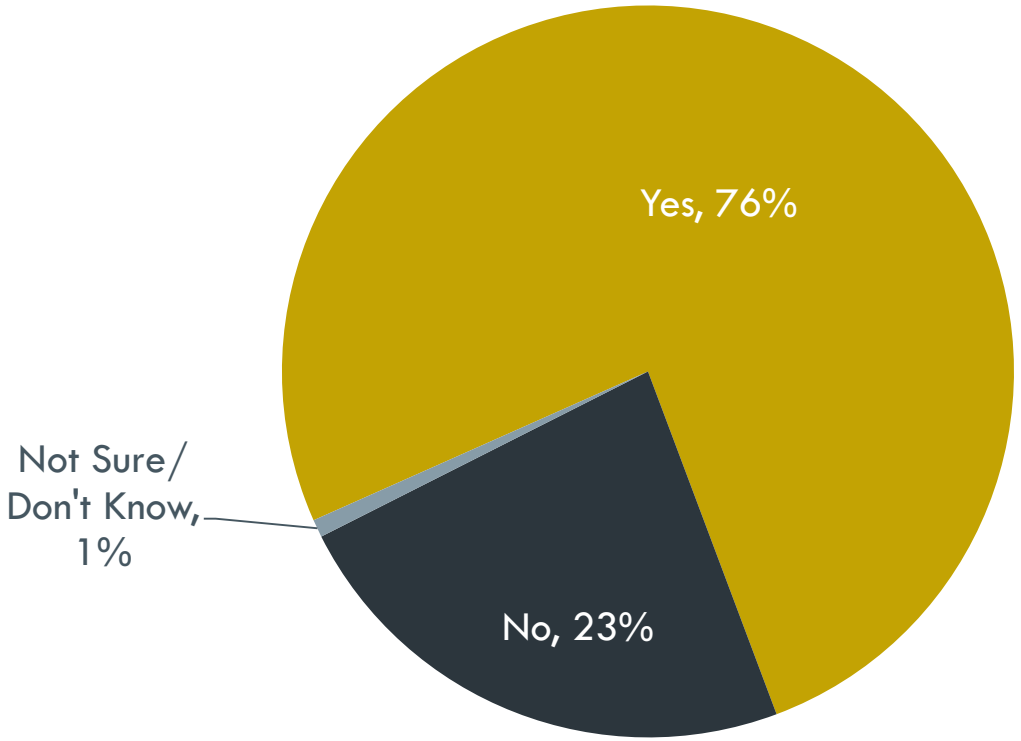
For those who answered other, the most common mentions were:

- Did not wash clothes
- Turn off outside/Christmas lights
- Used wood stove



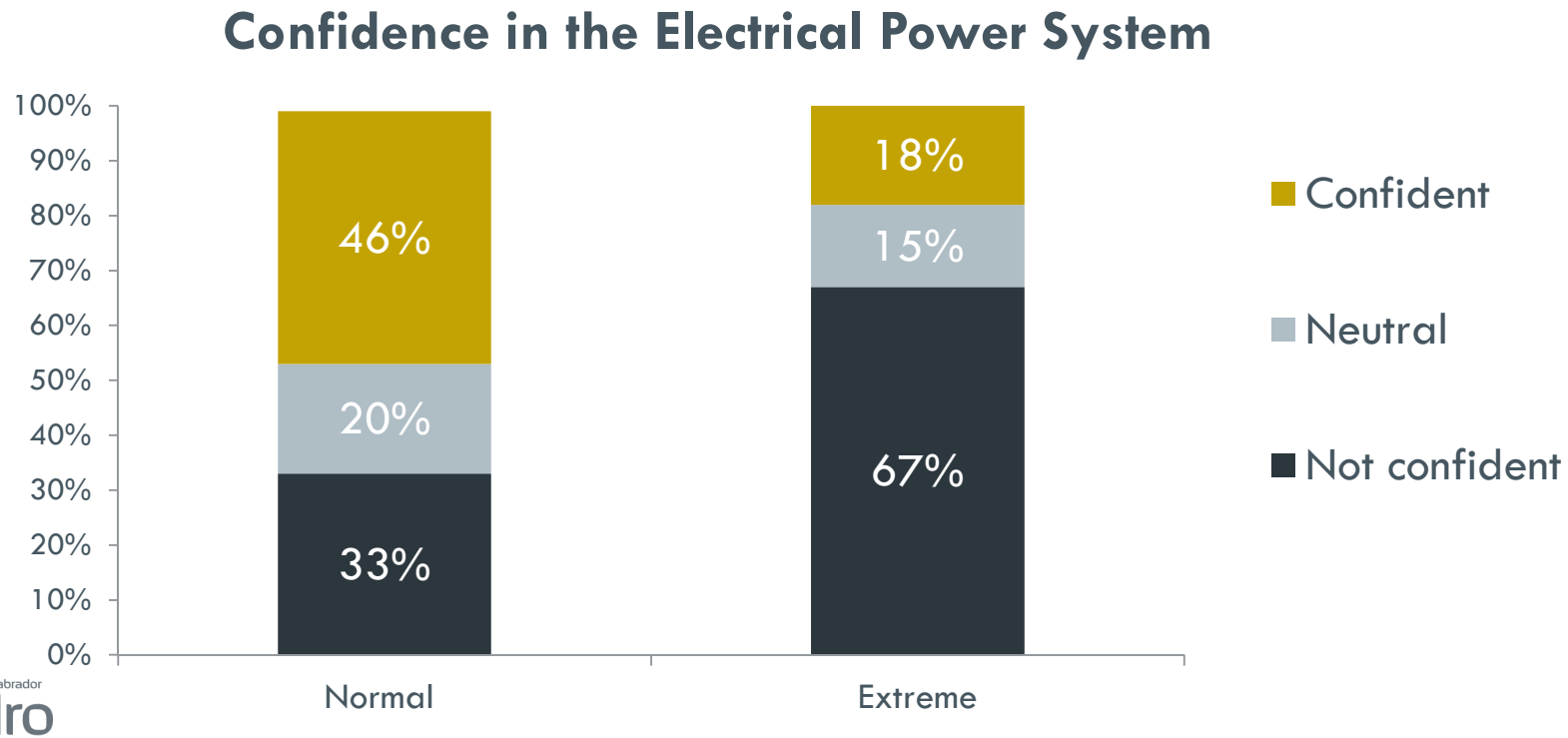
Energy Conservation Measures

Have you continued with these energy conservation measures?



Confidence in the Electrical Power System

- Confidence in the electrical power system is not great, particularly in extreme weather situations. Interestingly, younger respondents are less confident in both normal and extreme weather situations.

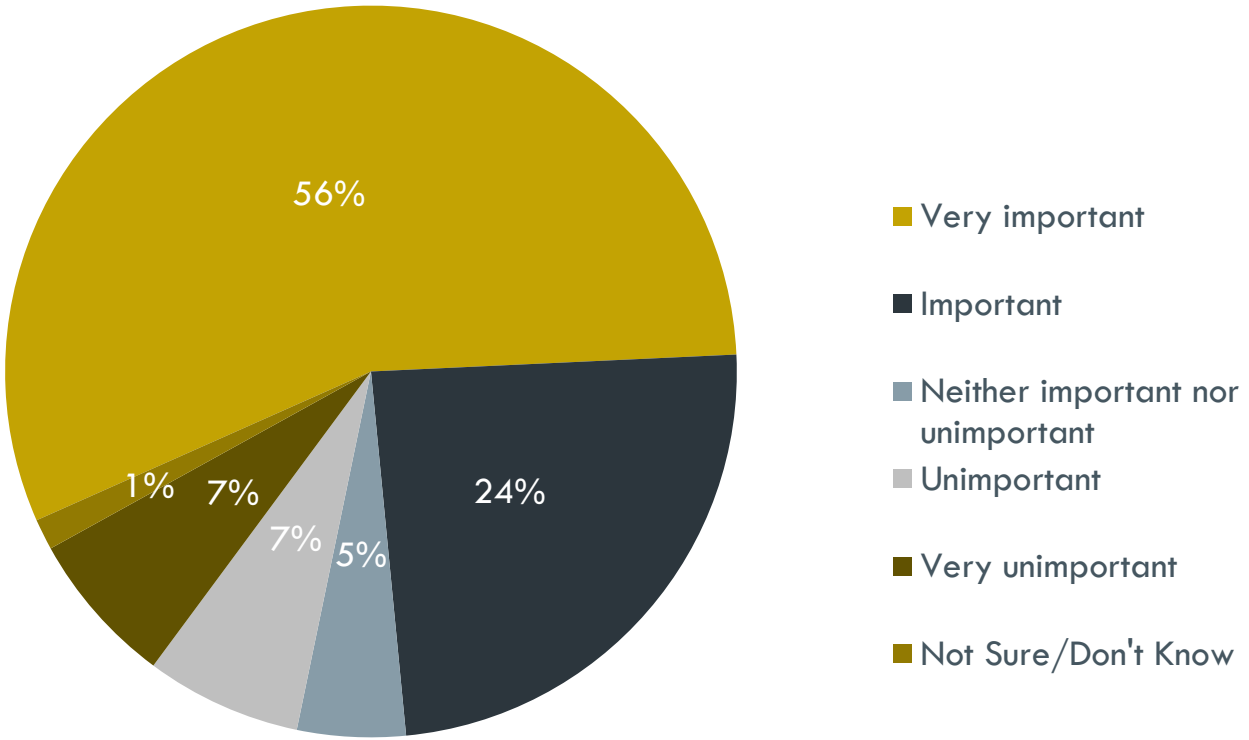


What would restore confidence?

- When asked what would restore their confidence in the electrical system, most people mentioned upgrading equipment and stations, more maintenance and more backup.
- Others took the question more as a when would they be confident rather than what would have to be done. These people tended to mention that one or more storms would have to happen without serious power loss before they would be confident again.
- Of interest is the fact that virtually nobody mentioned anything the general public should be doing to decrease the demand for power.

Review Causes of Outages

How important do you think it is that an independent review of the causes of the outages take place?



Key Findings

- The suggestions for how confidence can be restored places the responsibility squarely with the main players in the system. Respondents mostly suggested infrastructure improvements, upgrades, maintenance and backups.
- There is a strong sentiment that an independent review of the causes of the outages should take place.
- Hydro's performance during the outages were rated reasonably well. The efforts of the employees to restore power are certainly recognized.
- The tone of these findings seems to be more about taking steps to ensure it doesn't happen again rather than how Hydro did during the event.
- The majority of the respondents (86%) practiced energy conservation measures around the time of the outages and most have continued with these measures since.

Social Media Report – NL Hydro Outages

January 2-12, 2014

Executive Summary

With over 60 million impressions achieved through almost 50,000 mentions, social media and more specifically Twitter, was the second most-used source for information during the outages over the ten day period in January. Radio ranked first, and other traditional news mediums including evening news, newspapers were not relied on as heavily for up to date information on the events and impacts.

The greatest benefit that Twitter provided was the ability for two-way conversation between customers and other stakeholders and the company. This was achieved through the use of the accounts by NL Hydro, NF Power and also through the personal account of Nalcor VP, Dawn Dalley. As a result of the speed at which information could be made available through Twitter, the dialogue was for the most part very neutral and fact based, or positive.

We know that Twitter was effective in getting information updates out because as you monitor the word clouds you can see that the language changes day to day based on what the company has tweeted and shared.

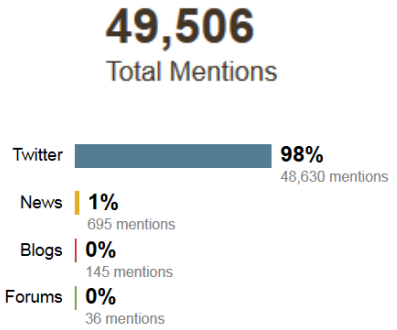
Throughout the event, more followers have come to rely on Twitter as a critical medium in which to get the most up to date information from NL Hydro and NF Power. During the January events, the tone and messages provided seemed disjointed at times and raised the question in peoples' minds if the two companies where on the same page. This is an area for improvement in future. While operationally the effort may have been seamless, the tone and information sharing on Twitter was not always well-aligned.

For NL Hydro, the use of a corporate account on Twitter as well as the personal account of spokesperson Dawn Dalley was an excellent approach to allow for ongoing updates and information, as well as very quick responses to specific questions and a call for conservation amongst customers. The response to Dalley's personal tweeting "humanized" the response and was well-received by stakeholders. While this approach is not required in all scenarios, during major events should be considered if resourcing the effort is possible.

Twitter will continue to be an important tool for two-way communication for NL Hydro and NF Power. While only so much information can be provided in 140 characters, it can be used for critical updates, messages of conservation, answering questions, and also for directing stakeholders to the tremendous amounts of information available to them through the company websites. Continued strategy development and focus on how to best leverage Twitter is important because it's the way that many stakeholders will now expect to be reached during any kind of event.

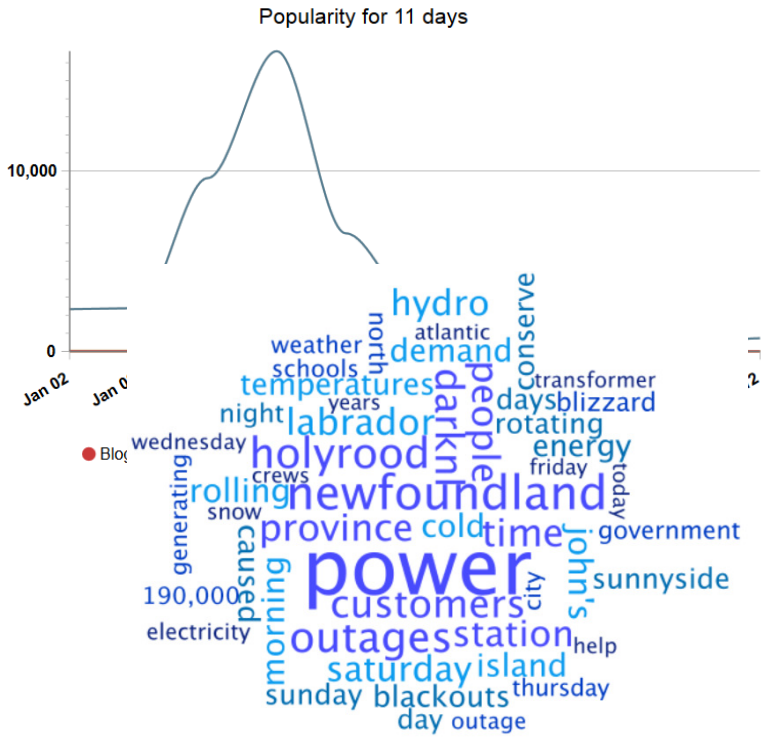
Highlights

- This report focuses on social media activity from January 2 until January 12, 2014 during the peak management and response period for Newfoundland and Labrador Hydro. There is a particular focus on Twitter since it accounted for 98% of almost 50,000 mentions during this period.
- The fact that there was almost 50,000 mentions in 11 days, 48,600 of which were on Twitter, demonstrates the resources required for NL Hydro to successfully monitor, respond and manage social media during the outages.
- Although the preference is always for NL Hydro to be the top source of information on social media, this would have been an unattainable goal in this instance. Given the number of media outlet and personnel accounts providing updates, as well as the required involvement of both NL Hydro and NF Power, no one Twitter account would successfully dominate social media updates. Understanding that, the focus becomes ensuring that NL Hydro, NF Power and where possible, media, are providing timely, accurate and consistent information so whether individuals receive updates from @NLHydro or @VOCMNews, the information should consistent. This is achieved on social media the same way it is in traditional media – by regularly providing up-to-date information to the media. The difference when we consider this in the context of social media is that the public and the media expect the information much faster (within minutes).



Popularity Graph – Social vs Traditional media

- Typically, (even for breaking news) graphs such as the popularity graphic below show traditional media peaks, followed shortly by social media peaks in conversation. Although this was generally the case during the outages, the ratio of traditional and social media mentions is so skewed that traditional media mentions are barely representing on the graph below. Although it is becoming increasingly common for social media mentions to be much higher than traditional media, the ratio of social to traditional media mentions for this issue is atypical.
- Despite 98% of mentions coming from Twitter, this doesn't mean social media deserves more (or even equal) attention compared to traditional media relations. Traditional media relations efforts arms media outlets with the information they're expected to relay online. And although many customers were also using Twitter to communicate, the daily word clouds at the end of this document that on a day-to-day basis, the conversation on Twitter was still driven by local media (multiple media Twitter handles and hashtags regularly



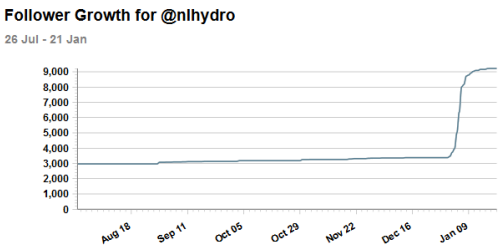
appear in daily word clouds) Instead, social media should be incorporated as part of a broader media and public response plan as it was in this incident.

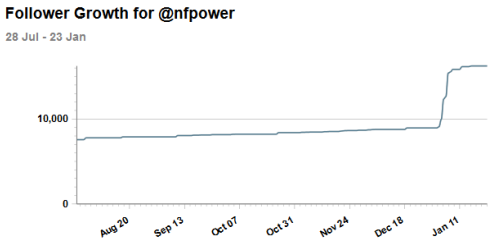
Word Clouds

- The word cloud to the right demonstrates the most commonly occurring words in online mentions during the outages. Larger words indicate more frequent mentions.
- Although many people were complaining and expressing frustrations on social media the most frequent words are a positive reflection of the utilities management of the issue. They are factual words, not emotional.
- Key words indicate that updates and facts were frequently shared online. This is evident by the presence of words such as transformer, generating, caused and multiple weekday mentions (Saturday, Sunday, Wednesday, Thursday, Friday).
- Key messages are also included (e.g., conserve, temperatures, 190,000)

Follower Growth

- The dramatic increase in followers to the @NLHydro account, which tripled in a few days, demonstrate that users recognized hydro as a useful source of information during the period.





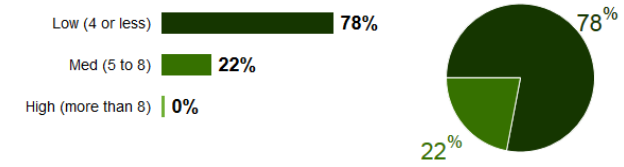
- This is especially significant since Newfoundland Power services 85% of customers on the island, so it is likely that most Twitter users consider Newfoundland Power to be their utility.
- Although Newfoundland Power's account has more followers, its increase was smaller and its customer base is significantly larger.
- Comparing updates from the two accounts during the outages, NL Hydro was much more efficient and active. Not only in terms of providing updates, but context and explanations that give followers the opportunity to understand what was happening and why.
- The word cloud to the right consists of the most frequently occurring words in the bios of twitter followers. Although it cannot connect followers with customers, it does indicate @NLHydro has been successful in reaching its target audience: customers and members of the general public. While such word clouds can often be dominated by government, union, industry-affiliated words, this is balanced and appears representative of the general public (student, mother, husband, university, business, NL, etc.)



Twitter Reach

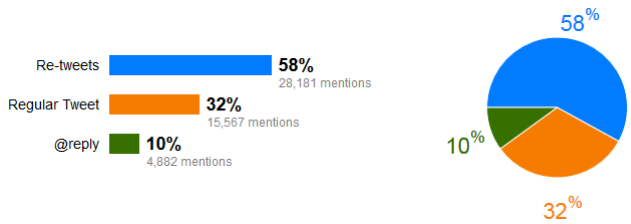
61.5 million estimated impressions
from 48,630 Twitter mentions by 20,497 users

Authority Breakdown



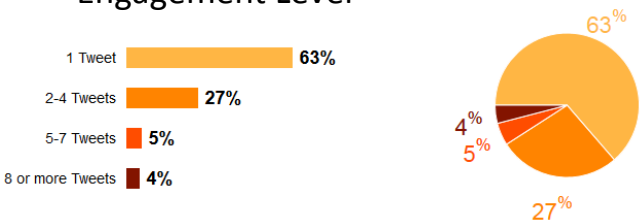
- There are no Twitter accounts based in NL that would be considered “high” authority. This would be for popular celebrities, Barack Obama, etc.
- Having more than 10,000 tweets from accounts of medium authority demonstrates the newsworthiness and reach of the issue. This would be accounts such as Justin Trudeau, George Stroumboulopoulos, Alan Hawco and Mark Critch, along with generic accounts such as CTV News, CBC Top News, the Weather Network and CBC NL.
- Most mentions are low authority but a low Twitter authority doesn't mean an account isn’t worth connecting with. In fact, NL Hydro’s target audience lies completely within this group. It’s the customers and local media who are interested in what is happening with electricity issues in the province.

Mention Type



- For issues that are heavily reported and updated by multiple media outlets, retweets would typically account for approximately 70% of the mentions.
- This demonstrates that while news updates and comical mentions are shared widely (as also seen in retweeted tweets statistics), many people are using social media to share their own experiences and opinions.
- 10% of mentions as replies is encouraging for this type of incident. It indicates that while people are engaging in conversations with one another, most are simply stating their own experience/opinion or providing an update, not engaging with other accounts. When @reply grows to 20% or more in an instance such as this, it is often an early indicator that the issue is snowballing and people’s level of frustration is growing at a crisis-level rate.

Engagement Level



- Most individuals are only tweeting once and about a quarter of mentions come from accounts that are tweeting more than once.
- While the percentage of those who have tweeted more frequently is low, considering the total number of tweets, this still means thousands of accounts tweeted more than 5 times.

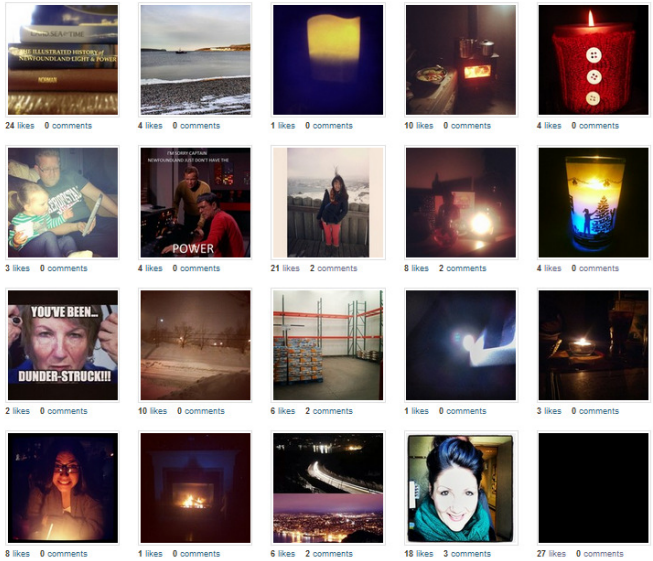
Most Retweeted Tweets

Although many of the tweets were complaints about the power outages, those that were shared and tweeted the most during the 11 days were not. The most retweeted tweets were those offering encouraging words, adding a new perspective to the conversation or providing an update on the situation.



Instagram

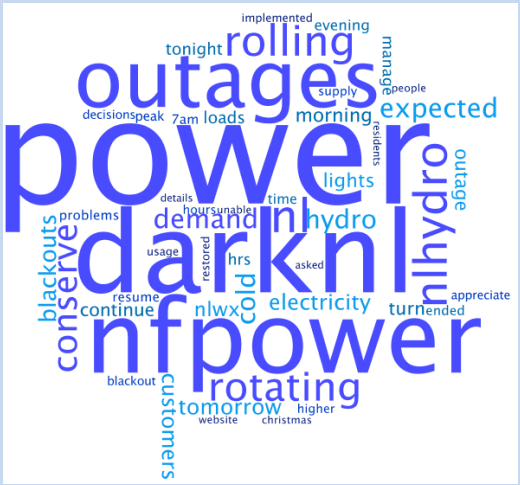
The collage of Instagram images to the right are those with the #darknl hashtag during the outages. There are no red flags here, typical Instagram pictures of people capturing what they're doing during the outages. Although there is one that is a meme, it is directed at the Premier. This is not surprising given the public discontent with the Premier's response and there is nothing of that nature directed at the utilities.

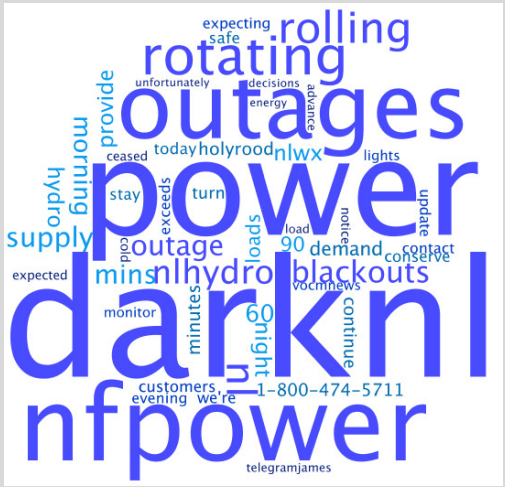
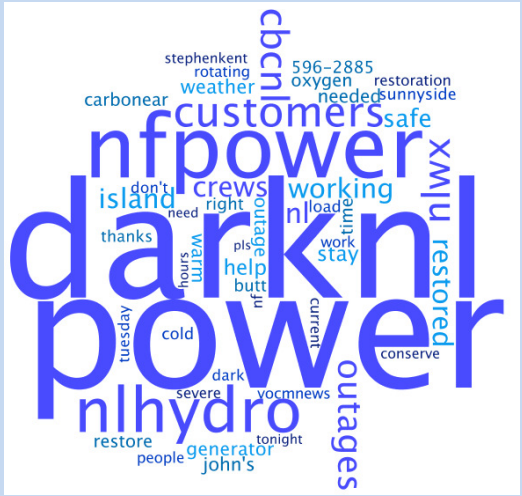


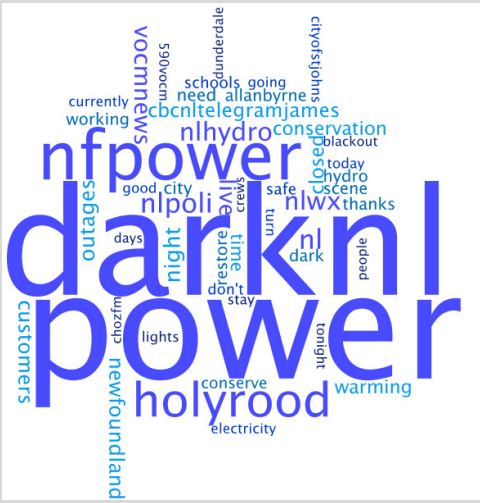
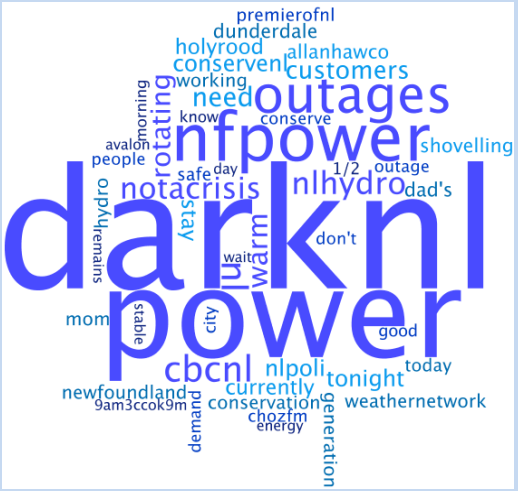
Daily breakdown

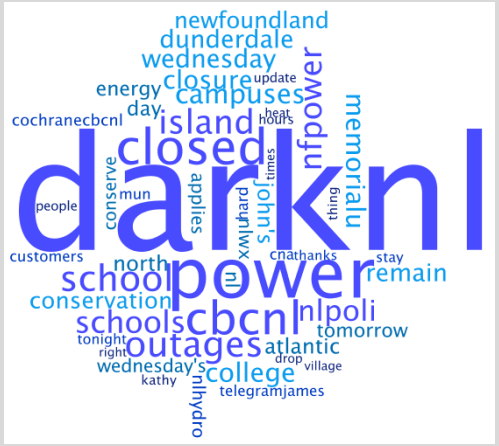
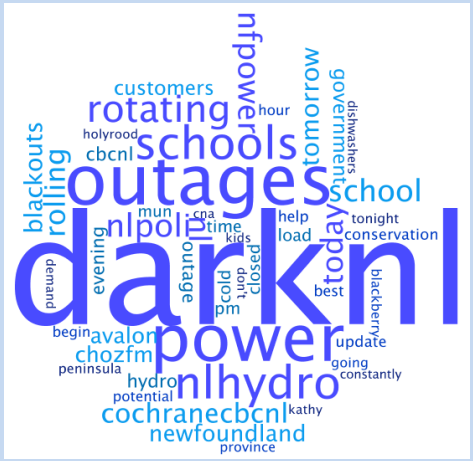
The following pages breakdown the mentions each day from January 2-12, including details about reach, the most retweeted tweets and word cloud capturing most frequently used words.

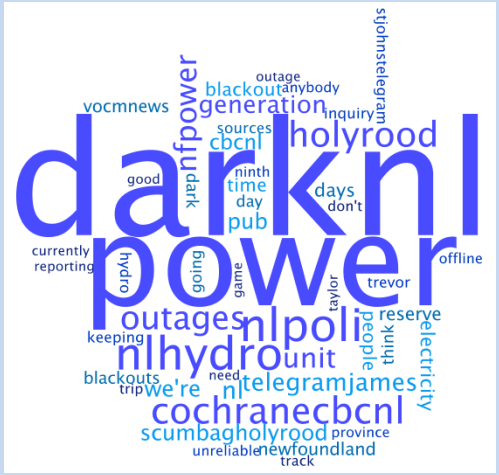
- It is positive that most retweeted tweets are generally factual, humorous or well wishes rather than complaints or frustrations. This is a testament to the utilities and media (via the utilities) ability to provide accurate and valuable information quickly.
- The conversation in the final days is largely driven by media. This is clear since many media twitter handles and hashtags appear in the word clouds. The conversation became especially light and humorous in tone during the final days as well. For example, one of the most retweeted tweets on January 10-12 is a joke about naming the generating stations in Holyrood and "Holyrood be trippin yo".
- Looking at 11 days of the top 4 tweets, only a couple are critical of Hydro.

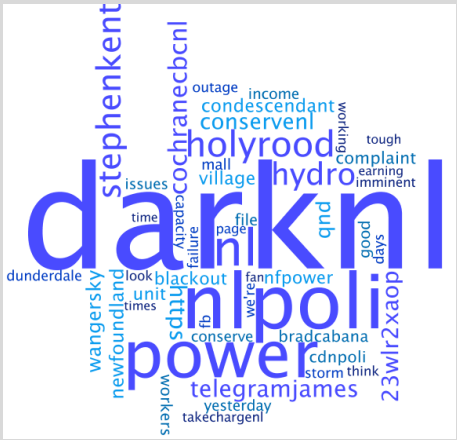
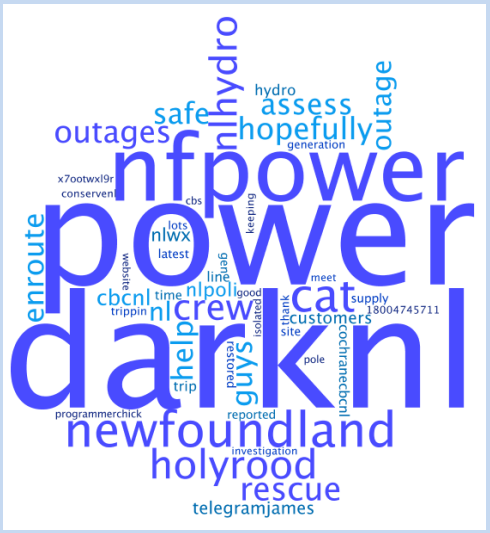
Date	Reach			Most Retweeted Tweets	Word Cloud
	Impressions	Mentions	Users		
Jan 2, 2014	3.5 million	2,342	1,050	Rotating outages implemented to manage electricity demand due to NLHydro system problems. Check website for details http://t.co/BXeOyN7YIe 2 Jan 2014 by Newfoundland Power Rotating power outages have ended for this evening and are expected to resume at 7am tomorrow morning. 2 Jan 2014 by Newfoundland Power Unfortunately we are unable to provide advance notice of rotating outages. Decisions are made quickly to balance supply and demand of power. 2 Jan 2014 by Newfoundland Power Due to @NLHydro power supply limitations we expect rolling outages to last between 30 & 60 mins. We appreciate your cooperation. 2 Jan 2014 by Newfoundland Power	

Jan 3, 2014	3.4 million	2,397	1,065	Rotating Outages have ceased for this evening. We will monitor loads throughout the night and provide an update in the morning. Stay Safe! 3 Jan 2014 by Newfoundland Power We're expecting rotating outages to last around 60 mins. If your outage exceeds 90 minutes please contact 1-800-474-5711. 3 Jan 2014 by Newfoundland Power Rolling blackouts in St. John's. From the complaints you'd swear it was random beheadings. #darknl #zombieapocalypse 3 Jan 2014 by Sean Panting We're expecting outages to last around 60 mins. If your outage exceeds 90 minutes please contact 1-800-474-5711. Thank you for you patience. 3 Jan 2014 by Newfoundland Power	
Jan 4, 2014	13.7 million	9,607	3,692	Generator needed for man in Carbonear on oxygen. If you can help, please call George Butt 596-2885. #darkNL #cbcnl 4 Jan 2014 by CBC Newfoundland It will likely be Tuesday before power will be restored to all customers. Crews are working around the clock. Stay safe everyone. 4 Jan 2014 by Newfoundland Power Please be advised, current outages taking place across the island are resulting from severe weather, not because of rotating outages. 4 Jan 2014 by Newfoundland Power Hoping that everyone affected by #DarkNL can stay safe and warm tonight. 4 Jan 2014 by Justin Trudeau, MP	

Jan 5, 2014	16.7 million	16,641	6,938	I'm on the scene, live at Holyrood. #DarkNL http://t.co/TuVrnE7peX 5 Jan 2014 by Allan Byrne Education Minister Clyde Jackman says all schools in Newfoundland, including MUN and CNA, will be closed Monday and Tuesday #DarkNL 5 Jan 2014 by OZFM Over 100,000 customers without power To everyone complaining to NL hydro, my dad just risked his life trying to restore the power and is currently in the hospital #HaveRespect 5 Jan 2014 by Danielle Vey Sending much warmth & good thoughts to glorious @Newfoundland 'rs that are without power again! #GodspeedToTheUtilityWorkersPart #DarkNL 5 Jan 2014 by G. Stroumboulopoulos	
Jan 6, 2014	10.9 million	6,544	2,724	Shovelling out Mom and Dad's back door. 1/2 @weathernetwork @CBCNL #DarkNL http://t.co/9aM3CCok9M 6 Jan 2014 by Allan Hawco To everyone complaining to NL hydro, my dad just risked his life trying to restore the power and is currently in the hospital #HaveRespect 5 Jan 2014 by Danielle Vey As long as generation from @nlhydro remains stable there should be no need to rotate outages this evening. Stay warm and safe. 6 Jan 2014 by Newfoundland Power Hang in der #DarkNL .Burn books in ur basement to stay warm. Pick the weakest in your family to eat if need b- (don't tellem) & 4 fun dance! 6 Jan 2014 by Shaun Majumder	

Jan 7, 2014	3.6 million	2,670	1,414	Wednesday's school closure also applies to @MemorialU and the College of the North Atlantic campuses on the island #darknl #cbcnl 7 Jan 2014 by CBC Newfoundland Conservation remains very important!Customers should be prepared for potential outages as temps drop & during peak usage times. 7 Jan 2014 by Newfoundland Power Village Mall: Revenge of The Fountain #DarkNL 7 Jan 2014 by Dave Sullivan There are no rotating power outages planned for this evening. It's important u con't to conserve energy. We're monitoring our system closely 7 Jan 2014 by Newfoundland Power Quidi Vidi, St. John's - The day after the	
Jan 8, 2014	4.8 million	4,365	2,020	Outage rotations affecting customers on the Avalon Peninsula will begin this evening. We will do our best to keep outages to 1 hour. 8 Jan 2014 by Newfoundland Power Due to extremely cold temperatures today & demand going up we're now facing rotating outages on the Avalon for the 1st time since Mon. 8 Jan 2014 by NLHydro Reporter theory is school kids are constantly running dishwashers and dryers to ensure schools stay closed #DarkNL 8 Jan 2014 by David Cochrane An update regarding schools across the province, including MUN and CNA, will be made by government officials at 4 PM today. #DarkNL 8 Jan 2014 by OZFM	

Jan 9, 2014	2.2 million	917	503	Did you buy gas at Ultramar Whitbourne TCH? Sign on the door of gas station there. #nltraffic #nlwx #DarkNL http://t.co/tFGHQ6BmpQ 9 Jan 2014 by Wayne Lannon if u don't follow me sure i'll cut ur heat and lights…… and u KNOWS what that's like lol #DarkNL what a sin 9 Jan 2014 by Kathy Dunderdale MT @CochraneCBCNL #Newfoundland Premier announces independent review of electricity system. Operations. Management. Regulation #darknl 9 Jan 2014 by CBC News Alerts St. John's Fire Department got about 46 calls a day during #darknl due to alarms sounding & medical calls. Almost 400% increase #cbcnl 9 Jan 2014 by CBC Newfoundland	
Jan 10, 2014	2.3 million	2,016	780	Unit 2 is still offline and problem being investigated. However, we currently have enough gen avail. from other sources to provide power. 10 Jan 2014 by NLHydro I think we should name the individual generators in holyrood so we can properly lay blame. #2s name is Stan. Stan why you be tripin #DarkNL 10 Jan 2014 by Stephanie Kennedy #DarkNL 2: Dark Harder. 10 Jan 2014 by Gerry Porter RT @TelegramJames : For anybody keeping track, we're now into the *ninth* day of unreliable electricity. #DarkNL 10 Jan 2014 by The Telegram All customers now have power restored. We had enough reserve generation to begin restoration efforts immediately. 10 Jan 2014 by NLHydro	

Jan 11, 2014	471,635	403	213	These are tough times for many Village Mall retail workers who are not working/earning an income through no fault of their own #DarkNL 11 Jan 2014 by Dale Kirby, MHA WANGERSKY: It's astounding how frequently Newfoundland Hydro reports talk about "imminent failure" http://t.co/Hc92g5PNL7 #DarkNL 11 Jan 2014 by James McLeod I think we should name the individual generators in holyrood so we can properly lay blame. #2s name is Stan. Stan why you be tripin #DarkNL 10 Jan 2014 by Stephanie Kennedy Holyrood back at 80% capacity where it was yesterday before issue with Unit 2. Fan in Unit 3 still under repair. #DarkNL #ConserveNL #nlpoli 11 Jan 2014 by Steve Kent, MHA	
Jan 12, 2014	810,514	728	351	A Newfoundland Power crew is enroute to assess the situation and hopefully help rescue the cat. Be safe guys. 12 Jan 2014 by Newfoundland Power Holyrood be trippin' yo #darknl 12 Jan 2014 by David Cochrane For anybody not keeping track, with the latest Holyrood trip, we are now into the 11th day of ongoing power disruptions. #DarkNL 12 Jan 2014 by James McLeod There are some isolated outages reported on @NFPower site http://t.co/X7OoTWXl9r or 18004745711. Hydro has lots of gen to meet supply. 12 Jan 2014 by NLHydro	

The following assessment of the communications activity was completed at the request of NL Hydro.

Cathy Dornan Public Affairs participated in the communications response at the request of NL Hydro during the power outages from January 4th onward, and therefore had an ability to see the communications team and the operations team in action.

This document is a critical independent assessment complemented by research results since the power outages that provides an overview of how effective the communications response was, but as well, where there may be opportunities for improvement.

February 2014

Assessment of Communications Efforts by NL Hydro

January 2-11 2014

Following an informal assessment, NL Hydro appears to have done a very good job of communicating to the public through the events of Jan 2 – 12, 2014. A strong use of social media and traditional media allowed the message to be swift and frequent. This ensured people had reliable information. Anecdotal comments have shown satisfaction with NL Hydro executives and staff on how they handled social media specifically.

In subsequent formal research of the public concerning the power disruptions, it was confirmed that people felt they received good information in a timely way from NL Hydro. A research overview is included later in the document to verify some of the statements and beliefs in the assessment.

General rules of managing emergency communications:

- **The more honest, transparent and sincere you are with your audience, the more you will appeal to them on a human level and gain their trust and forgiveness.**

  NL Hydro: This was done very well. There was honesty in the communications that allowed people to believe the company. They did not have to always like the message but believing it was important.

- **Learn your lesson. State what you are doing to make sure that it does not happen again – and then actually make sure that it does not happen again**.

  NL Hydro: The repeated outages over many days left people feeling unsure that it would not happen again. NL Hydro did a good job explaining what needed to happen to equipment to fix the issues and followed through operationally to fix them.

- **Sincerely apologize when an apology is due**.

  NL Hydro: This was handled well by Ed Martin. Considering his personal reputation and by extension Hydro's, this was well done.

- **When in doubt, always remember to focus on building a relationship with your stakeholders. Well-established relationships go a long way in and out of an emergency situation**.

  NL Hydro: Prior to the events of Jan 2, it appears that relationships were generally solid. During the outages there may not have been as much contact with stakeholders as desired. Recovery will involve mostly stakeholder management.

- **Be careful about what marketing messages and campaigns you launch during and immediately after the emergency situation**.

  NL Hydro has not over promised. Post event has been handled well.

- **Not ignoring the situation in hopes that it will go away.**

  NL Hydro: Although it is difficult to ignore a blackout, NL Hydro instead responded quickly.

- **Responding to the public's inquiries and demands for updates in real-time, with an understanding and sympathetic tone, while being as open and honest as you possibly can.**

  NL Hydro: Likely one of the best successes. Use of social media allowed for real time response and it was very well executed.

- **Put those impacted by the emergency and the public first.**

  Nl Hydro: This is the key to emergency communications response. It appears the message of public first was well established in the communications.

- **Be real. Be human. Be sincere. Be honest. Be understanding. Be current. Be reliable. Be apologetic.**

  NL Hydro: For the most part, this was all included in the messaging and approach taken by NL Hydro. The effectiveness of this comes down to the spokesperson. Hydro had a few different voices throughout the outages. Quite often, the less technical people are more effective in communicating what people can understand. Ed Martin and Dawn Dalley were very effective in this area.

Overall highlights:

- Use of social media was a main focus of communications efforts and worked very well.
- Support from local media cannot be underestimated. If radio stations had not stayed on air, NL Hydro would not have been as successful. The medium was available and Hydro officials made themselves available to media without hesitation.
- Willingness to respond immediately and not become tied down in approvals allowed for real time information release.
- Emphasis was on media response and coordination needed to be stronger on broader stakeholder outreach.

Strength of response:

- Timeliness of communications
- Honesty of message
- Frequency of message
- Use of social media
- Use of radio call in shows
- Regular media briefings
- Timing of bringing Ed Martin into the response
- Effective monitoring of comments and media and correction of inaccuracies
- Allowing for people to contact NL Hydro and quick response
- System Operations updates via email hourly
- Ongoing and frequent contact and cooperation with NL Power communications
- Having key operational personnel at response sites (Holyrood) allowed for fast moving information
- Availability of key spokespeople to traditional media
- Takeover page on Hydro web site
- Coordination between utilities and government
  Speed of approval and messages - enabled rapid response

Areas for improvement:

- Initial news conference was hurried and unsure although this is common in emergency communications response
- More focus on stakeholder outreach, needed stakeholder liaison in place early
- Early in response, more time should have been taken preparing message, this improved as days went on
- Did not have regular media/stakeholder media list readily available or stakeholders clearly mapped and identified, caused slow down in getting initial information out
- Daily summary meetings between utility communications
- Some early inconsistency in messages but this was corrected

- Need to increase internal communication and engagement through entire process and ensure one person accountable.

Post Outage Research

The following are research highlights taken from a research report provided by MQO Research. A survey of 400 Newfoundlanders and Labradorians was taken in the early part of February, post power outages.

When asked to rate the overall reputation of NL Hydro: 59% gave Newfoundland and Labrador Hydro a score of 7 or higher.

When respondents were asked what were the specific things they felt Newfoundland & Labrador Hydro did well during the outages. The top mentions are below:

- The dedication of the workers
- They tried their best to get the power back as quickly as possible
- Communication delivered to the public

Respondents were asked what they think Newfoundland Hydro could have done better during the power outages. The top mentions were:

- To be better prepared for power outages
- To give more information/updates during the power outages

When respondents were asked if they felt that Newfoundland & Labrador Hydro provided information in enough places, 66% said yes.

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OPERATIONS STANDARD INSTRUCTION

STATION:	All Stations	**Inst. No.**	010
TITLE:	System Equipment Outages	**Page** 1	**of** 4

To adequately plan the operation of the power system, it is necessary to have sufficient time to plan equipment outages and evaluate the effect of these equipment outages on system operation and customer service. This is particularly important for outages affecting Hydro's Rural customers, Industrial Customers or Newfoundland Power. Equipment outages on Hydro's system can affect customers on Newfoundland Power's operation and vice versa. Therefore adequate time for co-ordination between control centres must be provided.

1. PLANNED SYSTEM EQUIPMENT OUTAGES

a) Planned system equipment outages must be requested from the Energy Control Centre (ECC) as far in advance as possible.

A minimum of **FIVE WORKING DAYS** notice shall be given for equipment outages which are internal to Hydro (i.e., do not require customer outages).

For outages involving Newfoundland Power, Industrial Customers and Hydro Rural customers, a minimum of **SEVEN WORKING DAYS** notice is required.

b) The equipment outage is to be requested using the Planned System Equipment outage database application.

c) Requests for equipment outages shall originate from:

i. Short Term Work Planning and Scheduling – Planner (TRO Regions);
ii. Short Term Work Planning and Scheduling – Planner (Hydro);
iii. Short Term Work Planning and Scheduling – Planner (Thermal)
iv. Short Term Work Planning and Scheduling – Planner (Exploits)
v. Other departments shall direct their equipment outage requests through the appropriate planning areas; and
vi. Newfoundland Power Control Centre – Superintendent (or designate).

d) All requests shall be made to the Supervisor - ECC (or designate) with copies sent to stakeholders.

OPERATIONS STANDARD INSTRUCTION

STATION:	All Stations	**Inst. No.**	010
TITLE:	System Equipment Outages	**Page** 2	**of** 4

1. PLANNED SYSTEM EQUIPMENT OUTAGES (cont'd.)

e) Equipment outages requested by Transmission and Rural Operations shall contain the following information:

i. specific equipment affected (in case of transmission line indicate specific section)
ii. starting date and time*
iii. ending date and time*
iv. type of work protection required
v. purpose of equipment outage
vi. switching arrangements

* The starting and ending times will include switching time and work time. This is especially important when customer interruptions are involved.

f) Equipment outages requested by Hydro Operations, Thermal Operations or Exploits Generation shall contain the following information:

i. equipment affected
ii. starting date and time*
iii. ending date and time*
iv. purpose of equipment outage

* The starting time is the time the equipment is disconnected from the system. The ending time is the time the unit is restored to available status.

g) Equipment outage notification by Newfoundland Power shall contain the following information:

i) specific equipment affected
ii) starting date and time*
iii) ending date and time*
v) condition guarantee (if required)
vi) purpose of equipment outage
vii) switching arrangements

OPERATIONS STANDARD INSTRUCTION

STATION:	All Stations	**Inst. No.**	010
TITLE:	System Equipment Outages	**Page** 3	**of** 4

1. PLANNED SYSTEM EQUIPMENT OUTAGES (cont'd.)

h) Other equipment outage requests, from CF(L)Co, NUGs, Industrial Customer, etc. will be channelled through the Supervisor - ECC, (or designate) who will discuss the requirements with the area concerned before the request is granted.

i) When a decision has been made, the Supervisor, ECC (or designate) will notify the originator of the equipment outage request with copies to the same personnel as in the original request and to other stakeholders.

j) Switching arrangements shall be confirmed at the time of the equipment outage confirmation.

k) The equipment outage confirmation will be given as much in advance as possible notice.

l) If there is a requirement for an equipment outage to be extended the ECC Shift Supervisor shall be advised.

OUTAGE APPROVAL

Prior to the approval of any planned equipment outages, the Planned System Equipment Checklist is to be completed by the Supervisor –ECC (or designate). To assist with the checklist, the document - *System Constraints for Planned Equipment Outages* should be reviewed. This document provides guidelines, constraints and other considerations when approving outages to power system equipment. A link to this document follows:

..\..\ECC Management\INSTRUCTIONS\System Constraints for Planned Equipment Outages Rev 3.doc

SYSTEM OPERATING INSTRUCTION

STATION:	All Stations	**Inst. No.**	010
TITLE:	System Equipment Outages	**Page** 4	**of** 4

2. DEVIATION FROM STANDARD

All parties shall attempt to work within the time limits as outlined in this standard. Timeframes may be relaxed through discussion and agreement between all stakeholders.

3. FORCED REMOVAL OF EQUIPMENT

Non-scheduled removal of equipment from service shall be determined by the ECC Shift Supervisor in consultation with available personnel or system on-call.

In case of an emergency, when time limitations prohibit consultation, the ECC Shift Supervisor shall exercise proper judgement and report the problem and action taken to appropriate personnel or on-call as soon as possible.

REVISION HISTORY

Version Number	Date	Description of Change
0	1980-11-19	Original Issue
12	2012-11-08	General Changes and added link to document - *System Constraints for Planned Equipment Outages*

PREPARED: Art Bursey	**APPROVED:**

SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	A-003
TITLE:	Notification of Weather Warnings and Lightning Activity	**Page** 1	**of** 2

GENERAL

Weather warnings include extreme winds, heavy rainfalls or floods, lightning, ice storms, blizzards, and other extreme occurrences. Warnings are not the regular daily public forecasts that Environment Canada issues. Also, the Energy Control Centre operates a real time Lightning Tracking System (LTS) application to monitor the activity of lightning around Newfoundland and Labrador.

OBJECTIVE

Its primary purpose is to provide early warning of lightning activity and adverse weather. Use this information to improve power system security and reliability. In response to warnings, Energy Control Centre staff shall position the power system in order to guard against the impending threat of lightning and adverse weather.

ADVERSE WEATHER:

Procedure

When Environment Canada issues to the Energy Control Centre a special weather warning, the information contained in the warning shall be forwarded to regional and plant staff, who maybe potentially impacted. After hours, on-call persons shall be notified.

Use this information to improve power system security and reliability. In response to warnings, Energy Control Centre staff shall position the power system in order to guard against the impending threat of adverse weather.

LIGHTNING ACTIVITY

Similarly, others may benefit from notification of lightning activity. The Energy Control Centre shall notify other parties that may be impacted by lightning activity.

SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	A-003
TITLE:	Notification of Weather Warnings and Lightning Activity	**Page** 2	**of** 2

PROCEDURE

Energy Control Centre staff will notify the following parties of lightning that may affect their operations or activities:

1. Hydro personnel working in switchyards or near transmission lines.
2. Bay d'Espoir Control Room
3. Holyrood Control Room
4. Northern region personnel (Manager – Generation and Terminals or Production Supervisor during normal hours and on-call after hours) of any lightning activity in the vicinity of L'Anse au Loop and Lac Robertson
5. Newfoundland Power Control Centre
6. Industrial Customers
7. Exploits Grand Falls Control Room

**Part of the Emergency Response Plan

REVISION HISTORY

Version Number	Date	Description of Change
0	2004-08-23	Original Issue
2	2013-09-25	Add Exploits Grand Falls Control Room

PREPARED: Bob Butler/Ross Kearley	**APPROVED:**

SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES*, **	**Rev. No.**	07
		Page 1	**of** 2

INTRODUCTION

In the event of a system generation shortage, the following guidelines shall be followed in the sequence outlined in order to minimize outages to customers:

PROCEDURE

A. Normal Generation Loading Sequence

1. Bring on line all available Hydro hydroelectric generators and load them to near their full capacity.

2. Request Newfoundland Power to maximize their hydro production.

3. Make a Capacity Request of Deer Lake Power to maximize their hydroelectric generation.

4. Request Non-Utility Generators to maximize their hydro production.

5. Increase Holyrood production to near full capacity.

6. Notify customers taking non-firm power and energy that if they continue to take non-firm power, the energy will be charged at higher standby generation rates.

7. Ask Newfoundland Power to curtail any interruptible loads available.

8. Start and load standby generators, both Hydro and Newfoundland Power units, in order of increasing average energy production cost with due consideration for unit start-up time.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES	**Rev. No.**	07
		Page 2	**of** 2

PROCEDURE (cont'd.)

9. Cancel all non-firm power delivery to customers and ensure all industrial customers are within contract limits.

If load is still increasing and it is apparent that a generation shortage may occur, proceed as follows:

10. Ensure that steps A1 to A9 above have been followed and implemented.

11. Inform Newfoundland Power of Hydro's need to reduce supply voltage at Hardwoods and Oxen Pond and other delivery points to minimum levels to facilitate load reduction. Begin voltage reduction.

12. Request industrial customers to shed non-essential loads and inform them of system conditions.

13. Request industrial customers to shed additional load.

14. Request Newfoundland Power to shed load by rotating feeders. At the same time, shed load by rotating feeders in Hydro's Rural areas where feeder control exists.

Note:

Generation from Wind Farms may shutdown with little notice.

* Part of the Environmental Plan
** Part of the Emergency Response Plan

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES*, **	**Rev. No.**	07
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DRAFT

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PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
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SYSTEM OPERATING INSTRUCTION

STATION:	GENERAL	**Inst. No.**	T-001
TITLE:	GENERATION LOADING SEQUENCE AND GENERATION SHORTAGES	**Rev. No.**	07
		Page 2	**of** 2

PROCEDURE (cont'd.)

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12. Request industrial customers to shed non-essential loads and inform them of system conditions.

13. Make a Capacity Assistance request to Corner Brook Pulp and Paper.

14. Request industrial customers to shed additional load.

15. Request Newfoundland Power to shed load by rotating feeders. At the same time, shed load by rotating feeders in Hydro's Rural areas where feeder control exists.

Note:

Generation from Wind Farms may shutdown with little notice.

* Part of the Environmental Plan
** Part of the Emergency Response Plan

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 1992-07-16
Robert Butler		**REV. DATE:** 2009-04-29

DRAFT

SYSTEM OPERATING INSTRUCTION

STATION:	**Holyrood, Hardwoods and General**	**Inst. No.**	T-007
TITLE:	**Holyrood Black Start Restoration Using Hardwoods Gas Turbine****	**Page** 1	**of** 4

Introduction

The Avalon Peninsula may become separated from Bay d'Espoir and the remainder of the power system during ice, wind or other storm events. When this happens, Holyrood generation will likely trip due to an imbalance between area load and on-line generation. Customers will be without power until the Hardwoods Gas Turbine and Holyrood fossil units are placed in-service and the load is reconnected.

The goal of this instruction is to supply the necessary black start load (5-10 MW) of the Holyrood Generating Plant using the Hardwoods gas turbine via TL242.

Guidelines

Hardwoods Terminal Station

- Use the "Black Start - Open Breakers" command button to open the following breakers at HWD TS to facilitate energizing a dead bus:
  - B2L42
  - B1B2
  - B7C1
  - B7T1
  - B7T2
  - B8T4
  - B8T3
  - B8B9
  - B8C2
  - B7T5
- Confirm open the breakers listed above

Newfoundland Power Operations

- Consult with the Newfoundland Power Control Centre; inform them a black start will be initiated via the Hardwoods Gas Turbine. Request that they open all breakers associated with their 66kV Bus 6:
  - HWD-54L-B
  - HWD-5L-B
  - HWD-19L-B

SYSTEM OPERATING INSTRUCTION

STATION:	**Holyrood, Hardwoods and General**	**Inst. No.**	T-007
TITLE:	**Holyrood Black Start Restoration Using Hardwoods Gas Turbine****	**Page** 2	**of** 4

Guidelines (cont'd.)

Newfoundland Power Operations (cont'd.)

HWD-79L-B
HWD-72L-B
HWD-T2-B
HWD-T1-B

- With Newfoundland Power, confirm open the breakers listed above

Hardwoods Gas Turbine

- Request Hardwoods Gas Turbine to be started locally (Both Ends A & B, if available) in Black Start Operation as per Instruction T-075.

Holyrood Operations

- Consult with the Holyrood Control Room; inform them a black start will be initiated via the Hardwoods Gas Turbine. Request that they confirm open HRD B2L42 and HRD ST34. Have them standby until ECC is ready to energize their station service boards via transformer SST-34.

Holyrood Terminal Station

- Use the "Black Start - Open Breaker" command button to open the following breakers at HRD TS to facilitate energizing a dead bus:

B12B15
B12L18
B12L17
B6T10
B6L3
B7L2
B7T5
B7L38

SYSTEM OPERATING INSTRUCTION

STATION:	**Holyrood, Hardwoods and General**	**Inst. No.**	T-007
TITLE:	**Holyrood Black Start Restoration Using Hardwoods Gas Turbine****	**Page** 3	**of** 4

Guidelines (cont'd.)

Energizing TL242

- The present operating philosophy requires that a local operator is required to close the Gas Turbine breaker, G1T5 at Hardwoods, under a black start condition (as per Instruction T-075). Have the operator close G1T5. Check closed.
- Energize B8 by closing HWD B7T5. Check closed.
- Adjust the generator output voltage to achieve approximately 67 kV on Bus 8.
- Adjust HWD T3 tap to position 4 and energize B2 by closing HWD B8T3. Check closed.
- Close and/or check closed HRD B12L42.
- Energize HRD B12 via TL242 by closing HWD B2L42. Check closed. If necessary, adjust HWD T3 tap position to achieve acceptable voltage levels on HRD B12.

Energizing Holyrood Station Service Boards

- Close and/or check closed HRD B12T10. Note that B12T10 must be closed before B6T10 as they are interlocked (described in instruction T-048).
- Energize B6 by closing DRD B6T10. Check closed.
- HRD T10 tap position can't be adjusted without station service power, which is provided by the Holyrood Plant. Without station service available, HWD T3 tap position can be adjusted to achieve acceptable voltage levels on HRD B6. Once the Holyrood Plant energizes their Unit Service and Station Service Boards, station service power should become available in the Holyrood Terminal Station. Once station service power is available, HRD T10 tap changer can be used to achieve acceptable voltage levels on HRD B6.

SYSTEM OPERATING INSTRUCTION

STATION:	**Holyrood, Hardwoods and General**	**Inst. No.**	T-007
TITLE:	**Holyrood Black Start Restoration Using Hardwoods Gas Turbine****	**Page** 4	**of** 4

Guidelines (cont'd.)

Holyrood Operations

- Inform the Holyrood Control Room their station service boards are ready to be energized. When they are ready, energize transformer SST-34 by closing HRD B6L3. Check closed. They may close ST34 and proceed with their Black Start procedure.

ECC Operations

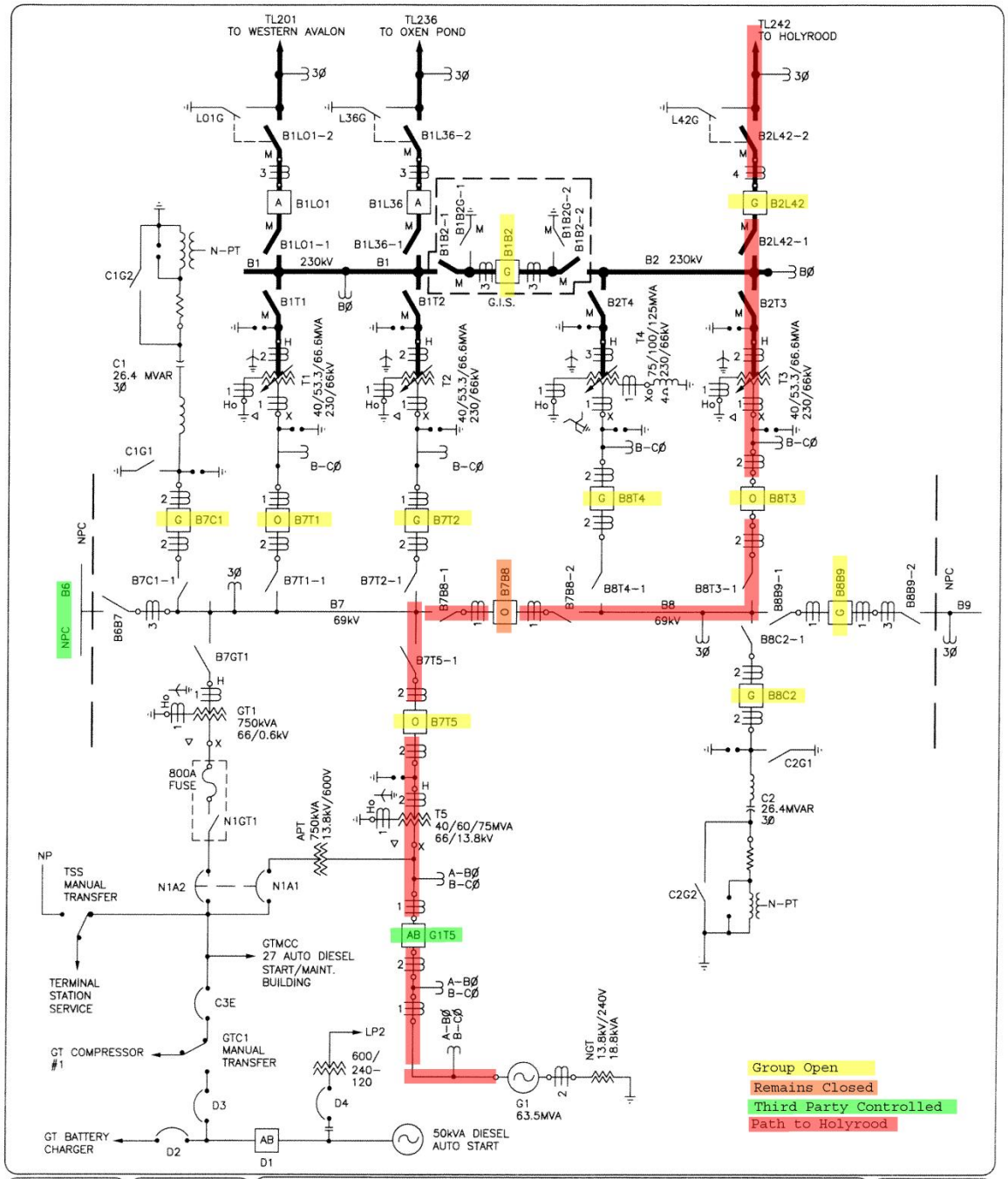
- Proceed with Instruction T-022 Restoration Of The Avalon Peninsula When Isolated From Bay d'Espoir.

** Part of the Emergency Response Plan

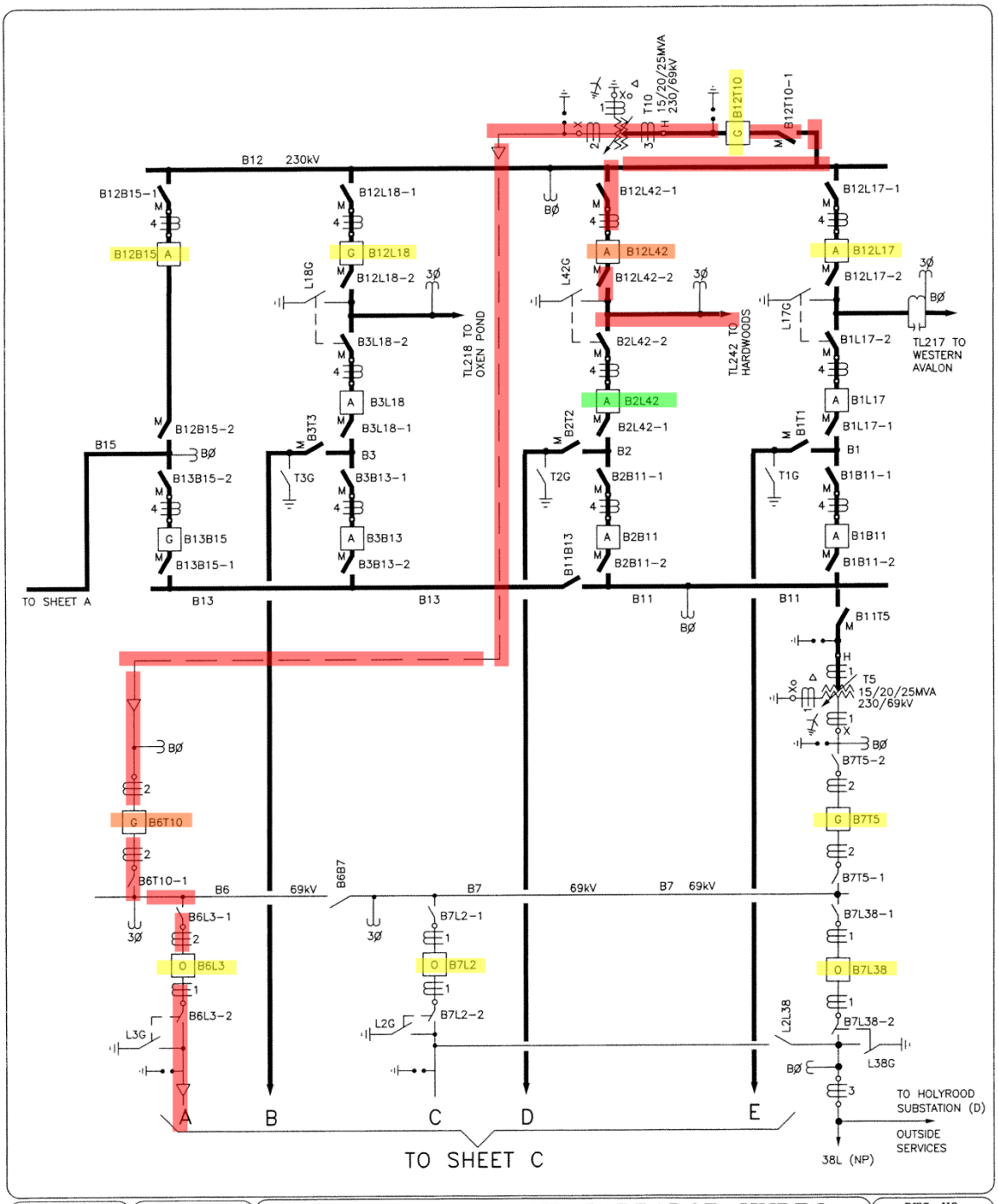
REVISION HISTORY

Version Number	Date	Description of Change
0	2012-06-07	Original Issue
1	2013-10-31	Updates

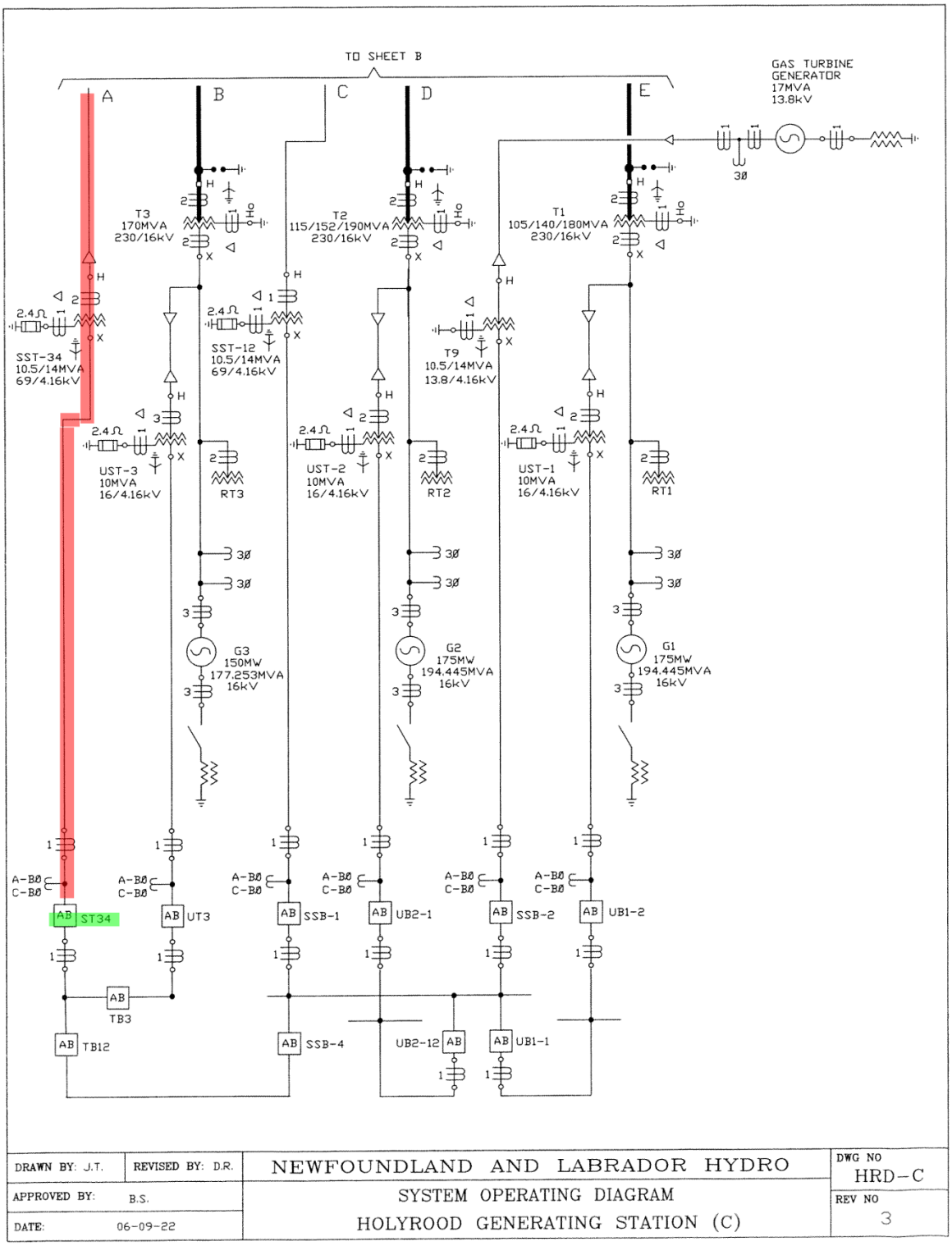
PREPARED: R. Coish	**APPROVED:**



DRAWN BY: J.T.	REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO	DWG NO HWD-1
APPROVED BY R. STOYLES		SYSTEM OPERATING DIAGRAM HARDWOODS TERMINAL STATION	REV NO 18
DATE 2007/10/25			



DRAWN BY: J.T. / REVISED BY: D.R.	NEWFOUNDLAND AND LABRADOR HYDRO		DWG. NO. HRD-B
APPROVED BY: J.F.	SYSTEM OPERATING DIAGRAM HOLYROOD TERMINAL STATION (B)		REV. NO. 10
DATE: 05-03-16			


TO SHEET B
A
B
C
D
E
GAS TURBINE
GENERATOR
17MVA
13.8kV
3Ø
T3
170MVA
230/16kV
T2
115/152/190MVA
230/16kV
T1
105/140/180MVA
230/16kV
SST-34
10.5/14MVA
69/4.16kV
SST-12
10.5/14MVA
69/4.16kV
T9
10.5/14MVA
13.8/4.16kV
UST-3
10MVA
16/4.16kV
UST-2
10MVA
16/4.16kV
UST-1
10MVA
16/4.16kV
RT3
RT2
RT1
G3
150MW
177.253MVA
16kV
G2
175MW
194.445MVA
16kV
G1
175MW
194.445MVA
16kV
A-BØ
C-BØ
AB
ST34
UT3
SSB-1
UB2-1
SSB-2
UB1-2
TB3
TB12
SSB-4
UB2-12
UB1-1
DRAWN BY: J.T.
REVISED BY: D.R.
APPROVED BY: B.S.
DATE: 06-09-22
NEWFOUNDLAND AND LABRADOR HYDRO
SYSTEM OPERATING DIAGRAM
HOLYROOD GENERATING STATION (C)
DWG NO
HRD-C
REV NO
3

SYSTEM OPERATING INSTRUCTION

STATION:	Energy Control Centre	**Inst. No.**	T-032
TITLE:	Restoration Plan for Loss of TL202 and TL206	**Page** 1	**of** 3

This plan is devised to assist in the restoration of the power system should TL202 and TL206 trip simultaneously. Newfoundland and Labrador Hydro's Energy Control Centre Shift Supervisor will direct all actions necessary to restore the power system to its normal operating state. Upon loss of both 230 kV transmission lines from Bay d'Espoir to Sunnyside, Hydro's automatic restoration scheme will activate. The goal of the scheme is to restore power to TL207 from either TL202 or TL206. A number of items can be performed while the auto-restoration program is running. If unsuccessful, the program will timeout after 1½ to 2 minutes. Complete the following items in preparation of restoring the system.

***Note*- Maintain Contact with Newfoundland Power throughout this Restoration Procedure.**

Newfoundland Hydro (NLH)		Comments
1.	Upon loss of TL 202/TL 206 auto-restoration program will execute.	***Check program status - Come -by-Chance (CBC) display set. (T-023)***
2.	Restore lines and customer load tripped due to underfrequency load shedding (TL 226, TL 220, GBK L1, St. Alban's, etc.)	***Reminder: - AGC has tripped to Monitor.***
3.	Monitor and Control West Coast voltage.	***Follow Guidelines for West Coast Voltage Control.***
4.	Request Bay d'Espoir Plant to take local control.	***Have Bay d'Espoir staff monitor and regulate frequency.***
5.	Notify North Atlantic Refining Ltd and Vale.	***NARL – 463-8811 ext.487 Vale – 758-8778 or 697-1102***
6.	Notify System On-Call and Corporate Relations.	
7.	Execute Group Breaker openings in OPD, HWD, HRD and WAV.	****NLH will verify group breakers open completed. *NP will verify Avalon feeders Open.***
8.	Check CBC, HWD, OPD Cap Banks Open.	****Verify all Avalon Capacitor Banks Open.***

SYSTEM OPERATING INSTRUCTION

STATION:	Energy Control Centre	**Inst. No.**	T-032
TITLE:	Restoration Plan for Loss of TL202 and TL206	**Page** 2	**of** 3

Newfoundland Hydro (NLH)		Comments
9.	If HRD Unit(s) tripped, Request Holyrood's Control Room to open all unit breakers.	***ECC will verify Holyrood unit breakers open.***
10.	Execute SSD Group Breaker opening.	***Separate 138 kV from 230 kV at Sunnyside and verify group breaker open completed.***
11.	Restore TL 202 and/or TL 206 (If not already done by auto-restoration). If TL202 and TL206 remain out, consider HRD Blackstart from either Newfoundland Power's Mobile Generation at HRD or HWD TL242 (refer to Instruction T-007 and T-023).	***TL 202 preferred to avoid energizing TL 203 when restoring SSD 138 kV bus. Adjust SSD LTC's to acceptable voltage levels.***
12.	Restore TL 207 (If not already done by auto-restoration) and restore TL 237 to WAV.	***Notify NARL to restore (30 MW). *May require adjusting all online generating units to achieve acceptable Avalon voltage levels.***
13.	Restore Sunnyside 138 kV bus. Monitor and Control Voltages. *Note:* ****Use of CBC caps will result in excessive Voltage spikes****	***Restore TL212 and TL219. Notify Newfoundland Power to restore Burin and SSD Feeders. *If required the removal TL219 (SSD-SPO) will help lower the Avalon voltage.***
14.	Restore second line from Bay d'Espoir to Sunnyside, if possible.	***Monitor and control voltage to acceptable levels.***
15.	Restore TL237 at WAV, adjust WAV LTC's to acceptable levels (142 kV) and notify Newfoundland Power to restore WAV Loads.	***64L, B2T1, B2T2, and 86L loads.***
16.	Close WAV L01L37 to energize TL201 to HWD via B1L01. Adjust HWD LTC's to acceptable levels (68 kV) and notify Newfoundland Power to restore HWD Loads.	****Use HWD Cap Banks after LTC's usage exhausted. *Start Hardwoods GT, if not already started.***

SYSTEM OPERATING INSTRUCTION

STATION:	Energy Control Centre	**Inst. No.**	T-032
TITLE:	Restoration Plan for Loss of TL202 and TL206	**Page** 3	**of** 3

	Newfoundland Hydro (NLH)	Comments
17.	Close HWD B2L42 to energize TL242 to HRD. *If not completed through Black Start T-007* Close HRD B12L42.	***HRD station service restored. Notify NP and restore 39L and 38L (If not already completed).***
18.	Close HRD B12L18 to energize TL218 to OPD. Close OPD B1L18. Adjust OPD LTC's to acceptable levels (68KV) and notify Newfoundland Power to restore OPD Loads.	****Use OPD Cap Banks after LTC's usage exhausted.***
19.	When HRD Unit(s) are Online, restore all remaining loads. Use CBC Cap Banks as required.	
20.	Restore all remaining 230kV Transmission Lines, TL203, TL217, & TL236.	***Monitor and control voltage to acceptable levels.***

Notes:

- To secure the system after load has been restored, place remaining 230 kV transmission lines in-service and start Paradise River plant. Newfoundland Power will restore the remainder of their system, picking up load in consultation with Hydro (ECC).
- The Wind Farms should not be re-connected to the system until the Holyrood plant is in a stable mode of operation and the load is restored. When connected, the output of the wind farm(s) should be limited to the total pick-up capability of the Holyrood plant in the event that the wind generation is suddenly lost or rejected.
- Under extenuating circumstances (HRD offline for extended period), the Wind Farms could possibly supply load to Newfoundland Power's system and help maximize the available Avalon Generation capacity.

REVISION HISTORY

Version Number	Date	Description of Change
0	2013-04-11	Original Issue

PREPARED: Jason Dean	**APPROVED:**

EAST COAST

POWER SYSTEM

RESTORATION PLAN

(Loss of TL202 and TL206)

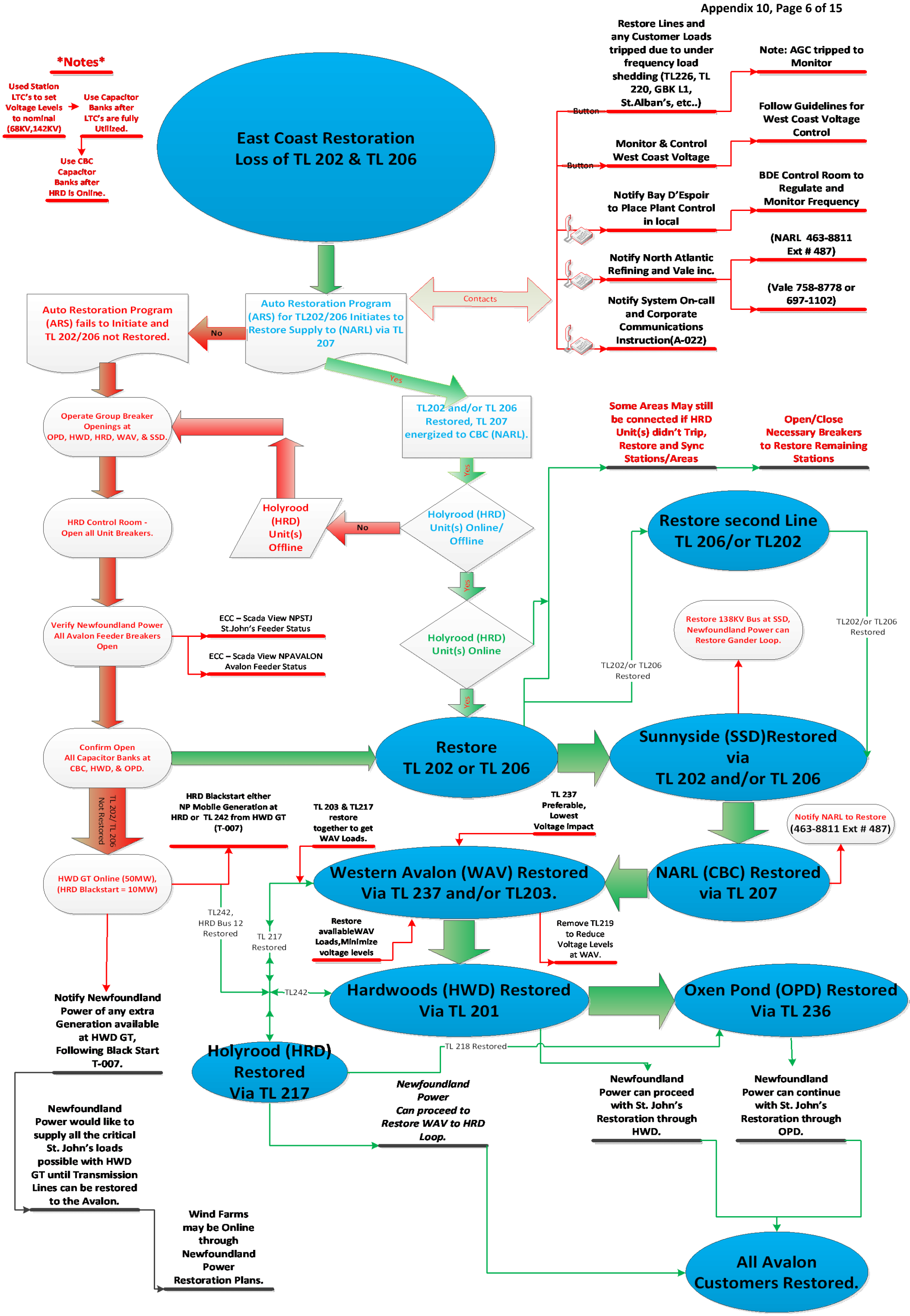
Newfoundland and Labrador Hydro _____

Newfoundland Power _____

Revision 0 ***2013-04-09***

Instruction T-032 – Newfoundland Hydro's East Coast Restoration Plans

Appendix – Newfoundland Power's East Coast Restoration Plans


Notes
Used Station LTC's to set Voltage Levels to nominal (68KV,142KV)
Use Capacitor Banks after LTC's are fully Utilized.
Use CBC Capacitor Banks after HRD is Online.
East Coast Restoration Loss of TL 202 & TL 206
Restore Lines and any Customer Loads tripped due to under frequency load shedding (TL226, TL 220, GBK L1, St.Alban's, etc..)
Note: AGC tripped to Monitor
Button
Follow Guidelines for West Coast Voltage Control
Monitor & Control West Coast Voltage
Button
BDE Control Room to Regulate and Monitor Frequency
Notify Bay D'Espoir to Place Plant Control in local
(NARL 463-8811 Ext # 487)
Notify North Atlantic Refining and Vale inc.
(Vale 758-8778 or 697-1102)
Notify System On-call and Corporate Communications Instruction(A-022)
Contacts
Auto Restoration Program (ARS) for TL202/206 Initiates to Restore Supply to (NARL) via TL 207
No
Auto Restoration Program (ARS) fails to Initiate and TL 202/206 not Restored.
Yes
TL202 and/or TL 206 Restored, TL 207 energized to CBC (NARL).
Some Areas May still be connected if HRD Unit(s) didn't Trip, Restore and Sync Stations/Areas
Open/Close Necessary Breakers to Restore Remaining Stations
Operate Group Breaker Openings at OPD, HWD, HRD, WAV, & SSD.
HRD Control Room - Open all Unit Breakers.
Holyrood (HRD) Unit(s) Offline
No
Holyrood (HRD) Unit(s) Online/ Offline
Yes
Restore second Line TL 206/or TL202
Verify Newfoundland Power All Avalon Feeder Breakers Open
ECC – Scada View NPSTJ St.John's Feeder Status
ECC – Scada View NPAVALON Avalon Feeder Status
Holyrood (HRD) Unit(s) Online
Yes
Restore 138KV Bus at SSD, Newfoundland Power can Restore Gander Loop.
TL202/or TL206 Restored
TL202/or TL206 Restored
Confirm Open All Capacitor Banks at CBC, HWD, & OPD.
Restore TL 202 or TL 206
Sunnyside (SSD)Restored via TL 202 and/or TL 206
TL 202/ TL 206 Not Restored
HRD Blackstart either NP Mobile Generation at HRD or TL 242 from HWD GT (T-007)
TL 203 & TL217 restore together to get WAV Loads.
TL 237 Preferable, Lowest Voltage Impact
Notify NARL to Restore (463-8811 Ext # 487)
HWD GT Online (50MW), (HRD Blackstart = 10MW)
Western Avalon (WAV) Restored Via TL 237 and/or TL203.
NARL (CBC) Restored via TL 207
TL242, HRD Bus 12 Restored
TL 217 Restored
Restore availableWAV Loads,Minimize voltage levels
Remove TL219 to Reduce Voltage Levels at WAV.
TL242
Hardwoods (HWD) Restored Via TL 201
Oxen Pond (OPD) Restored Via TL 236
Notify Newfoundland Power of any extra Generation available at HWD GT, Following Black Start T-007.
Holyrood (HRD) Restored Via TL 217
TL 218 Restored
Newfoundland Power can proceed with St. John's Restoration through HWD.
Newfoundland Power can continue with St. John's Restoration through OPD.
Newfoundland Power would like to supply all the critical St. John's loads possible with HWD GT until Transmission Lines can be restored to the Avalon.
Wind Farms may be Online through Newfoundland Power Restoration Plans.
Newfoundland Power Can proceed to Restore WAV to HRD Loop.
All Avalon Customers Restored.

Appendix A

Newfoundland Power Restoration Plan

East Coast Restoration (Loss of TL-202 & TL-206)

Overview

NLH will open all 230 kV Breakers at SUN OXP and HWD and HRD (Duff's) to disconnect the 230 kV network from the sub transmission components. NLH will operate breakers at SUN and WAV to attempt to energize NARL from one 230 kV line from Sunnyside

NP will begin the process of separating all NP lines and loads from the NLH system to allow NLH to restore voltage to the 230 KV at WAV. NP will then pickup load from the Western Avalon System to provide sufficient load to mitigate the effects of the charging assocated with the 230 kV network. NLH will decide when we have picked up enough load to allow them to energize the 230 kV system to HRD and on to HWD and OXP.

NP SCC operators will contact the following and inform them that we are implementing the East Coast Restoration Plan.

1. Systems On-Call
2. On-Call Supervisor - St. John's,
3. On-Call Supervisor - Avalon,
4. MUN – Electrical Maintenance, and request that an operator stands by at MUN substation to operate feeder breakers if required.

Each of these will be responsible for contacting the following and or dispatching field staff to the locations identified for each area.

Systems On-Call,

1. Contact the following:
2. Manager of Operations
3. Corporate Communications.
4. Superintendent of Generation (or designate).

St. John's On- Call

1. Contact Manager St. John's Region.
2. Dispatch staff to RRD, BIG, CAB, FER, SCV to contact SCC and operate feeders as directed.

Avalon On-Call

1. Contact Manager Eastern Region
2. Dispatch Staff to HOL, COL, SPF, WAV, DUN, CAR, ILC, HGR, HCT,OPL & RVH to contact SCC and operate feeders as directed.

Superintendent of Generation (or designate)

Arrange to have operators visit each of the hydro plants that locked out to reset plants that should be made available to go online. Refer to the Southern Shore restoration plan for details of the Southern Shore system.

Prepare to run GRT, and WES GTs if requested.

Dispatch staff to SCV and TOP, PHR, SCV and PHR operators should be familiar with feeder recloser operation if needed to manage loading.

NP SCC

Preparation for Restoration

NP SCC Operators will disconnect the NP system from the NLH system by opening the following Circuit Breakers

Table 1

HWD-T3-B	OXP-34L-B
HWD-49L-B	OXP-70L-B
HWD-73L-B	OXP-01-B
HWD-54L-B	OXP-32L-B
HWD-5L-B	OXP-31L-B
HWD-19L-B	OXP-35L-B
HWD-79L-B	OXP-67L-B
HWD-72L-B	OXP-58L-B
HWD-T1-B	
HWD-T2-B	WAV-86L-B (NLH)

NP will breakup its 66 kV and 138 kV sub-transmission networks into sections to prepare for restoration by opening the following breakers.

Table 2 – Avalon Transmission

BRB-39L-B	BLK-55L-B
BRB-56L-B	BLK-94L-B
BRB-57L-B	BLK-80L-B
CAR-40L-B	BLK-86L-B
CAR-41L-B	
CAR-68L-B	HCT-43L-B
HGR-57L-B	

Table 3- St. John's Transmission

KEL-52L-B	SLA-13L-B
	SLA-15L-B
GOU-17L-B1 (or B2)	SLA-69L-B
PHR-3L-B	
MOB-24L-B	KBR-16L-B
	KBR-12L-B

NP will open all remote controlled distribution feeders in St. John's and Avalon from the Feeder Summary Screen using the group Commands where available. Any feeders that cannot be opened via the Group Commands due to tagging or configuration must be accessed by Individual feeder control from the substation SLD.

Open the following Bus Tie and Transformer Breakers to Drop the feeders at RRD and MUN

Table 4 St. John's Distribution

RRD-TB-2-3	MUN-TB-1-2
RRD-T2-B	MUN-T1-B
RRD-T3-B	MUN-T2-B

System Restoration

WAV 230 kV Bus Energized

Close the following Breakers monitoring voltage and loading with NLH

Use Group Feeder Group Close Commands when picking up large blocks is load is acceptable. There will be a slight delay between feeder close commands. If there is a need to pickup load slower or in smaller blocks use the individual feeder controls at these locations.

Table 5 Western Avalon Restoration

Breaker / Control	**Subsystem Energized**	**Peak Load (MVA)**
WAV-B2T1 (NLH)	WAV Feeders (3)	12.0
WAV-B2T2 (NLH)		
WAV-B4L64 (NLH)	BLK - BRB 138 & 66 kV	
BRB-Group-1	BRB Feeders (5)	20.4
BRB-39L-B	SPF-COL_HOL	16.5
BLK-Group-1	BLK Feeders (2)	10.2
BLK-55L-B	PJN-QTZ-DUN Feeders & CLK 66 kV	7.9
CLK-Group-1	CLK Feeders (3)	8.6
BLK-94L-B	SCT- RVH-TRP	8.9
BLK-80L-B	NHR-ISL-HCT	11.4
BRB-56L-B	CAR Feeders (4)	16.5
BRB-57L-B	ILC Feeders (2)	11.1
HGR-57L-B	HGR Feeders (3)	9.5
CAR-40L-B	VIC Feeders (2)	8.6

CAR-41L-B	Complete 66 kv Loops BRB-BLK Systems	
CAR-68L-B		
HCT-43L-B	NCH & OPL Feeders (6)	12.6
WAV-86L-B (NLH)	Complete WAV-BLK 66 kV Loop	
BLK-86L-B		

System Restoration

HWD 230 kV and 66 kV Buses Energized

Close the following Breakers monitoring voltage and loading with NLH

Use Group Feeder Group Close Commands when picking up large blocks is load is acceptable. There will be a slight delay between feeder close commands. If there is a need to pickup load slower or in smaller blocks use the individual feeder controls at these locations.

Table 6 Hardwoods Restoration

Breaker / Control	Subsystem Energized	Peak Load (MVA)
HWD-T3-B	HWD 25 kV Bus	
HWD-07-B and HWD-08-B	HWD 25 kV Feeders	24.9
HWD-T1-B	HWD 12.5 kV Bus	
HWD-T2-B		
HWD-Group-1	HWD 12.5 kV Feeders (5)	38.4
HWD-72L-B	GDL-GOU-SJM 66 kV & Distribution Busses	
HWD-73L-B		
GDL-Group-1	GDL-12.5 kV Feeders (6)	45.1
GOU-Group-1	GOU-12.5 kV Feeders (3)	32.3
SJM-Group-1	SJM-12.5 kV Feeders (4)	14.5
SJM-Group-2	SJM-12.5 kV Feeders (4)	16.5
SJM-Group-3	SJM-12.5 kV Feeders (3)	11.0
SJM-12-B	SJM-4.16 kV Feeder	2.7
PHR-3L-B	PHR 33 kV & 4.16 kV Feeder	2.5
GOU-17L-B1	BIG 66 kV and 12.5 kV Feeders	10.1
HWD-19L-B	MOL-66 kV and 12.5 kV	
MOL-Group-1	MOL-12.5 kV Feeders (8)	47.1
HWD-54L-B	KEN-66 kV and 25 kV	
KEN-Group-1	KEN-25kV Feeders (4)	49.2

Table 6 (cont'd) Hardwoods Restoration

HWD-49L-B HWD-79L-B	CHA-KEL 66 kV and Distribution Busses	
CHA-Group-1	CHA 25 kV Feeders (3)	48.9
KEL-01-B & KEL-02-B	KEL 12.5 kV Feeders	22.2
KEL-52L-B	SCV-66 kV and SCV Feeders (2)	10.4
HWD-5L-B	BCV 66 kV and 12.5 kV	
BCV-Group-1	BCV 12.5 kV Feeders (4)	21.5
MOB-17L-B	MOB-66 kV-FER 66KV, CAB-01 & FER-01 Feeders	7.5
MOB-01-R, MOB-02-R	MOB 12.5 kV Feeders	10.2

System Restoration

OXP 230 kVand 66 kV Buses Energized

Close the following Breakers monitoring voltage and loading with NLH

Use Group Feeder Group Close Commands when picking up large blocks is load is acceptable. There will be a slight delay between feeder close commands. If there is a need to pickup load slower or in smaller blocks use the individual feeder controls at these locations.

Table 7 Oxen Pond Restoration

Breaker / Control	Subsystem Energized	Peak Load (MVA)
OXP-01-B	OXP 12.5 kV Feeder	10.7
OXP-31L-B OXP-70L-B	SLA 66 kV and Distribution Busses & MUN 66 kV	
SLA-Group-1	SLA-4.16 kV Feeders (5)	11.6
SLA-Group-2	SLA 12.5 kV Feeders (3)	20
SLA-Group-3	SLA 12.5 kV Feeders (3)	20
MUN-T2-B	MUN 12.5 kV Feeders (3)	5.5
MUN-T1-B	MUN-12.5 kV Feeders (6)	11.1

MUN-TB-1-2		
OXP-32L-B	RRD-66 kV KBR 66 kV and Distribution Busses	
OXP-67L-B		
RRD-T2-B	RRD-12.5 kV Feeders (4)	17.6
RRD-T3-B	RRD-12.5 kV Feeders (4)	17.6
RRD-TB-2-3		
KBR-Group-1	KBR-4.16 kV feeders (8)	15.5
KBR-Group-2	KBR-12.5 kV Feeders (4)	24.0
OXP-35L-B	VIR-PEP-PUL 66 kV and Distribution Busses	
OXP-58L-B		
VIR-Group-1	VIR 12.5 kV Feeders (8)	65.8
PEP-Group-1	PEP 12.5 kV feeders (4)	22.3
PUL-Group-1	PUL 12.5 kV Feeders (4)	34.1

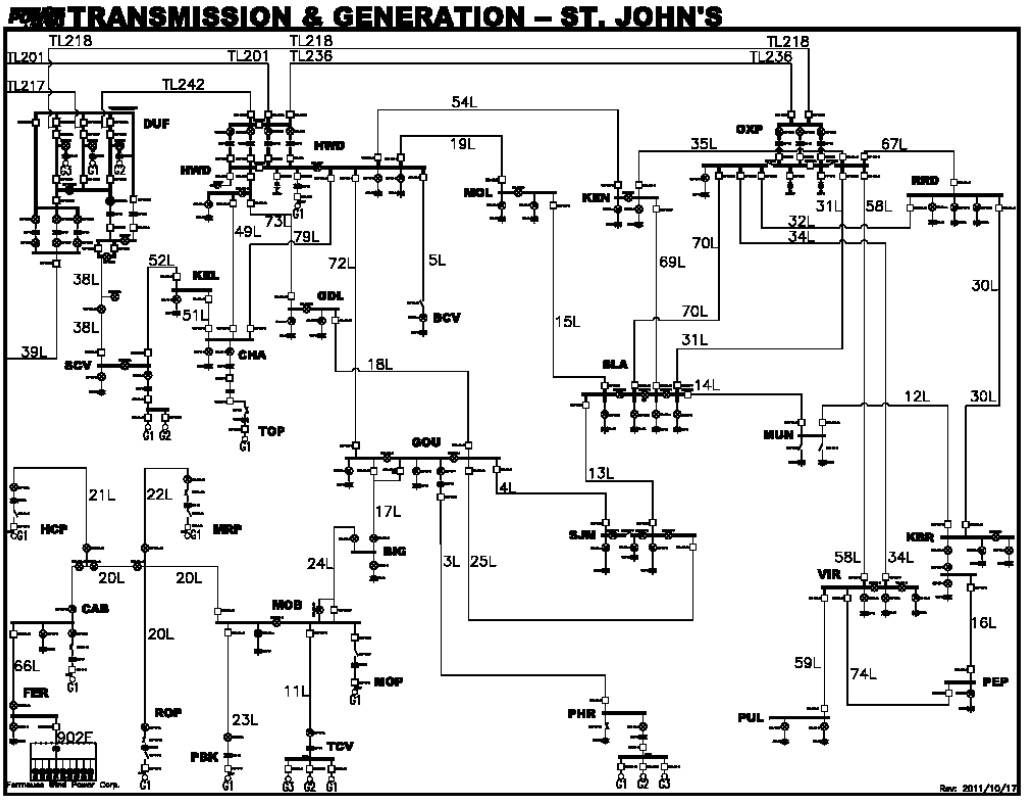
Completion of Restoration

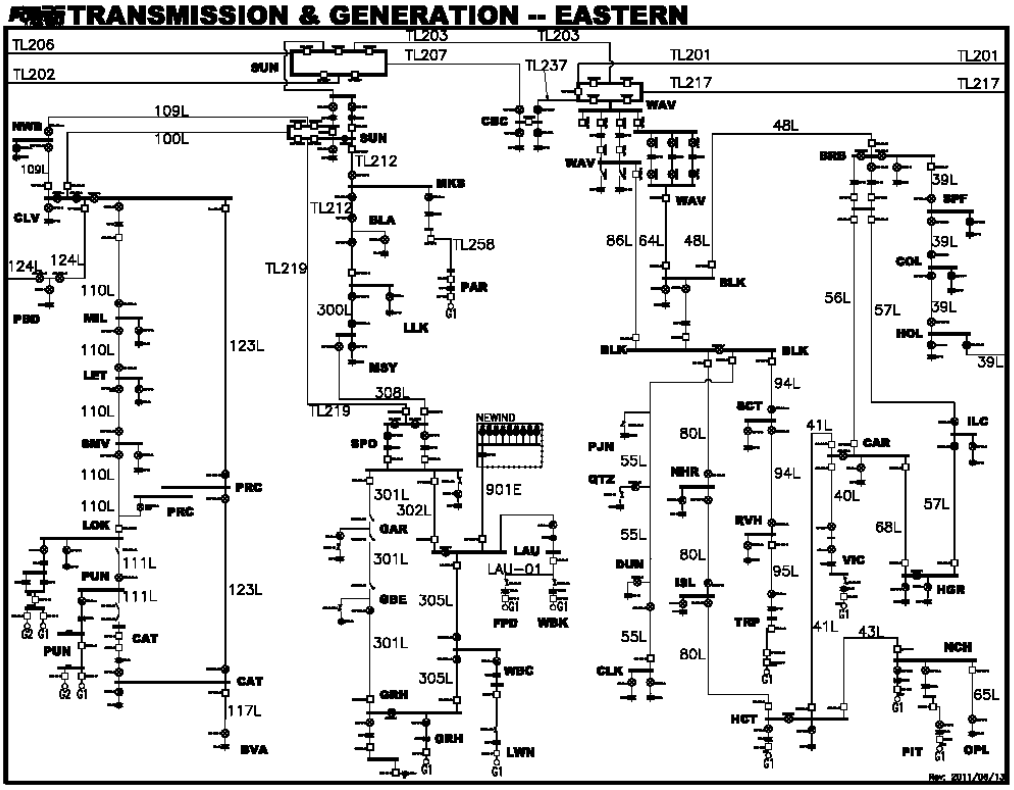
Close the following breakers to restore all loops in the St. John's 66 kV transmission system.

Table 8 Transmission Loops

SLA-13L-B	KBR-16L-B
SLA-15L-B	KBR-12L-B
SLA-69L-B	HRD-B7L38 (NLH)
OXP-35L-B	HRD-B8L39 (NLH)

Newfoundland Power Schematics:





HYDRO
THE POWER OF COMMITMENT

SYSTEM OPERATING INSTRUCTION

STATION:	**Hardwoods and Oxen Pond**	**Inst. No.**	T-078
TITLE:	**Hardwoods and Oxen Pond Restoration ****	**Rev. No.**	
		Page 1	**of** 6

Introduction:

Newfoundland and Labrador Hydro (**NLH**) supplies Newfoundland Power (**NP**) customers in the St. John's and surrounding areas using three delivery points

- Hardwoods 66 kV (busses 7 and 8);
- Oxen Pond 66 kV (busses 2 and 5); and
- Holyrood 69 kV (38L).

During one peak (on February 15, 2003 at 1800 hours) when the system load was 1402 MW, the total area load was approximately 520 MW. Hardwoods station, including its gas turbine, supplied 216 MW, Oxen Pond supplied 222 MW and Holyrood 38L, 36 MW. The remaining 46 MW was supplied by Newfoundland Power's generation.

The Newfoundland Power's 66 kV system is configured with connections between the three delivery points. Hardwoods is connected to Holyrood via two lines, 49L and 79L, which run from Hardwoods to Chamberlains. Real power normally flows from Hardwoods to Chamberlains. Oxen Pond does not directly connect into Holyrood. Hardwoods and Oxen Pond are connected via three lines, 13L (St. John's Main to Stamp's Lane), 15L (Molloy's to Stamp's Lane) and 54L (Hardwoods to Kenmount). The net real power flow across all three lines, under normal conditions, is relatively low. Most of Newfoundland Power's generation is located in the Hardwoods systems, with a small amount of generation in the Holyrood system.

Capacity:

It is important to understand the capacity of transmission and terminal equipment when meeting customers load requirements, especially under a contingency situation. These physical capabilities, or limits, shall always be respected.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 2003-03-19
B. Butler		**REV. DATE:**

HYDRO
THE POWER OF COMMITMENT

SYSTEM OPERATING INSTRUCTION

STATION:	**Hardwoods and Oxen Pond**	**Inst. No.**	T-078
TITLE:	**Hardwoods and Oxen Pond Restoration**	**Rev. No.**	
		Page 2	**of** 6

Introduction (cont'd.)

The transmission line capacity into Hardwoods and Oxen Pond stations are provided below for different ambient temperatures.

Hardwoods (MVA)	25°C	15°C	0°C	SCADA Alarm
TL201	208	260	322	User shall
TL236	237	298	370	define
TL242	330	420	524	limits *
	775	978	1216	

Oxen Pond (MVA)	25°C	15°C	0°C	SCADA Alarm
TL218	237	298	370	User shall
TL236	237	298	370	define
	474	596	740	limits *

* seasonally adjusted

Terminal station transformer capacities at Hardwoods and Oxen Pond, assuming all cooling mechanisms are functioning properly, are provided. Normal operating and firm capacities are included. Firm indicates capacity under the largest single contingency, the loss of the biggest transformer.

Hardwoods	Capacity	Trip Setting	SCADA Alarm
Transformer T1	67 MVA	95 MVA	60 MVA
Transformer T2	67 MVA	95 MVA	60 MVA
Transformer T3	67 MVA	95 MVA	60 MVA
Transformer T4	125 MVA	175 MVA	115 MVA
Gas turbine	50 MVA		
Station	376 MVA		
	358 MW (95% pf)		
Firm	251 MVA		
	240 MW (95% pf)		

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B. Butler		**REV. DATE:**

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SYSTEM OPERATING INSTRUCTION

STATION:	**Hardwoods and Oxen Pond**	**Inst. No.**	T-078
TITLE:	**Hardwoods and Oxen Pond Restoration**	**Rev. No.**	
		Page 3	**of** 6

Introduction (cont'd.)

Oxen Pond	Capacity	Trip Setting	SCADA Alarm
Transformer T1	67 MVA	95 MVA	60 MVA
Transformer T2	125 MVA	191 MVA	115 MVA
Transformer T3	125 MVA	191 MVA	115 MVA
Station	317 MVA		
	300 MW (95% pf)		
Firm	192 MVA		
	182 MW (95% pf)		

Oxen Pond & Hardwoods	Capacity
Firm	568 MVA
	540 MW (assume 95% pf)

Holyrood	Capacity	Trip Setting	SCADA Alarm
Transformer T5	25 MVA	38 MVA	22 MVA
Transformer T10	25 MVA	33 MVA	22 MVA
Station	50 MVA		
	48 MW (95% pf)		

Reliability

Newfoundland Power operates its 66 kV transmission in the St. John's and surrounding area as a system, connecting the Hardwoods 66 kV, Oxen Pond 66 kV and Holyrood 69 kV delivery points. Interruption of one or two of these three delivery points may affect customers, however, it depends on the time of year, time of day, which particular delivery points are affected, configuration of the Newfoundland Power system and other related conditions.

Interruption of the Holyrood 38L delivery point should not affect customer service as customers will be supplied through the Hardwoods delivery point via 49L and 79L.

HYDRO
THE POWER OF COMMITMENT

SYSTEM OPERATING INSTRUCTION

STATION:	**Hardwoods and Oxen Pond**	**Inst. No.**	T-078
TITLE:	**Hardwoods and Oxen Pond Restoration**	**Rev. No.**	
		Page 4	**of** 6

Reliability (cont'd.)

Interruption of Oxen Pond or Hardwoods may result in service outages to some of Newfoundland Power's customers. During heavier load periods customers will be affected when all the load switches to the in-service delivery point and overloads Newfoundland Power's transmission. During lighter load periods, Newfoundland Power may be able to supply all their customers through the remaining delivery point. However, voltage remains a concern when supplying Newfoundland Power without Hardwoods or Oxen Pond available, due mainly to the lack of regulation on their system.

Restoration Guidelines

Perform the following steps after the loss of Hardwoods or Oxen Pond, resulting in customer interruption

1. NLH will monitor the system frequency and ensure AGC status is ON and the frequency stable. At the same time NLH will contact NP to initiate this restoration procedure.
2. If required, NLH will direct personnel to the problem station to investigate. TRO personnel will normally be contacted first, however, ECC staff are available should the need arise.
3. If applicable, NLH will isolate problem and restore remaining station equipment to service. The fully capable station will be used to restore as many customers as possible to service while personnel attend to and isolate the problem area.
4. Supply as many NP customers in the Holyrood – Seal Cove area from 38L by opening the loop near the Hardwoods end. The objective is to offload as much as possible the load on 49L and 79L at Hardwoods.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 2003-03-19
B. Butler		**REV. DATE:**

HYDRO
THE POWER OF COMMITMENT

SYSTEM OPERATING INSTRUCTION

STATION:	**Hardwoods and Oxen Pond**	**Inst. No.**	T-078
TITLE:	**Hardwoods and Oxen Pond Restoration**	**Rev. No.**	
		Page 5	**of** 6

Restoration Guidelines (cont'd.)

5. NP will isolate their substations in preparation for the restoration process. Depending on the load and if not already tripped, NP shall be prepared to separate OPD and HWD systems to facilitate the restoration process. During restoration, NLH will approve the connection of OPD and HWD into one system.
6. NLH will secure generation requirements. Have as many generating units on-line as possible to assist with frequency regulation during the restoration process. Start the Hardwoods gas turbine using both gas engines. Ensure both Cat Arm units are placed in speed mode. If possible, place Holyrood units at an output level that will assist with frequency regulation. Units are at their maximum shall be reduced by about 15 to 20 MW each, depending on the unit load and if there is sufficient other generation. Ensure the Holyrood units are in speed load control. These steps shall not slow greatly the restoration of customers and should be done co-incidentally if these actions have a long duration.
7. NP will start their generation, to be ready to be connected to the transmission network as it is restored. This will offload the requirement from NLH.
8. NP will have ready 20- to 40-MW load blocks to restore using their individual or group breaker control schemes. NP will set the priority for customer restoration. NP will provide to NLH reasonably accurate measures of the load being restored and will, if necessary, apply appropriate cold load pickup relationships.
9. NLH will schedule the frequency setpoint to 60.05 Hertz.
10. Establish and maintain between NLH and NP control centres a continuous and dedicated voice communications channel during customer restoration.
11. NLH will direct the restoration of NP customer load blocks. NP will begin with their larger load blocks and end with the smaller loads.
12. NP will restore load as directed by NLH.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 2003-03-19
B. Butler		**REV. DATE:**

HYDRO
THE POWER OF COMMITMENT

SYSTEM OPERATING INSTRUCTION

STATION:	**Hardwoods and Oxen Pond**	**Inst. No.**	T-078
TITLE:	**Hardwoods and Oxen Pond Restoration**	**Rev. No.**	
		Page 6	**of** 6

Restoration Guidelines (cont'd.)

13. NLH will
    - monitor the frequency level and ensure AGC is ON,
    - check for potential transmission line or station transformer overloading (ALARMS and SCADA displays), and
    - monitor station voltages (ALARMS and SCADA displays).

14. NP will monitor their system for potential equipment overload and low voltages.
15. NLH may adjust Holyrood and other generation output level to assist in frequency regulation. This action should not slow greatly customer restoration.
16. Repeat steps 11 to 15 until all customers are restored to service.
17. Return all system operating parameters to normal.

** Part of the Emergency Response Plan

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 2003-03-19
B. Butler		**REV. DATE:**

Temporary Capacity Assistance Agreement with Corner Brook Pulp and Paper

The arrangement between Hydro and Corner Brook Pulp and Paper was finalized on December 31, 2013 with an initial term specified to the end of January 2014. The details are:

- Payment for all energy received into the Hydro system during a period of the capacity assistance (the four-hour assistance window) is included in the fixed payment below and there shall be no payment through the secondary energy arrangement;
- Payment will be only for the highest MW interruption requested. For example, if the initial notice is for 40 MW and it is later modified to a 60 MW requirement, only the 60 MW related payment shall apply. Specifically, for each four-hour request, the payment is the following:
    - 20 MW - $40,000;
    - 40 MW - $100,000; or
    - 60 MW - $180,000,

      depending on the largest amount requested during the four-hour period;
- A capacity assistance request shall be made to Corner Brook Pulp and Paper with no less than 15 minutes prior notice to the time that the capacity assistance period is scheduled to commence. Hydro will endeavour to provide additional notice when possible, with the option of cancelling the notice at least 20 minutes prior to the time that the capacity assistance period is scheduled to commence; and
- If the load at the Corner Brook Paper Mill is reduced for any other reason and Hydro asks for maximized Corner Brook Pulp and Paper hydro generation, Corner Brook Pulp and Paper will comply with this request to provide power to the system, under the terms of the existing Service Agreement, with payments only as per the ongoing secondary energy arrangement.
- In addition to the amounts for the interruption blocks, Hydro has agreed to pay a capacity fee of $63,000 per month for each of the months of February and March of 2014. These amounts are payable whether or not Hydro makes a capacity assistance request in those months.

Communications Highlights
System Disruptions

January 2014

Boundless Energy



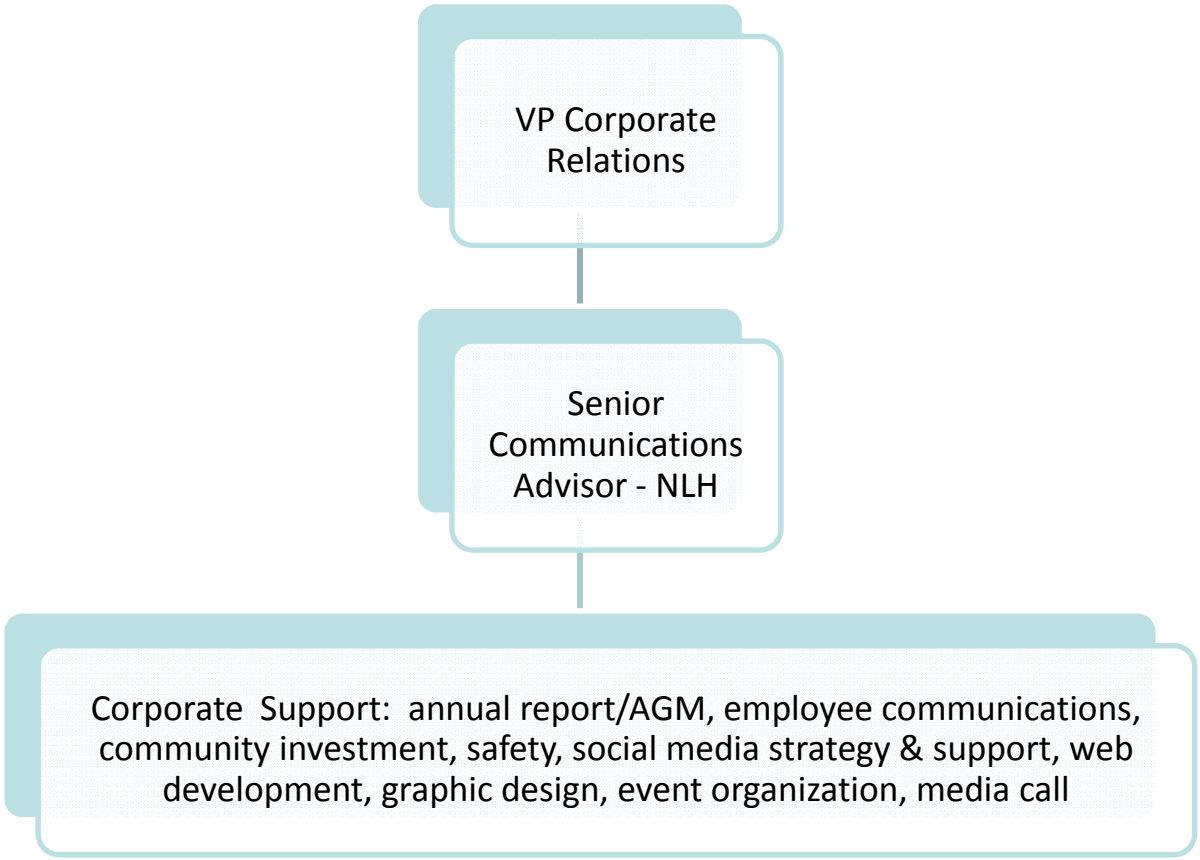
newfoundland labrador hydro
a nalcor energy company

Take a

MOMENT

for Safety

Communications Organization



Communication Principles & Objectives

- Principles grounded by our core values:
  - Open Communication
  - Honesty and Trust
  - Respect and Dignity
  - Teamwork
- Objectives
  - to be transparent and accessible, providing timely info via communication channels
  - manage expectations on service interruptions and return
  - manage and correct misinformation

Communications Highlights - Media

- Frequent distribution of information through varied channels
- Completely accessible to media throughout disruptions
- More than 100 media interviews, and 7 media briefings
  - Proactive updates through media (tv, radio, print)
  - Daily media briefings - Jan 3 to 8 (media briefings done with NFP & Gov't)
  - VOCM live coverage of media briefings
  - Regular CBC morning show updates
  - Very quick presence on live radio when required
    - (ex. on air within 10 minutes after Jan 5 Holyrood event)
  - News releases sent to media, posted to social media and Hydro website

Communications Highlights - Digital

- High volume of information and interaction via social media
  - 350+ Twitter Posts – more than tripled followers
  - 60+ Facebook Posts – more than doubled followers
  - More than 49,000 total social media mentions
- Created takeover page of Hydro website on January 5
- Three communications team members managed public responses and messages through twitter/facebook
- VP Corporate Relations tweeted from personal account (RTs by Hydro)
- Additional team members reviewing/monitoring twitter/facebook to capture questions for response
- Directed people to Hydro and NF Power outage info pages
- Retweeted/posted NF Power info
- Info on outages, and conservation and safety messages

Communications Highlights - Internal

- Email to staff on Jan 2 and 3 with conservation request and updates on events
- Email update to staff on Jan 6 with update of events
- Updates provided to Customer Service managers
- Update provided in internal newsletter – Newswire
- Regular updates provided to Board of Directors

Communications Highlights – Gov't

- Regular updates sent to Government by VP Corporate Relations throughout entire period
- Participated in joint media briefings
- Particpated and assisted joint energy conservation campaign with Gov't, Hydro and NF Power (radio, print, social media, and website with conservation tips)

Coordination of Information

- ECC/Operations
  - Jan 2-3 – Comms team in regular contact with Operations
  - Jan 4-5 – Comms team onsite in CEOC
  - Ongoing - system updates provided through email multiple times/day, meeting as required
- Customer Service
  - Coordination of messages with customer service to ensure consistent information provided to customers
- NF Power
  - Ongoing and regular dialogue between Comms teams

Communications Protocols Followed

- Power Outage and Emerg. Notification Procedures
  - Currently being reviewed/updated
  - Last full update, March 2011
  - Helps provide clear communications plan during outages
  - Includes communication with NFP if their customers impacted
- Emergency Communications Plan
  - Draft version, updated November 2013
  - Training & exercise scheduled for Q1, 2014
- Hydro Communications Lead – On-call
  - Mobilized Jan 2; additional comms staff also mobilized Jan 2
- CERP initialization
  - January 4 & 5 - Four communications team members mobilized

Thursday, January 2

- 8:00 am - call from operations confirmed peak load may exceed capacity
- 11:30 – 12:30pm several discussions with NF Power comms on advisory and messaging
  - Decision that Hydro would take lead on releasing advisory
  - Decision to release conservation request balanced against maintaining public confidence. i.e. Imp. to ensure it was required
- 12:30 pm - Advisory and messages drafted
- 1:00 pm– Update provided to Government
- 1:30 pm– Advisory distributed for internal approval
- 1:51pm – Advisory sent to media/public – posted to website and social media
- 2:30 pm– Key messages sent to NF Power communications

Thursday, January 2, con't

- 3:00pm– Confirmed media interviews w/ NTV, VOCM, CBC, Telegram, CBC National
- 3:12pm – Info sent to all employees – conservation messages
- 4:30 pm– Rotating outages began, regular updates through social media
- 9:30 pm– Updated advisory sent to media/public, rotations stopped for the night

Friday, January 3

- 7:00 am – Updated NF Power communications on loads and messages for the day. Media interviews with CBC morning shows, VOCM and Telegram
- 12:20pm – Requested NF Power join Hydro for joint media brief
- 1:15pm – Advisory for media briefing sent to NFP Power comms for approval
- 1:37pm – Media advisory distributed
- 2:30pm – Joint media briefing at Hydro Place
- 4:30 pm – Dawn Dalley - interview with CBC Here and Now
- 4:30 pm – Updated advisory sent to media/public on rotating outages
- 6:00pm – Rob Henderson on VOCM
- 8:30 pm – Rotating outages end, information updated on social media
- Social media updates continue with safety and conservation messages throughout day and into evening

Saturday, January 4

- 9:00 am – social posts indicating outages likely result of severe weather, investigating
- 10:00 am– begin media interviews and social posts indicating investigation into incident at Sunnyside terminal station
- 1:00pm – prepared messages with NF Power at Hydro Place
- 2:00pm - joint media briefing – Hydro, NF Power, Fire & Emergency Services (FESNL)
- Continue real-time updates, Q&A on social media throughout day
- 4:40 pm- info on outage sent to media/public and posted on website
- 5:30pm - prepared key messages with NF Power at Hydro Place
- 6:00pm – joint media briefing – Hydro, NF Power, FESNL
- Continue real-time updates and frequent messages about conservation and safety

Sunday, January 5

- Frequent messages on social media about conservation and safety
- 11:00 am – launched take-over page on Hydro website – containing links to important information, advisories and contact numbers
- 11:30 am - Briefing at Gov't with stakeholders
- 1:30pm – Joint media briefing w/Premier, Hydro and NF Power
- ~2:30pm - Ed Martin does call with VOCM open line show
- Started work on joint media campaign sponsored by Gov't, Hydro and NF Power. Hydro comms and Hydro takeCHARGE team – worked with Gov't to develop messages and collateral. NF Power also provided input.
- 5:30pm– Hydro advises its customers of rotating outages – schedule posted online
- 9:40pm – Trip at Holyrood - Dawn Dalley updates VOCM and CBC less than 10 min after event
- 9:50-11:00pm - real-time information distributed on social media until all customers restored

Monday, January 6

- Ed Martin interviews with CBC morning show
- Continue posting information on social media with real-time updates and responding to questions
- Gov't joint conservation advertisements begin running, included posting conservation info to Gov't website and using hashtag #conserveNL
- 1:30pm – Joint media briefing Premier, Hydro
- Hydro continues frequent conservation messages on social media

Tuesday, January 7

- No planned rotating outages
- Conservation and safety messages continue via social media
- Continue answering questions about generation and load on social media
- 1:00 pm – Joint briefing with Premier, NF Power and Hydro
- 4:40 pm – posted update on Hydro takeover page and on social media

Wednesday, January 8

- 10:30 am update on Hydro takeover page
- Gov't tweets top 10 conservation tips – Hydro re-tweets
- New peak load reached – conservation messages continue on social media
- ~3:30 pm– rotating outages resume. Hydro posts lists of communities and times on website for outages in Hydro distribution service territory
- 4:00 pm – media advisory issued on rotating outages and posted on Hydro takeover page online
- 4:15 pm - Joint briefing, Premier, Hydro and NF Power
- 6:30 pm – advisory posted on Hydro takeover page that Unit#1 at Holyrood back online

Jan 9 to 14

January 9

- Ed Martin interviews with CBC On the Go, NTV Evening News and CBC Here and Now

January 10 – 14

- Hydro comms team continues to answer question and provide social media updates
- Preparation for PUB reporting
- Prepared public advertisement and stakeholder outreach apologizing to customers for impact of outages and supporting reviews
- Prepared post outage survey with general public to assess communication and impact including conservation measures

Next steps post outage

- January 29 – Posting daily supply and demand reports on Hydro website
- February 17 – Posted blog post explaining peak demand and generation
- February 17 – Posted live feed of Hydro System generation and Island System generation on Hydro website
- Full review and update of Hydro website including mobile accessibility to be completed within 6 weeks.
- Discussion of lessons learned and improvements

Quick Lessons Learned

- Rapid response on all channels important for outage communication
- Quick approvals worked well and executive engagement enabled quick response
- Coordinated stakeholder outreach with clearly assigned accountable necessary in future
- Daily summary meetings between utility communications required to supplement ongoing communication
- Takeover page or “dark site” ready and implemented immediately.
- Embedded conservation team members with communication team to assist in promotion of conservation messages and responding to customer, public and social media questions

Our Values

Sharing our ideas in an open and supportive manner to achieve excellence.

Teamwork

Open Communication

Fostering an environment where information moves freely in a timely manner.

Honesty and Trust

Being sincere in everything we say and do.

Safety

Relentless commitment to protecting ourselves, our colleagues and our community.

Respect and Dignity

Appreciating the individuality of others by our words and actions.

Leadership

Empowering individuals to help, guide and inspire others

Accountability

Holding ourselves responsible for our actions and performance.

Public Advisory – Island Interconnected Customers

January 22, 2014 – Due to unseasonably cold conditions and very high load forecasts for the next 24 hours, Newfoundland and Labrador Hydro (Hydro) is requesting that customers on the island take steps to conserve electricity where possible.

Given the extreme cold conditions, Hydro is forecasting a very high peak load this evening and tomorrow morning. "We are asking customers to assist us by reducing, where they can, their electricity usage during peak times," said Dawn Dalley, Vice President Corporate Relations, Nalcor Energy.

To ensure we can meet the high customer demands, homes and businesses on the island are asked to avoid unnecessary electricity usage and reduce their consumption as much as possible from 4:00 p.m. to 8:00 p.m. Thursday, January 2, 2014 and from 7:00 a.m. to 10:00 a.m. Friday, January 3, 2014.

Customers can assist by doing the following:

1. Reducing electric heat by a few degrees
2. Conserving hot water by not running dishwashers, washers and showers
3. Avoid using clothes dryers
4. Turning off Christmas lights

Hydro thanks customers for their support and cooperation at this time.

-30-

Media Contact:
Erin Squires, Senior Communications Advisor
t. 709.737.1311 c. 709.697.1186
ErinSquires@nlh.nl.ca

Attention all residents and business owners.

Our work continues to maintain power supply across the island. Conserving power is essential and your ongoing efforts can impact the power available in homes and communities.

- **Turn down thermostats a few degrees**
- **Reduce hot water usage**
- **Unplug unnecessary appliances**
- **Turn off lights when not needed**

Visit gov.nl.ca for more conservation tips.

Every effort to conserve power counts.

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A FORTIS COMPANY

newfoundland labrador hydro
a nalcor energy company

Newfoundland Labrador

@NFPower | @NLHydro | @GovNL | #ConserveNL

Radio script for conservation request – January 2014

Attention all residents and business owners. Our work continues to maintain power supply across the island. Conserving power is essential and your efforts can impact the power available in homes and communities. Turn down thermostats a few degrees, turn off lights, reduce hot water usage and unplug unnecessary appliances.

Visit gov.nl.ca for more conservation tips. Every effort to conserve power counts.

A message from the Provincial Government, Newfoundland and Labrador Hydro, and Newfoundland Power.

Newfoundland Labrador

ELECTRICITY CONSERVATION MEASURES

Residents and businesses are asked to take steps to conserve electricity where possible. Conserving power is essential and all efforts can affect the power available in homes and communities.

Your ongoing efforts are particularly important during times of increased demand, including 7:00-10:00 a.m. and 4:00-8:00 p.m. daily.

Every effort to conserve power counts!

CONSERVATION AT HOME

Heating

- Turn down thermostats to its minimum setting in rooms that are not being used
- Turn back the heat in your main rooms by a few degrees

Lighting

- Turn off lights in rooms that are not being used
- Use CFL bulbs and/or only turn on lights that have CFLs installed
- Replace incandescent bulbs with CFL or LED bulbs
- Use lower wattage lights for general lighting
- Reduce the number of lights used to light outside your home
- Use sensors or timers on your exterior lighting to reduce the amount of time your lights are on

Appliances

- Unplug electrical appliances and chargers when they are not in use (including computers, tablets, printers and televisions)
- Do not preheat the oven when cooking
- Use alternate cooking sources such as a pressure cooker, toaster oven or microwave oven. Smaller appliances generally use less energy
- Use a kettle with an automatic shut off
- Set the temperature inside your refrigerator to the mid-level setting, usually 4°C
- Avoid washing and drying clothes during the increased demand times of 7:00-10:00 a.m. and 4:00-8:00 p.m.
- Wash and rinse laundry in cold water
- Set the dishwasher to energy or water saver mode and air dry dishes instead of heat drying
- Set the timer to wash dishes overnight

Around the House

- If you have a fireplace, close the flue damper when it's not in use
- Keep shades and curtains open during the day so the sun can warm your home and close them in the evening to keep the heat in
- Use kitchen and bathroom fans sparingly. Ventilation fans can extract all of your home's heat in 2 to 3 hours
- Turn off your electric water heater at the electric panel if you will be away from home for more than one week

CONSERVATION AT WORK

Whether you own or work in a small, medium or large business, conservation at work really adds up. Here are a few things that can be done around the office to conserve energy.

Heating

- Only heat spaces where necessary
- Reduce heating spaces used only for short periods. If possible reduce temperatures or shut off heating in vestibules, stairwells, lobbies and unused spaces.
- Keep shades and curtains open during the day so the sun can warm your space and close them in the evening to keep the heat in
- Lower your thermostat to the lowest comfortable setting when your business is occupied. Set the temperature back further when the business is unoccupied.
- Review programmed schedules for heating and ventilation equipment for opportunities to better match the schedule to actual occupancy and reduce runtimes.
- Avoid using electric snowmelt loops for walkways whenever possible, when temperatures allow, rely on proper snow removal and salting procedures. If it is necessary to use a snow melt loop, ensure it is not left on unnecessarily after snowfall has ceased.

Equipment

- Unplug equipment and electronic items not in use, for example, commercial grade coffee makers which continually heat the water it stores.
- Turn off machinery, computers, printers, appliances and photocopiers whenever possible
- Shut down non-critical equipment during peak demand period
- Use large equipment during off-peak hours whenever possible
- Avoid leaving any equipment on 'stand by' mode. It will still use energy and should be switched off instead
- When the building is unoccupied, turn off exhaust fans in washrooms and kitchens if possible

Lighting

- Remember to turn off outside safety and security lighting at the start of each day
- Adjust lighting levels to match needs at different times of the day
- Use natural light whenever possible. Ensure windows are clean and encourage staff to open blinds before thinking of switching on lights.
- Turn off non-essential lights, signs and billboards inside and outside the building
- Scale back to half lighting or reduce lights on a dimmer where possible
- Turn off the lights when leaving the office/building for the day. Ensure after-hours security and cleaning staff are briefed on the importance of turning unnecessary lighting off.

NEWFOUNDLAND AND LABRADOR HYDRO

Technology and Communications Infrastructure

March 2014

newfoundland labrador hydro
a nalcor energy company

Table of Contents

EXECUTIVE SUMMARY 1
1 INTRODUCTION 4
2 REVIEW PROCESS 4
3 BACKGROUND 4
4 SEQUENCE OF EVENTS 6
5 KEY FINDINGS AND RECOMMENDATIONS 12

Appendices:
Appendix 1 Acronyms and Definitions
Appendix 2 HP Emergency Generation
Appendix 3 Hydro - Operations Standard Instruction

EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (Hydro) has completed a comprehensive review of the events surrounding the supply disruptions on the Island Interconnected System during January 2-8, 2014. The review included an investigation of the rotating outages which occurred between January 2-8, 2014[1] and the transmission/terminal station equipment failures which occurred on January 4 and 5, 2014.

This report outlines the results of Hydro's internal review of the availability and performance of the Energy Management System (EMS), administrative computing systems, telecommunication and network systems, and the Hydro Place (HP) emergency generating system during the electricity supply disruptions.

Hydro has four levels of back-up in the event that power is lost to the Energy Control Centre (ECC): diesel, battery, manual and a remote back-up control centre. On January 4, 2014, Hydro's diesel emergency generation system shutdown shortly after it was automatically activated as a result of the widespread power disruptions, and loss of the Newfoundland Power (NP) distribution feeder to HP. When the diesel emergency power source shutdown, Hydro's Uninterruptible Power Supply (UPS) batteries were activated. The batteries supplied power to the EMS and administrative computer facilities until they were fully depleted and the systems shut down due to complete power loss (11:03). When the EMS shut down, the ECC Operators followed manual protocol, and began voice communication with key stakeholders, including Hydro generation sites, terminal stations, and NP.

Information Technology (IT) on-call support was notified of the resultant system shutdown. Minutes later, the diesel emergency generator was manually restarted by on-site Building Operations Supervisor, providing power to HP.

[1] Rotating outages occurred on January 2, 3, 5 and 8, 2014.

IT on-call support arrived on site within 30 minutes (11:30) and the EMS was restored to operation within 16 minutes (11:46). After the EMS core system was restored, there was further activity required to restore the EMS auxiliary systems and to validate that the data and system integrity checks were complete. After the EMS systems were recovered, the focus shifted to the administrative system recovery. IT support consulted with senior management regarding the order and priority of system recovery in response to the critical business needs identified on site during the power failure. IT staff then began the effort required to implement the required controlled systematic recovery of servers, storage and application systems. Integrity checks took place during recovery to ensure no data loss, data corruption and/or systems damage resulted from the loss of power. This testing identified no significant system or data damage (two hard drives on redundant back-up servers were affected and a minor amount of real time EMS data were recovered and replaced). The critical administrative systems were recovered and operational by 15:00.

In total, EMS was inoperable for 43 minutes between shutdown and restoration due to loss of electrical power, shutdown of the emergency generation system, and depletion of the UPS batteries. Consequently, the EMS system was not able to control and monitor activities at the generating and transmission facilities, requiring the ECC to follow established protocol for the loss of EMS function. Without the administrative systems, certain business functions, such as the ability to update outage information on Hydro's website, electronically manage the Work Protection Code System to track work plans, and send/receive corporate e-mail, were negatively impacted.

Overall, the review found that HP Operations and Information Systems employees responded quickly to the events of January 4, and worked together to restore building power and computer systems. As well, telecommunications and network systems functioned as designed ensuring the availability of data, voice, and teleprotection circuits between the ECC and remote terminal and generating stations. The EMS system and administrative computing systems also performed as designed outside the period affected by loss of power.

Following the events of January 4, 2014 Hydro reconfirmed that the NP distribution feeder to HP be restored on a priority basis. This protocol is now in place in the event of future power outages. Investigation of the cause of the diesel unit failure is complete, and the identified issues have been addressed.

Based on the findings, the following recommendations are being actioned.

- TCI 1: Establish a protocol with Newfoundland Power to have HP power feeder restored as soon as possible if interrupted.
- TCI 2: Investigate the cause of the "under frequency" and synchronization alarms experienced on January 3 and 4, 2014.
- TCI 3: Identify documents related to system restoration including cold start procedures, which need to be available in an offline, hard copy format.
- TCI 4: Investigate and rectify problems with ventilation louver control.
- TCI 5: Investigate options to provide redundant operation of the HP diesel generation room cooling system.
- TCI 6: Review design of emergency lighting at HP.
- TCI 7: Identify documents related to system restoration including cold start procedures, which need to be available in an off-line, hard copy format.
- TCI 8: Establish a process for monitoring critical alarms from the HP UPS on a 24/7 basis.

1 INTRODUCTION

This report outlines the results of Hydro's internal review of the availability and performance of the EMS, administrative computing systems, telecommunication and network systems, and the HP emergency power generation system.

The sequence of events, which resulted in the loss of power to the EMS and administrative computer systems, and the timing of the restoration of power to HP and computer systems are detailed in full. The report presents immediate recommendations that have been implemented, as well as future actions. These recommendations aim to mitigate or prevent similar events.

2 REVIEW PROCESS

In completing the review, Hydro reviewed the data from the local Remote Terminal Unit (RTU), electronic logs from computer systems, UPS systems, and emergency generation system to establish a timeline of events. The input of the employees who were involved in operating and managing key assets, and those who participated in the response and restoration efforts, was also critical in documenting timelines and actions taken. The ECC team, who are the primary users of the EMS, were also engaged to provide their perspective. Additional input was solicited from the maintenance contractors during the review of the HP emergency generation system.

3 BACKGROUND

3.1 EMS and Administrative Computing Systems

Control and monitoring of devices on the interconnected grid is carried out from the ECC, located at HP in St. John's. The EMS is a computer system that supports these functions for the ECC. All components of the EMS are dual redundant, meaning in the event of a failure of the prime component, a secondary component assumes that function within seconds. This system has had a 100% availability factor since its initial deployment in June 2006.

The EMS is powered by a UPS. A UPS is typically used to protect hardware such as computers, data centers, telecommunication equipment, or other electrical equipment where an unexpected power disruption could cause injuries, serious business disruption, or data loss. The UPS is comprised of three units. The UPS was designed to tolerate the loss of a single UPS unit and still meet the EMS power requirements. If the NP distribution feeder to HP is interrupted, the UPS is designed to carry the EMS power load until the emergency diesel generators are operational, and provide stable power, or time to properly shut down the protected equipment.

The administrative computing environment includes all corporate computing systems, for example, financial tracking and planning, supply chain management, human resources monitoring and planning, plant maintenance, work order management, customer service, safety, work protection code, as well as access to shared storage of files (printing, systems access and security, email, Smartphones, Microsoft Office Suite, Adobe, etc.). These systems are located in a separate computer room from the EMS, and are powered by a separate UPS system. There is a comprehensive Disaster Recovery Plan (DRP) to address the loss of administrative computer systems. In the event that the administrative computing systems at HP cannot be recovered in a timely manner, there is a plan in place to relocate critical administrative operations to a data site in Markham, Ontario, which is tested annually.

Similarly, there is a comprehensive DRP, including the option of relocating to a back-up control centre, in place to address the loss of the EMS. This DRP is tested annually.

3.2 Telecommunications and Network Systems

Hydro's owned and maintained telecommunications infrastructure provide teleprotection that is used in conjunction with power system protective relaying to provide the best possible means of isolating faults on high voltage transmission lines. These protection schemes are designed to limit the impact of the provincial power grid during fault conditions by selectively removing the faulted line in the shortest possible time. The protection equipment, in

combination with teleprotection circuits, not only helps to preserve power system stability, but also protects Hydro's transmission and generation assets from damage during fault conditions.

3.3 HP Emergency Power Supply

The ECC, Corporate Emergency Operations Centre (CEOC), engineering and functional support staff, as well as the systems that support electricity operations and other business functions, are located in HP in St. John's.

HP emergency generation system has two diesel generators supported by other systems including fuel, power control, and pneumatic controls. In the event of a loss of building power, both generators will start and provide power to the building's essential services. After 15 minutes of run time, one of the diesel generation units will shut down and the power load will be serviced by the single on line unit. If that on line unit fails, the standby unit starts in order to maintain power supply. Historically, the HP emergency power generation system has met its design criteria of having at least one of the two generators (G1 or G2) available at all times since installation in 1989.

The HP emergency power generation system is tested on a bi-weekly schedule, and any noted issues are addressed by contracted technicians.

4 SEQUENCE OF EVENTS

This section of the report provides the sequence of events (SOE) at HP related to the emergency power systems that resulted in the loss of power to the EMS, and administrative computer systems.

Table 1: Sequence of Events

DEC 27, 2013		
DATE	**EVENT**	**COMMENT**
Dec. 27, 2013		Planned annual maintenance was completed on both HP generator engines (G1 and G2) by Hydro's contractor. Minor issues were addressed accordingly.

JAN 3, 2014		
TIME	**EVENT**	**COMMENT**
06:44	G2 failed to synchronize	While HP emergency generation system was being started to reduce the interconnected system load, G2 failed to synchronize and was shut down. The diesel technicians were unable to immediately determine why G2 would not synchronize so the unit was tagged out of service. G1 was running for 12 minutes when a high temperature alarm forced its shutdown. The high temperature alarm was triggered by lack of cooling air, caused by mechanical failure of the ventilation louver activation system, which allows cooling air to enter the diesel generation room.
08:30		Johnson Controls investigated the cause of the failure of the ventilation louvers. It was determined that the air dryer for the pneumatic system operating the actuator had failed. Parts were not available to repair the failed air dryer so it was bypassed, and a new one ordered.
10:08		G1 was manually started to help reduce the Interconnected System load.

JAN 3, 2014		
20:19		G1 was shut down when the Interconnected System load demand decreased.

JAN 4, 2014		
TIME	**EVENT**	**COMMENT**
08:45 Approx.	Building Operation Supervisor arrives at HP	After receiving supervisory alerts from ADT Security services, Building Operations Supervisor attended HP to ensure no significant events were in progress.
09:05	NP feeder lost to HP	EMS and administrative UPS units were immediately switched to battery power.
		Building Operations Supervisor ensured HP emergency generation system was operating as required, including ventilation louvers.
09:05:45	Emergency generator G1 at HP started	G1 was ready to service HP essential power load including the EMS and administrative computers. G2 was unavailable because of the synchronization failure on January 3, 2014.
09:05:53	All four transfer switches switched to emergency power	EMS and administrative UPS were being supplied from G1.
09:11:54	Main Bus under frequency condition	Automatic load shedding, to stabilize frequency, resulted in the loads on transfer switches 2, 3, 4 being dropped. Administrative UPS and Unit 2 of the three units in the EMS UPS were running on battery.

JAN 4, 2014		
TIME	**EVENT**	**COMMENT**
10:10:00 Approx.	EMS UPS Unit 2 shutdown	Batteries in EMS UPS Unit 2 were depleted. EMS UPS Unit 2 had been running on battery since 09:11. (one-hour run time). Only two units in the EMS UPS were active (Units 1 and 3). These units were still being powered by G1.
10:15 Approx.	Building Operations Supervisor leaves HP	Building Operations Supervisor left HP temporarily to assist ECC Operations Supervisor who was stuck in snow enroute to HP.
10:38:44	G1 Shutdown	Shutdown resulted from a high temperature alarm. EMS UPS Units 1 and 3 were running on battery.
10:40 Approx.	Building Operations Supervisor notified of G1 shut down.	Building Operations Supervisor received call that G1 has shut down, and returned to HP immediately, arriving approximately 10:55.
11:02:50	EMS UPS shutdown	Batteries in the EMS UPS were depleted; resulting in the loss of EMS system and remaining administrative computer systems. Runtime on EMS UPS was 24 minutes. EMS on-call support was contacted by ECC operator.

JAN 4, 2014		
TIME	**EVENT**	**COMMENT**
11:02:50	ECC DRP implemented	ECC operators did not have a direct electronic overview of the status of the power grid. ECC operators activated the initial steps of the DRP, a manual protocol, including voice communication with key stakeholders and consideration of return to service at the backup site. The Standard Instruction 'Contingency Plan for Loss of EMS Function' is included as Appendix 3.
11:03:03	G1 restarted	The Building Operations Supervisor rectified the problem with the generator room vent louvers which resulted in the high temperature alarm at 10:38, forcing G1 to shut down. The unit was manually started by the Building Operations Supervisor, and appropriate actions taken to maintain reliable operation.
11:05	NP feeder restored	ECC called Newfoundland Power to request restoration of the feeder to HP. The feeder was immediately restored.
Approx. 11:08		EMS UPS restarted, requiring manual intervention to restart. Network Services on-call personnel were not on site at this point in time, but others perform restart. Restoration of the EMS and administrative computer systems could have proceeded. This is a manual process and the EMS on call person was not yet on site.

JAN 4, 2014		
TIME	**EVENT**	**COMMENT**
Approx. 11:30		The EMS on-call person was on site within 30 minutes of being called (required to be on site within one hour). EMS took immediate action to recover the EMS.
Approx. 11:40		Other team members arrived on site to provide assistance in restoring the administrative computing systems and assist with the restoration of the EMS.
11:46	EMS on-line	EMS system on line and providing grid control for ECC operators. Normal operations of the ECC resumed within 43 minutes.
	EMS system confirmation	EMS auxiliary systems restored, validated that the data and system integrity checks were complete.
	Administrative Computer Systems	IT support consulted with senior management regarding the order and priority of system recovery in response to the critical business needs identified onsite.
15:00 Approx.	Administrative Computer Systems restored	All critical administrative systems were restored and operational.
SUBSEQUENT RESOLUTIONS TO ISSUES IDENTIFIED		
	Synchronization failure remediation	Subsequent investigation indicated the synchronize failure resulted from a faulty rectifier, which has been replaced, and sticking breaker which is scheduled for service in April 2014.

JAN 4, 2014		
TIME	**EVENT**	**COMMENT**
	Ventilation louver remediation	Ventilation louver actuators are scheduled to be installed in April 2014, replacing the pneumatic system with more reliable electronically controlled equipment. The new activation system will provide redundancy in this area.
	Under frequency alarm remediation	The under frequency condition cleared, and has not recurred since. It is currently under investigation by Hydro contractor Madsen.

5 KEY FINDINGS AND RECOMMENDATIONS

5.1 HP Equipment Performance

The diesel generation units at HP are started and their ability to supply essential load is verified every two weeks. The last test prior to the January 4, 2014 outage being completed on January 2, 2014. In addition, fuel supplies are maintained at HP to run backup generation. After receiving notification of supervisory alerts from ADT, the Building Operations Supervisor attended HP to ensure there were no significant issues related to the inclement weather. The fuel supply was at approximately 8,000 litres, and with the exception of the actuators for the cooling system louvers, all systems operated as designed, including the shut down of G1 for a 25-minute duration due to the high heat alarm. Equipment is regularly tested and maintained. The annual preventative maintenance of the diesel engines was performed on December 27, 2013. Subsequent to the 25-minute shut down due to overheat alarm, the emergency generation system successfully ran in excess of 213 hours between January and March of 2014.

Following the issues with the building emergency power systems on January 4, 2014, there was limited emergency lighting to allow personnel to work and there was no battery powered emergency lighting in key areas, including the stairwells.

A review of the loss of power to HP on January 4, 2014 has identified several opportunities for improvement and areas for further investigation.

RECOMMENDATION		STATUS	
TCI 1	Establish a protocol with NP to have HP power feeder restored as soon as possible if interrupted.	Complete	Protocol includes HP not to be dropped, and in case of interruption, to have priority restoration.
TCI 2	Investigate the cause of the under frequency and synchronization alarms experienced on January 3 and 4, 2014.	In Progress	Cause of synchronization alarms has been determined and repaired. Under frequency is still being investigated by Madsen.
TCI 3	Identify documents related to system restoration including cold start procedures, which must be available in hard copy format.	In Progress	The emergency diesel SOE log is now being reviewed daily to highlight potential issues. Review of Preventative Maintenance (PM) program now complete and in the process of being documented.
TCI 4	Investigate and rectify problems with ventilation louver control.	In Progress	Replacement to be complete by April 2014.
TCI 5	Investigate options to provide redundant operation of the HP diesel generation room cooling system.	In Progress	Replacement of ventilation louver controls will include redundancy protection.
TCI 6	Review design of emergency lighting at HP.	Planned	To be complete by June 30, 2014.

5.2 EMS and Administrative Computing Equipment Performance

The EMS and administrative computing systems performed as expected, other than issues arising from loss of power. On January 4, 2014, Hydro's diesel emergency generation system shutdown shortly after it was automatically activated by the widespread power disruptions. When this diesel emergency power system shutdown, Hydro's UPS batteries were activated. The batteries supplied power to the EMS and administrative computer facilities until the batteries were fully depleted and the systems shut down due to complete power loss (11:03).

IT on-call support was notified of the resultant system shutdown. Minutes later, the diesel emergency generator was manually started, providing power to computer facilities, allowing the process of system restoration to begin upon arrival of the IT on-call support, who arrived within thirty minutes.

The EMS was restored to operation within 16 minutes of the on-call support personnel arrival. Following EMS restoration, further activity required to restore EMS auxiliary systems and to validate that the data and system integrity checks were completed. IT staff then began to implement the required controlled, systematic recovery of servers, storage, and application systems. The abrupt shutdown, due to loss of power, introduced the potential for systems and data damage. Consequently, extra effort was required to ensure integrity checks took place during recovery restart to ensure no data loss, data corruption and/or systems damage. The critical administrative systems were recovered and operational by 15:00.

As a part of storm preparation, the ECC had additional staff working during the morning of January 4, 2014.

With the functional loss of the EMS computing systems, the ECC responded by taking the following actions in order to secure the power system: 1) the ECC coordinated with NP to inform them of the situation and to request that they monitor the power system and to advise

the ECC of any issues on the power system; 2) the ECC contacted the Bay d'Espoir control room to advise them of the situation, requested that they monitor and control the system frequency, and monitor and control the generating units at the hydro plants; and 3) the ECC communicated with the Holyrood Generating Facility control room, terminal stations, and generating stations which had personnel to advise them of the situation and to advise the ECC of any issues at those locations.

Coincident with the above, discussions took place between System Operations and Energy Systems personnel regarding the activation of the Backup Control Centre Disaster Recovery Plan (BCC DRP). The decision was made to stay at the HP ECC.

At the time the EMS function was lost, the ECC were working towards restoring transmission lines and stabilizing the system frequency. Once the EMS was returned to service, the ECC continued to restore transmission lines to service and stabilize the power system.

RECOMMENDATION		STATUS	
TCI 7	Identify documents related to system restoration including cold start procedures, which must be available in hard copy format.	In Progress.	Continuous improvement related to system restoration. The system cold-start procedures are currently being updated and stored as hard copy. To be completed by April 15.

5.3 Telecommunications and Network Systems Equipment Performance

All backup generators and battery supplies for telecommunications and network systems equipment at remote microwave, terminal, and generating sites worked as designed during the January 4, 2014 system outage. As well, all data, voice, and teleprotection circuits functioned

as designed. This performance ensured the availability of data, voice, and teleprotection circuits between the ECC and all remote terminal and generating stations as well as the system protection signalling between terminal stations.

The two UPS systems that provide backup power supply to the EMS and administrative computing equipment in HP also operated as intended on January 4, 2014 and provided backup power to the EMS (24 minutes) and administrative computing equipment (95 minutes), in excess of design criteria.

A review of the January 4, 2014 events highlighted opportunities to improve UPS alarm monitoring and communication. These improvements are required to expedite employee response to ensure controlled shutdown[2] and restoration of the systems if the UPS batteries are depleted.

RECOMMENDATION		**STATUS**	
TCI 8	Establish a process for monitoring critical alarms from the HP UPS on a 24/7 basis.	In Progress	The critical alarms from the EMS UPS are now monitored 24/7. Methods and protocols are being investigated to provide 24/7 monitoring of the administrative computing UPS. An alternate method is required for the other UPS systems. The EMS critical alarms are now displayed on the operator console in ECC, as well as being e-mailed to on-call staff.

[2] A controlled shutdown of the computer systems would avoid potential damage resulting from an uncontrolled shutdown resulting from loss of power.

APPENDICES

Appendix 1 - Acronyms and Definitions

Administrative Computing Systems –All Nalcor computing services except the EMS.

DRP – Disaster Recovery Plan – A document detailing how computer services will be restored when lost.

ECC – Energy Control Center - Control room at HP that is staffed 24/7 by operators who manage the interconnected power grid.

EMS – Energy Management System - Computer system located at HP that provides control and monitoring of the power grid to the ECC.

IS – Information Systems – The department within Nalcor that is responsible for the EMS and administrative computing services.

NMC – Network Management Center – A room at HP that is staffed during business hours were the Nalcor communications networks are monitored.

NP – Newfoundland Power.

UPS – Uninterruptable Power Supply – A battery system used to supply temporary power.

Corporate Emergency Operations Centre – The Corporate Emergency Operations Centre (CEOC) is located in HP and is the area where personnel will meet to manage Nalcor's response to any emergency.

WPC - Work Protection Code – A safety protocol to provide workers with a safe work area when working around energized equipment. In the absence of the electronic system, a paper-based process is used to ensure worker safety.

Computer Rooms - There are three Nalcor computer rooms.
The EMS computer room is located on the second floor of HP and hosts the EMS and ancillary services related to the control and monitoring of the power grid.
The administrative computer room is located on the first floor of HP and hosts the administrative computing systems.

Mapboard - The front wall of the ECC is comprised of a grid of tiles and lamps referred to as a mapboard. The overall layout of the power grid is depicted on this mapboard; the lamps are color-coded to dynamically represent the status of various devices on the power grid.

Remote Terminal Unit (RTU) - A device used to collect readings from equipment and communicate that data to the EMS. A RTU resides at HP and is used to collect information regarding the status of the emergency power system as well as environmental data such as temperature in the computer rooms.
An alarm is generated at the operators console in ECC when an abnormal condition is detected by the RTU.

HP Emergency Generation - HP emergency diesel generation system is comprised of two generators (G1 and G2), along with supporting systems. In the event of a loss of building power both generators will start and provide power for building essential services including the UPS systems. After 15 minutes of generator run time, one of the generators will shut down and the power load will be serviced by a single on-line generator. If that on-line generator were to fail the standby generator, if available, would start and pick up the system power load.

ECC UPS - This UPS is comprised of three units, it was designed to tolerate the loss of a single unit and still meet the EMS power requirements. It is designed to provide a minimum of 17 minutes run time. The expectation is that the diesel units would have started and picked up system load within that time frame.

Admin UPS - This UPS is comprised of two units, it was designed to tolerate the loss of a single unit and still meet the power requirements. It is designed to provide a minimum of 17 minutes run time. The expectation is that the diesel units would have started and picked up system load within that time frame.

Transfer Switches - Transfer switches automatically control the switch to the emergency generators in the event of the loss of the NP distribution feeder.

There are five transfer switches incorporated in the NLH emergency power system. With regard to the operation of the EMS and administrative computer systems four of the transfer switches are relevant.

- Switch 1 supplies Unit 1 of the three units in the EMS UPS.
- Switch 2 supplies Unit 2 of the three units in the EMS UPS.
- Switch 3 supplies both Units of the Administrative UPS.
- Switch 1 or Switch 2 supplies Unit 3 of the three units in the EMS UPS depending on the position of switch 5.

When diesel generators are supplying power to HP, the voltage and frequency from the generators are monitored. If these values are not within an acceptable range, transfer switches will drop load from the diesels. The switches are prioritized with regard to the order in which loads will be dropped. If after a load is dropped on a particular switch the voltage and frequency are within acceptable ranges higher priority loads will remain on diesel power. The load in transfer Switch 1 which supplies the EMS will never be dropped by this automated system.

Appendix 2 - HP Emergency Generation

The HP emergency generation system is designed to provide power to key areas of HP when power is not available from the NP distribution system. The system was commissioned when HP, which opened in 1989, was constructed.

The generation system is centered on two Caterpillar model 3406B diesel generation sets, designed to provide redundant emergency power supply to the building. They are described as G1, and G2. Each unit is rated to produce 300 Kw, while the typical demand during operation is approximately 180 Kw. As of the 2013 preventative maintenance carried out on December 27, 2013, G1 had 295 operating hours, and G2 had 291 operating hours, for a combined total of 586 hours since their installation in 1989. Both units are installed in an indoor room on level two, at the northwest corner of HP. Both diesel engines are subject to a comprehensive annual inspection, and advanced generator preventative maintenance plan, carried out by Glenn Nichols Engine Services Ltd, a Caterpillar trained technologist.

Fuel is provided by a fuel system including a 9,092-litre above ground tank installed outside of HP, and a 630-litre day tank in the generator room. This system was commissioned in 2005, replacing previously installed underground fuel storage system. Fuel dips are carried out on a weekly basis, at which time there is also a visual inspection of the system. Given the low consumption rate, the fuel in the system is quality tested on an annual basis.

The diesel generation room is kept at a minimum temperature of approximately 20 C during standby to ensure maximum reliability and ease of starting as required. Once the diesel generator units are running, the room is cooled using forced air, driven by fans on the diesel units, and a system of ventilation louvers which are normally closed, but open for cooling purposes when the diesel generation units are running. The ventilation louvers are operated by means of a pneumatic control system installed in the mechanical penthouse of HP. Among other systems in HP, this single pneumatic system provides control for the louvers on both diesel generators, and rooftop exhaust fan in the diesel generation room.

The emergency generation system is controlled through a series of breakers and switches. The recommended service interval on the breakers is three to five years. They were last serviced by the manufacturer's agent in December 2010, and are scheduled for next service in April 2014.

The diesel generation system at HP is tested on a biweekly basis by building operations personnel. This involves initiating a manual test on each of the four transfer switches that starts both diesel generation sets, allowing one of them to take the load, then the second unit to synchronize to the to the first and then share the load. One unit automatically stops after 15 minutes, entering stand-by mode. The diesel generators alternate which unit stays on each time they are operated. This testing procedure lasts approximately 30 minutes.

It is estimated that of the combined 586 hours operating time recorded on these units as of December 27, approximately 450 hours would have been from the testing routine since 1989. As of March 13, 2014, G1 had a total of 482 operating hours, while G2 had 317, for a combined total of 799 hours. Total run time, primarily in support of island load since December 27 has been 213 hours exceeding the total non-testing run time since commissioning in 1989, estimated at 136 hours.

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NEWFOUNDLAND AND LABRADOR HYDRO - OPERATIONS

STANDARD INSTRUCTION

TITLE: **Contingency Plan For Loss of The Energy Management System Function**	**Inst. No.** 015 **Rev. No.** **Page** 1 **of** 4

Introduction

The Energy Management System (EMS) is used by the Energy Control Centre (ECC) to operate the power systems on the Island and in Labrador. If the EMS fails and is unable to function, operation of the power system must be carried out by staffing generation and terminal stations normally operated using the EMS. The details of this plan, which are directed by ECC staff, are included in the Contingency Plan for Loss of EMS Function retained as part of several technical and administrative instructions maintained by ECC. This instruction outlines the responsibilities of operating staff who are required to attend stations, the preparation required, and the frequency for testing the contingency plan.

Preparedness

To ensure that individuals are familiar with the procedures and responsibilities associated with this instruction, this contingency plan will be simulated yearly to measure effectiveness.

Responsibilities

Asset Managers – Generation and Terminal Stations	1.	Managers should ensure that personnel are aware of this procedure and the rationale for its creation.

PREPARED BY:	**APPROVED/CHECKED BY:**	**ISSUED DATE:** 2003-07-15
C. Kirby		**REV. DATE:**

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STANDARD INSTRUCTION

TITLE: **Contingency Plan For Loss of The Energy Management System Function**	**Inst. No.** 015 **Rev. No.** **Page** 2 **of** 4

Responsibilities (cont'd.)

Asset Managers – Generation and Terminal Stations	2.	Managers should ensure that the detailed contingency plan referred to in the introduction, equipment manuals, paper/pencils, functional communications equipment, PPE for switching, and other equipment/materials needed by staff during an EMS outage, to manually monitor and control a station, are available at each station listed in the detailed plan.
Regional On-call Supervisors	1.	When contacted by ECC, supervisors will be required to staff stations with switching personnel, and plant operators where appropriate. ECC will identify the stations or plants that require manual operation.
	2.	When presented with event logs from switching or plant personnel, the logs should be forwarded to the Superintendent of ECC.
Hydro Generation On-call Supervisors	1.	When contacted by ECC, supervisors will dispatch operators to the plants specified by ECC.
	2.	ECC will indicate if personnel are required at flow control structures.

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STANDARD INSTRUCTION

TITLE: **Contingency Plan For Loss of The Energy Management System Function**	**Inst. No.** 015 **Rev. No.** **Page** 3 **of** 4

Responsibilities (cont'd.)

Hydro Generation On-call Supervisors	3.	When presented with event logs from plant personnel, the logs should be forwarded to the Superintendent of ECC.
Switching Staff and Plant Operators	1.	When arriving on site contact the Energy Control Centre, identify oneself, location and any unsafe conditions that would require immediate attention. Await instructions from ECC. The priority for communications is Operational Voice, Newfoundland Telephone, then VHF.
	2.	ECC staff will contact station personnel hourly to obtain operating data key to that station, (i.e. generation levels, transmission lines flows, bus voltages, delivery point voltages etc. which ever are appropriate). Station personnel shall maintain an hourly log of information and record the time and nature of any abnormal system event, (i.e. time of alarm/outage and activating device/relay), and contact ECC when such an event occurs.

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STANDARD INSTRUCTION

TITLE: **Contingency Plan For Loss of The Energy Management System Function**	**Inst. No.** 015 **Rev. No.** **Page** 4 **of** 4

Responsibilities (cont'd.)

Switching Staff and Plant Operators	3.	Staff should retain their event logs and present them to the appropriate on-call supervisor.
ECC Superintendent	1.	Shall arrange for an annual simulation of the plan to ensure its effectiveness.

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C. Kirby		**REV. DATE:**