Q. In response to CA-NLH-017 Hydro stated that:

> *Hydro's staff is of the opinion that Hardwoods can meet the black start requirements at Holyrood.*

If Hardwoods was not capable of providing black start in January 2013, and this was recognized by Hydro and acknowledged after reviewing the outage of January 2013, describe in detail the changes that would have occurred that would have led Hydro to believe that Hardwoods could meet the black start requirements after it was determined that Newfoundland Power Inc.'s mobile units were not capable of providing black start to Holyrood. Include in the response any documentation that clearly supports why the Hardwoods option, previously found to be inadequate, was chosen over the pursuit of some other option immediately after the removal of the Newfoundland Power Inc. mobile units in May 2013.

A. As indicated in Hydro's response to CA-NLH-017, Hydro is still of the opinion that the Hardwoods Gas Turbine (HWDGT) is capable of providing blackstart to the Holyrood Thermal Generating Station (HTGS) for the scenario of an extended transmission supply interruption to the broader Avalon Peninsula. Hydro simulated a blackstart using its Operator Training Simulator with successful results. Using the results of the simulations, an operating instruction was developed to help guide Hydro's operating staff in carrying out the blackstart procedure.

Safe shutdown and the security of staff and facilities of the HTGS is provided by battery power and on site diesel generation. As a result, starting the HTGS when the broader Avalon Peninsula area is isolated from the remainder of the power system was viewed as the primary purpose for the Holyrood blackstart facility. A blackstart facility at HTGS is required to get the plant operating to begin restoration of customer load when the remainder of the grid is separated from the Avalon Peninsula. Hydro decided in 2012 that while there was no local blackstart facility, the least cost solution for this requirement was to use the HWDGT in the interim until the new Holyrood combustion turbine planned for 2015 was in place.

In January 2013, there was no extended transmission supply interruption to the broader Avalon Peninsula and therefore the HWDGT was not required to start the HTGS. The issue on that date was related to the unavailability of the transmission system connected to the HTGS, a rare occurrence that occurred only once (see PUB-NLH-023 Attachment 1[1]). Hydro undertook steps to prevent the recurrence of this event as outlined in the action items arising out of the January 2013. Please refer to PUB-NLH-023 Attachment 2.

It was identified following the event that larger local generation, had it been available, would have provided the benefits of securing the station service supply to the HTGS to keep much of the plant auxiliary equipment operating in a warm state, thereby reducing the start-up time once the transmission supply was restored. Hydro estimates that the lack of pre-warming resulted in an 11-hour delay in restoring the HTGS to supply power customers after the transmission system was restored. As described in PUB-NLH-023 Attachment 3[2], Hydro recognized this benefit and took steps to provide alternate blackstart capability for the HTGS following the January 11, 2013 events by requesting that Newfoundland Power locate its mobile generation to the HTGS.

[1] Filed as PUB-NLH-003 in the *Island Interconnected System Supply Issues and Power Outages* review.
[2] Filed as PUB-NLH-081 in the *Island Interconnected System Supply Issues and Power Outages* review.

Hydro determined that, following the failure to start the large boiler feed water pumps using the Newfoundland Power mobile units and their removal in May 2013, it would continue to rely on the HWDGT as the least cost blackstart solution for a greater Avalon Peninsula interruption from the remainder of the grid until the new Holyrood combustion turbine is in place in 2015. However, as described in PUB-NLH-023 Attachment 3, in November 2013 Hydro made application to install an interim, least cost, local blackstart facility to provide additional system security.

PUB-NLH-003
Island Interconnected System Supply Issues and Power Outages

Q. How many times in the period 2004 to 2013 has Hydro been unable to supply the load of the Island Interconnected system due to the unavailability of generation capacity, transmission capacity and terminal station capacity? List each time and identify whether the cause was due to generation or transmission or terminal station capacity problems, weather conditions, planned maintenance, equipment failure or other conditions.

A. The following table indicates the instances in the period from 2004 to 2013 when Hydro was unable to supply the load of the Island Interconnected System due to unavailability of generation, transmission, and terminal station capacity. From a broad system impact, the two extraordinary events that required conservation or curtailment of customers are reflected below.

Date/Time	Cause	Notes
January 23, 2006 from 1125 to 1230 hours	Unavailability of Generation Capacity/Weather Conditions and Equipment Issues	The Upper Salmon plant experienced frazil ice, Holyrood Unit 2 was not available due to boiler tube failure, the Hardwoods and Stephenville Gas Turbines were de-rated due to issues with fuel nozzles, and the Holyrood Gas Turbine was unavailable.
January 11, 2013 from 0642 hours to 2359 hours	Unavailability of Generation and Transmission Capacity/ Weather Conditions and Equipment Issues	Trips of all three units at Holyrood (with Unit 1 experiencing an extended outage), trip and lockout of the Holyrood terminal station, transmission line TL201 line trip, and significant loss of generation and transmission in the central and western areas. Weather affected the restoration.

Board Order No. P.U. 3(2014)
Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System

NEWFOUNDLAND AND LABRADOR HYDRO

Events of January 2013

March 24, 2014

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SUMMARY

A severe winter storm experienced in the eastern region of the province on January 10 and 11, 2013, resulted in island-wide power outages and significant customer impact. The storm was characterized by high winds and heavy snowfall which caused issues in the Holyrood Terminal Station. The period of heaviest snow fall occurred between 06:30 and 09:30 on January 11, 2013.

The power system events began early on the morning of January 11, 2013, at the Holyrood Generating and Terminal Stations, where high winds and heavy, salt contaminated, snow created electrical faults and significant disturbances resulting in the loss of all three generating units and trips and lockouts of the 138 kV and 230 kV busses. This effectively isolated the Holyrood generating and terminal stations from the remainder of the grid. There was a significant customer impact, primarily to customers on the Avalon Peninsula.

This report summarizes the sequence of events that occurred on the power system, the problems experienced, the damage incurred, and identifies remedial actions being taken as a result of follow up investigations.

1 INTRODUCTION

On January 10, 2013 at approximately 16:30, weather in the eastern region of the Island began to deteriorate in snow and blowing snow. These conditions continued, and worsened through the evening hours and overnight, finally changing to freezing rain at about 14:30 on January 11, 2013. The heaviest snow fall occurred between 06:30 and 09:00 on January 11, 2013. The hourly weather data for January 10, 11, and 12, 2013, is contained in Appendix A.

The high, northerly, onshore winds combined with blowing snow caused salt contamination of equipment in the Holyrood Terminal Station which resulted in faults in the station and on adjacent transmission lines. These faults led to a large number of events of differing severity in terms of equipment outages and customer impact.

The number of events and the incidents were quite challenging to analyze and further work is required to fully understand the specific details of some as they were of a significant and abnormal nature, and have not been previously encountered over the years of system operation. To conduct the analysis, information such as sequence of events records, digital fault recorder traces and relay records have been collected and reviewed.

The system map in Figure 1 illustrates the extent of the power system problems experienced on January 11, 2013.

To completely understand the events and failures that occurred on January 11, 2013, follow up investigations were initiated once the power system had been restored. This report summarizes the system events, Hydro's preparation for and response to the events, the results of the investigation and analysis of these events, and the remedial actions being taken to prevent or lessen the impact of such events in the future.

Specifically, discussion of the following is presented:

- Life Safety Review – Holyrood Thermal Generating Station;
- Power System Performance;
- Energy Management System;
- Storm Preparation and Response;
- Holyrood Unit 1 Failure Root Cause Analysis;
- Holyrood Unit 1 Refurbishment; and
- Corporate Emergency Response.

1 **Figure 1: Locations Where Problems Were Encountered**

2 SEQUENCE OF EVENTS

Following is a chronological summary of the power system events of January 11, 2013. System generation prior to the initial event was 1022 MW. All major generation was operating excluding the Stephenville and Hardwoods Gas Turbines.

2.1 January 11, 2013

At 04:13, Unit 3 tripped at the Holyrood Thermal Generating Station. The analysis of this event indicates that it resulted from a single phase fault which occurred somewhere between the high side of the unit transformer and the 230 kV unit breakers. The unit was loaded to 68 MW at the time of the trip. No customer impact was reported as a result of this event.

At 06:42, while Holyrood plant personnel were in the process of restoring Unit 3, there were trips of Units 1 and 2 and transmission line TL 217 at the Western Avalon end. Both units were loaded to 110 MW. Newfoundland Power's 138 kV line, 39L, also tripped at this time. This resulted in a significant customer impact with nearly 250 MW of Newfoundland Power load loss, primarily on the Avalon Peninsula. This was caused by a fault on Unit 1 230 kV breaker B1L17, which was a result of salt contamination.

At 06:48, while all units were off at Holyrood and TL 217 was still open at the Western Avalon end, there was a 138 kV bus lockout and a breaker failure operation associated with the 230 kV breaker B12L17. This resulted in the loss of TL 218 and TL 242. These events effectively de-energized the Holyrood Terminal Station and removed all station service supply to the generating units. There was approximately 240 MW of Newfoundland Power load loss, again primarily on the Avalon Peninsula.

At 07:42, with the Holyrood terminal and generating stations out of service, there was a fault and trip on TL 201, the remaining 230 kV line from Western Avalon to the major load centres in St. John's. Due to protection misoperations on key transmission circuits caused by the significant system over frequency upon the loss of load, there was separation of the eastern and western areas of the power system. This created widespread power outages in the central and western areas of the province, resulting in the loss of multiple generating stations and transmission lines and the separation of the Deer Lake Power system from the grid. Generating stations at Upper Salmon, Granite Canal, and Cat Arm were out of service at this time.

Restoration efforts started almost immediately but issues were encountered during the western area restoration due to station communications problems at Stony Brook and general switching and equipment issues, all of which resulted in additional abnormal events and equipment trips. The eastern area restoration efforts proceeded as expected but were hampered by storm conditions which delayed personnel gaining access to reset lockouts in the Holyrood Terminal Station.

At 08:51, while Energy Control Centre (ECC) operators were attempting to restore the system within the limits of the generation that was available, TL 201 faulted and tripped again. Approximately 230 MW of customer load was lost during this event. Restoration started again on the eastern system with the re-energization of TL 201. On the west coast, some progress was made through Stony Brook but breaker issues delayed this progress and, at around 09:00, resulted in other abnormal system events.

At 09:07, TL 201 was re-energized and restoration of the St. John's area proceeded again. By 09:30, TL 201 was loaded to approximately 200 MW. By 09:39, restoration was also proceeding in the western area with the Massey Drive Terminal Station re-energization and loading. Restoration of the system continued with conditions returned to normal in the western area by noon with most load busses re-energized and the Deer Lake Power system reconnected. At 10:08, the Granite Canal station was returned to service.

By 13:30, the Holyrood lockouts were reset and at 14:58 the Holyrood 230 kV bus B12 was energized via TL 242. This was followed by restoration of TL 218 and, at 15:08, TL 217 was put in service, paralleling TL 201 and completing the restoration of the 230 kV transmission system on the Avalon.

At 14:44, the Upper Salmon unit was returned to service following the reset of the unit lockout relay. The Cat Arm units were both back online by 18:53 following resets of the unit lockouts and restoration of the station service supply.

Transformer T1 at Buchans was returned to service at midnight after having locked out earlier in the day. The station was at this time fully restored.

2.2 January 12, 2013

Holyrood Units 2 and 3 were back online at 03:54 and 05:13 on January 12, 2013, respectively. This restored the power system to service across the island.

A detailed sequence of events for the power outage is contained in Appendix B.

3 LIFE SAFETY REVIEW – HOLYROOD PLANT

An investigation team was assembled to investigate the issues encountered at the Holyrood Generating Station during the events of January 11, 2013. Members of this team included representatives of Corporate Health and Safety and the Holyrood Generating Station.

Identifying the key findings and addressing the root cause of life safety concerns that were experienced by the Operators and providing recommended corrective and preventative actions for these issues were part of the investigation team's objective.

The investigation identified the challenges that the Operations department experienced, as noted through their interview statements.

The areas reviewed by the life safety review team were:

- Emergency response technician (ERT) coverage;
- Operator coverage with emergency response training;
- Familiarity of Operations personnel with emergency response equipment;
- Number of hours worked by Operations staff and then operating vehicle by driving home;
- Adequacy of powerhouse emergency lighting;
- Adequacy of powerhouse ventilation;
- Access/Egress from plant;
- Operation of fixed fire suppression system;
- Portable fire extinguishing equipment;
- SWOP not entered or communication of major incident in timely manner; and
- Employee Assistance Program (EAP) response.

There were 14 recommendations made as a result of the Life Safety Review. The majority of these recommendations were generally within the categories of plant emergency response coverage and training, the conditions under which plant staff responded to the event, firefighting equipment operation and major event reporting.

The Life Safety Review Report is contained in Appendix C.

4 POWER SYSTEM PERFORMANCE REVIEW AND ANALYSIS

Upon the restoration of the power system, a review and analysis of the events associated with the power outages across the system was undertaken. This review and analysis of the system events resulted in a number of recommendations for improvements to the system.

The recommendations cover the issues which led to the significant power system events which occurred, generally in the following categories:

- Preventative maintenance procedures and scheduling;
- High voltage breaker replacement, inspection, and repair;
- Function testing and enhancement of protection and control circuitry;
- Digital protective relay firmware and setting changes;
- System stability studies;
- System voltage and frequency studies and control enhancements; and
- Development and enhancement of operating procedures.

The review and analysis of the power system events resulted in 56 recommendations for improvements to the power system in various areas. Specifically, the areas and associated number of recommendations are:

• Transmission and Rural Operations	18
• Thermal Generation	4
• Protection and Control Engineering	20
• Electrical Engineering	2
• Transmission & Distribution Engineering	1
• System Operations and Energy Systems	4
• System Operations and Planning	2
• System Operation, Planning, and P&C Engineering	2
• Hydro Generation	3

4.1 Transmission and Rural Operations

Within the Transmission and Rural Operations (TRO) area, there were many issues with breakers, particularly the 230 kV class. A review of the preventive maintenance program for these breakers has been recommended. The remaining recommendations are related to further inspection and testing of power system equipment and protection and control systems across the power system to ensure proper operation.

4.2 Thermal Generation

The specific recommendations related to thermal generation include a review of data collection and reporting requirements for protection operations and trips. In addition, function testing of specific protection equipment has been recommended.

4.3 Protection and Control Engineering

The recommendations assigned to Protection and Control (P&C) Engineering are, in the majority, related to system protection design, operation and reporting. Protection reviews are recommended on system equipment, transmission lines, and generating station equipment to ensure proper operation. A number of changes to protection are also recommended to prevent nuisance tripping and other issues experienced during the event.

4.4 Electrical Engineering

The recommendations for electrical engineering relate primarily to the specification and installation of new breakers and associated equipment. Specifically, recommendations to increase the insulation creepage distance specified for such equipment to ensure its suitability for operation in contaminated environments such as the Holyrood Terminal Station. Installation of current transformers on both sides of breakers is also recommended to provide for overlapping protection zones.

4.5 Transmission and Distribution Engineering

A review of the standards applied to transmission line jumper length is recommended as a result of the fault and trip on TL 201.

4.6 System Operations and Energy Systems

The recommendations for System Operations and Energy Systems involve the review of existing and preparation of new operating procedures which address how to proceed under some of the conditions experienced during the January 11, 2013, event, such as voltage conditions outside normal limits and incorrect or questionable data being returned from remote locations. Also, further investigation is recommended into the issues with sequence of events (SOE) reporting, and the overvoltage condition which occurred.

4.7 System Operations and Planning

In order to gain a full understanding of the events which occurred, recommendations within the System Operations and Planning area include a detailed load flow and transient stability analysis and a comprehensive review of the sequence of events. The development of guidelines for optimum reactive power dispatch and levels of Avalon loading are also recommended.

4.8 System Operation, Planning, and P&C Engineering

Recommendations include consideration to perform a system voltage study which would simulate normal loading scenarios and abnormal scenarios such as those which occurred on January 11, 2013. From the study, an operation strategy should be developed to assist the ECC operators in maintaining system voltages within acceptable limits. As well, surge and trouble reports should be prepared by System Operations for all disturbances on the power system as they provide valuable information regarding the system equipment and its operation. These reports should be circulated and reviewed by all stakeholders to ensure all necessary investigations and recommended remedial actions are carried out in a timely manner.

4.9 Hydro Generation

With respect to Hydro Generation, recommendations are made for the investigation of lockout operations which occurred at the Cat Arm and Upper Salmon generating stations and the performance issues with the station service supplies at Cat Arm. It is also recommended that, in future, investigations be carried out into all trips of larger generating units to determine the cause and whether the systems operated properly.

The Power System Performance Review and Analysis Report is contained in Appendix D. Detailed descriptions of the report recommendations are contained in Appendix F.

5 ENERGY MANAGEMENT SYSTEM REVIEW

During the power system events on January 11, 2013, communications between the Stony Brook remote terminal unit (RTU) and the Energy Management System (EMS) were lost at 07:45 and were restored by a remote restart of the RTU at 08:55.

The problem with the communications between the ECC and the Stony Brook Terminal Station RTU associated with the system wide power disruptions initially appeared as a RTU lockup. The result was a temporary (two hour) loss of remote control and monitoring of the terminal station until a manual reset to the RTU was performed remotely from the ECC. The result of this loss of monitoring was that some of the SOEs which contained information useful for the power system post analysis were lost.

Upon analysis, the problem was determined to be a buffer overflow problem in the routers used to provide the communications. The communications problem was triggered by an unusually large number of events (99) generated by the system power disruptions. The resolution of the communication problem experienced involves increasing the buffer length from 16 to 64 bytes in the routers which operate at 38,400 bps across the system including routers located at both remote sites and at Hydro Place. This is necessary for all RTU circuits operating at 38,400 bps.

While the failure mechanism and fix now seem obvious, they took a considerable amount of time to determine, as the both the trigger and location of the problem were not clear. In particular, the trigger condition requires all of the following:

- The RTU must be operating at 38,400 bps;
- The buffer length must be 16 bytes (as was the case for all RTUs prior to the implementation of the fix);
- There must be at least 40 events being sent by the RTU (test results have shown that 30 events will not trigger the problem but 40 or over will); and
- The circuit must be on the live SCADA network with traffic loading (the problem could not be replicated with back-to-back routers in the shop).

To resolve the issue with communications resulting from the conditions above, the following remotely located routers have been re-configured over the power system:

- Bay d'Espoir Hydro Plant - Power House 1;
- Bay d'Espoir Hydro Plant - Power House 2;
- Come By Chance Terminal Station;
- Hinds Lake Concentrator;
- Oxen Pond Terminal Station;
- Stony Brook Terminal Station;
- Sunnyside Terminal Station;
- Upper Salmon Concentrator; and
- Upper Salmon Hydro Plant.

The following routers at Hydro Place have also been re-configured:

- ECC1;
- ECC2;
- EMS1; and
- EMS2.

6 STORM PREPARATION AND RESPONSE

6.1 Preparation

In preparation for the forecasted severe winter storm of January 11, 2013, Hydro took the following steps to aid in safe and timely response to system problems:

- All communications between Hydro and Newfoundland Power were tested (VHF, Cell, Satellite, Hotline, & Power fail phone);
- Hydro VHF communications were tested between the ECC and the Holyrood control room and between the ECC and the Bay d'Espoir control room;
- The emergency diesel generators at Hydro Place were tested;
- Hydro alerted Newfoundland Power that it may be seeking assistance for any distribution problems on the Burin Peninsula, if Hydro could not access the area;
- All supervisory personnel in TRO were asked to be on heightened alert for the duration of the storm and be available by cellphone;
- All vehicles at the TRO Eastern office at Whitbourne were fueled up and had pre-use inspections completed to ensure readiness for a quick response;
- Key employees were assigned work vehicles, (mostly four wheel drive and all wheel drive vehicles) and asked to take the vehicles to their home locations, in anticipation that the TCH would be impassible and closed (vehicles were located at Holyrood, St. John's, Bay Roberts, Harbour Grace, and New Harbour);
- The Hardwoods Gas Turbine operator was situated in St. John's and assigned a four wheel drive pickup truck;
- Track vehicles were loaded on trailers at the Whitbourne office ready to be deployed if required;
- At the Holyrood Generating Station, the snow clearing contractor (who clears the site roads) was called to come in early and stay ahead of the storm;
- Operation and security personnel were called in early to relieve the night shift at 16:00 (this was not completely successful as only 2 out of 6 operators were able to gain access to the site); and

- In the lab at Holyrood, polisher regeneration was completed a day early and the units were chemically dosed slightly above normal but below EPRI guidelines, in the event that water treatment staff couldn't make it to site on the morning of January 11, 2013.

6.2 Site Access and Road Conditions

Due to safety and accessibility concerns, Hydro Place and the TRO area office at Whitbourne closed at approximately 06:00 on January 11, 2013.

At just before 07:00 on January 11, 2013, TRO personnel were requested to respond to the Holyrood Terminal Station and to the Hardwoods Gas Turbine. At this time, the storm was in full force, most roads on the Avalon Peninsula were impassable, visibility was near zero, and the RCMP was advising people to stay off the roadways. While some of the major thoroughfares were passable by large four wheel drive vehicles, most secondary roads were impassable. Therefore, while several Hydro employees had work vehicles at home and were ready to respond, they could not leave their residential neighborhoods due to road and weather conditions.

At approximately 07:30, the TRO Stations Supervisor began calling Works, Services and Transportation depots at Whitbourne and Holyrood, as well as several contractors, in an effort to have the road to the Holyrood Generating Station cleared. All of those contacted reported that they would not put employees on the road due to zero visibility conditions. As well, the RCMP at Holyrood was contacted and they advised not to put anyone on the road until conditions improved. At this point, a contractor clearing snow with a backhoe around the Holyrood site was redirected to attempt clearing the 3 km section of access road from the Holyrood Generating Station to the Conception Bay Highway. This section of road was reported to have 1.25 meter drifts in sections.

At approximately 08:00, Corporate Safety and Health contacted EMO to inquire if they could assist in getting personnel into the Holyrood Generating Station. At approximately 09:30, Works, Services and Transportation contacted Hydro indicating that they would do what they could to have the road cleared.

The acting Gas Turbine Operator and an Electrical Maintenance worker were able to report to the Hardwoods Gas Turbine at approximately 08:30 and they remained there well into the evening.

By approximately 11:30, a single lane had been cleared to the Holyrood Generating and terminal stations. Two TRO employees (a P&C technologist and electrical maintenance A) walked to Route 60 at a location near the town of Holyrood and were transported to the Holyrood Generating Station by a Newfoundland Power vehicle which had been able to gain access to Route 60.

At around the same time, a snow clearing contractor from Whitbourne, who was working for Hydro, travelled the Trans Canada Highway (TCH) from Whitbourne to the Salmonier Line and then plowed a single lane down the Salmonier Line from the TCH to Route 60. This allowed a mechanic who resides on the Salmonier line to access Route 60. Hydro employees entered the terminal station at Holyrood at approximately 11:30 and began inspection, troubleshooting, and restoration of affected equipment.

The regular shift change at the Holyrood Generating Station would have normally occurred at 20:00 on January 10, 2013. Attempts were made to get shift operators into the plant early on the evening of January 11, 2013, such that the plant would not be caught without relief at 20:00. This effort was partially successful as only two of the six operators were able to get to the plant. For this reason, operators who were scheduled to go off shift were asked to stay at work, some working as many as 30 hours before being relieved. Some operators who live in the St. John's area obtained a four wheel drive vehicle from Hydro Place in St. John's and arrived at the plant on the afternoon of January 11, 2013. Otherwise, it was late afternoon on January 11, 2013, when road conditions improved, before Holyrood Generating Station employees could begin returning to work.

Throughout much of January 11, 2013, system problems requiring checkout and troubleshooting were experienced at Hydro facilities throughout central and western Newfoundland. While regular winter driving conditions were experienced in many of these areas, snowmobile travel to the Upper Salmon Generating Station was challenging due to snow drifts as high as 1.25 meters.

6.3 Coordination of Efforts

As with any power system outage or disturbance, the ECC at Hydro Place takes the lead to safely and systematically restore system equipment to service.

At approximately 07:30, a group of TRO operations personnel with access to real time system information at the ECC, gathered at the TRO Central office in Bishop's Falls to offer assistance to field personnel and coordination with the ECC.

At approximately 08:30, the Executive on Call (EOC) issued an alert under the corporate emergency response plan (CERP) which saw a partial mobilization of the CERP team at Hydro Place, to provide overall support and guidance during the storm and associated power outage.

Customer Services personnel were in place to respond to customer calls and to update customers and other stakeholders.

6.4 Communications - Contacting Key Resources

In many cases key resources were contacted, and while willing to do whatever they could do to help, they were unable to leave their neighborhoods due to road conditions. All Hydro vehicles had mobile VHF radios which worked well. There were several reports of employees who had only cordless phones in their homes which did not function during the power failure. While many key operations personnel in Hydro have cellphones, it became evident that more cellphones would have improved overall communications.

6.5 Safety

While everyone involved in the restoration efforts understood the criticality of getting personnel into the Holyrood generating and terminal stations on the morning of January 11, 2013, Hydro needed to ensure that we were not asking our employees to do anything that was clearly unsafe or making decisions that might put ourselves or someone else in danger. Conditions appear to have been much worse in the areas between Holyrood and Whitbourne than they were in the St. John's metro area. Department of Works, Services, and Transportation personnel, RCMP and contractors were off the road. Despite this, efforts continued to get employees into the Holyrood Terminal Station in as safe a manner as possible.

6.6 Opportunities for Improvement

The primary areas in which there is opportunity for improvement are communications and site accessibility.

6.6.1 Communications

- ***Improved communication between field personnel and the ECC***

  While it is understood that System Operations is extremely busy during such emergency situations, in order to make the best use of response personnel it is critical that field personnel be able to discuss system conditions and equipment priorities with the ECC. During several periods on January 11, 2013, repeated calls to the ECC went unanswered. One operator or shift supervisor assigned to communicate with field personnel would have been an improvement.

- ***Ability to contact key employees when required***

  Many employees reported that that they did not possess hard wired telephones and that the batteries in their cordless phones had run down. As a result, it was difficult to contact them. As well, several key employees did not have cell phones. As a follow up, it is recommended that managers ensure that key employees have cell phones and agree to carry them as required.

- ***Updating of social media***

  Given the widespread use of social media by customers, it would be beneficial to have one Customer Services Representative dedicated to managing and updating social media updates.

- ***Availability of information for media updates***

  Corporate Communications found it necessary to contact multiple sources for information pertaining to outages and system conditions. One operations liaison responsible for providing necessary information to Corporate Communications would have been an improvement.

- ***Improved communication between field personnel and the Bay d'Espoir and Holyrood Plants***

  In some incidents, it was difficult for field personnel to contact necessary technical resources in the generating stations. One technical resource identified as a liaison for field personnel would have been an improvement.

- ***Communication with Newfoundland Power and Industrial Customers***

  There was a general feeling that Hydro could have provided more prompt updates to these customers.

6.6.2 Site Accessibility

Transportation and accessibility to Hydro facilities proved to be a major problem during the storm. Some potential areas of improvement include:

- ***Increased planning to ensure that key facilities are staffed during storm events***

  Given the unpredictable nature of the storm, it would have been possible and beneficial to arrange for extra personnel to staff the Holyrood Generating Station (possibly extra operating, instrumentation, electrical and emergency response personnel).

- ***Access road clearing during storms***

During the early morning of January 11, 2013, Hydro had notification that the Department of Works, Services and Transportation, who normally plow the access road to the Holyrood Generation Station, did not have plows on the road. At approximately 07:30, upon realizing that plowing by the Department of Works, Services and Transportation would be delayed, a contractor plowing the site at Holyrood was redirected to concentrate on the access road, such that when conditions improved employees could gain access to the site. In hindsight, had the contractor begun working on the access road sooner, overall system restoration on the east coast may have been realized sooner.

- ***Use of larger and more capable response vehicles.***

All of the available four wheel drive and all wheel drive vehicles at the Eastern Area office at Whitbourne were assigned to employees to take home for the duration of the storm, to allow for quicker response. However, due to the amount of snowfall and drifting (1.25 meters in some areas), employees simply could not leave their residential neighborhoods. Under the conditions on January 11, 2013, large four or six wheel drive vehicles may have allowed Hydro to pick up employees and bring them to the required locations earlier.

6.6.3 Other Opportunities for Improvement

- ***Use of Mobile Generators***

Due to the complete power outage at the Buchans Terminal Station, station service power was not available to operate compressors and other critical services. TRO Central personnel rented a portable diesel generator which was used to power the station to aid in restoration efforts. Portable diesel generators located at key terminal stations, could greatly improve Hydro’s response in the event of complete station outages.

- ***Timely retrieval and analysis of fault data and related fault information***

In order to properly troubleshoot and identify the type and location of faults on the electrical system, fault information must be retrieved from remote devices and analyzed. At present, this information is retrieved by Project Execution and Technical Services personnel. During such storm conditions, these employees should be on call and available to respond at all times.

7 HOLYROOD UNIT 1 FAILURE ROOT CAUSE ANLAYSIS

On January 11, 2013, severe weather conditions, high winds and heavy, wet snow were experienced on the Avalon Peninsula. At 06:42, Holyrood Units 1 and 2 tripped in response to an electrical fault in the Holyrood switchyard, caused by wet snow buildup and salt contamination. Unit 1 experienced higher than normal vibration as it coasted down, with fires occurring at bearing locations along the unit's rotational shaft. The fires were extinguished and, once the unit was secured, an investigation was initiated by Hydro staff and Alstom Power.

Once the initial assessment was complete, the unit was disassembled to allow a more detailed inspection of unit components, for condition assessment purposes. This inspection revealed damage to all five bearings along the turbine-generator shaft, as well as damage to the shaft journal areas at the bearing locations. Other unit components were damaged as well.

A root cause analysis into the failure of Unit 1 was completed by a team of internal and external personnel with expertise in the equipment function and root cause analysis theory. The TapRooT® root cause analysis techniques were applied for this investigation.

Three causal factors were identified:

1. The established maintenance test procedures did not adequately validate the system function for the direct current (DC) lubrication oil pump which serves as a contingency for bearing lubrication when two alternating current (AC) pumps are unavailable.

2. During the incident, the station service system voltage was insufficient to start the second alternating current (AC) lubricating pump, due to the system wide voltage depression experienced after the electrical fault in the Holyrood Terminal Station.
3. The direct current (DC) lubrication oil pump started based upon the loss of both AC pumps, but it did not maintain adequate lubrication to the bearings due to an undetected motor speed issue.

Root causes and corrective actions were determined for each causal factor. Most corrective actions pertain to strengthening internal operating and maintenance procedures and specifications for third party maintenance. Several of the corrective actions have already been implemented.

Following are the key lessons learned from this incident:

A. The overall system function must be considered when developing and reviewing equipment functional test procedures. In this case, established maintenance test procedures verified that the Holyrood Unit 1 DC Lube Oil Pump was operating but failed to verify that it was providing the system's overall function of delivering sufficient lubricating oil to the bearings. OEM recommended test procedures may not be adequate for ensuring full functionality of equipment and systems.
B. Technical specifications for third party maintenance contracts must be sufficiently detailed to ensure that equipment performance criteria and suitable maintenance testing and adjustments are clearly and thoroughly specified. In this case, the DC pump maintenance specification did not adequately specify the performance criteria and adjustments, and a pump was returned to service that was not able to perform.
C. Equipment specifications and system design must include fail safe design for both black-out and brown-out conditions. In this case, there was a brown-out condition such that the station service voltage was too low for the South AC Pump to start.

These lessons learned will be shared broadly by the investigation team with Holyrood plant personnel, Hydro's engineering personnel, applicable third party consultants and contractors, and other operating units within Nalcor Energy.

The Unit 1 Failure Root Cause Analysis report is contained in Appendix E.

8 HOLYROOD UNIT 1 REFURBISHMENT

The refurbishment plan for Holyrood Unit 1 was determined by completing two phases of disassembly and inspection. The phase 1 inspection was primarily a visual inspection after removal of the covers. This inspection began on January 18, 2013, and was completed on January 28, 2013, with a recommendation to proceed to a full assessment through disassembly of the unit.

The Phase 1 inspection revealed the following:

- Bearings T1 through T5 all damaged (wiped);
- Oil deflectors T1 through T5 inner and outer damaged (wiped);
- Thrust bearing damaged (wiped);
- Journals T1 through T3 damaged;
- Journals T4 and T5 in good condition;
- Hydrogen seals TE and CE had slight damage;
- Hydrogen seal casings TE and CE in good condition;
- Hydrogen seal casings gas side oil seal TE and CE damaged;
- No damage to fan blades;
- Speed probes and 60 tooth wheel damaged;
- Vibration probes T1 through T3 damaged; and
- Melted babbitt throughout the bearing pedestals and oil system.

The phase 2 inspection began on March 1, 2013, and was completed on March 16, 2013. The result of the phase 2 inspection was a refurbishment plan to return the unit to service. The steam turbine was disassembled and a complete visual and NDE inspection was performed on the upper and lower diaphragms and turbine rotor. This included the mechanical inspection of the turbine rotor and the generator rotor. Testing was also performed on the generator rotor and stator.

Phase 3 of the project included repairs of the various components to restore them to acceptable running condition. Where original parts could not be reused, replacement parts were fabricated.

The phase 3 repairs included:

- Rotor bucket cover repairs;
- Rotor journal repair;
- HP/LP/IP rotor machining;
- Bearing repair;
- Packing and spill strip repair;
- Laser alignment;
- Lube oil flush;
- Lube oil pump repair;
- Generator reassembly;
- Turbine reassembly; and
- Unit commissioning and balancing.

Final balancing of the unit was completed and the unit was subsequently released for service on October 10, 2013.

9 CORPORATE EMERGENCY RESPONSE PLAN REVIEW

A review of the Corporate Emergency Response Plan performance was included in the Life Safety Review conducted into the events of January 11, 2013.

On January 11, 2013, at approximately 08:00, the Manager of Safety and Health received a call from the Holyrood Thermal Generating Station Emergency Response Coordinator (ERC) reporting an incident involving a fire on Unit 1. It was reported that the fire had been extinguished and the unit was no longer on line. On site employees donned self-contained breathing apparatus (SCBAs) in order to respond to the incident. It was also reported that Unit 2 and 3 had also tripped and there was a developing issue in the switchyard, however the ERC was not sure of the nature. The ERC was unaware if the EOC had been alerted of the developing situation. The Manager of Safety and Health advised he would contact the EOC and get direction on next steps, if any were warranted.

At 08:30, the EOC was contacted and advised of the incident at Holyrood. The EOC advised that the CEO and the Vice President Regulated Operations were aware of the incident and the resulting problems with power generation. Through discussions, the EOC and Manager of Safety and Health thought it prudent to issue a CERP 811 (standby) Alert with a pending partial mobilization. The Manager of Safety and Health contacted the ECC and advised that an 811 Alert be issued. Shortly thereafter, the situation at Holyrood was complicated with loss of generation at Upper Salmon and Granite Canal. At this stage, it was agreed to issue another CERP 811 Alert identifying a partial mobilization of the CERP team at Hydro Place. A concern identified was the potential difficulty of getting CERP team members into the Corporate Emergency Operations Centre (CEOC) at Hydro Place as well as operational and technical staff into the Holyrood plant. The Manager of Safety and Health contacted the Emergency Measures Organization (EMO) to inquire if they could provide assistance on getting the employees into the CEOC and thermal plant. The EMO on-call representative advised the EMO does not provide this service and the only thing they could possibly assist with was to help us contact the

Department of Works, Services and Transportation and request assistance in clearing the access road leading to the thermal plant.

At approximately 09:30, the Manager of Safety and Health received a call from a Department of Works, Services and Transportation representative stating they would investigate what they could do, particularly redirecting a snow plow to clear the access road to the plant. There was no further contact with the Department of Works, Services and Transportation.

At 10:00 the CEOC was "live" with CERP members representing Supply Chain Management, Communications and Safety and Health, the Deputy Incident Commander, and the Operations Liaison. All team members began carrying out their respective role related duties as outlined in the Corporate Emergency Response Plan. Regularly scheduled conference calls were held with the full CERP team approximately every hour.

The Supply Chain Management and Safety and Health representatives supported the Deputy Incident Commander as requested and assisted by picking up additional technical support (P&C Engineer) using a company four wheel drive vehicle, and transporting them to Hydro Place. At approximately 15:00, the Supply Chain Management and Safety and Health representatives were no longer required and were relieved of their roles in the CEOC.

The CERP process worked well and there was good communication and mobilization of the partial team in a timely fashion.

Recommendations were made related to the CERP performance for the improvement of communications and the assignment of four wheel drive vehicles to assist with mobilization of CERP members in severe weather conditions.

10 CONCLUSION

The winter storm which occurred in the eastern region of the province over January 10 and 11, 2013 caused wide spread outages to the power system and damage to equipment. The first event occurred at 04:13 on January 11, 2013, and the power system was restored to service across the island at 05:13 on January 12, 2013.

While Hydro personnel were prepared for the storm and possible problems on the power system, the weather and road conditions made it challenging to access Hydro sites to respond to problems being experienced.

Once the power system was restored, follow up investigations were initiated to fully understand the events and failures that occurred on January 11, 2013. These detailed investigations and analyses have resulted in numerous recommendations for improvement in a number of areas. Remedial action plans have been developed to ensure that the recommendations are studied and appropriate improvements implemented.

Appendices

January 10, 2013 Hourly Data										
Time	Temp, C	Dew Point Temp, C	Rel Hum	Wind Dir, 10s deg	Wind Spd, km/hr	Visibility, km	Stn Press, kPa	Hmdx	Wind Chill	Weather
00:30‡	-10.4	-12.5	85	18	12	24.1	100.39		-16	NA
01:30‡	-9.9	-12.1	84	21	8	24.1	100.4		-14	NA
02:30‡	-9.7	-12.2	82	20	13	24.1	100.39		-16	Clear
03:30‡	-7.8	-10.2	83	18	15	24.1	100.23		-14	NA
04:30‡	-5.7	-8.1	83	19	11	24.1	100.11		-10	NA
05:30‡	-5.1	-7.6	83	19	9	24.1	99.99		-9	Cloudy
06:30‡	-4.8	-6.8	86	13	9	24.1	99.82		-9	NA
07:30‡	-3.7	-5.4	88	18	9	24.1	99.77		-7	NA
08:30‡	-2.3	-4.5	85	15	26	24.1	99.57		-9	Cloudy
09:30‡	-1.6	-4	84	15	31	24.1	99.48		-9	NA
10:30‡	-1.1	-3.2	86	15	36	24.1	99.34		-9	NA
11:30‡	-0.9	-3.1	85	14	41	24.1	99.19		-9	Cloudy
12:30‡	-0.9	-2.6	88	13	39	24.1	98.92		-9	NA
13:30‡	-1.1	-3	87	12	42	24.1	98.76		-9	NA
14:30‡	-1.2	-2.9	88	10	36	24.1	98.49		-9	Cloudy
15:30‡	-1.2	-2.9	88	11	41	24.1	98.36		-9	NA
16:30‡	-1.7	-2.4	95	11	46	2	98.21		-10	Snow, Blowing Snow
17:30‡	-1.6	-2	97	10	40	24.1	98.1		-10	Snow, Blowing Snow
18:30‡	-1.6	-1.9	98	9	50	1.6	97.95		-10	Snow, Blowing Snow
19:30‡	-1.6	-1.9	98	8	51	0.8	97.94		-10	Snow, Blowing Snow
20:30‡	-1.5	-1.8	98	7	39	0.8	98.03		-9	Snow, Blowing Snow
21:30‡	-1.6	-1.9	98	1	52	0.6	97.85		-10	Snow, Blowing Snow
22:30‡	-1.7	-1.8	99	4	51	0.6	97.78		-11	Snow, Blowing Snow
23:30‡	-1.9	-2	99	4	59	0.4	97.7		-11	Snow, Blowing Snow

January Go 3

Hourly Data Report for January 11, 2013

Time	Temp, C	Dew Point Temp, C	Rel Hum, %	Wind Dir, 10s deg	Wind Spd, km/hr	Visibility, km	Stn Press, kPa	Hmdx	Wind Chill	Weather
0:30	-1.7	-1.8	99	3	55	0.6	97.61		-11	Snow, Blowing Snow
1:30	-1.4	-1.5	99	3	54	0.6	97.64		-10	Snow, Blowing Snow
2:30	-1.3	-1.4	99	3	71	0.6	97.69		-11	Snow, Blowing Snow
3:30	-1.2	-1.5	98	2	57	0.6	97.6		-10	Snow, Blowing Snow
4:30	-1	-1.3	98	2	48	0.6	97.58		-9	Snow, Blowing Snow
5:30	-1	-1.1	99	1	59	0.6	97.51		-10	Snow, Blowing Snow
6:30	-0.9	-1	99	2	75	0.4	97.45		-11	Heavy Snow, Blowing Snow
7:30	-0.9	-1	99	1	67	0.2	97.47		-10	Heavy Snow, Blowing Snow
8:30	-0.8	-0.9	99	1	74	0.4	97.43		-11	Heavy Snow, Blowing Snow
9:30	-0.7	-0.8	99	1	79	0.2	97.48		-11	Heavy Snow, Blowing Snow
10:30	-0.4	-0.5	99	1	74	0.2	97.56		-10	Moderate Snow, Blowing Snow
11:30	-0.2	-0.3	99	2	60	0.4	97.63		-9	Moderate Snow, Blowing Snow
12:30	-0.1	-0.4	98	2	54	0.8	97.74		-9	Snow, Blowing Snow
13:30	-0.1	-0.2	99	2	53	0.8	97.91		-8	Snow, Blowing Snow
14:30	-0.1	-0.2	99	1	46	4.8	98		-8	Freezing Drizzle,Fog
15:30	-0.1	-0.2	99	1	49	4.8	98.11		-8	Freezing Drizzle, Fog
16:30	0	-0.1	99	1	50	4.8	98.22		-8	Drizzle, Fog
17:30	-0.1	-0.2	99	1	46	4.8	98.28		-8	Snow, Fog
18:30	-0.1	-0.2	99	36	45	4.8	98.38		-8	Snow, Fog
19:30	-0.1	-0.2	99	36	40	2.4	98.43		-8	Snow, Fog
20:30	0.1	0	99	2	36	1.6	98.56			Rain, Snow, Fog
21:30	0.2	0.1	99	1	43	2	98.56			Rain, Fog
22:30	0.2	0.2	100	2	49	2	98.57			Rain, Fog
23:30	0.2	0.2	100	1	46	2	98.63			Drizzle, Fog

Hourly Data Report for January 12, 2013

TIME	Temp °C	Dew Point Temp °C	Rel Hum %	Wind Dir 10's deg	Wind Spd km/h	Visibility km	Stn Press kPa	Hmdx	Wind Chill	Weather Definition
00:30	0.2	0.2	100	1	44	1.2	98.73			Drizzle,Fog
01:30	0.3	0.3	100	1	38	1	98.78			Drizzle,Fog
2:30	0.2	0.2	100	36	39	1	98.86			Drizzle,Fog
03:30	0.3	0.3	100	36	36	1.2	98.82			Rain,Fog
04:30	0.4	0.4	100	36	47	1.2	98.85			Rain,Fog
05:30	0.4	0.4	100	36	44	1.2	98.86			Rain,Fog
6:30	0.5	0.5	100	36	42	1.2	98.95			Rain,Fog
07:30	0.5	0.5	100	36	39	1.2	99.04			Rain,Fog
08:30	0.7	0.7	100	36	40	1.2	99.1			Rain,Fog
09:30	0.9	0.9	100	1	36	0.8	99.15			Rain,Fog
10:30	0.9	0.9	100	1	33	0.4	99.17			Drizzle,Fog
11:30	1	1	100	36	30	0.8	99.15			Rain,Fog
12:30	1	1	100	1	29	0.4	99.13			Rain,Fog
13:30	1.2	1.2	100	1	32	0.4	99.14			Rain,Fog
14:30	1.5	1.5	100	2	31	0.8	99.18			Rain,Fog
15:30	1.5	1.5	100	1	29	0.8	99.24			Rain,Fog
16:30	2	2	100	3	38	0.4	99.28			Rain,Fog
17:30	2.2	2.2	100	3	37	0.2	99.28			Drizzle,Fog
18:30	2.4	2.4	100	3	23	0.2	99.25			Drizzle,Fog
19:30	2.3	2.3	100	36	21	0.2	99.27			Drizzle,Fog
20:30	2.5	2.5	100	2	22	0.2	99.34			Drizzle,Fog
21:30	2.7	2.7	100	2	24	0.2	99.34			Drizzle,Fog
22:30	2.9	2.9	100	3	27	0.4	99.36			Moderate Drizzle,Fog
23:30	3.2	3.2	100	1	15	0.6	99.37			Rain,Fog

Location:	ST. JOHN'S INTL A									
	NEWFOUNDLAND									
Hourly Data Report for January 10, 2013										
Time	Temp, C	Dew Point Temp, C	Rel Hum, %	Wind Dir, 10s deg	Wind Spd, km/hr	Visibility, km	Stn Press, kPa	Hmdx	Wind Chill	Weather
0:30	-10.4	-12.5	85	18	12	24.1	100.39		-16	NA
1:30	-9.9	-12.1	84	21	8	24.1	100.4		-14	NA
2:30	-9.7	-12.2	82	20	13	24.1	100.39		-16	Clear
3:30	-7.8	-10.2	83	18	15	24.1	100.23		-14	NA
4:30	-5.7	-8.1	83	19	11	24.1	100.11		-10	NA
5:30	-5.1	-7.6	83	19	9	24.1	99.99		-9	Cloudy
6:30	-4.8	-6.8	86	13	9	24.1	99.82		-9	NA
7:30	-3.7	-5.4	88	18	9	24.1	99.77		-7	NA
8:30	-2.3	-4.5	85	15	26	24.1	99.57		-9	Cloudy
9:30	-1.6	-4	84	15	31	24.1	99.48		-9	NA
10:30	-1.1	-3.2	86	15	36	24.1	99.34		-9	NA
11:30	-0.9	-3.1	85	14	41	24.1	99.19		-9	Cloudy
12:30	-0.9	-2.6	88	13	39	24.1	98.92		-9	NA
13:30	-1.1	-3	87	12	42	24.1	98.76		-9	NA
14:30	-1.2	-2.9	88	10	36	24.1	98.49		-9	Cloudy
15:30	-1.2	-2.9	88	11	41	24.1	98.36		-9	NA
16:30	-1.7	-2.4	95	11	46	2	98.21		-10	Snow, Blowing Snow
17:30	-1.6	-2	97	10	40	24.1	98.1		-10	Snow, Blowing Snow
18:30	-1.6	-1.9	98	9	50	1.6	97.95		-10	Snow, Blowing Snow
19:30	-1.6	-1.9	98	8	51	0.8	97.94		-10	Snow, Blowing Snow
20:30	-1.5	-1.8	98	7	39	0.8	98.03		-9	Snow, Blowing Snow
21:30	-1.6	-1.9	98	1	52	0.6	97.85		-10	Snow, Blowing Snow
22:30	-1.7	-1.8	99	4	51	0.6	97.78		-11	Snow, Blowing Snow
23:30	-1.9	-2	99	4	59	0.4	97.7		-11	Snow, Blowing Snow

Hourly Data Report for January 11, 2013										
Time	Temp, C	Dew Point Temp, C	Rel Hum, %	Wind Dir, 10s deg	Wind Spd, km/hr	Visibility, km	Stn Press, kPa	Hmdx	Wind Chill	Weather
0:30	-1.7	-1.8	99	3	55	0.6	97.61		-11	Snow, Blowing Snow
1:30	-1.4	-1.5	99	3	54	0.6	97.64		-10	Snow, Blowing Snow
2:30	-1.3	-1.4	99	3	71	0.6	97.69		-11	Snow, Blowing Snow
3:30	-1.2	-1.5	98	2	57	0.6	97.6		-10	Snow, Blowing Snow
4:30	-1	-1.3	98	2	48	0.6	97.58		-9	Snow, Blowing Snow
5:30	-1	-1.1	99	1	59	0.6	97.51		-10	Snow, Blowing Snow
6:30	-0.9	-1	99	2	75	0.4	97.45		-11	Heavy Snow, Blowing Snow
7:30	-0.9	-1	99	1	67	0.2	97.47		-10	Heavy Snow, Blowing Snow
8:30	-0.8	-0.9	99	1	74	0.4	97.43		-11	Heavy Snow, Blowing Snow
9:30	-0.7	-0.8	99	1	79	0.2	97.48		-11	Heavy Snow, Blowing Snow
10:30	-0.4	-0.5	99	1	74	0.2	97.56		-10	Moderate Snow, Blowing Snow
11:30	-0.2	-0.3	99	2	60	0.4	97.63		-9	Moderate Snow, Blowing Snow
12:30	-0.1	-0.4	98	2	54	0.8	97.74		-9	Snow, Blowing Snow
13:30	-0.1	-0.2	99	2	53	0.8	97.91		-8	Snow, Blowing Snow
14:30	-0.1	-0.2	99	1	46	4.8	98		-8	Freezing Drizzle,Fog
15:30	-0.1	-0.2	99	1	49	4.8	98.11		-8	Freezing Drizzle, Fog
16:30	0	-0.1	99	1	50	4.8	98.22		-8	Drizzle, Fog
17:30	-0.1	-0.2	99	1	46	4.8	98.28		-8	Snow, Fog
18:30	-0.1	-0.2	99	36	45	4.8	98.38		-8	Snow, Fog
19:30	-0.1	-0.2	99	36	40	2.4	98.43		-8	Snow, Fog
20:30	0.1	0	99	2	36	1.6	98.56			Rain, Snow, Fog
21:30	0.2	0.1	99	1	43	2	98.56			Rain, Fog
22:30	0.2	0.2	100	2	49	2	98.57			Rain, Fog
23:30	0.2	0.2	100	1	46	2	98.63			Drizzle, Fog

Hourly Data Report for January 12, 2013										
TIME	Temp, C	Dew Point Temp, C	Rel Hum, %	Wind Dir, 10s deg	Wind Spd, km/h	Visibility, km	Stn Press, kPa	Hmdx	Wind Chill	Weather Definition
0:30	0.2	0.2	100	1	44	1.2	98.73			Drizzle,Fog
1:30	0.3	0.3	100	1	38	1	98.78			Drizzle,Fog
2:30	0.2	0.2	100	36	39	1	98.86			Drizzle,Fog
3:30	0.3	0.3	100	36	36	1.2	98.82			Rain,Fog
4:30	0.4	0.4	100	36	47	1.2	98.85			Rain,Fog
5:30	0.4	0.4	100	36	44	1.2	98.86			Rain,Fog
6:30	0.5	0.5	100	36	42	1.2	98.95			Rain,Fog
7:30	0.5	0.5	100	36	39	1.2	99.04			Rain,Fog
8:30	0.7	0.7	100	36	40	1.2	99.1			Rain,Fog
9:30	0.9	0.9	100	1	36	0.8	99.15			Rain,Fog
10:30	0.9	0.9	100	1	33	0.4	99.17			Drizzle,Fog
11:30	1	1	100	36	30	0.8	99.15			Rain,Fog
12:30	1	1	100	1	29	0.4	99.13			Rain,Fog
13:30	1.2	1.2	100	1	32	0.4	99.14			Rain,Fog
14:30	1.5	1.5	100	2	31	0.8	99.18			Rain,Fog
15:30	1.5	1.5	100	1	29	0.8	99.24			Rain,Fog
16:30	2	2	100	3	38	0.4	99.28			Rain,Fog
17:30	2.2	2.2	100	3	37	0.2	99.28			Drizzle,Fog
18:30	2.4	2.4	100	3	23	0.2	99.25			Drizzle,Fog
19:30	2.3	2.3	100	36	21	0.2	99.27			Drizzle,Fog
20:30	2.5	2.5	100	2	22	0.2	99.34			Drizzle,Fog
21:30	2.7	2.7	100	2	24	0.2	99.34			Drizzle,Fog
22:30	2.9	2.9	100	3	27	0.4	99.36			Moderate Drizzle,Fog
23:30	3.2	3.2	100	1	15	0.6	99.37			Rain,Fog

newfoundland labrador
hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO

January 11, 2013 - Winter Storm Events

Power System Sequence of Events

Power System Review and Analysis Committee
June 2013
Final

Time	Event
04:13	Unit No. 3 at Holyrood tripped while supplying a load of approximately 70 MW. This resulted in a system underfrequency of approximately 59 Hz however there was no customer impact. The unit tripped due to a B-phase fault (due to salt contamination) somewhere in the overhead lines between the unit and the terminal station. The unit cleared quickly (seven cycles).
06:42	A C-phase fault (due to salt contamination) developed on the C phase stack of Unit 1 230 KV unit breaker - B1L17. The fault was in the Holyrood Unit 1 transformer differential zone. The protection operated to clear Unit 1 quickly from the system (in six cycles). The unit was loaded to 110 MW at the time of the trip. The fault, located at the breaker and in a 'blind spot' in terms of protection zones, was not cleared immediately. Transmission Line TL217 tripped only at the remote end (Western Avalon). The fault eventually migrated over to the line protection zone of TL217 and cleared, but not until 68 cycles had elapsed. The slow clearing time and voltage depression resulted in a trip of Holyrood Unit 2 and Newfoundland Power's 138 KV line 39L. Unit 2 was loaded to approximately 110 MW at the time of its trip. It should be noted that there was damage to the unit breaker, B1L17, and it was subsequently taken out of service for an extensive overhaul and repairs. ***At this point all three Holyrood units have tripped and locked out. Transmission line TL217 is tripped at the Western Avalon end. All remaining load in St. John's and area is being supplied by transmission line TL201 (Western Avalon to Hardwoods). Approximately 250 MW of load has been lost (primarily on the Avalon). Permanent damage had resulted to breaker B1L17 which was subsequently repaired.***

Time	Event
06:48	A C-phase fault occurred on TL217. The line tripped via breaker B12L17 and began its reclose sequence. During the reclose time, a fault occurred on the 138 KV bus in the Holyrood terminal station. This caused the 138 KV bus to trip and lock out.
	TL217 reclosed, however it closed in on a B to C-phase fault and tripped again – three phase. The B phase of breaker B12L17 closed again and re-faulted. The protections on TL218 (Hardwoods) and TL242 (Oxen Pond) overreached causing these lines to trip at the remote ends.
	At this point there were no 138 or 230 KV connections to the Holyrood terminal station and the 230 KV bus and the persisting B-phase fault on TL217 was being supplied via NP’s 66 KV line 38L through ungrounded transformation. The resultant high voltages caused a flashover and multiphase fault somewhere in the area of the 230 KV bus B12.
	The breaker failure protection associated with TL217 line breaker B12L17 operated to trip and lockout the 230 KV bus. The 66 KV connection provided by NP’s line 38L remained in service until 23 seconds later when it also tripped.
	At this point all three units at Holyrood are offline, the 230 and 138 KV busses at the Holyrood terminal station are de-energized and locked out and the entire Avalon load, east of the Western Avalon terminal station, is being supplied by TL201 with some local Newfoundland Power generation still in service. There was approximately 240 MW of load loss during this event.
07:42	A C-phase fault developed on the only remaining 230 KV line (TL201) supplying load east of the Western Avalon Terminal station. The fault was later determined to be caused by high winds and a jumper issue. This interrupted the load on the eastern Avalon (St. John’s and area). The loss of load resulted in an extreme system overfrequency and system upset which would now affect the power system in the central and western areas.

Time	Event
07:42 (cont'd)	The 230 KV line to the Cat Arm plant, the 230 KV lines from Bay d'Espoir to Stony Brook and the 138 KV loop from Stony Brook to Sunnyside all tripped due to misoperations of the line protections resulting from the high system frequency. Cat Arm was loaded to 120 MW at the time of the plant trip. The central/western region separated into islanded systems. There was one in the eastern portion from Bay D'Espoir to Western Avalon, supplied by the Upper Salmon, Granite Canal and Bay D'Espoir generation. The other, in the western portion - west of Stony Brook, but including the 138 KV loads from Stony Brook to the Clarenville area, was supplied by the Hinds Lake, Deer Lake Power and Exploits generation. The lines to the Upper Salmon and Granite Canal plants tripped shortly afterwards, removing this generation from the eastern islanded area (115 MW in total). TL206 from Bay d'Espoir to Sunnyside also tripped. These lines all tripped due to protection misoperations. There were many other protection misoperations which eventually resulted in outages to the Massey Drive, Buchans, Bottom Brook and Stephenville terminal stations and the loads supplied from those stations. The entire supply to the Great Northern Peninsula (GNP) was also interrupted. The customers supplied via the 138 KV (north of Parsons Pond) were only momentarily interrupted as the line reclosed. The 138 KV loop from Stony Brook to Sunnyside reclosed momentarily, re-energizing the Stony Brook station and back-energizing the western 230 KV system under very low voltage conditions. This was undesirable and caused a number of trips to the lines out of the Stony Brook, Buchans, Massey Drive, Bottom Brook and Stephenville terminal stations – all via the Optimho relay switch on to fault (SOFT) feature.

Time	Event
07:42 (cont'd)	***At this point there was a power outage to a large portion of the eastern Avalon, east of Western Avalon terminal station, including St. John's and the surrounding areas. In addition, the frequency in the central/western power system had become very high, resulting in trips of numerous transmission lines and stations and the loss of the generating plants at Cat Arm, Upper Salmon, Granite and Star Lake, with major and widespread customer outages. The central/western system islanded into two separate areas with each supplied from the Bay d'Espoir and Hinds Lake/Deer Lake Power/Exploits generation.*** It should be noted that due to RTU communications issues at the Stony Brook terminal station, the equipment status and telemetry from this station were no longer being reported back to the ECC operator. For one hour, during the restoration efforts that followed, this created significant confusion and resulted in additional abnormal conditions and equipment trips.
07:48	The ECC closed transmission Line TL231 from Bay d'Espoir to Stony Brook. This energized the Stony Brook 230 KV and 138 KV busses and picked up loads in the Grand Falls and South Brook areas only as the line breakers associated with the lines going west were still open (unknown to the ECC Operator). In addition, the 230 KV transmission line (TL235) to the Exploits generation in Grand Falls/Bishop's falls tripped during this operation due to the severe voltage depression and protection operation.
07:55	The 230 KV line (TL201) from the Western Avalon to Hardwoods terminal stations was restored. The efforts to restore the load on the eastern Avalon had now commenced. By 08:42 the load had increased to 260 MW. A disturbance at this time however, (likely originating on the NP system) caused a significant amount of load loss.

Time	Event
07:59	The 138 KV loop from Stony Brook to Howley was restored via breaker B1L22 at Springdale. This tied the Bay d'Espoir and Hinds Lake plants together momentarily, before an internal problem in this breaker caused a fault and the breaker tripped again. It was later discovered that resistors, internal to the breaker, had been damaged and fallen to the bottom of the tank. This breaker is currently undergoing replacement.
07:59	GNP customers north of Deer Lake to Parsons Pond were restored by the ECC via the 66 KV supply out of Deer Lake.
08:00	The ECC closed the 230 KV transmission line from Deer Lake to Massey Drive (TL248). Unknown to the operator at the time was that the supply from Stony Brook was still interrupted. This picked up the customer load at Massey Drive and energized numerous 230 KV lines, all from the Hinds Lake plant. A period of significant underfrequency and overexcitation of equipment resulted (approximately 10 minutes) and eventually caused the trip and lockouts of Buchans transformer T1 and Massey Drive transformer T2. The latter operation tripped the 230 KV bus at Massey Drive and interrupted the supply from Hinds Lake again. Customers on the Great Northern Peninsula, north of Deer Lake to Parsons Pond and those in the communities of St. Anthony, Main Brook and Roddickton were also interrupted during this period due to underfrequency protection operations.
08:30	Customers in St. Anthony, Main Brook and Roddickton were restored with re-connection to the grid (i.e. the western islanded system - supplied by Hinds Lake).
08:38	Communications were now restored to the Stony Brook RTU, confirming the equipment status and telemetry at this station for the ECC operator.

Time	Event
08:44	The 138 KV loop from Stony Brook to Howley was again restored via breaker B1L22 at Springdale. The loop remained closed at this time even though there were internal issues with the breaker. This tied the Hinds Lake and Bay d'Espoir systems together.
08:51	Another C-Phase fault developed on the only in-service transmission line from Western Avalon terminal station to the eastern Avalon (TL201). The line tripped and reclosed at the Western Avalon end only, causing the loss of 225 MW load and another outage to St. John's and area. The line trip is suspected to have been caused by the C-phase jumper issue. This reversed most of the eastern Avalon restoration efforts that had occurred to now. ***At this time the 230 KV supply east of Western Avalon is outaged again. Holyrood Units 1, 2 and 3 are out of service. The HRD 230 KV and 138 KV busses are de-energized and locked out.*** ***The Bay d'Espoir generating station is operating, connected to the Hinds Lake plant via the 138 KV loop from Stony Brook to Howley. Areas/customers being supplied are the Connaigre Peninsula, Sunnyside, NARL, the VBN terminal station, the remaining Avalon load via the 138 KV and 66 KV at Western Avalon, the Burin Peninsula, the Grand Falls area, Springdale area, Baie Verte peninsula, Howley, White Bay, and the GNP north of Parson's Pond. Other pockets of customers in various areas have supply (supplied by NP's local generation).*** ***All 230 KV busses west of Stony Brook are still de-energized. Transformers T2 at Massey Drive and T1 at Buchans are locked out. Cat Arm, Upper Salmon, Granite, Star Lake, and the Exploits generation are all off-line. Deer Lake Power is operating islanded from the rest of the system.***

Time	Event
08:54	The St. Anthony Diesel plant was started and synchronized for system generation support.
08:58	Transmission line TL205 (Stony Brook to Buchans) was energized. Unknown to the ECC at this time was that the breaker L05L33 at Buchans (associated with TL233) was only closed on one phase (B-phase). This energized lines and equipment at the Buchans, Massey Drive and Bottom Brook terminal stations on a single phase. Loads were also energized (single phase) from Bottom Brook via the 138 KV lines TL214 (supplying the Doyles and Port Aux Basques area) and TL250 (supplying the Burgeo area). Voltages were extremely high during this period. The loads supplied by TL214 and TL250 were tripped in less than 20 seconds via the line protection. What followed however was a single phasing condition that lasted for approximately 25 minutes in which there were numerous protection operations and equipment trips that led to a significant amount of confusion for ECC personnel.
08:59	The Hawkes Bay Diesel plant was started and synchronized for system generation support.
09:07	The ECC restored transmission line TL201, energizing the Hardwoods and Oxen Pond terminal stations. By 0910 hours, it was loaded to over 60 MW and, by 0936 hours, to nearly 220 MW.
09:10	The ECC restored transmission line TL209 at Bottom Brook. Unknown at the time however is that this operation energized the load at Stephenville on a single phase (the single phasing condition still existed). The transformer and line protection quickly operated to trip the load bus and the line.
09:16	The Hardwoods gas turbine was put on line for system generation and voltage support. There were numerous trips and restarts of this unit throughout the restoration period.

Time	Event
09:18	Customers north of Deer Lake to Parsons Pond were restored via the 66 KV supply.
09:22	Breaker L05L33 at Buchans closed on A and C phases (most likely due to loss of air supply). This ended the western system single phasing period. It should be noted that breaker L05L33 was taken out of service following this event for an extended period to facilitate for extensive repairs and overhaul.
09:35	Transmission line TL206 from Bay d'Espoir to Sunnyside was restored.
09:39	Line TL228 was closed into Massey Drive - energizing the Massey Drive 230 KV bus and NP 66 KV load busses. The pickup of load caused an underfrequency and interrupted customers north of Deer Lake to Parsons Pond again.
10:08	The Granite Canal unit was put on line.
10:23	There was a significant load increase followed by a drop of approximately 60 MW in the St. John's area, most likely related to activity at the NP stations in St. John's. This caused a significant voltage upset.
10:57	The NP 66 KV line, 38L, was closed and tripped again at the Seal Cove end. This appears to have been caused by a fault in the breaker B7T5 in the Holyrood terminal station. This also resulted in a lockout of transformer T5 at Holyrood.
11:16	The Bottom Brook breaker B1L09 was closed by the ECC in an attempt to restore the loads in the Stephenville area but opened and closed multiple times due to suspected breaker air problems.

Time	Event
11:19	The Bottom Brook breaker L11L33 was closed, energizing the 230 and 138 KV busses and transmission line TL214 into the Doyles terminal station.
11:46	The Deer Lake Power and Hydro systems were tied together at Deer Lake.
12:34	The Holyrood terminal station lockouts associated with the 138 and 66 KV busses and transformer T5 were reset. This marked the beginning of the restoration of the Holyrood terminal station. Personnel were delayed in their efforts to perform these operations due to the ongoing storm which impeded travel.
12:43	The Bottom Brook breaker B1L09 was successfully closed while station was in local control, restoring Stephenville loads.
13:11	Transmission line TL214 was restored putting Doyles transformer T1 back in-service.
13:16	Transmission line TL211 was restored.
	At this point all 230 KV lines in the central/western area were back in-service with the exception of TL247 (Cat Arm to Deer Lake).
13:29	The Holyrood breaker fail lockout associated with 230 KV breaker B12L17 was reset.
14:44	The Upper Salmon unit was put online following the reset of the unit lockout by personnel.
14:58	Transmission line TL242 from Hardwoods to Holyrood was restored.
	At this point TL201 was still the only 230 KV line in service supplying the St. John's and area loads (approximately 220 MW).

Time	Event
15:03	The Holyrood 66 KV busses B6 and B7 were energized.
15:07	Transmission TL218 from Oxen Pond to Holyrood was restored.
15:08	Transmission line TL217 from Western Avalon to Holyrood was restored - paralleling TL201. Load on both lines now totalled to approximately 280 MW.
15:41	The Holyrood 230 KV bus - B15 along with transformers T6, T7, T8 and the 138 KV bus - B8 were re-energized.
15:44	The NP 138 KV line 39L was restored.
16:37	The NP 66 KV line 38L was restored.
17:38	The Holyrood transformer T5 was placed back into service.
18:21	Cat Arm Unit 1 was put on line.
18:53	Cat Arm Unit 2 was put on line.
	It should be noted that there was considerable delay in restoring the Cat Arm units as personnel were required to travel to site to reset lockouts. While at site there was difficulty in restoring station service supply to the plant.
20:58	Personnel reset breaker failure and transformer lockouts at the Buchans terminal station.

Time	Event
23:55	At this time Buchans transformer T1 and the remainder of the station was fully restored. It should be noted that there was considerable delay in restoring the 66 KV portion of the Buchans terminal station as personnel were required to travel to site to reset lockouts. While at site, transformer T1 testing was required as a lockout had occurred and it was uncertain as to what initiated it.
00:10 (Jan 12)	The Star Lake unit was put online.
03:54 (Jan 12)	Holyrood Unit 2 was put online.
05:13 (Jan 12)	Holyrood Unit 3 was put online.

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Unit 1 Failure – Holyrood
Life Safety Review
SWOP # 2013000599
January 11, 2013

Investigating Team	Ron LeDrew, Wade Kelloway, Steve Tilley, Brian Lannon
Manager (Safety Leader One)	John Hollohan
Regional/LOB Safety Coordinator (Safety Leader Two)	Wade Kelloway

PRIVILEGED REPORT

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1.0 Introduction

Holyrood's Thermal Generating Station (HTGS) provides a major source of power for the Avalon Peninsula during peak winter months and not having the units in Holyrood available caused outages indirectly for Newfoundland Power's residential customers.

On January 11, 2013, during a severe winter storm, three (3) units tripped off-line in Holyrood causing power outages to customers on the Avalon Peninsula. After the loss of unit service in Holyrood, station service was lost as well. Basic lighting and ventilation/exhaust systems were affected in the plant. A subsequent fire on generator unit # 1 meant that Operations personnel had to address the immediate concerns of the fire before initiating procedures for unit service and station service reinstatement.

A Life Safety (LS) investigation team was assembled on Thursday, January 17, 2013 and members of the Life Safety team, based in St. John's, travelled to Holyrood to observe the damage to Unit 1 on Friday, January 18, 2013. The remaining members of the Life Safety team are based in Holyrood and had exposure to the damage prior to January 18th.

The Team was assembled to investigate the incident and provide recommendations. A systematic causation analysis technique was used to complete the investigation which included interviewing Operations personnel, reviewing documentation, and looking at photographs.

The Life Safety review was one of nine segments of an investigation led by the Manager of Regulated Operations. The investigation involved reviewing challenges that the Operations department experienced, (as noted through their interview statements),identifying the key findings and addressing the root cause of these life safety concerns, and providing recommendations for these issues were part of the investigation team's objective.

2.0 Background Information

HTGS is part of Thermal Generation, a division of Newfoundland and Labrador Hydro operating under Nalcor Energy Company. It is located in Holyrood on the Avalon Peninsula in Newfoundland and Labrador. It is the largest fossil fuelled station in the Province and is capable of providing approximately 500 MW of electricity. HTGS typically generates between 25-40% of the power requirements for the Province. The station burns approximately 2700 m3 per day in its three operating units when operating at maximum load.

There are a total of five shifts in Holyrood that cover a 24 hour, 365 day operation. While the generating units in Holyrood are operating, Operators have the responsibility of ensuring safe operation of the Units and associated equipment. The shift schedule for the Operations personnel are on 12 hour cycles (8 am – 8 pm). There are normally six Operations personnel per shift, with one Operator responsible for each unit, a Shift Supervisor, a Lead Hand and an outside floor/plant person.

On January 11th, the Operators were comprised of members from 3 different operating shifts. As per the Boilers Act of Newfoundland and Labrador, each pressurized boiler has an Operator twenty-four hours a day operating it. As a result of the predicted snow storm on the evening of January 10th, some Operators reported for work earlier than their normal shift change while others had to stay as their relief could not report to HTGS because of the inclement weather.

The establishment of the 4 Emergency Response Technician (ER Tech) positions at HTGS was a direct result of the recommendations provided within the 2007 Emergency Preparedness and Response Capability Report. The spirit and intent of these positions is to provide a dedicated fire and life safety presence at HTGS and, amongst other duties and responsibilities, act as an Emergency Response Team Leader in the event of an emergency.

These positions were staffed in February 2010 and their hours of work are defined by the number of units operating in the Powerhouse. When two or more units are in operation (traditionally November - April), they provide 24/7 coverage through two ten hour days, followed by two 14 hour night shifts (one Technician on at all times) on a rotational basis. When one or no units are in operation (traditionally May - October), two ER Techs are scheduled to work four 10 hour days within Monday - Thursday, with the two remaining ER Techs working Tuesday – Friday.

On the evening of the incident in question, the scheduled ER Tech called the facility to inform the supervisor that he could not travel to the Plant to report for work due to inclement weather and poor road conditions. Without mandatory backfill, the position was not staffed, nor was a replacement sought to provide ER Technician coverage on overtime for the evening in question.

3.0 Incident Timeline

January 11, 2013:

04:13	-	Unit 3 tripped.
06:42	-	Unit 1 and Unit 2 tripped.
06:42 – 08:00	-	Fire on Unit 1 and call made to HTGS's Emergency Response Coordinator informing him of situation.
08:00	-	HTGS's Emergency Response Coordinator made contact with the Manager of Safety and Health to communicate issue in Holyrood thereby activating the Corporate Emergency Response Plan (CERP) process.
08:30	-	Executive On Call (EOC), Vice President of Customer Service notified.
09:30	-	Transportation and Works contacted regarding snow removal.

10:00 - Corporate Emergency Operations Center (CEOC) operational at this time. Members representing Supply Chain Management, Communications, Operations Liaison, Safety & Health as well as the Deputy Incident Commander were present and conference calls were held on an hourly basis with the full CERP team.

15:00 - Supply Chain Management and Safety & Health representatives were relieved of their CEOC duties.

22:02 - Email from Deputy Incident Commander (DIC) reflecting on the day's activities and challenges and thanking everyone for the work they had completed. DIC also requested everyone to forward comments on the activities and areas where NL Hydro could improve in their operations.

January 12, 2013:

02:24 - Holyrood G2 start

05:13 - Holyrood G3 start

4.0 Detailed Description of Events

The following information is an account of what occurred, taken from the Operations staff through interview statements, the equipment that was used during the incident and the evidence and pictures that were collected at the scene in the days following the generating unit trip and subsequent damage.

On January 11, 2013 a power outage affected a large portion of the Avalon Peninsula. A contributing factor to this outage was the loss of 3 generating units at HTGS. Operations staff reported for work at approximately 20:00 hours on January 10th and was present at the time of the generating units tripping on the early hours of January 11th.

From witness statements, all Operations personnel stated that Unit #3 was the first to trip on the morning of January 11, 2013 at approximately 04:20 hours. While trying to get Unit #3 back on line, Units #1 and #2 tripped a couple of hours later resulting in total unit service loss of power in HTGS. After unit service was lost in the Holyrood plant, the Operations personnel realized that station service from Holyrood's switchyard was unavailable due to the snow storm's impact on the power distribution system. With the loss of station service and no gas turbine auxiliary power, the HTGS was basically unable to black start the steam generating units and produce power.

After generating Units #1 and #2 tripped off-line the plant had to rely on manually operated diesel engines to power the plant providing mechanical ventilation/exhaust capability.

During the time between generating units tripping and restoration of power from the diesel engines, the Operations personnel reported that the plant was almost in total darkness. It was during this time that the Operations Personnel noticed that a fire had occurred on Unit #1 and the Operations department communicated a picture of a plant that was dark with flickering flame silhouettes coming from generating Unit #1. While the Operations Shift Supervisor went to investigate the origin of the fire, the Operations volunteer emergency responders began to don their fire fighting bunker clothing to assist in extinguishing the fire. As a result of the fixed fire suppression system not activating, the employees used the portable wheeled fire extinguishing units to put the fire out. Several portable and wheeled fire extinguishing units were used to extinguish the fire and keep it from spreading to other parts of generating Unit #1 and other parts of the plant.

No Emergency Response Technicians (ERT) were on site during this incident which added pressure on the Operations Supervisor and the Operations Emergency Response team members in fighting the fire rather than allowing their full concentration on the other demands that required their attention during the fire and shut down of generating Unit #1.

HTGS currently has an Emergency Response Team (ERT) comprised of 15 volunteer members of which 10 are Operations personnel. ERT members are subject to a medical to prove their ability to safely wear self-contained breathing apparatus and to conduct the required firefighting training. Each ERT Operator is equipped with personal NFPA compliant firefighting turn-out gear and Self Contained Breathing Apparatus and face pieces, located adjacent to the Control Room for rapid response to a fire incident.

The Emergency Response Manual Chapter 9 (ERM-09) Fire Response, located in Appendix provides the standard operating procedure for an incipient phase (beginning) stage fire response with a view to minimizing losses. It is not the intent of ERM -09 to train, equip and support a fully functional 24/7 fire response to all situations that may be encountered. Therefore, ERT responders are expected to use best judgment when approaching any fire situation and work within the bounds of their training and capabilities.

Because participation in the ERT is voluntary, membership is not divided evenly amongst the 5 operating shifts, thus some shifts have more available ERT Operators than others. This manning position increases the potential that a fire incident may arise where there are no ERT Operators on shift. During this incident, 2 ERT Operators were on-shift, though they were called in and not operating with their regular shift. These findings are captured and recommendations have been identified and implemented.

Once the Operations department had extinguished the fire on generating Unit #1, the Operators next concern was to dump the hydrogen from generating Unit #1. Two ERT Operations personnel, wearing full PPE and SCBA, travelled to the second level in the plant underneath generating Unit #1 to manually release the lever to allow the hydrogen to escape through a valve to the outside. There is no propelled dumping system on the hydrogen system as the hydrogen escapes under atmospheric pressure. This release of hydrogen under atmospheric pressure may increase the likelihood of an explosion or accelerated fire.

During the naturally venting hydrogen system dumping, which takes approximately 1.5 hours to fully disperse, the Operations department completed other tasks that have to be completed to bring the generating unit to a stop. One of these tasks is to start auxiliary diesel generators which provide power to run equipment such as exhaust fans and lighting systems in the plant. Comments by the Operations department, through the interview process, revealed that large amounts of smoke could be seen in the Control Room during the incident.

After the shutdown of the generating units in Holyrood, the Operations crew relied on the transmission and distribution (T&D) crew from Whitbourne to restore power to the switchyard and ultimately to the plant, providing station service. One of the challenges the crew from Whitbourne had in accessing the Holyrood generating plant was the amount of snow on the public roadway. Once station service power was restored Operations personnel had to start the process of getting the generating units back up and running. This process, called a black start, basically is a step by step procedure to get the generating units back on-line. It was noted that some Operations department personnel are relatively new and have not completed a black start at the HTGS. A recommendation has been identified for this finding.

At 08:00 hours, the Emergency Response Coordinator in Holyrood received a call from the Shift Supervisor informing him of the incident and subsequent fire on Unit 1. The Shift Supervisor requested personnel assistance with the incident although none could be immediately provided due the poor road conditions and inaccessibility to the powerhouse. The ER Coordinator placed a call to the Manager, Safety and Health to determine if CERP was activated for this incident. During these initial stages of the incident, when communication was made that HTGS was without power, the Corporate Emergency Response Plan (CERP) was activated by the Executive on Call in consultation with the Manager, Safety and Health. Members of the CERP who were on-call during the incident mobilized and gathered at the command post at Hydro Place to offer assistance to HTGS personnel in whatever capacities they could.

The Incident Timelines, found in Section 3.0, communicate the transactions of the CEOC activities.

Finally, during the week following the incident, the Occupational Health Nurse offered each employee, who worked the shift during the incident, the option to meet with counsellors through the Company's Employee Assistance Program (EAP) to discuss any issues they may have. Although all Operations personnel declined this invitation, they did acknowledge that it was appreciated.

5.0 Observations/Recommendations/Status

The observations that were found throughout the investigation focused on fourteen (14) key focus areas. The following is a list of the observations, recommendations and their status to date.

1. Compliance with Emergency Response Procedures (Holyrood Emergency Response Manual)
2. Emergency Response Technician (ERT) coverage
3. Operator coverage with emergency response training
4. Familiarization of Operations personnel with emergency response equipment
5. Number of hours worked by Operations staff before driving home exceeded a safe allowable limit

6. Emergency lighting inadequate in powerhouse after unit failure.
7. Ventilation inadequate in powerhouse due to loss of both unit and station service
8. Access/Egress from plant, through Operator's door due to blocked snow
9. Fixed fire suppression system never activated
10. Portable fire extinguishing equipment
11. Safe operating procedures under Unit Vibration conditions
12. SWOP not entered or communication of major incident in timely manner
13. Corporate Emergency Response Plan (CERP) response
14. Employee Assistance Program (EAP) response

5.1 Emergency Response Manual Compliance (in relation to this incident)

HTGS has an Emergency Response Manual (ERM) developed for all emergency response personnel and employees. It serves as a reference for proper response procedures and to obtain pertinent information that ensures a safe, effective and professional emergency response is undertaken. The ERM describes the emergency response structure at HTGS and the general roles and responsibilities for personnel under emergency situations.

The goal of the document is to reduce the probability of emergency events escalating to catastrophic proportions and minimize losses. The ERM is not intended to provide commentary on legal relationships between Nalcor/Hydro and outside response organizations and government agencies.

ERM-09 Fire provides a standard operating procedure for an incipient (beginning) stage fire response with a view to minimizing loss. In the event of an escalating fire involving (or in the vicinity of) the turbine/generating units, Shift Supervisors, Operations employees and ERT members shall consult and implement as necessary, response procedures outlined in *ERM Appendix E, Emergency Shutdown Procedures (Fire-Related) for Turbine/Generator Units and Associated Equipment.*

ERM Appendix E, *Emergency Shutdown Procedures (Fire-Related) for Turbine/Generator Units and Associated Equipment* was developed by AMEC under contract to prepare detailed emergency shutdown procedures, describing the most suitable course of action for protecting the assets and reducing downtime in case of a fire in the turbine building at Holyrood. These procedures were derived to serve as guidelines for the operating staff that run the units under four scenarios:

1. A fire under control by the fixed fire protection equipment or ERT;
2. A fire that is not under control by fixed fire protection or ERT and the turbine is under a quicker controlled shutdown;
3. A fire that is not under control and threatening to spread to other units; or
4. A fire on Unit 3 while under synchronous condense mode.

The incident on January 11, 2013 would fall under #1 guideline in the procedures above. However, during this incident of the un its tripping, a fire resulted, severe vibration of the unit and complete loss of power ensued. The procedures within ERM Appendix E relate to combating a fire on the turbine generating units which have not experienced a trip.

Witness statements indicate that the fire fighting procedures outlined in ERM-09 were generally followed and were effective. The procedures within ERM Appendix E, *Emergency Shutdown Procedures (Fire-Related) for Turbine/Generator Units and Associated Equipment,* were not relevant to this incident as the equipment was already in various states of shutdown.

Recommendation:

Review both ERM-09 and ERM Appendix E with all operations personnel to ensure staff understands their roles and responsibilities in the event of a fire on the Turbine / Generators.

5.2 Emergency Response Technician Coverage

The establishment of the 4 Emergency Response Technician (ER Tech) positions at Holyrood Thermal Generating Station (HTGS) was a direct result of the recommendations provided within the 2007 Emergency Preparedness and Response Capability Report. The spirit and intent of these positions is to provide a dedicated fire and life safety presence at HTGS and, amongst other duties and responsibilities, act as an Emergency Response Team Leader in the event of an emergency.

These positions were staffed in February 2010 and their hours of work are defined by the number of units operating in the Powerhouse. When two or more units are in operation (traditionally November-April), they provide 24/7 coverage through two ten hour days, followed by two 14 hour night shifts (one Technician on at all times) on a rotational basis. When one or no units are in operation (traditionally May-October), two ER Techs are scheduled to work four 10 hour days within Mon-Thurs, with the two remaining ER Techs working Tues-Fri.

On the evening of the incident in question, the scheduled ER Technician called the facility to inform the supervisor that he could not travel to the Plant to report for work due to inclement weather and poor road conditions. Without mandatory backfill, the position was not staffed, nor was a replacement sought to provide ER Technician coverage on overtime for the evening in question.

The ER Techs are not legislated by the Province to provide this coverage, nor is the Corporation mandated under the provisions of the Collective Agreement to provide automatic backfill for an ER Technician, unless required under OHS legislation (for example Confined Space Rescue coverage). The possibility exists that situations will arise where there is no ER Technician on shift during the operating season and/or maintenance periods.

Recommendation:

In light of the incident and the original intent of these positions as stated in the 2007 Emergency Preparedness and Response Capability Report, Plant Management should review the options to increase the coverage of the ER Technicians during the operational season.

Status:

ER Coordinator has ensured ER Technician coverage is maintained during impending inclement weather as no annual leave will be granted at this time. Shift exchanges are permitted with advance notice.

5.3 Emergency Response Team – ERT Operator Coverage

HTGS currently has an Emergency Response Team (ERT) comprised of 15 volunteer members of which 10 are Operations personnel. ERT members are subject to a medical to prove their ability to safely wear self-contained breathing apparatus and to conduct the required firefighting training. Each ERT Operator is equipped with personal NFPA compliant firefighting turn-out gear and Self Contained Breathing Apparatus and face pieces, located adjacent to the Control Room for rapid response to a fire incident.

The Emergency Response Manual Chapter 9 (ERM-09) Fire Response; located in Appendix; provides the standard operating procedure for an incipient phase (beginning) stage fire response with a view to minimizing losses. It is not the intent of ERM-09 to train, equip and support a fully functional 24/7 fire response to all situations that may be encountered. Therefore, ERT responders are expected to use best judgment when approaching any fire situation and work within the bounds of their training and capabilities.

Because participation in the ERT is voluntary, membership is not divided evenly amongst the 5 operating shifts, thus some shifts have more available ERT Operators than others. This manning position increases the potential that a fire incident may arise where there are no ERT Operators on shift. During this incident, 2 ERT Operators were on-shift, though they were called in and not operating with their regular shift.

Recommendation:

Operations Manager should, in consultation with the ER Coordinator and applicable Plant Management, explore possibility of increasing the number of trained ERT Operators and/or ensure that the current number of ERT Operators is spread evenly amongst all shifts. Ideally, there should be a minimum of two ERT Operators on each shift to assist the ER Technician in emergency response situations.

Status:

ER Coordinator has secured another Operations volunteer for the ERT from the one remaining shift without an ERT Operator, who has undergone the appropriate medical and fire fighting training.

5.4 Familiarization of Operations personnel with Emergency Response Equipment

HTGS maintains a variety of mobile Emergency Response equipment based upon the hazards within the site. Equipment directly related to combating fire incidents include mobile dry-chemical and foam wheeled firefighting units, hand-held extinguishers and fixed firefighting systems designed with automatic and manual operation.

ERT Operations personnel are given familiarization training on the operation of portable and fixed firefighting equipment during ERT Training Days held a minimum of twice annually. However, Operations personnel who are not a member of the ERT do not currently receive familiarization of this equipment on a formal basis. Formal Fire Fighting Training for the ERT Operators is comprised of an initial Industrial Fire Fighting Course at Marine Institute with at least two internal exercises held annually.

Due to the 24/7 shift scheduling for operations personnel it has been accepted that all operations personnel, not only ERT Operators, require basic instruction on the use of portable fire extinguishers and manual/automatic fixed fire suppression within the Powerhouse. Portable fire extinguisher training was available to all plant employees during Safety Week in 2011 but no subsequent fire extinguisher training has been offered to any HTGS personnel beyond the ERT Operators.

The ER Coordinator had purchased a live-fire extinguisher trainer in late 2012 with the purpose of providing realistic fire extinguisher training for all employees in 2013, including Operations. However, this initiative did not get implemented before the January 11th incident in question. Initiatives have been immediately introduced to begin instruction in the above areas for the Operations group with the intention to complete all staff before 1 April 2013.

Recommendation:

ER Coordinator to expedite training in fire extinguisher/mobile wheeled fire extinguishing units with all HTGS employees.

Status:

- Operations ERT members have received Industrial Fire Fighting training on February 15 - 17, 2013 at the Marine Institute's Fox Trap campus. It should be noted that this fire training was not reactive from the incident on January 11th but rather a previously scheduled training session.

- All Operations personnel have received refresher training in both Wheeled and Portable fire fighting equipment. These training sessions were conducted in conjunction with each shift's Monthly Safety Meeting in March 2013.

- All Operations shifts have received re-fresher training in the operation of the fixed fire suppression systems associated with the Turbine/Generators. These training sessions were conducted with each shift's Monthly Safety Meeting in March 2013.

- Fire extinguisher training has been scheduled to be conducted by the ER Technicians during Safety Week 2013 (6-10 May). These sessions will include both practical and classroom instruction.

5.5 Number of hours worked by the Operations staff before driving home exceeded a safe allowable limit

The investigative team discovered that most of the Operations personnel, who worked the shift of the incident, were in the plant for an extended period of time. All Operations personnel worked beyond their normal shift hours while some worked between twenty and thirty-six hours before being relieved by another Operator.

Recommendations:

1. Have plant management review the shift duration that Operations personnel can work before driving their own vehicle home and communicate the arrangement to all employees.
2. Communicate the shift duration that an employee can work to other Nalcor sites so they can also address any deficiencies they may have in their regions.

5.6 Emergency lighting inadequate in powerhouse after unit failure.

Through interviews with the Operations personnel, it has been noted that powerhouse lighting was not adequate once power was lost to the plant.

Recommendations:

1. Plant Management to assign appropriate personnel to conduct a review of:
   a) all plans/drawings/manuals for existing conditions regarding emergency lighting;
   b) inspection/maintenance/testing on existing emergency lighting and identify gaps;
   c) existing conditions regarding locations/power supply with code requirements and identify gaps; and
   d) short and long term improvements/scheduling and cost to upgrade if necessary.
2. Once the review has been completed in Holyrood, lessons learned should be generated and communicated to all Nalcor sites that have the potential for emergency lighting issues.

Status:

- ER Coordinator has started a review of the emergency lighting issue with the Electrical Department in Holyrood. ER Coordinator has met with Assets Manager and Electrical Engineer to provide the scope and intent for a review for emergency lighting in the powerhouse. Existing emergency lighting has been field tested. Review of plans/drawings/manuals for existing conditions regarding emergency lighting has been conducted. Electrical Engineer has checked existing AC Lighting with regards to feeds and transfers to UPS 347V (helps determine capability/cost to tie into existing infrastructure for future EL upgrades).

- ER Coordinator has determined code requirement for inspection / maintenance /testing intervals with current Preventative Maintenance Work Orders on existing emergency lighting. ER Coordinator and Electrical Engineer conducting on-going review of existing conditions regarding locations/power supply with code requirements and identification of gaps.

5.7 Ventilation inadequate in powerhouse due to loss of both unit and station service.

Through interviews with the Operations personnel, it was communicated that smoke was found in the powerhouse and also in the Control Room of the plant during the January 11th incident. As a result of the loss of unit and station service, there was no emergency power to operate exhaust fans. Moving forward, black start capability with mobile generating units can provide additional power for ventilation, if required. As a result of the Control Room containing large volumes of smoke, a review is required to confirm that the Control Room and the powerhouse plant is independent of each other.

Recommendations:

1. Plant Management should assign appropriate personnel to conduct a review, determining if adequate ventilation (exhaust fans) was available in the powerhouse during the incident and if there are independent ventilation systems in Holyrood.

2. All plant Operations personnel attend training on the mobile units that will be installed for black start capability.

5.8 Access/Egress from plant through Operation's person door due to blocked snow

Through the investigation process it was learned that snow had blocked the person door in Holyrood thus preventing Operations personnel from exiting the plant on the east side. It was noted that the operators removed the glass window in the door to aid in exiting the plant.

Recommendation:

Plant Management should develop and communicate procedures (within Emergency Response Manual) to ensure snow removal for all exits has been completed in the event of inclement weather.

Status:

A shovel has been placed in the Control Room to allow Operations personnel to keep the person doors on Level 1 of the Powerhouse (their normal exit route) clear of snow. Communication has been completed on why the shovel is placed there and the intention in case of large amounts of snow.

5.9 Fixed fire suppression systems never activated.

All three generating units in Holyrood are protected with fixed fire suppression systems that were fully upgraded in 2008 to provide Pre-Action sprinklered fire protection over each unit in the general high potential areas of the turbine generator bearings. The valves are checked weekly by the ER Technicians and annually by a certified fire protection technician to ensure proper operation of the system.

It was noted by Operations employees that the Pre-Action fixed fire protection system on Unit #1 did not activate during the incident. This was verified the following day by the ER Coordinator who confirmed that neither the sprinkler heads had melted nor the heat detector activated in the vicinity of where Operations employees indicated.

The Pre-Action fire suppression on Unit #1 operates in the following manner:
A valve in the water supply lines serving Bearing 1 can only release if two conditions are met:

1. Air pressure downstream of the valve has to be released (sprinkler head bulb melts), and;

2. The heat detector mounted above Bearing 1 activates (hence "double-interlocked"). This double interlocked concept is commonly used in applications where flooding of the piping can have serious consequences and it's important to control accidental flooding. Bearings 2-5 are non-interlocked systems and will introduce water after the sprinkler bulb melts and the air pressure in the line releases. There is no heat or smoke detectors on bearings 2-5.

   The firefighting system was verified operational on the following day of the incident by the ER Coordinator but did not activate at the time of the incident. This leads to speculation that there may not have been sufficient heat in the vicinity of the sprinklers to melt the temperature rated bulbs on each sprinkler head. A local certified fire protection technician was called on site the following Monday morning to verify Unit 1 Deluge System and it was still fully operational.

Recommendation:

Plant Management to assign appropriate personnel to investigate positioning of the sprinklers in the vicinity of the Turbine Generator to ensure proper activation of the system is achieved. If modifications/additions are necessary, ensure they apply to both Unit 1 and 2 Turbine/Generator bearing fire suppression systems.

Status:

ER Coordinator has asked FM Global Fire Protection Engineer to assist in the review of the Fire Suppression System for both Unit 1 and 2, as both units incorporate the exact system configuration. This review will be conducted during FM Global's annual compliancy inspection scheduled for April 29, 2013.

5.10 Portable fire extinguishing equipment

Mobile Dry Chemical and portable dry chemical fire extinguishers were deployed to extinguish the fire on Unit 1. All portable fire extinguishers and mobile units operated properly and were inspected in accordance with applicable standards. All equipment was recharged and replaced immediately following the January 11th incident.

Recommendation:

Continue checking the fire extinguishing equipment as per the appropriate codes and standards.

5.11 Safe operating procedures under severe vibration conditions

When Unit #1 was running down from 3600 RPM to zero, loss of oil lubrication resulted in the Unit experiencing high vibration. Acceptable vibration level is less than 100 microns and normal operating conditions being in the around 40 microns. During the run down on the unit with a loss of oil lubrication, vibrations levels in excess of 400 microns (maximum readable level) were experienced.

Operations personnel were in close proximity of Unit #1 while involved with fire fighting, hydrogen venting and other emergency response activities while vibration levels exceeded four times the normal vibration level. There is a risk that the casing/housing may fail with the resulting explosion sending projectile parts of the equipment throughout the turbine hall and there remains a significant concern for physical harm to personnel in the powerhouse (and Control Room).

Recommendation:

Plant Management to develop safe operating procedure to ensure personnel maintain a safe distance from the turbine generating units while under a vibration event in excess of 300 microns or level deemed acceptable by the authority having jurisdiction.

5.12 Safety Observation (SWOP) not entered or communicated through a Major Incident Announcement in a timely fashion.

Communication of the incident in Holyrood never occurred in a timely fashion. There was no SWOP initiated or major incident announcement communicated to workers in the Holyrood plant or Nalcor immediately following the incident in accordance with Corporate Safety Standard.

Recommendation:

Management to review the Incident Investigation standard for communication improvements.

5.13 Corporate Emergency Response Plan (CERP)

Good communication and mobilization of partial team in a timely fashion.

On Friday, January 11, 2013, at approximately 0800h, the Manager of Safety & Health received a call from HGTS Emergency Response Co-coordinator (ERC) reporting an incident involving a fire on Unit 1. It was reported that the fire had been extinguished and the unit was no longer on line. On site employees donned self contained breathing apparatus (SCBAs) in order to respond to the incident. It was also reported that Unit 2 and 3 also tripped and there was a developing issue in the switchyard, however, the ERC was not sure of the nature. The ERC was unaware if the Executive On-Call (EOC) had been alerted of the developing situation. The Manager of Safety & Health advised he would contact the EOC and get direction on next steps, if any were warranted.

At 0830h the EOC was contacted and advised of the incident at Holyrood. The EOC advised that the CEO and V.P. Regulated Operations were aware of the incident and the resulting problems with power generation. Through discussions, the EOC and the Manager of Safety & Health thought it prudent to issue a CERP 811 Alert with a pending partial mobilization. The Manager of Safety & Health contacted the Emergency Control Center (ECC) and advised that an 811 Alert be issued. Shortly thereafter the situation at Holyrood was complicated with loss of generation at Upper Salmon and Granite Canal. At this stage it was agreed to issue another CERP 811 Alert identifying a partial mobilization of the Corporate Emergency Response Plan (CERP) at Hydro Place. A concern identified was the potential difficulty of getting CERP team members into Corporate Emergency Operations Center (CEOC) at Hydro Place as well as operational and technical staff into the Holyrood plant. The Manager of Safety & Health contacted the Emergency Measures Organization (EMO) to inquire if they could provide assistance on getting the employees into the CEOC and thermal plant. The EMO on-call representative advised the EMO do not provide this service and the only thing they could possibly assist with was to help us contact the Transportation and Works Department and request assistance in clearing the access road leading to the thermal plant.

At approximately 0930h the Manager of Safety & Health received a call from a Transportation and Works representative stating they would investigate what they could do, particularly redirecting a snow plow to have the access road to the plant cleared. There was no further contact with the Transportation and Works representative.

At 1000h the CEOC was "live" with CERP members representing Supply Chain Management, Communications, Deputy Incident Commander, Operations Liaison and Safety & Health. All team members began carrying out their respective role related duties as outlined in the CERP document. Regularly scheduled conference calls were held with the full CERP team approximately every hour. At approximately 1300h the CEO jointed the CEOC.

The Supply Chain Management and Safety & Health representatives supported the Deputy Incident Commander as requested and assisted by picking up additional technical support (Protection and Control Engineer) using a company 4x4 vehicle and transporting them to Hydro Place. At or about 1500h the Supply Chain Management and Safety & Health representatives were no longer required and were relieved of their roles in the CEOC.

Overall, it was generally felt that the partial CERP mobilization was appropriate for this event. The use of conference calling for updates was sufficient and even the declining numbers of personnel on successive calls indicated support for partial mobilization only.

Internal communications seemed to work well, with the Operations liaison largely keeping in touch with Operations and the Deputy Incident distributing the information as required. There did not seem much the CERP team could do regarding snow clearing and we were at the mercy of Transportation and Works and there was not much we could do without roads being open.

Given partial mobilization, there was no need for two centers (CEOC and Level 6 Boardroom) as initially established.

Thoughts were that the chain of command was stretched a few times with calls from other parties, not working through the CERP process, which at times caused unnecessary distractions.

Recommendations:

1. Assign a 4x4 vehicle to Safety & Health and Supply Chain Management to assist with mobilization of team members under severe weather or poor site accessibility conditions.

2. Document a bridge contact number in the CERP document to ensure guaranteed communications for those who wish to call in for updates.

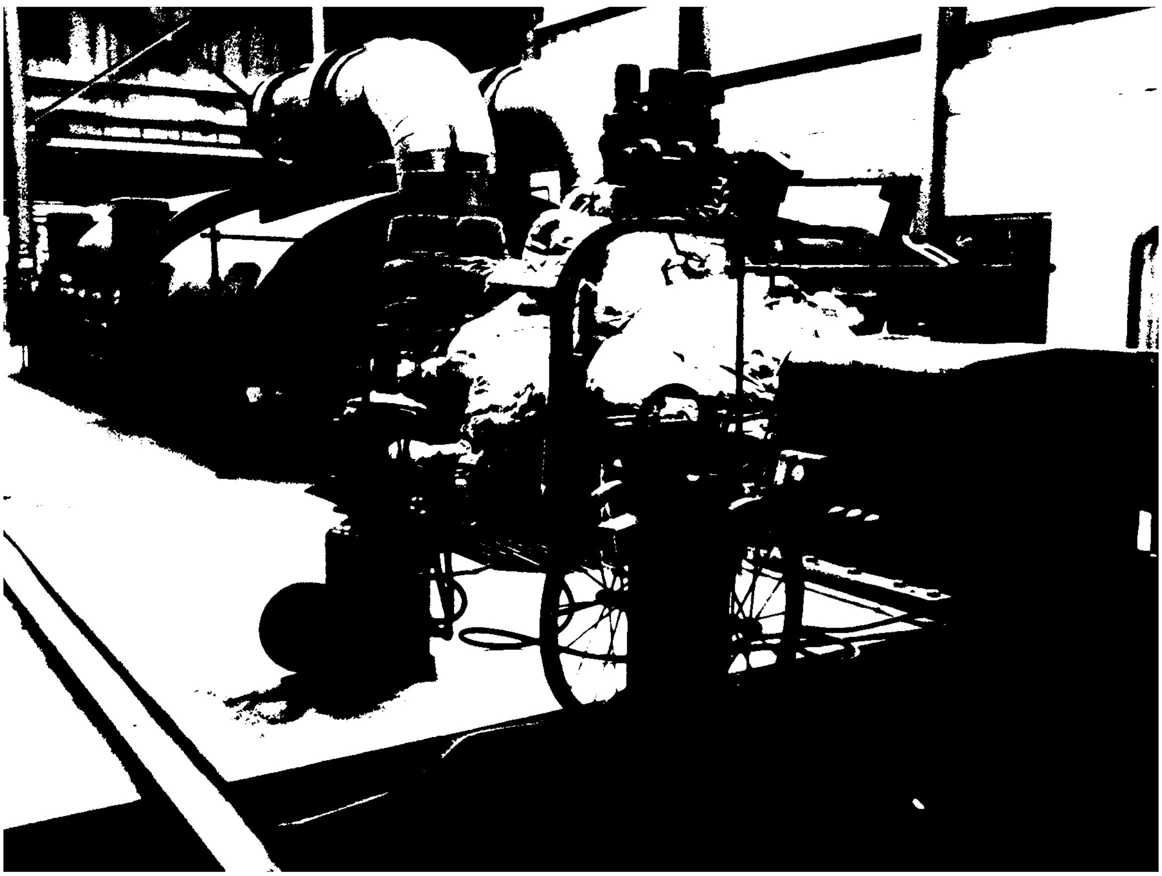
3. Assignment of smart phone devices to the CERP "on-call members" so the entire CERP team can be updated and communicated all at once.

5.14 Employee Assistance Program (EAP) response.

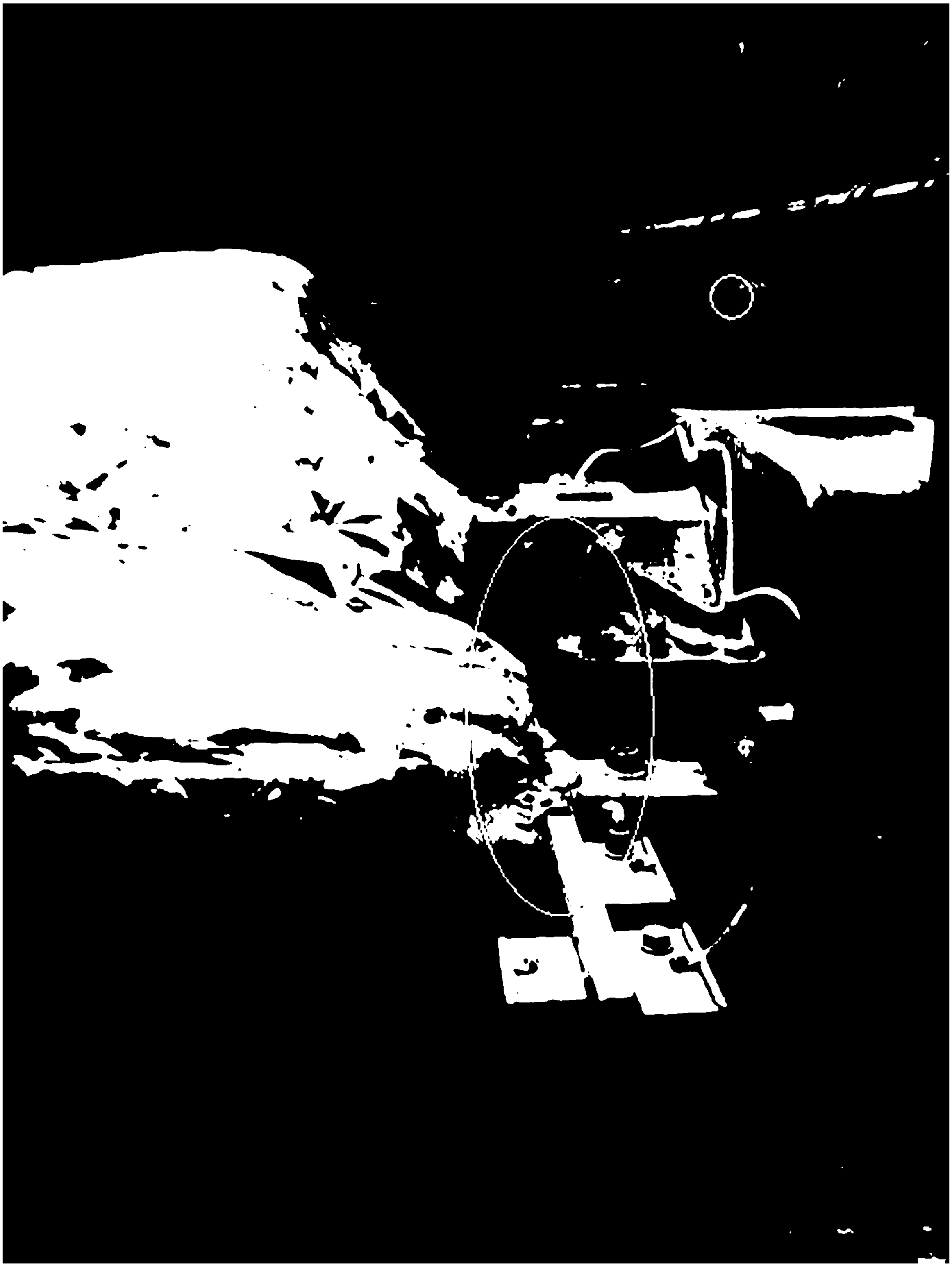
Nalcor's Occupational Health Nurse initiated the EAP response and provided each employee in the Operations department the opportunity to speak with a counsellor from Morneau Shepell. Although this invitation was not taken advantage of by the Operators, they did acknowledge the fact that it was available and thanked the Occupational Health Nurse for her offer.

6.0 Pictures

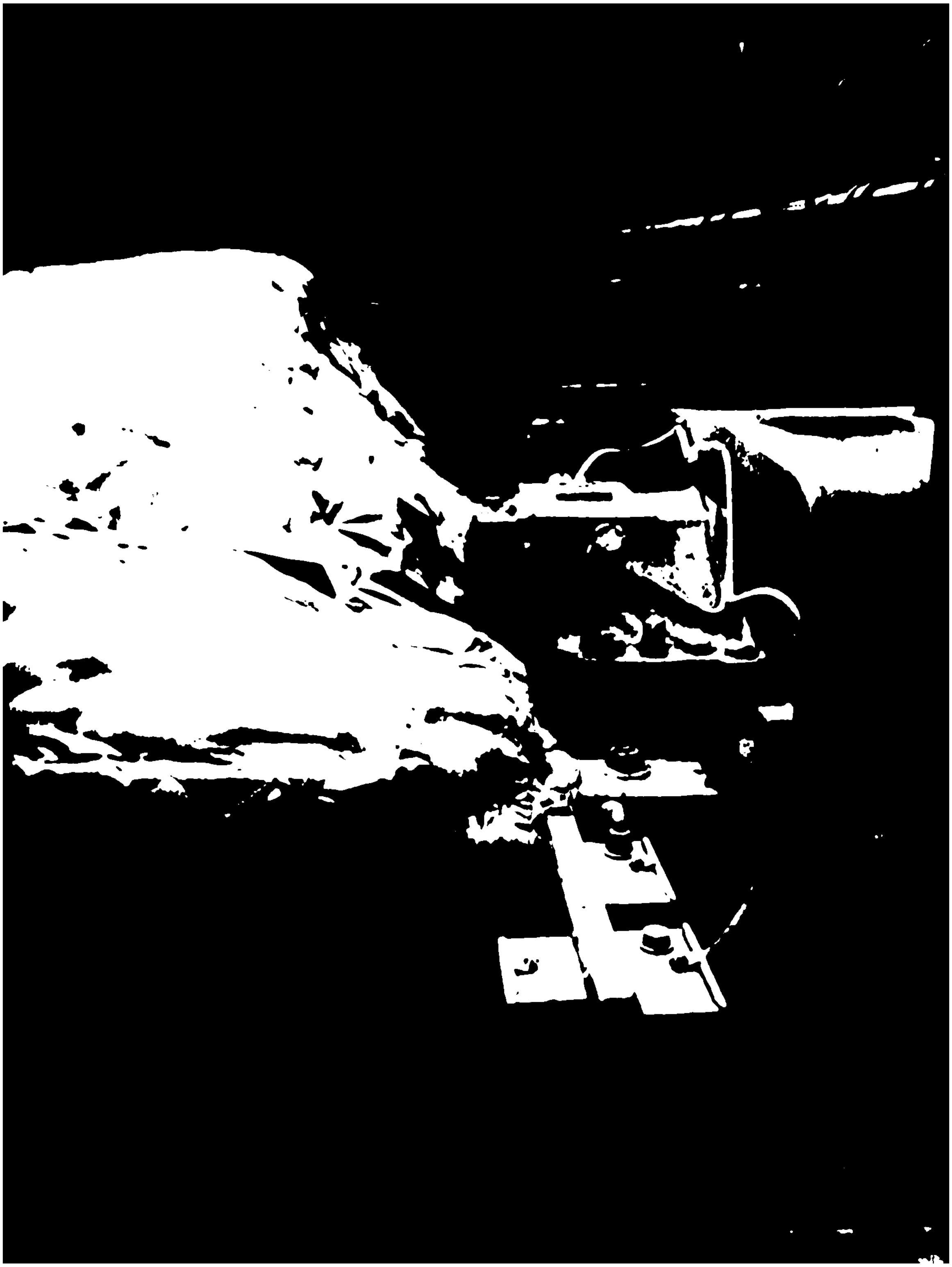
Picture of Unit 1 on January 12, 2013. This picture was taken the day after the fire and shows the wheeled dry chemical fire extinguishers that were used to put the fire out. The yellow dry chemical powder indicates the location of the fire.



The following picture (Bearing #1) demonstrates the location of the fixed fire suppression system heads (red circle), heat detector (white circle) and the location of the fire that was extinguished by the Operations personnel (yellow circle).



Picture of Unit #1, Bearing #1 and the dry chemical residue from the fire extinguishers that were used by the Operations personnel in extinguishing the fire



Picture of Unit #1, Bearing #1 and the dry chemical residue from the fire extinguishers that were used by the Operations personnel in extinguishing the fire

APPENDIX A

ERM-09 Fire

ERM-09 Fire

1. Scope of Response:

a) The scope of this action plan is to detail an emergency response to a fire at HTGS. The intent of ERM-09 is to provide a standard operating procedure for an incipient (beginning) stage fire response with a view to minimizing the degree of loss.

b) It is not the intent of this ERM to train, equip and support a fully functioning fire response for all fire situations that may be encountered. *Therefore, responders are expected to use best judgment when approaching any fire situation and work within the bounds of their training and capabilities.*

c) In the event of an escalating fire involving, or in the vicinity of, the turbine/generating units, Shift Supervisors, Operations employees and ERT members shall consult and implement as necessary, response procedures outlined in *Appendix E, Emergency Shutdown Procedures (Fire Related) for Turbine/Generator Units and Associated Equipment.*

d) During any fire incident, the three (3) priorities for responders are in the following order:

i) The safety and protection of yourself and your co-workers;
ii) The protection and preservation of property and assets;
iii) The protection and preservation of the environment.

2. Fire Response Activities:

a) The First Person discovering the fire will:

- Contact the Shift Supervisor via the normal communications system (P.A. system/phone) and, identify the location and type of emergency.

- Effect any obvious and immediate response
  - Use portable fire extinguishers
  - Manually activate fire protection systems
  - Isolate fuel source, etc. within the limits of his/her knowledge or skills

b) The Shift Supervisor will:

- Assess the situation to determine if the fire can be controlled safely and immediately with available personnel, if not or unsure, then activate the Emergency Evacuation Alarm and make the following announcement via the Plant PA System:

"FIRE, FIRE, FIRE. FIRE IN THE VICINITY OF *(ie. column number/equipment/location/level)* **. EMERGENCY RESPONSE TEAM MUSTER** *(ie. Control Room/Mechanical Shops),* **ALL REMAINING PERSONNEL EVACUATE TO THE TRAINING CENTER"**

- Dispatch available on-shift personnel from Operations to effect isolation of plant systems that may worsen the ongoing emergency;
- Dispatch ER Technician and members from the ERT to the location of the emergency, wearing full fire-fighting PPE including SCBA;
- Call 911, Holyrood Fire Department and, depending on the magnitude and nature of the fire, will also call CBS Fire Department;
- Call ER Coordinator/ER Technicians for all fires, regardless of size or impact and will notify OSC-2 for any fires requiring outside response agency support;
- Notify Plant Security of the emergency;
- Direct Security to escort emergency response agencies to the on-site location;
- Delegate one on-shift operator (if available) to detail events and times in the Event Log;
- Resume his/her normal duties and initiate an A/I report upon termination of the incident.

After normal working hours or on the weekend, when members of the Emergency Response Team is at a minimum, the Shift Supervisor, upon receiving notification of the emergency, will call the Holyrood Fire Department and direct the on-site trained members of the Emergency Response Team (ER Techs and/or operators) to the scene of the emergency. Following the call to the fire department, the Shift Supervisor or delegate will call off-shift members of the Emergency Response Team using the standard home telephone system.

The Shift Supervisor will assume the position of OSC-1 until such time as the ER Coordinator, OSC-1 or another person qualified to act in this position arrives on site.

c) The ER Technician(s) will:

- Respond immediately to the Control Room or location as designated by the Shift Supervisor or OSC-1;

- Assume role of Fire Attack Team Leader for all fire-related responses, communicating and coordinating response activities with the Shift Supervisor or OSC-1;
- Respond accordingly wearing full fire-fighting PPE including SCBA;
- Activate or isolate, as necessary, fixed fire protection systems;
- Effect key point isolations (if applicable);
- Direct ERT to cordon off response perimeter upon termination of the incident;
- Assist Shift Supervisor in the investigation for fire cause and determination;
- Be the first point of contact for external fire response agencies.

d) The ER Team Members (Operators) will:

- Respond to designated Muster Station (Control Room) immediately, or as directed by the Shift Supervisor or OSC-1;
- Respond accordingly wearing full PPE including SCBA;
- Activate or isolate, as necessary, fixed fire protection systems;
- Effect key point isolations (if applicable).

e) The ER Team Members (Non-Operators) will:

- Respond to designated Muster Station (Outside Tool Crib on Level 1) immediately, or as directed by the Shift Supervisor or OSC-1;
- Don full fire fighting PPE including SCBA and establish communication with Shift Supervisor via Paging System;
- Inform Control Room on number of ERT personnel available and await direction from Shift Supervisor or OSC-1;
- Respond accordingly wearing full PPE including SCBA;
- Activate or isolate, as necessary, fixed fire protection systems;

- Effect key point isolations (if applicable).

After normal working hours or on weekends, when members of the Emergency Response Team (non-operators) is at a minimum, the primary Muster Point for the ERT will be the Control Room. If there is more than one ER Technician on shift, they will muster at both locations, one outside the Tool Crib and the remainder at the Control Room.

f) Plant Security will:

- Once directed by the Shift Supervisor, ensure they are immediately available at the Main Gate to escort the outside response agency(s) to the scene;

- Direct all responding Fire Department volunteers, who are in their own personal vehicles and are not traveling in a response vehicle, to park in the designated Emergency Staging Area, the ERT building gravel parking area;

- Remain in communication with the Control Room at all times via two-way radio on Channel 1.

3. Post-Fire Response Activities:

a) Immediately after the ERT and/or outside response agency declare that the fire is extinguished, the on-scene OSC/Shift Supervisor, ER Coordinator/ER Technicians or other qualified personnel will collectively address how the fire scene will be secured and limit further smoke and water damage.

b) Securing of the scene will occur after the event and **before clean-up** to permit an investigation to be conducted by qualified individuals. The purpose of this investigation is to determine fire cause and assess the effectiveness of both active (suppression and detection) and passive (smoke and fire barriers) fire protection systems.

APPENDIX B

Witness Statements

[redacted]

28 January 2013 @ 11:00 am

Interviewers: [redacted], & [redacted]

1. Tell us in your words what happened?

At approximately 0415 hrs unit 3 tripped. During the process of trying to get unit 3 back on line, a trip occurred on unit 1 & 2. Unit 1 & 2 tripped at 0630 hrs. As a result of the three units tripping, the plant was dark except for emergency lighting. Through the darkness noticed a fire on unit one bearing 3 & 4. [redacted] and [redacted] proceeded to don bunker gear. [redacted] went to investigate the fire on bearing 3 & 4. During the investigation, unit 1 bearing caught on fire. There was excessive smoke in the powerhouse and control room. [redacted] proceeded to put the fire out on bearing 1. [redacted] and [redacted] returned with their bunker gear on and went to vent hydrogen gas on the second floor. They used a flashlight for lighting. Lights returned to the plant one hour later. Duration of my shift was 23 hours.

2. Are you a member of the volunteer Emergency Response Team?

No

3. Have you attended fire related training?

No

4. Do you believe you should receive fire related training?

Yes. I believe that all operators should receive training.

5. Do you feel that your life safety was threatened during the incident?

Yes

6. Was a SWOP entered?

No. Never really thought about it.

[redacted]

[redacted]

28 January 2013 @ 11:30 am

Interviewers: [redacted] & [redacted]

1. Tell us in your words what happened?

Began work at 2000 hrs on the 10th of January 2013. Unit 3 tripped at 0410 hrs on the 11th of January 2013. In the process of trying to get unit 3 on line, unit 1 & 2 tripped, resulting in total darkness in the plant. Emergency lighting was on in the control room and the plant but the lighting was very poor. There was smoke in the plant and control room. Noticed a fire on bearing 3 & 4 which was approximately 15 feet high. Number one bearing caught on fire a half hour later. Hydrogen was vented by [redacted] and [redacted] It took approximately two hours to vent the hydrogen by manual operation on second floor.

2. Are you a member of the volunteer Emergency Response Team?

No

3. Have you attended fire related training?

Have not received fire training in a long while but had previous involvement in fire team.

4. Do you believe you should receive fire related training?

Yes

5. Do you feel that your life safety was threatened during the incident?

Don't feel life was in danger.

6. Was a SWOP entered?

No

[redacted]

[redacted]

31 January 2013 @ 9:00 am

Interviewers: [redacted] & [redacted]

1. Tell us in your words what happened?

At approximately 0400 hours, unit 3 tripped off line. At 0630 hours, units 1 & 2 went down. Unit 1 started vibrating. The plant went black. A fire was noticed on bearing 3 & 4 on unit 1. [redacted] and [redacted] proceeded to put our bunker gear on. I grabbed the fire extinguisher to put the fire out. The fire on bearing 3 & 4 burned out but then there was a fire on bearing 1. I then grabbed the 150 lb dry chemical and sprayed it on the bearing. I told [redacted] and [redacted] to vent the hydrogen gas. Lighting was very poor in the plant. The plant was black for 1.5 hours. Duration of work 36 hours.

2. Are you a member of the volunteer Emergency Response Team?

No

3. Have you attended fire related training?

Yes, external training (Marine Institute in 2005).

4. Do you believe you should receive fire related training?

Yes, all operators should have fire related training.

5. Do you feel that your life safety was threatened during the incident?

Yes, at times.

6. Was a SWOP entered?

No

[redacted] Feb. 21, 2013

[redacted]

31 January 2013 @ 8:30 am.

Interviewers: [redacted] & [redacted]

1. Tell us in your words what happened?

I was assigned to unit 3. At approximately 0430 hours, unit 3 tripped off line. We were trying to get unit 3 back on line for the next 2 hours. At 0630 hours, units 1 & 2 went down. Unit 1 started vibrating. The plant went black. A fire was notice on bearing 3 & 4. [redacted] and I proceeded to put our bunker gear on. We couldn't find the mask to the SCBA. We then ran down to the bottom floor to leave the building. We couldn't open the operator's door due to snow. We broke the window in the door and climbed out through. We drove to the guard shack to get the keys to the ERT building as we knew we could get SCBA masks there. After leaving the ERT building, we returned to the plant and proceeded to cut the fuel supply to the fire. [redacted] and I went to the second floor to vent the hydrogen gas. The plant was still dark. The plant and the control room were full of heavy smoke as there was no ventilation. Work duration was 22 hrs.

2. Are you a member of the volunteer Emergency Response Team?

No, resignation submitted to ERT Coordinator late last year.

3. Have you attended fire related training?

Yes, external training (Marine Institute).

4. Do you believe you should receive fire related training?

Yes, there should be mandatory training for ERT volunteers.

5. Do you feel that your life safety was threatened during the incident?

Yes

6. Was a SWOP entered?

No

[redacted]

[redacted]

23 January 2013 @ 13 30 pm

Interviewers: [redacted]

1. Tell us in your words what happened?

Unit 3 tripped around 0400 hours. Proceeded to put back on line. Noticed a fire on bearing 3 & 4. [redacted] and I went to don our bunker gear. We couldn't find the mask to the SCBA. Exit the plant via window in the operator's door to find SCBA mask. The operator's door was blocked with snow and unable to open. Proceeded to the guard shack to retrieve the keys to the ERT building to obtain masks. Learned after they were in an interior pouch inside the bag but hard to find. Very little lighting on the third floor. The first floor was dark. Shut off hydrogen on the second level 20 minutes after the fire was extinguished on number one bearing. Diesels; after manual starting; provided the emergency lighting.

2. Are you a member of the volunteer Emergency Response Team?

Yes

3. Have you attended fire related training?

Yes, every three years at the Marine Institute. In house training not sufficient. My bunker gear is to small and I had to borrow [redacted] as he is similar in size. Location of the masks was not communicated to the operators.

4. Do you believe you should receive fire related training?

Yes, Marine Institute is good. In house training not sufficient.

5. Do you feel that your life safety was threatened during the incident?

Yes, when the turbine was vibrating.

6. Was a SWOP entered?

No

[redacted]

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO

January 11, 2013 - Winter Storm Events

Power System Performance Review Report

Power System Review and Analysis Committee
June 2013
FINAL

Summary

The severe winter blizzard on January 11 resulted in major issues on the Island's Interconnected power system. The high northerly on shore winds combined with the blowing snow caused salt contamination of station equipment in the Holyrood terminal station which resulted in faults in the station and on transmission lines. By 0648 hours all three Holyrood units had tripped and the Holyrood terminal station was completely de-energized and locked out.

It should be noted that the damage experienced at Unit 1 during the shutdown process at 0642 hours is not addressed in this report as it is covered in a separate report completed by others.

At 0742 hours (with the Holyrood generating and terminal stations still out of service) there was a fault and trip on the only remaining 230 KV line supplying the St. John's and area (TL201), resulting in a major power outage to the customers in this region. The severe overfrequency issues caused by this sudden load loss resulted in numerous protective relay misoperations and multiple trips to transmission lines and generating units in the Central and Western Regions. There was separation and islanding of the East/West power systems and the customer impact spread island wide. Total customer impact was estimated to be in excess of 700 MW.

Transmission line TL201 was restored, however at 0851 hours, while ECC operators were attempting to restore the system within the limits of the generation that was available, the line faulted and tripped again. This resulted in another outage to customers in St. John's and area but in this case it was limited to this area because the Western area was still being restored and the on-line generation was significantly less.

Throughout the day restoration efforts in the Eastern area were hampered by storm conditions that impaired travel and delayed personnel from resetting lockouts in the Holyrood Station. In the Western and Central areas, efforts were delayed by several equipment issues, in addition to RTU communications issues at the Stony Brook terminal station, all of which resulted in additional abnormal events and additional equipment outages. The system was fully restored by the early morning hours of January 12.

The significant number of events and the incidences, along with their abnormal nature, proved to be quite challenging in the efforts to fully understand the specific details of the same. Some of these events had not previously been encountered during the many years of system operation. To conduct the analysis, information such as SOE (Sequence of Events) records, DFR (Digital Fault Recorder) traces and relay records were collected and reviewed.

This report presents the results of the analysis of the events on January 11, from the onset of the storm and the first issues at the Holyrood generating and terminal stations to the completion of the system restoration efforts during the early morning hours of the next day. The report summarises all actions taken to date, in addition to presenting numerous recommendations for future action (55 in total) to help avoid or lessen the impact of such events in the future. The recommendations are identified by area of responsibility and cover all the issues which led to the significant power system events on this day, including recommendations in areas such as:

- Review of preventative maintenance procedures and schedules
- High voltage breaker replacement, inspections and repairs
- Protection and control circuitry - function testing and enhancements
- Digital protective relay firmware and setting changes
- System stability studies
- System voltage/frequency studies and control enhancements
- Development and enhancement of procedures

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1.0 INTRODUCTION

On January 11 a severe winter blizzard with high winds and heavy snowfall resulted in major issues on the Island's Interconnected power system. The high northerly on shore winds combined with the blowing snow caused salt contamination of station equipment in the Holyrood terminal station which resulted in faults in the station and on transmission lines. These faults led to a large number of events of differing severity, in terms of equipment outages and customer impact.

The number of events and the incidences were quite challenging to analyze and still require more work to fully understand the specific details of some as they were of a significant and abnormal nature, some of which were not previously encountered over the years of system operation, certainly not as many during one day. To conduct the analysis, information such as SOE records, DFR traces and relay records have been collected and reviewed.

This report analyzes the System events but does not address the internal events in Holyrood and the other plants in detail. In particular, a separate report on the significant damage which occurred on Unit 1 generator at Holyrood has been prepared by others and covers the internal plant issues experienced. Some items associated with the plants have been identified as they surfaced during the analysis.

At 0413 hours, Unit No. 3 tripped at the Holyrood plant. The analysis indicates that it resulted from a single phase fault which occurred somewhere between the high side of the unit transformer and the 230 KV unit breakers. The unit was loaded to 68 MW at the time of the fault. There was no customer impact reported.

At 0642 hours, while HRD personnel were in the process of restoring Unit 3, there were trips of Units 1 and 2 and transmission line TL217 at the Western Avalon end. Both units were loaded to 110 MW. This resulted in a significant customer impact with nearly 250 MW of Newfoundland Power load loss (primarily on the Avalon Peninsula).

At 0648 hours, while all units were off at Holyrood and TL217 was still open at the Western Avalon end, there was a 138 KV bus lockout and a breaker failure operation associated with the 230 KV breaker, B12B17. These events effectively de-energized the terminal station and removed all station service supply to the units. There was approximately 240 MW of Newfoundland Power load loss, again primarily on the Avalon Peninsula.

At 0742 hours, with the Holyrood terminal and generating stations out of service, there was a fault and trip on TL201, the remaining 230 KV line from Western Avalon to the major load centres in St, John's. Due to protection misoperations on key transmission circuits, caused by the significant system overfrequency upon the loss of load, there was separation of the East/West power systems. This created wide spread power outages in the Central and Western areas resulting in the loss of multiple generating stations and transmission lines, and the separation of the Deer Lake Power system from the grid. Total customer impact is estimated to be in excess of 700 MW.

Restoration efforts started almost immediately but issues were encountered during the Western area restoration due to station RTU communications problems at Stony Brook and general switching and equipment issues, all of which resulted in additional abnormal events and additional equipment tripping. The Eastern area restoration efforts proceeded as expected but was hampered by storm conditions which delayed personnel from resetting lockouts in the Holyrood Station.

At 0851 hours, while ECC operators were attempting to restore the system within the limits of the generation that was available, TL201 faulted and tripped again. Approximately 230 MW of customer load was lost during this event. Restoration started again on the Eastern system with the re-energization of TL201. On the West Coast some progress was made through Stony Brook but breaker issues delayed this progress and, at around 0900 hours, resulted in other abnormal system events.

At 0907 hours, TL201 was re-energized and restoration of the St. John's area proceeded again. By 0930 hours TL201 was loaded to approximately 200 MW. By 0939 hours restoration was also proceeding in the Western area with the Massey Drive terminal station re-energization and loading. Restoration of the system continued with conditions getting back to normal in the Western area by noon with most load busses re-energized and the Deer Lake Power system reconnected.

At 1008 hours the Granite Canal unit was put on line.

By 1330 hours, the Holyrood lockouts were reset and at 1458 hours the Holyrood 230 KV bus, B12, was energized via TL242. This was followed by restoration of TL218 and, at 1508 hours, TL217 was put in service, paralleling TL201 and completing the restoration of the 230 KV transmission on the Avalon.

At 1444 hours the Upper Salmon unit was put online following the reset of the unit lockout relay. The Cat Arm Units were both back online by 1853 hours following resets of the unit lockouts and restoration of the station service supply.

The Buchans transformer T1 was put back in service at midnight after locking out earlier in the day.

Holyrood Units 2 and 3 were back online at 0354 and 0513 hours on January 12, respectively.

2.0 SIGNIFICANT EVENTS

2.1 Event No. 1 at 0413 Hours - Holyrood Unit 3 Trip with no Load Loss

At 0413 hours, Holyrood Unit 3 tripped while supplying a load of 68 MW. This resulted in a system frequency deviation to 58.98 HZ before recovering. There was no underfrequency load shedding as the highest instantaneous underfrequency load shedding trigger is 58.8 HZ. Therefore, there was no customer load loss reported for this event.

The Holyrood DFR trace, Figure 2-1, for the event at 0413 hours follows. As indicated in the trace, there was a single phase 230 KV voltage depression (B-phase) to almost zero volts. Both 230 KV Unit 3 breakers B3B13 and B3L18 tripped and cleared the fault in seven cycles. There was no unit lockout operation recorded in the system SOE, however the Holyrood plant SOE indicated an operation of the Unit 3 lockout 86-2 which trips both unit breakers and shuts down the unit. Analysis of the fault data indicates that the fault was on the 230 KV line somewhere between the high side of the unit transformer and the unit breakers, most likely caused by the salt contamination of the station insulation which was prevalent, due to the high northerly winds in from the ocean.

2.1.1 Additional Observations

- There appear to be some discrepancies between the unit lockouts recorded in the plant SOE and that recorded on the system SOE. There was no lockout recorded on the system SOE but it was indicated in the plant SOE. Also no protection targets were recorded by the Holyrood Plant Operators for the trip because none operated or because the operators did not record them before resetting. Although it cannot be confirmed, the fault was most likely detected by the unit transformer differential protection 87GT3, a differential harmonic restraint relay (GE BDD15B11A) in Unit 3's protection which operates into the unit lockout 86-2.

- Heavy salt contamination in the station due to the high on shore northerly winds is suspected to have caused the flashover.

2.1.2 Actions Taken

- Subsequent inspection of the Unit 3 suspected faulted area, the overhead tie from the plant to the unit breakers, did not show any signs of the fault or damage, most likely due to the fast clearing time.

2.1.3 Further Actions Required

- Although an inspection of the suspected faulted area was performed following this event, a more thorough inspection of the area should be performed during a scheduled outage, to ensure that no damage exists and to confirm the fault mechanism.

- Plant management should review the instructions for recording protection targets after unit trips to ensure that they are recorded by the operator before they are reset. Protection panel cards should be updated and made available to the operator for recording the targets as required.

- During the next scheduled maintenance outage of Unit 3, a function test of the 87GT3 relay should be performed to ensure that the relay targets flag when the relay operates into the lockout.

- The plant SOE indicates operation of the Unit 3 generator lockout 86-2 but no lockouts were reported in the system SOE at this time. Therefore, a request to have the system SOE for this point and the other Unit 3 lockouts operation tested has been initiated.

- Internal plant trip reports for all unit trips should be completed by plant personnel and distributed to ensure that all systems worked as designed.

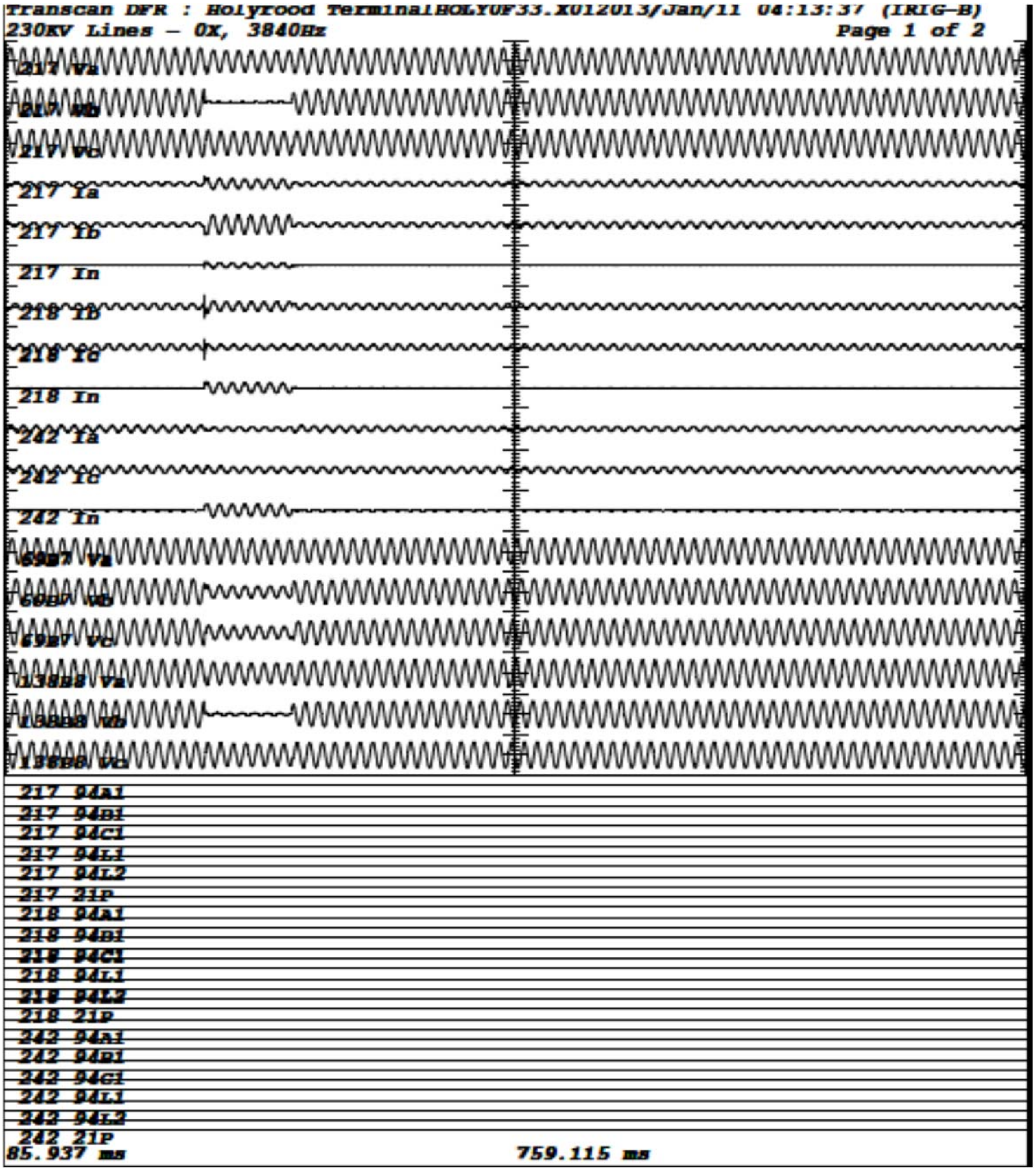

Figure 2-1: Holyrood DFR Trace at 0413 hours during Unit 3 Trip

2.2 Event No. 2 at 0642 hours – Units 1 and 2 Trips, 39L HRD Trip, TL217 Reclose at HRD and Trip at WAV with Load Loss of 250 MW

The sequence of events table for the events starting at 0642 hours is presented in Appendix A-1. At 0642 hours a single phase C-phase to ground fault occurred on the Holyrood 230 KV station equipment due to heavy salt contamination. The Holyrood and Western Avalon DFR traces, Figures 2-2 and 2-3 respectively, and subsequent inspection of the station equipment revealed that there was a fault on the C phase stack and breaker head of the 230 KV breaker B1L17, located on the CT (Current Transformer) side of the breaker contacts. Refer to the Holyrood station single line diagram, Figure 2-4, for the positioning of this breaker. This resulted in a severe depression of the 230 KV C-phase voltage, to almost zero volts. This fault was in the Unit 1 transformer differential zone and was most likely detected by the 87GT1, a differential harmonic restraint electromechanical relay (GE BDD15B11A) in Unit 1's protection which operates into the unit lockout 86-2, tripping Unit 1 breakers, B1B11 and B1L17. This operation cleared the unit from the system in six cycles and initiated shutdown. The load on the unit at the time was 110 MW.

(It should be noted that the damage experienced at Unit 1 during the shutdown process is not addressed in this report as it is covered in a separate report completed by others.)

Following the trip of Unit 1, the 230 KV voltage remained depressed as the fault was not cleared and was being supplied from bus B12 and TL217 via breaker B12L17. The fault current was in excess of 3,000 amps for approximately 64 cycles, although fault current shown on the TL217 neutral DFR channel indicates only approximately 380 amps for the first 30 cycles as this is the current contribution from TL217 only. TL217 tripped at Western Avalon on back up time Zone 2 ground protection in 30 cycles. Due to the fault location and the direction of the currents in the B12L17 and B1L17 CTs, the current on TL217 was indicated to be zero as the fault contribution that passes through B12L17 CT also passes through B1L17 CT, in the opposite direction, therefore summing to zero on the TL217 neutral and C phase DFR channels. During this time, the fault current was still in excess of 3,000 amps. A fault in this location should have been cleared by the B1L17 breaker failure protection, activated via the 86-2 lockout operation. This would have tripped B12L17 in approximately 21 cycles, thus clearing the fault much more quickly. However, unit lockouts from Unit 1 and 2 presently do not operate into the breaker failure protection.

Figure 2-3 shows the Western Avalon DFR trace and the tripping of TL217 in 30 cycles via the Zone 2 time delayed ground distance protection, and indicates that both P1 and P2 protections operated correctly. After 64 cycles the fault migrated from where it started on the breaker head, over to a location on the line side of the B1L17 CT (approximately 2 meters). This is in the TL217 line protection zone and resulted in the fault clearing in four cycles via TL217 Zone 1 line protection (P1 Optimho protection only) which tripped B12L17 C-Phase at 68 cycles. This fault migration is evident on the DFR trace from the increase of current in the TL217 neutral channel, just before the fault was cleared. This was confirmed from subsequent inspection of the B1L17 breaker, during which marks and damage were discovered on the connecting conductors on both sides of the B1L17 CT, as shown in the pictures of B1L17 breaker and the B1L17 CT in Figure 2-5 (a to d).

At 50 cycles, the electromechanical time overcurrent relays, 51T1 A and C associated with Holyrood Unit 1 transformer T1, operated and activated the 94TS/T1 trip relay in the terminal station. At that time however, the unit breakers were already opened. These relays are connected in the B1B11 and B1L17 CTs and sum the current. Although the unit breakers were open, due to the location of the fault as described above, the B1L17 CT supplied current to the 51T1 relay’s delta connected circuit until breaker B12L17 tripped. At first glance this protection operation was thought to indicate delayed clearing of Unit 1 but it does not, as the unit was cleared after six cycles as noted above. However this protection, 94TS/T1, should have started a B1L17 breaker failure timer (16 cycles) and should have been very close to operating or have operated when breaker B12L17 tripped to clear the fault.

The protection operated on line 39L and tripped this line at 52 cycles. The protection on this line is the electromechanical type, consisting of phase distance and ground overcurrent. No targets were flagged when inspected. The timed ground overcurrent protection would have started to operate with the ground fault contribution on the line, but should not have operated within this time (52 cycles). Testing of the protection should be done with particular emphasis on the 51N relay to ensure that the disk is fully resetting.

Unit 2 tripped at 71 cycles with an 86-3 lockout operation tripping unit breakers B2B11 and B2L42. The unit was loaded to 110 MW at the time. It is suspected that the backup voltage restrained overcurrent relays, 51V/G2, operated into the unit’s 86-3 lockout, although no targets were recorded. The unit shut down safely following the trip.

Following the TL217 and Unit 2 trips, the 138 KV and 69 KV voltages rose significantly, indicating that the fault had now cleared. TL217 reclosed via B12L17 C phase at the Holyrood end at 112 cycles (44 cycles after tripping) and all voltages recovered at this point.

There was a fair amount of confusion in the analysis of this event as the open/close indication for Holyrood breaker B12L17 does not appear to be functioning properly. This may be an indication of issues with the auxiliary contacts on the breaker.

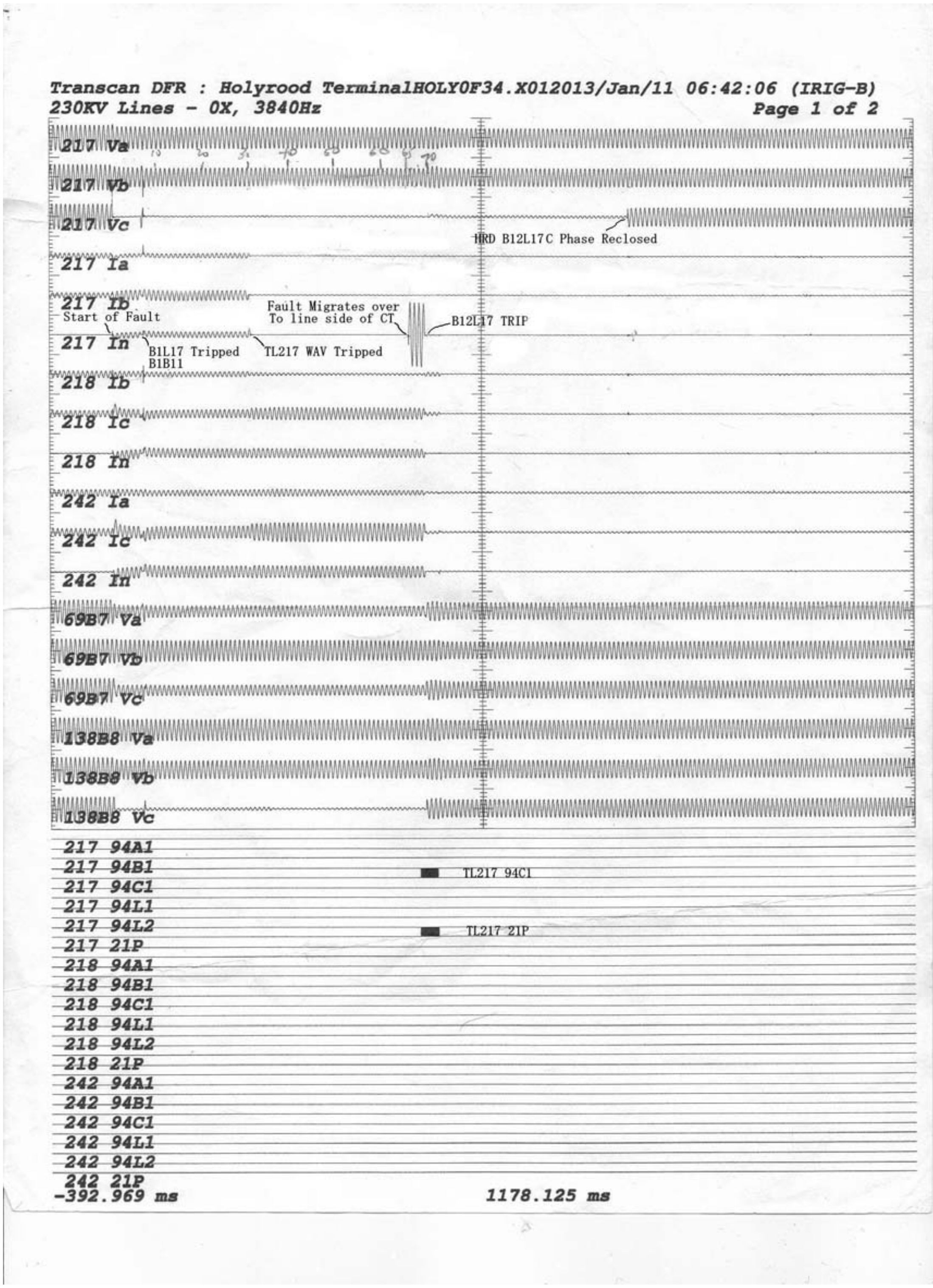

Figure 2-2: Holyrood DFR Trace at 0642 Hours during B1L17 Fault

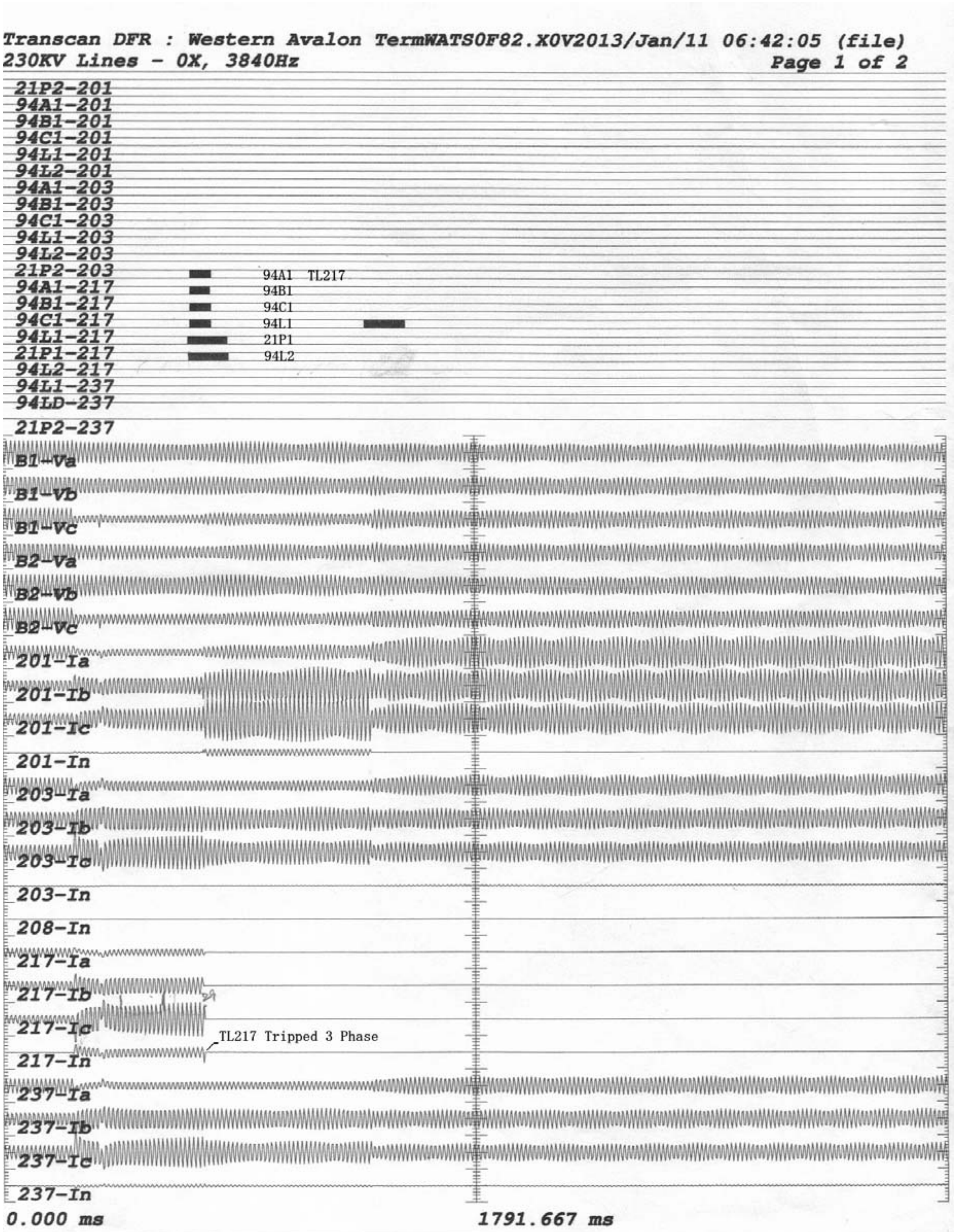

Figure 2-3: Western Avalon DFR Trace at 0642 Hours during B1L17 Fault

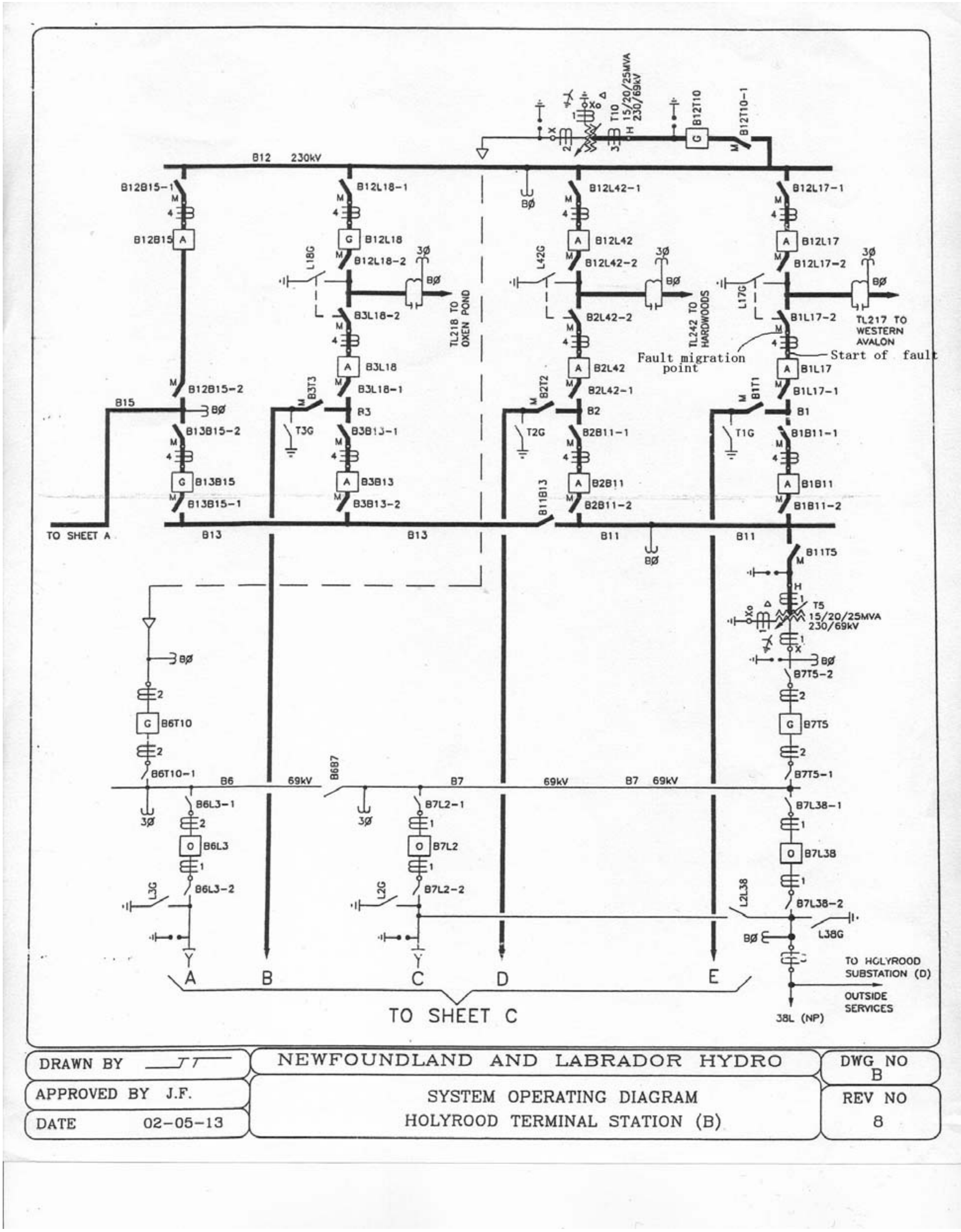

Figure 2-4: Holyrood Single Line Diagram

Figure 2-5a: Holyrood Breaker - B1L17 C Phase

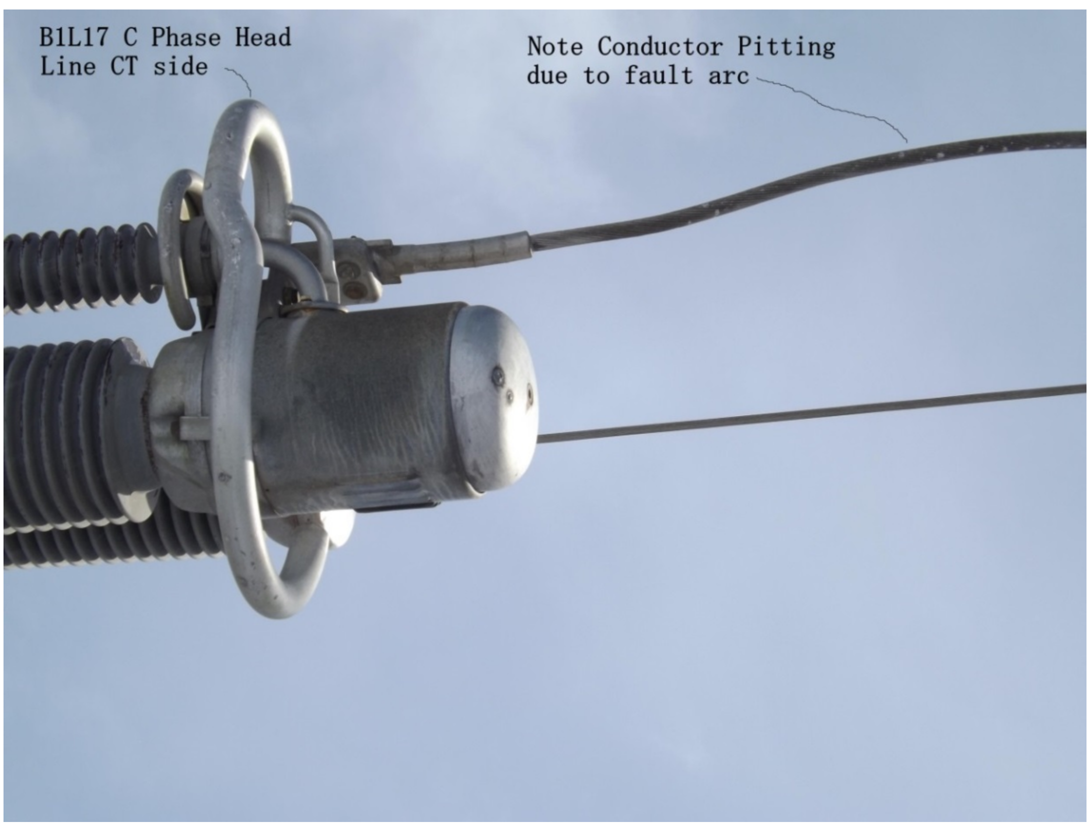

Figure 2-5b: Holyrood Breaker - C Phase Conductor

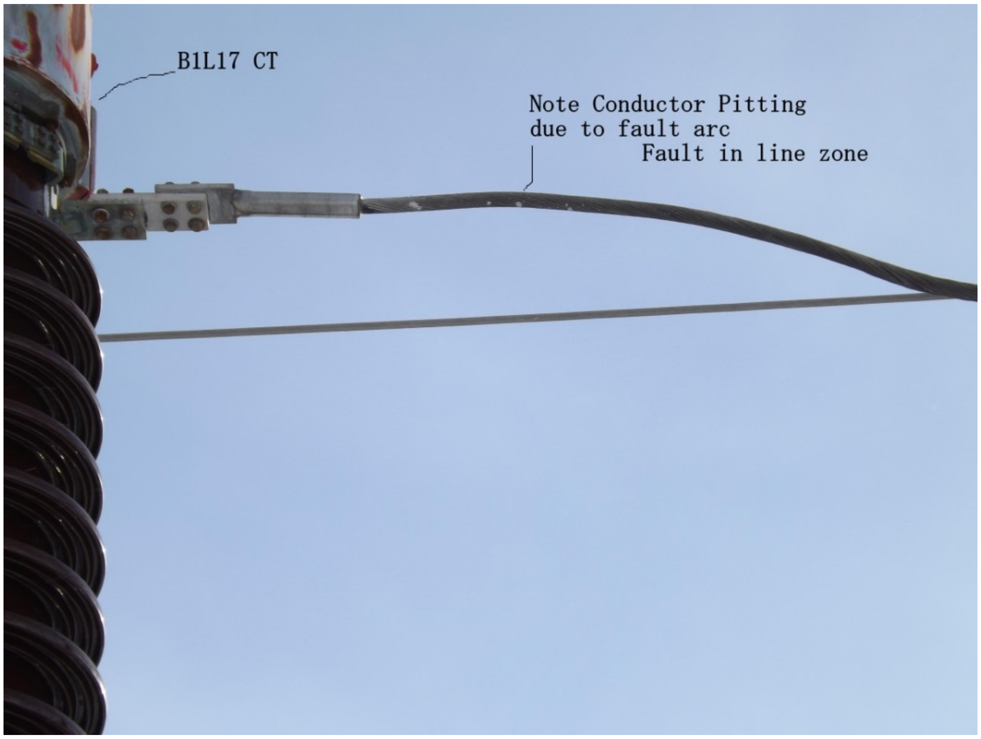

Figure 2-5c: Conductor Between Breaker B1L17 to B1L17 CT

Figure 2-5d: B1L17 Vertical Column Arcing Damage

2.2.1 Additional Observations

- The fault at 0642 hours in the Holyrood terminal station resulted in the tripping of both Units 1 and 2. Given the fault location on B1L17, one of Unit 1's breakers, the tripping of this unit was expected and required. However, it was the slow clearing of the fault (69 cycles) that resulted in the trip of Unit 2. The absence of the unit lockouts operating into the breaker fail scheme is a serious design flaw. If this was in place, Unit 2 may have tripped with a breaker failure clearing time of approximately 21 cycles. This time is also long and exists because of the station design which uses CTs on only one side of 230 KV breakers for economic reasons, thereby relying on the breaker failure protection scheme to clear for faults on the breaker and the short section between the CT and breaker. This clearing time can be shortened to approximately six cycles with the addition of a second set of CTs on the other side of the breaker, for each breaker. It should be noted that the lockout relay for Unit 3 does operate into the breaker failure scheme.

- The Holyrood Terminal Station has a history of equipment contamination for storms such as the one that occurred on this day, in particular the 230 KV breakers such as B1L17, a Brown Boveri (now ABB) DLF nc2 245 KV class, manufactured in 1973. The insulation creepage on this unit is questionable for an environment such as that which Holyrood presents. The insulation creepage measured on the breaker stack which flashed over is approximately 4,470 mm or 19.4 mm per KV (2 vertical units per stack). This is a level recommended in some guidelines for ceramic insulation for application in medium contaminated areas. For areas with a high exposure to salt contamination, guidelines[1] recommend an insulation creepage of 25 mm per KV for highly contaminated areas or greater than 31 mm per KV for very highly contaminated areas. In the past this issue was mitigated in the Holyrood yard with the application of a Room Temperature Vulcanizing (RTV) coating on the insulation equipment which is intended to improve its ability to avoid flashover during periods of high salt contamination. According to the manufacturer, the RTV coating needs to be regularly maintained and reapplied to maximize the benefits. Whether this coating would have actually prevented the flashovers that occurred on this day is not known for certain.

- The fault was detected by the remote ground distance protection Zone 2 elements on transmission lines TL218 at Oxen Pond, TL242 at Hardwoods and TL217 at Western Avalon. Although the Oxen Pond and Hardwoods Schweitzer records were overwritten

[1] Reference guideline IEC 815 "Guide for the selection of Insulators in Respect of Polluted Conditions"

by the time the records were manually retrieved in the stations, there were a number of transfer trips sent and received on these lines during the fault, indicating that the TL218 and TL242 distance protections were marginally detecting the fault. This fault was in the zone of protection of these relays which is set at 120% the line impedance. The Zone 2 ground distance protection timers for TL218 and TL242 are set at 60 cycles instead of the more conventional 18 cycles. TL217 ground distance protection at Western Avalon tripped but the Schweitzer record for that line indicated that the zone element initially picked up and dropped out (indicating marginal detection) before picking up again and timing out to trip. The timer for TL217 Zone 2 protection is set at 18 cycles.

- At 68 cycles, when the fault migrated into the TL217 line protection zone, the P1 (Optimho relay) Zone 1 operated to clear the fault but the P2 (Schweitzer relay) did not operate for the fault. This is because the latter was blocked by the loss of potential (LOP) feature on the relay which prevents the protection from operating because it sensed zero volts prior to detecting the fault current. When it detected the fault current the voltage was still at zero which prevented the relay from operating. This feature is by design for this relay. However, the Optimho relay operated because its LOP feature unblocks once the current magnitude goes above its high set point. This highlights the value of having two different types of protections from two different manufacturers applied on the lines.

- During the time the fault was present on the 230 KV system, there was a considerable voltage depression in the Eastern area which persisted for some minutes, causing load loss and mitigation of the attained underfrequency level. The minimum frequency recorded was 58.9 HZ, which is above the first instantaneous underfrequency load shedding level of 58.8 HZ. Once the fault was cleared, voltages at the 66 KV load busses such as Hardwoods and Oxen Pond continued to be low at approximately 75 to 80 percent of nominal levels for approximately 6 minutes. This was due to loss of the Holyrood unit voltage/load support.

- The voltage depression impacted not only customers but the Holyrood unit station auxiliaries as the 69 KV supplying the plant's station service transformers (SST12 and SST34) was recorded to be only 43 percent of nominal on the Holyrood DFR during the fault. Post fault voltages initially recovered to approximately 67 percent and then recovered to almost 80 percent in six minutes or so, just prior to the next fault incident at 0648 hours.

- There were issues with the indications for breaker B12L17 which showed opening and closing statuses incorrectly during its operation. This is most likely an indication of a problem with the breaker's auxiliary contacts.

2.2.2 Actions Taken

- The Holyrood terminal station equipment was inspected. The only damage and signs of fault were that on breaker B1L17 and the marks on the conductors connecting both sides of B1L17 CT.

- The damage to Holyrood B1L17 C phase breaker was repaired. The breaker was taken out of service and repaired by replacement of the damaged stack using insulator columns with higher creepages of 23 mm per KV. Spares were available to facilitate this.

- The stacks of Unit 1 breakers, B1B11 and B1L17, were disassembled and recoated with RTV under indoor conditions with the assistance of a manufacturer's representative. Other unit breakers are to be coated at a future date.

2.2.3 Further Actions Required

- The lockouts from Unit 1 and 2 which trip the unit breakers, should be added into the Holyrood breaker fail scheme design of the terminal station for the required breakers. A review of all breaker fail designs schemes on the system should be conducted to ensure that all schemes are adequate, in that they have the correct initiating inputs such as the lockouts, and trip the required breakers in the event of a breaker failure.

- Function testing of the 94TS/T1 Unit 1 transformer backup protection contacts in the breaker failure (B1/TF) and breaker failure lockout (86/BF - B1L17) circuits should be performed to ensure the timer is set and operating correctly to trip the breaker failure lockout.

- The Zone 2 protection reaches on TL218, TL242 and TL217 need to be increased to ensure that they operate for faults at the remote terminal end. The second zone timers for TL218 and TL242 should also be decreased from 60 cycles to 18 cycles.

- Previous reviews by Henville Consulting[2] have recommended Zone 1 and Zone 2 protection setting changes for the Eastern lines in addition to setting changes for other line relaying. These should be revisited and implemented as soon as possible.

- Customers were subjected to significant undervoltage conditions, outside normal limits for several minutes, with the trip of both Holyrood units simultaneously. The procedures pertaining to ECC operator action required during abnormal voltage conditions should be reviewed to ensure they are adequate in maintaining customer supply voltages within acceptable limits.

- Further investigation into why the Come by Chance 230 KV Capacitor bank, C4, tripped during the fault is required.

- The maintenance program pertaining to the application of the RTV coating on the Holyrood station equipment should be reviewed. The review should also address the extent of the equipment involved, as the current coverage appears to be associated with the unit breakers only.

- Many of the breakers in the Holyrood station are proposed to be replaced in the near future as part of the Muskrat Falls DC infeed upgrade requirements. New breakers and associated equipment shall be specified with insulation creepage distances suitable for use in highly contaminated environments. For breakers with ceramic type insulation, creepages of 31 mm per KV or greater are recommended.

- With the acquisition of the new breakers, CTs should be specified on both sides of the breakers to provide for overlapping protection zones. Faults such as the one that occurred on B1L17 will then be cleared high speed, without reliance on the time delayed breaker failure protection.

- In conjunction with the recommendation to install CT's on both sides of the Holyrood terminal station 230 KV breakers, a new protection design philosophy should be developed with overlapping protection zones to cover all new installations.

- The indications associated with the Holyrood Unit 1 disconnect should be checked during opening, as there appears to be no “in transit” position but rather two “opens”. The auxiliary cam switches which provide for the indication need to be checked.

[2] "Circuits TL201, TL217, TL218, TL236, and TL242 East Coast Transmission line Protection Performance and Settings Review" by Charles Henville, December 2011.

- Testing should be carried out on line 39L protection, in particular the 51N relay as it appears that the disk is not fully resetting.

- The analysis of these events has highlighted the value of having two different types of protections from two different manufacturers applied on the transmission lines. This philosophy should be considered for all new or upgraded protection applications.

2.3 Event No. 3 at 0648 hours - Fault on TL217 at HRD, 138 KV Bus B8 Fault, TL217 Reclose/Restrike at HRD, B12L17 HRD Breaker failure, 230 KV Bus B12 Fault with Load Loss of 240 MW

Prior to this event all three units at Holyrood were offline and TL217 was connected to the Holyrood bus B12 via breaker B12L17, with the Western Avalon end open on all three phases. TL201, from Western Avalon to Hardwoods, was supplying most of the Avalon Load with TL218, TL236 and TL242 in service. Line 39L was open. With reference to the Holyrood DFR trace, Figure 2-6, a C phase fault occurred on TL217 as also indicated in the SOE table in Appendix A-2. Breaker B12L17 tripped C phase and cleared the C phase fault via both line ground distance protections, P1 and P2, in six cycles and initiated single pole reclosing. During the TL217 reclose interval, at 13 cycles, an A phase fault occurred on the Holyrood 138 KV equipment in the B8 bus zone which was cleared by bus differential 87B8B9 and bus lockout 86B8B9B15. The bus tripped and locked out three phase in six cycles.

At 48 cycles, TL217 (via breaker B12L17) reclosed C phase and TL217 faulted again, this time line to line (B-C phases). TL217 line phase and ground protection operated at 49 cycles at Holyrood, both P1 and P2 protections, and tripped breaker B12L17 three phase. Indications are that B phase cleared temporarily (the current went to zero) followed by A and C phases. Approximately 2 cycles later B phase re-faulted with a B phase current of approximately 1,300 A. At about the same time, Hardwoods TL242 and Oxen Pond TL218 phase distance protections, P2 (Schweitzer) Zone 1's, momentarily operated (over reached) during the B-C ground fault. This tripped TL242 at the Hardwoods and TL218 at the Oxen Pond ends only.

At that point transmission lines TL218 and TL242 were open on the remote ends and there were no 138 or 230 KV connections to the Holyrood terminal station. The Holyrood 230 KV bus B12 and the faulted line TL217 - B phase were being supplied from the 66 KV supply via 38L (NP 66 KV line) and transformer T10 (230 KV delta winding). Indications are that B phase was still faulted but now on an ungrounded 230 KV delta connected bus B12. Breaker B12L17 B phase current was very low for approximately 1 cycle before C phase flashed over somewhere on the

230 KV in the vicinity of B12 causing a B-C ground fault. Figure 2-7 shows a current of approximately 230 A in the B12L17 CT supplied from the 66 KV into the B-C-ground fault. This figure also shows the TL242 CVT's voltages, connected to B12 via line breaker B12L42, collapsing when B and C phases faulted. This was followed by A phase flashing over approximately 2 cycles later. Figure 2-8 is a blow-up, showing voltages at the TL242 CVTs and the TL217 B phase current. All three phases were faulted.

At 88 cycles TL217 protection, P1 (Optimho), operated via the SOTF (switch on to fault) function which initiated B12L17 breaker failure protection. The latter timed out and tripped all connected breakers on the 230 KV bus B12 including breaker B12T10 which cleared the fault from the 66 KV system at 109 cycles. The 66 KV connection between Hardwoods and Holyrood remained in service until 23 seconds later when it tripped at the Seal Cove end via breaker SCV-38L-B due to overvoltage, this according to the NP SOE data.

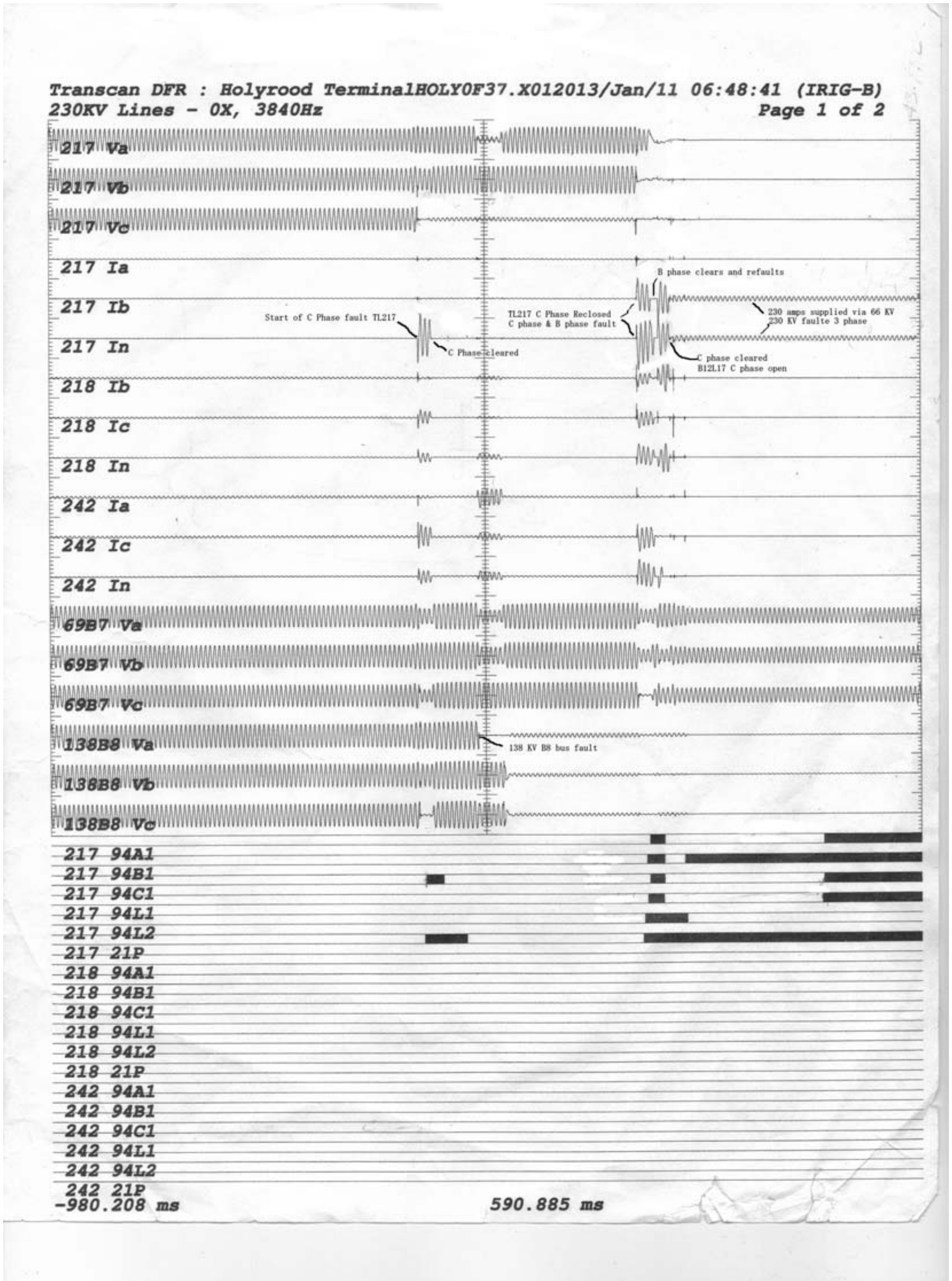

Figure 2-6: Holyrood DFR Trace at 0648 Hours Showing TL217 & Reclose

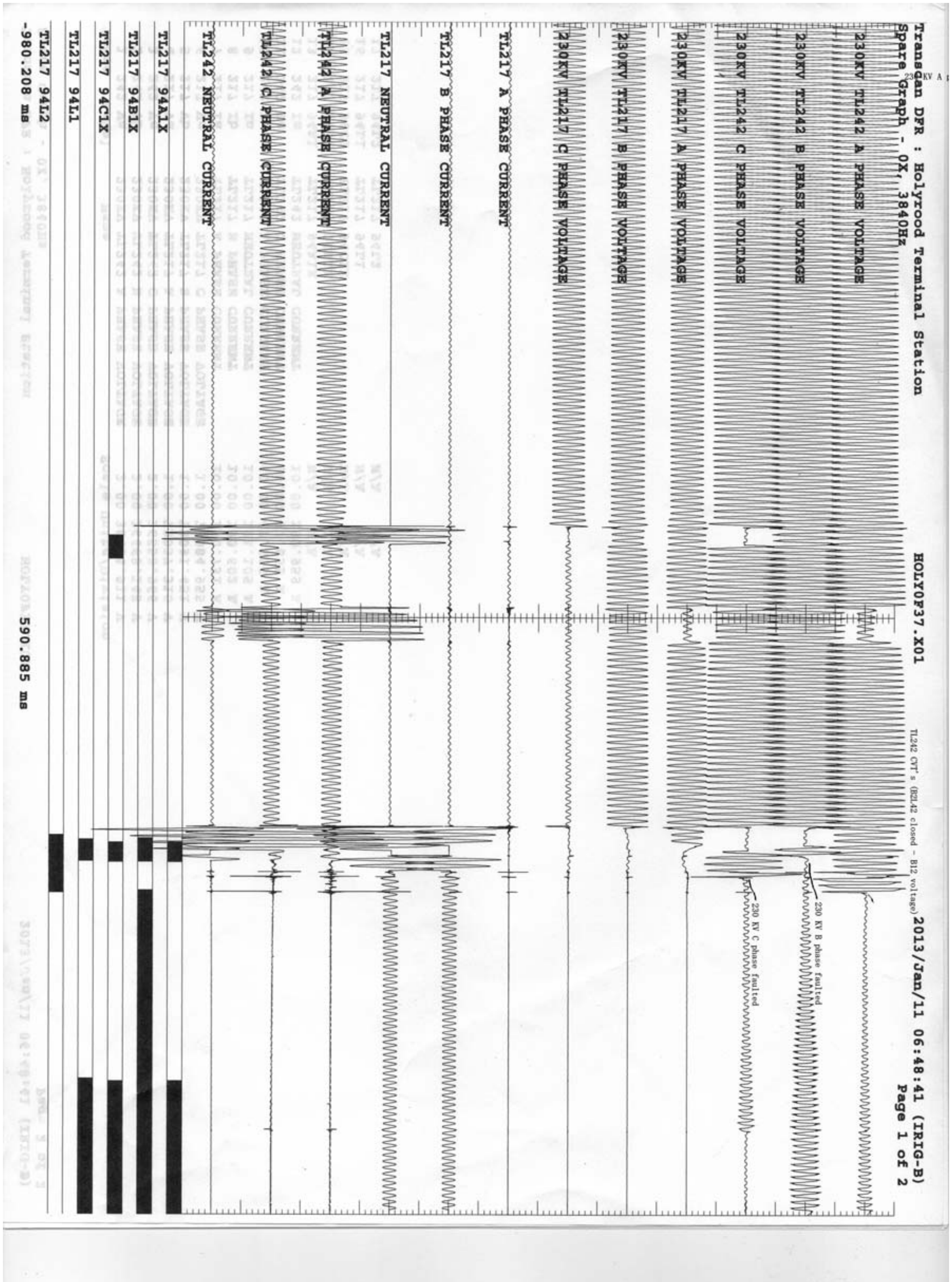

Figure 2-7: Holyrood DFR Trace at 0648 Hours Faults Showing TL242 CVT Voltages

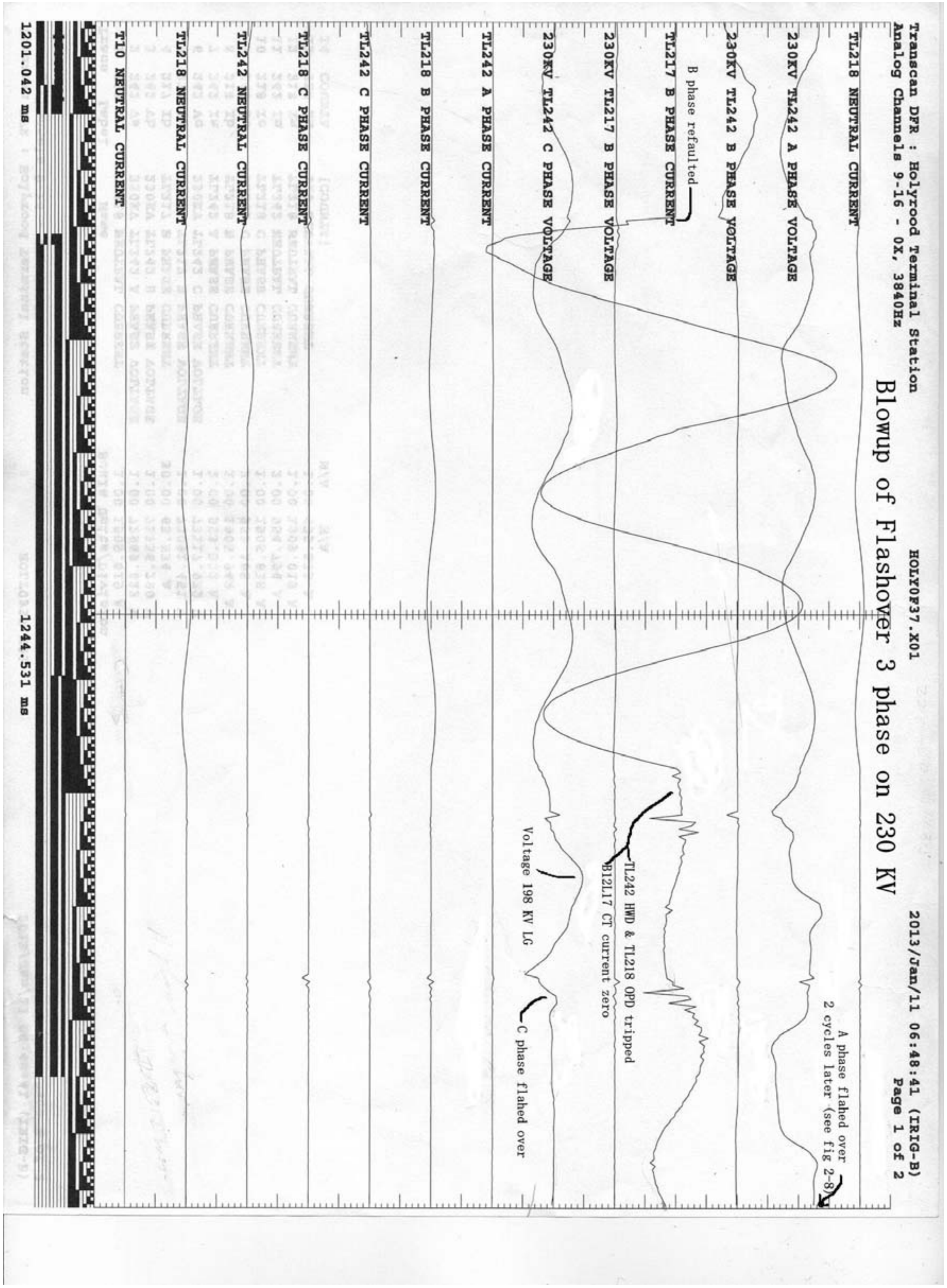

Figure 2-8: Holyrood DFR Traces Blow-Up Showing 230 KV Flashover

2.3.1 Additional Observations

- The initial fault started in the TL217 protection - Zone 1 on C phase but was not on B1L17 breaker which faulted earlier at 0642 hours, as this time the fault current was recorded in the TL217 protections (P1 and P2) at a magnitude of approximately 2,000 A. If the fault was on B1L17 the current would have been recorded as zero (similar for the fault at 0642 hours on B1L17) due to the summation in the two CTs, one on B12L17 and the other on B1L17. The fault was close to or in the station as evident by the fault location indications on both TL217 line protections - recording a distance of 0.4 to 0.5 km. A line patrol of TL217 in January did reveal insulator damage on Structure 282 on A and C phases (the two outside phases) with four insulators on one phase and five insulators on the other broken, see photos in Figure 2-9 (a and b). They are believed to have been shot-off. The structure is about 4.6 km from the Holyrood station. The subsequent B-C fault, which occurred when TL217 reclosed, was recorded by the P1 (Optimho) protection at a distance of 6.3 km. No location was given by the P2 (Schweitzer) protection, however the broken insulators, even though the B phase insulators at Structure 282 were not damaged, could have been involved in this second fault .

  Inspection of the station equipment did not reveal any damage or areas where the flashovers might have occurred, but given that the Zone 1 protections over reached on both TL218 at OPD and TL242 at HWD for the second fault and that the other faults in the station were due to the heavy salt contamination, the faults were most likely to have occurred in the station.

- Once TL218 and TL242 tripped and the faults were supplied only from the 66 KV system (a weak infeed) and a 230 KV delta system, neither of the line protections operated. This was most likely due to the low fault current, approximately 230 A on the primary. The Schweitzer's LOP (loss of potential) function would have operated as the current was below 540 A (the current monitor 50M setting, below which the LOP operates with loss of the potential supply) and prevented any Schweitzer distance element trip. Similarly, the Optimho would have also identified a LOP but as the 230 KV voltage eventually increased (Figure 2-7), probably due to the changing nature as the arc blew outward, the voltage sensors most likely reset and saw the line as being reenergized and permitted the SOTF function to operate and initiate the breaker failure protection on B12L17.

- Breaker B12L17 appears to have failed to trip B phase for the second fault (B-C-ground) which occurred upon reclosing. There is the possibility however, that B phase of the breaker did open and the fault was on B12L17 breaker head on the bus B12 side. In that case the fault would have been in the line protection zone but would not have been cleared with the tripping of B12 phase B and the current would appear in the TL217 line B phase channel of the DFR. The C phase fault could have been on the line side of breaker or out on the line as it cleared with the tripping of breaker B12L17 C phase. Inspections of B12L17 breaker and immediate areas in January did not reveal any signs of damage or flashover. At that time it was assumed that B12L17 failed to trip B phase due to issues with an auxiliary contact in the breaker trip coil circuit. The emphasis of the inspection in the station was primarily on the unit breaker B1L17 due to the Holyrood Unit 1 damage concerns. There were also significant issues with the indication of B12L17 status in the SOE and EMS, with the breaker showing open and closed at various times. These issues are thought to be associated with the breaker's auxiliary contacts. Further inspection and testing of breaker B12L17 are recommended to ensure that the breaker is functioning properly and to look closely for signs of external damage or flashover.

- TL218 and TL242 Zone 1 phase protections at Oxen Pond and Hardwoods overreached to see the second fault momentarily. For this particular situation it resulted in the Holyrood 230 KV Bus B12 becoming back energized and ungrounded. In the future, under different circumstances, overreaching of these protections could result in the loss of all lines into Holyrood for a similar fault close in on TL217. The Zone 1 (both P1 and P2) on TL218 at OPD is currently set at 88% of is line length and TL242 is set at 82% of its line length. These settings need to be reduced to ensure that the protections do not overreach. Previous protection reviews recommended reduction of the reach to 80% (still to be done). However even a lower reach should be considered such as 75%, particularly for TL242 the shorter of the two lines.

- The situation with the 230 KV Holyrood bus B12 operating ungrounded and back energized from the 66 KV was not anticipated nor considered in the protection design. Any line to ground faults on the bus under this scenario results in full line to line volts on the unfaulted phases of equipment and would most likely result in flashover on the unfaulted phases, as happened in this case. The low fault levels resulted from energization via a 66 kV supply only. The existing B12 230 KV bus diff - 87B12, an overcurrent differential scheme, is set above this infeed fault level to accommodate CT mismatch during normal system external faults and would not operate for this situation. Consideration should be given to lowering this 87B12 setting or upgrading the differential scheme to a different scheme (high impedance bus differential) with increased sensitivity to account for this ungrounded scenario if it should occur in the future.

The overvoltage on the 230 KV (due to back-energization of the delta) did not impact the customers connected on the 66 KV system. This scenario presents a very unique situation. Overvoltage protection on the 230 KV could be applied to trip the 66 KV infeed if such an event occurs and a fault develops line to ground. Additional CVTs would be required on the 230 KV bus B12 in addition to the associated relaying. An alternative is to prevent the situation from occurring by possibly using the EMS status of the lines and infeeds into B12 to develop a switching logic to trip the 66 KV infeed for the situation where all grounded sources are disconnected from B12.

- Following the trips of the Holyrood 230 KV bus and lines, there was an initial load loss of approximately 60 MW and a voltage increase on the St. John's 66 KV buses to approximately 72 KV from 60 KV. There was an additional load loss of approximately 160 MW some 13 seconds later which led to a severe overvoltage on the 66 KV system of approximately 78 - 80 KV (from the numbers recorded on the EMS PI data which most likely did not capture the highest voltages). From the NP SOE data there appears to have been some 66 KV line switching ongoing at this time in the St. John's area, probably in an attempt to alleviate the undervoltage condition still prevalent from the previous trip. In addition, from the NP SOE data, 32L (Ridge Road to Oxen Pond) tripped on protection just previous to the 160 MW load loss followed by the very high voltages. The high voltage condition was mitigated by the immediate tripping of three of the four Come By Chance capacitor banks (one had tripped earlier). This was followed by the tripping of two Hardwoods capacitor banks (four seconds) and one Oxen Pond (six seconds) after the Come By Chance banks. Based on the overvoltage settings and the inverse time curve on the Hardwoods and Oxen Pond capacitor banks, which have a pickup of 110% (72 KV) of the nominal 66 KV, the voltage was still quite high during the seconds prior to trip of the banks (assuming the banks did trip on the overvoltage protection). Consideration should be given to application of an overvoltage definite time delay setting on these banks with a 5 cycle or so time delay, staggered on each bank (i.e. the first bank would trip in 5 cycles, the second bank would have a 10 cycle trip time, third bank in 15 cycles, etc.) to allow for step tripping of the banks but still provide for tripping in less than one second for severe overvoltages.

Figure 2-9a: Picture of TL217 Structure 282 with Damaged Insulators

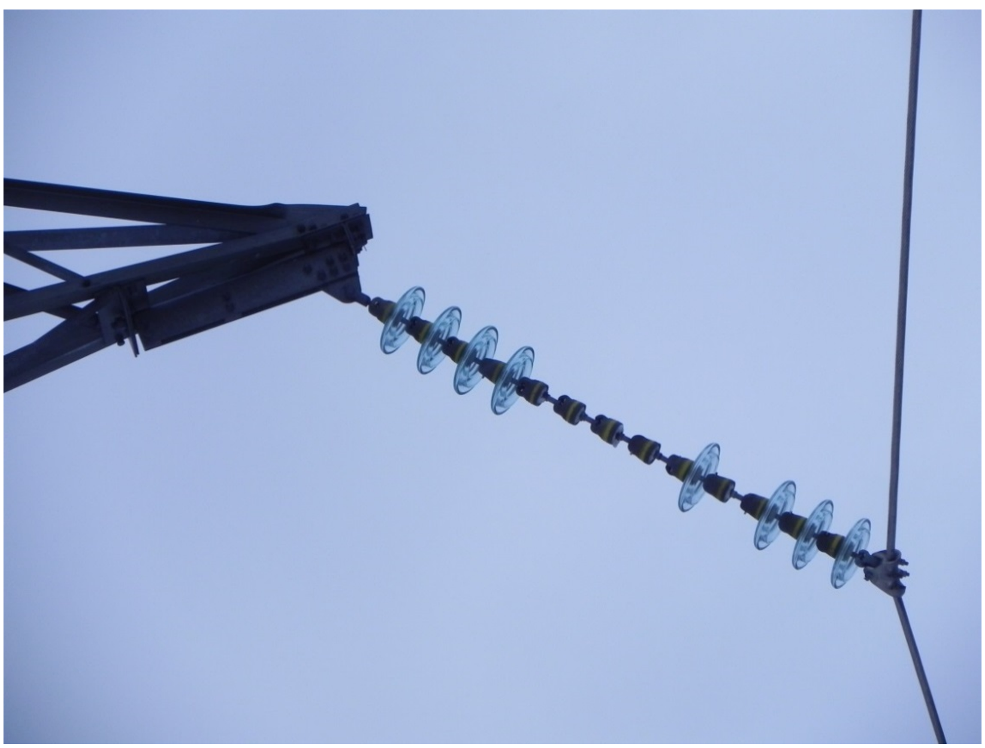

Figure 2-9b: Picture of TL217 Structure 282 Showing Damaged Insulators (one of two strings)

2.3.2 Actions Taken

- The Holyrood station equipment, including the breaker B12L17 and the area in its vicinity was inspected for evidence of an external fault, particularly B phase. There was no indication of this external fault.

- Following the breaker failure operation, breaker B12L17 at Holyrood was operated several times to verify three pole operation without pole disagreement and to ensure that C phase tripped as required. The breaker operated properly and there was no indication of disagreement. The cause of the breaker failure was not determined but it is speculated that the most likely cause was an issue with the breaker's auxiliary contact which is in series with the trip coil. When operated once this contact gets 'wiped' thereby decreasing any contact resistance and re-enabling operation of the trip coil and breaker tripping. Breaker B12L17 was put back in-service in order to put transmission line TL217 back in-service and to keep B1L17 breaker out of service.

- The damaged insulators strings on both phases of TL217 Structure 282 were replaced.

- All the trip contacts associated with TL217 protections (P1 and P2) were checked to ensure that they were not damaged as the trip coil on B12L17 was suspected to have failed to open due to a suspected problem with the breaker 52a auxiliary contact in series with the trip coil. The concern was that the relay trip contacts opened and interrupted the breaker trip coil and may have been damaged during the breaker fail event. The contacts were all found to be in good condition.

2.3.3 Further Actions Required

- A more thorough inspection of the equipment associated with the 138 KV bus - B8 (A phase) at the Holyrood terminal station should be performed to determine the location of the bus fault that resulted in the bus lockout.

- A thorough inspection of the external area of B12L17 should be conducted to look for evidence of an external fault on B and C phases in the TL217 line protection zone. Particular emphasis should be on B phase, the phase of B12L17 which failed to clear.

- Further testing and inspection of breaker B12L17 is required to determine why the breaker failed to clear the fault on B phase. In addition, the problem with the erratic status indication of B12L17 should be investigated, beginning with examination and testing of the auxiliary contacts used for the indication. If no evidence of an external fault is found on B phase in the area of the breaker and it's CT, an internal inspection of the B phase contacts and operating mechanism should be performed, as it suggests that B phase faulted, tripped and re-struck internally before being cleared via the breaker failure operation of B12T10.

- The Zone 1 distance protection settings on TL218 and TL242 (presently set at 88% and 82% of line lengths, respectively) should be decreased to a suitable level. A maximum 75% setting is recommended to ensure the protection does not overreach as occurred during these events. Previous studies have recommended a maximum setting of 80%.

- Further investigation and discussion is required regarding the overvoltage condition which occurred, in particular as to why the additional 160 MW load on the NP system was shed following the trip of Holyrood terminal station.

- Consideration should be given to the application of definite time overvoltage protection on the Hardwoods and Oxen Pond capacitor banks, with a trip time of approximately 5 cycles for the first bank and an added 5 cycles or so for each other bank (i.e., second bank at 10 cycles, third at 15 cycles, fourth at 20 cycles). This will permit for staggered tripping but still allow for the tripping of all banks in less than one second for severe overvoltages.

2.4 Event No. 4 at 0742 hours - TL201 Trip, Avalon Peninsula Outage and Loss of 286 MW, System Overfrequency, Islanding, and West Coast Outage With Load Loss of Approximately 700 MW

Prior to this event, all three units at Holyrood were offline, the 230 and 138 KV busses at Holyrood were de-energized with busses B12, B15 and B8 locked out and the Avalon Peninsula load, east of the Western Avalon (WAV) terminal station, was being supplied by TL201 with some local Newfoundland Power generation suspected to be still in service. As illustrated in the fault trace, Figure 2-10, a line to ground (C phase) fault developed on TL201 at 0742 hours. The line tripped C phase in four cycles at the Western Avalon end on P1 (Optimho protection only), followed by C phase at Hardwoods in seven cycles on both P1 & P2 protections and finally A and B phases at Hardwoods in 8 cycles on P1 protection only, eventually resulting in a 3 phase trip of the line. The trip of TL201 resulted in outages to the major load centers east of Western Avalon. At 41 cycles TL201 successfully reclosed at the Western Avalon end but faulted C phase and tripped again approximately 2 seconds later, see Figure 2-11. The line fault was later revealed to be related to a jumper issue at Structure 210 located 49.9 km from WAV.

As can be seen in the table of events in Appendix A-3, immediately following the loss of TL201 the capacitor banks at Come-by-Chance tripped due to the high voltages. This effectively resulted in 286 MW of load and 137 MVAR of reactive support being removed from an already weakened system. This load loss caused a significant frequency increase over the next four seconds to a value of approximately 65 Hz. What followed was a period of significant system upset resulting in the tripping of transmission lines, major generation loss and separation of the interconnected system into islanded areas.

At 4.03 seconds, TL247 (DLK to CAT) tripped at Cat Arm due to an operation of the Zone 1 distance P2 protection, resulting in the loss of Cat Arm units and the removal of 120 MW of generation from the system. This was followed at 4.2 seconds with the trip of TL204 (BDE to STB) and three cycles later by TL231 (BDE to STB), both at the Bay D'Espoir ends only on Zone 1 P2 distance protection. These P2 protection operations were owing to the misoperation of the Schweitzer 321 Zone 1 distance elements due to the high system frequency and its high rate of change. At 4.7 seconds (approximately 0.5 seconds later than the trip of TL231), lines 100L and 109L tripped at Sunnyside on Zone 1 distance protection due to misoperation of the ERLPHASE LPRO2100 relays caused by the frequency conditions. This separated the system into two islanded areas. One in the Eastern area from Bay D'Espoir to Western Avalon, supplied by Upper Salmon, Granite Canal and Bay D'Espoir generation. The other in the Western area from Stony Brook westward (but including the 138 KV loads from Stony Brook to the Clarenville area) supplied by Hinds Lake, Deer Lake Power and Exploits generation. The Eastern area system frequency continued to increase while the Western area system frequency began to decrease.

Approximately 0.5 seconds after the system split in islanded areas, at 5.2 seconds, TL263 (USL to GCL) tripped at Upper Salmon, removing the Granite Canal unit and 35 MW of generation from the Eastern connected system. This was followed by the tripping of TL206 (BDE to SSD) at Bay d'Espoir and TL234 (BDE to USL) at Upper Salmon with the latter resulting in the trip of the Upper Salmon unit at 80 MW from the Eastern connected system. All three lines tripped due to misoperation of the line's Schweitzer 321 protection caused by the frequency conditions.

On the Western connected system, at 5.1 seconds, TL222 (STB to SPL) tripped at Springdale followed by a trip at the Stony Brook end at 5.2 seconds. Both ends tripped due to misoperation of the LPRO2100 relays at each end caused by the frequency conditions. This opened the 138 KV loop which was connecting Stony Brook and Deer Lake. The Stony Brook terminal station was then energized only from the 230 KV system, which was still being supplied from the generation at Hinds Lake, Deer Lake Power and the Exploits. In 5.1 seconds the customers from Wiltondale to Parsons Pond were interrupted following a trip of the 66 KV line TL226 at Deer Lake. At approximately 5.8 seconds, TL239 (DLK to BHL) and TL210 (STB to Cobb's Pond) tripped at Deer Lake and Stony Brook respectively, also due to misoperation of the LPRO2100 protection on the lines due to the underfrequency condition on the Western connected system. At the time the frequency was believed to be in the 55 Hz range. The trip of TL239 interrupted all remaining customers on the GNP north of Parsons Pond. This line reclosed 12 seconds later restoring customers as far as the Bear Cove terminal station.

At 5.9 seconds Massey Drive transformer T1 breaker, B4T1, tripped via underfrequency and reverse power protection, followed by the tripping of TL225 (DLK to DLP) at Deer Lake due to misoperation of its LPRO2100 relay at 6.3 seconds. The trips of B4T1 and TL225 isolated Deer Lake Power from the 230 KV Western area. Then at 6.4 seconds, TL248 (DLK to MDR) tripped at Deer Lake due to misoperation of its Schweitzer 321 relay which separated the Hinds Lake generation from the Western 230 KV system resulting in outages to Massey Drive, Buchans, Bottom Brook and Stephenville and the loads supplied from those stations. It is suspected that the Exploits generation tripped at this time as well. The Hinds Lake plant continued to operate, supplying customers in the Howley-White Bay and Indian River to Springdale areas.

Approximately 1.4 seconds after the outage to the Western 230 KV system, at 9.9 seconds, 100L reclosed at Sunnyside. This energized the 138 KV loop from Sunnyside into the Stony Brook terminal station momentarily, for approximately 10 cycles (see Figure 2-11), backenergizing the 230 KV Western area from Stony Brook to Massey Drive to approximately 50 per cent voltage and picking up any connected loads. This caused many of the 230 KV line P1 (Optimho) protections to pick up on their switch on to fault (SOTF) function and trip their respective 230 KV lines. Lines TL205 (STB-BUC), TL232 (STB–BUC), TL228 (BUC-MDR) and TL233 (BUC-BBK) tripped at both ends and TL209 (BBK-SVL) tripped at the Bottom Brook end. This was followed by the tripping of 100L Sunnyside again at 10.0 seconds via its Zone 1 protection. At this point all the West Coast system was without power except for the loads off the 138 KV system still connected to the Hinds Lake generation (Howley, White Bay area and Indian River to Springdale areas) and those supplied from the Deer Lake Power system. Following the momentary energization of the terminal station at 9.9 seconds, a communication issue occurred at Stony Brook between the Stony Brook RTU and EMS. The status of the terminal station was no longer updating due to a buffer overflow problem with the routers between the EMS and Stony Brook. Therefore the ECC operator was not aware of the tripping of lines TL205 and TL232 or other changed conditions in Stony Brook after 07:42:26 (10.0 seconds). This incorrect Stony Brook status condition existed for nearly an hour until the issue was cleared at 0837 hours.

Numerous 230 KV and 138 KV transmission lines were out of service at this point. There were widespread customer outages in almost every region. It should be noted that there were areas that remained powered, including:

- The Burin Peninsula, the Sunnyside and Come by Chance area (including the North Atlantic Refinery), the VBN terminal station, and the Avalon Peninsula loads supplied by the 138 KV and 66 KV at Western Avalon, all supplied via the Bay d'Espoir generation. (There were also some Newfoundland Power customers still supplied from NP's own hydro generating plants.)

- The Howley and White Bay area, the GNP (north of Parsons Pond to Bear Cove following the reclose of TL239) and the Baie Verte Peninsula/Springdale areas, all supplied via the Hinds Lake plant.

- The towns of Pasadena and Steady Brook, Deer Lake Power and Corner Brook Pulp and Paper all supplied by the Deer Lake Power plant.

Figure 2-10: Western Avalon DFR Trace at 0742 Hours Showing TL201 Trip and Reclose

Figure 2-11: Western Avalon DFR at 0742 Hours Showing Second Fault to TL201

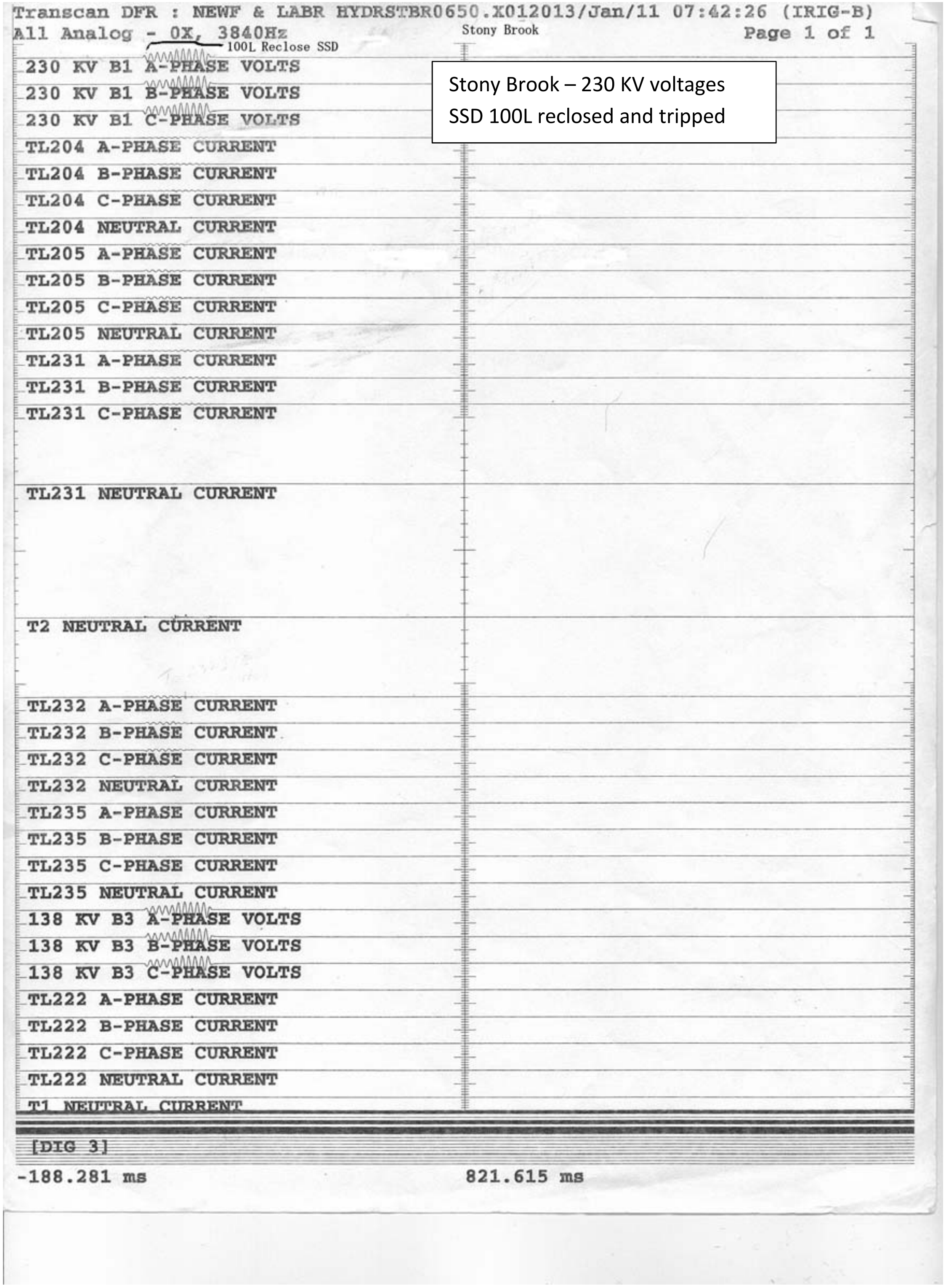

Figure 2-12: Stony Brook DFR Trace at 0742 Hours Showing SSD 100L Reclose

2.4.1 Additional Observations

- The TL201 fault and line trip resulted in the load loss of 286 MW and caused significant frequency excursions on the system which led to the misoperation of many of the digital line protections. These misoperations caused separation and islanding of the system, loss of generation and eventual collapse of part of the system over an approximate seven second interval. The loss of generation, such as the trips at Cat Arm, Upper Salmon and Granite Canal for the initial overfrequency, was not detrimental to the system and actually assisted in mitigating the overfrequency once the load loss had occurred. However, the islanding of the Western area caused by the trips of TL204 (BDE-STB) and TL231 (BDE-STB) did lead to significant upset and additional outages with the trip of the entire 230 KV Western system. Prevention of these relays from tripping on frequency excursions is important to avoid similar system upsets in the future. If these relays had not operated the most likely outcome would have been an overfrequency on the system as occurred, probably to approximately 65 Hz, as per the frequency/stability analysis in the System Planning report in Appendix B. The system would most likely have remained intact and islanding and subsequent loss of the West Coast system would not have happened. With the separation of the Western and Central areas from the Bay d'Espoir plant and the additional loss of that load from the remaining Eastern system, the frequency on the Eastern system most likely went as high as 69.6 Hz as measured on the Bay d'Espoir Unit 7 RPM transducer which registered as high as 261 rpm before declining. It should be noted that the accuracy of this RPM meter unknown.

- There were no frequency charts available which accurately displayed the frequency once it was above 62 Hz. The monitoring system used for analyzing underfrequency performance is located in Hydro Place but was out of service for this event and the others which followed because it is connected to the supply into the building which was out of service. Determination of the actual experienced frequency was taken from the digital relay reports which indicate one number (i.e. a 'snapshot') at the time of the event. Additional frequency measurements for events such as these would be useful in gaining a clearer picture of what occurred and why. In addition, knowing the quality of the supply to customers during these events would assist in determining what action to take, to avoid such anomalies in the future and to monitor performance.

- To prevent persisting overfrequency conditions on the loss of major loads, a generation shedding scheme set to trip specific generators at various frequency levels would be required. Any such scheme would have to be studied with attention paid not only to the frequency levels but also to voltage and reactive power loading to determine the best approach.

- The fault on TL201 was caused by a jumper on Structure 210 which was too long and flashed to the pole, see Figure 2-13 (a and b). This fault, from analysis of the SEL relay traces, had considerable resistance - estimated to be around the 100 ohm mark which is the resistance setting of both P1 and P2 protections. For the first C phase fault, the P2 protection failed to trip at the WAV end but operated for the second fault after the reclose. This is believed to be due to the fact that the fault resistance made operation marginal. If the resistance had been slightly higher neither distance protection would have operated and the fault would have been cleared via 51N protection after several seconds. No further action is recommended with regards to the protection of TL201 for this incident, however there should be a review of the standards applied for transmission line jumper length.

Figure 2-13a: TL201 Structure 210 Looking East

Figure 2-13b: TL201 Structure 210 Right Phase Jumper

- The tripping of TL236 at Oxen Pond occurred after the fault to TL201 had cleared. It was a nuisance trip which did not cause any additional outages, however it should not have happened. At the time the Oxen Pond and Hardwood stations were both backenergized from the Newfoundland Power system via the 66 KV, as all 230 KV supplies were tripped. The voltages and frequency were collapsing on the 230 KV and caused operation of the Zone 2 elements in each relay. From the SEL reports of the P2 protection on both ends of TL236, the Zone 2 at Hardwoods picked up first and initiated a transfer trip to Oxen Pond. After nine cycles the Zone 2 picked up at Oxen Pond momentarily (three cycles), and overlapped for one cycle with the permissive trip from Hardwoods, tripping Oxen Pond. The permissive overreach logic should have prevented this trip at Oxen Pond as the Zone 2 elements at each end were not picked up simultaneously. The Hardwoods end did not trip because the Zone 2 elements were not picked up simultaneously at each end and the permissive trip signal from Oxen Pond was received after the Hardwood Zone 2 element had dropped out.

- The reclosing of 100L and subsequent re-energization of the 230 KV system at Stony Brook and west was not desirable even though it was only for 10 cycles. In addition, the reclosing failed to reenergize the intended loads. This event caused considerable confusion when the P1 (Optimho) relays on the 230 KV lines tripped the 230 KV lines on the switch on to fault (SOTF) function. This occurred because of the weak infeed from the long 138 KV loop and the amount of load pickup. This resulted in a non-recovery of the voltage on the 230 KV bus, making it appear to the Optimhos that the lines had been switched back in on a fault. The SOTF function is activated when current is picked up in the relay (sensing that the line breaker has closed) and the voltage fails to recover to a 70% of nominal value within 20 msec. If the voltage fails to recover as in this case, the protection trips the respective breakers as the line is thought to be faulted. This can be prevented by eliminating occurrences such as experienced here where considerable load was picked up on a weak system.

- The buffer overflow problem which occurred at the Stony Brook RTU caused significant confusion as the terminal station status changes which occurred after 7:42:26 were not shown on the Energy Control Centre EMS display, in the alarms or events, nor in the SOE, all for a period of approximately an hour. This problem required that the events at Stony Brook be re-constructed prior to incorporation in the SOE tables for this hour. Testing to determine the cause of the problem was required before a permanent solution was implemented.

2.4.2 Actions Taken

- The jumper on TL201 Structure 210 was replaced with a shorter length of conductor.

- Hydro's System Planning Department conducted a preliminary stability analysis into this event (attached as Appendix C), with the main conclusion as follows:

  …the SLG event on TL201 resulted in sudden interruption of the flow over 280 MW at WAV. This sudden loss of load resulted in overvoltage and overfrequency conditions across the system. While a comprehensive analysis of the Sequence of Events is required for a detailed understanding of the disturbance, it is clear from this preliminary analysis that the system conditions would have triggered responses from protective devices across the system. Without these protective measures, the system frequency would have exceeded 65 Hz and voltages on select 230 kV buses would have exceeded 1.10 per unit.

- There are two different types of digital protections which misoperated for this frequency event. They are the Schweitzer SEL 321 relay which is the P2 protection on the 230 KV lines and the ERLPhase LPRO2100 relay which is applied on some 138 KV and 66 KV lines (see sample reports from the relays showing operation at 0742 hours, Figures 2-14 and 2-15). Both seem to have experienced similar issues, with the Zone 1 elements operating for the large frequency excursions. Both manufacturers were contacted and the relay files containing the information regarding the operation were sent to each. This was followed by analysis and discussion regarding the appropriate solution.

The manufacturer of the LPRO2100 relays (ELPhase), following some testing and analysis, suggested that a firmware upgrade be applied to the 138 and 66 KV lines protection. They subsequently provided the firmware upgrade, intended to improve the frequency tracking for the memory polarization for the mho distance element (Zones 1 and 2). When this firmware was tested by ERLPHASE using the relay records captured for this event there was no relay misoperation.

The manufacturer of the 230 KV line protection SEL 21 relays (Schweitzer) also suggested initially that a firmware upgrade might also correct the problem in conjunction with increasing the relay's current monitor setting. However, after further consideration, the recommended approach to prevent operation for frequency excursions is to supervise the distance elements with the load encroachment function. The setting for the load encroachment still has to be determined for the various relays. One recommendation is to set the load encroachment at a level above the Zone 2 setting of the relay to avoid any issues with operation of both the Zone 1 and Zone 2 protection. Another approach is to set the current monitors, 50PP1s which supervise the Zone 1 trips, to a level above the maximum load. SEL's recommendations for the setting values are still to be finalized. The SEL preliminary report outlining the reasons for the misoperations and the load encroachment approach is attached as Appendix B. The preferred solution is to use the load encroachment function. A setting of 100 ohms primary for all lines should be adequate based on the protection settings for the longest line on the system, TL206. This setting will accommodate a load of 529 MVA before blocking. The setting angles are PLAF=90, NLAF=-90, PLAR=90, and NLAR=270. This approach is preferred over the setting of the 50PP1 as it is independent of minimum fault levels.

- The buffer overflow problem was resolved and implemented in the Stony Brook station after some investigation and testing. This involved increasing the buffer length from 16 to 64 bytes in the serial NM cards in the Cisco routers, both at site and at Hydro Place. This has been completed for other sites which may have also been affected by the same condition.

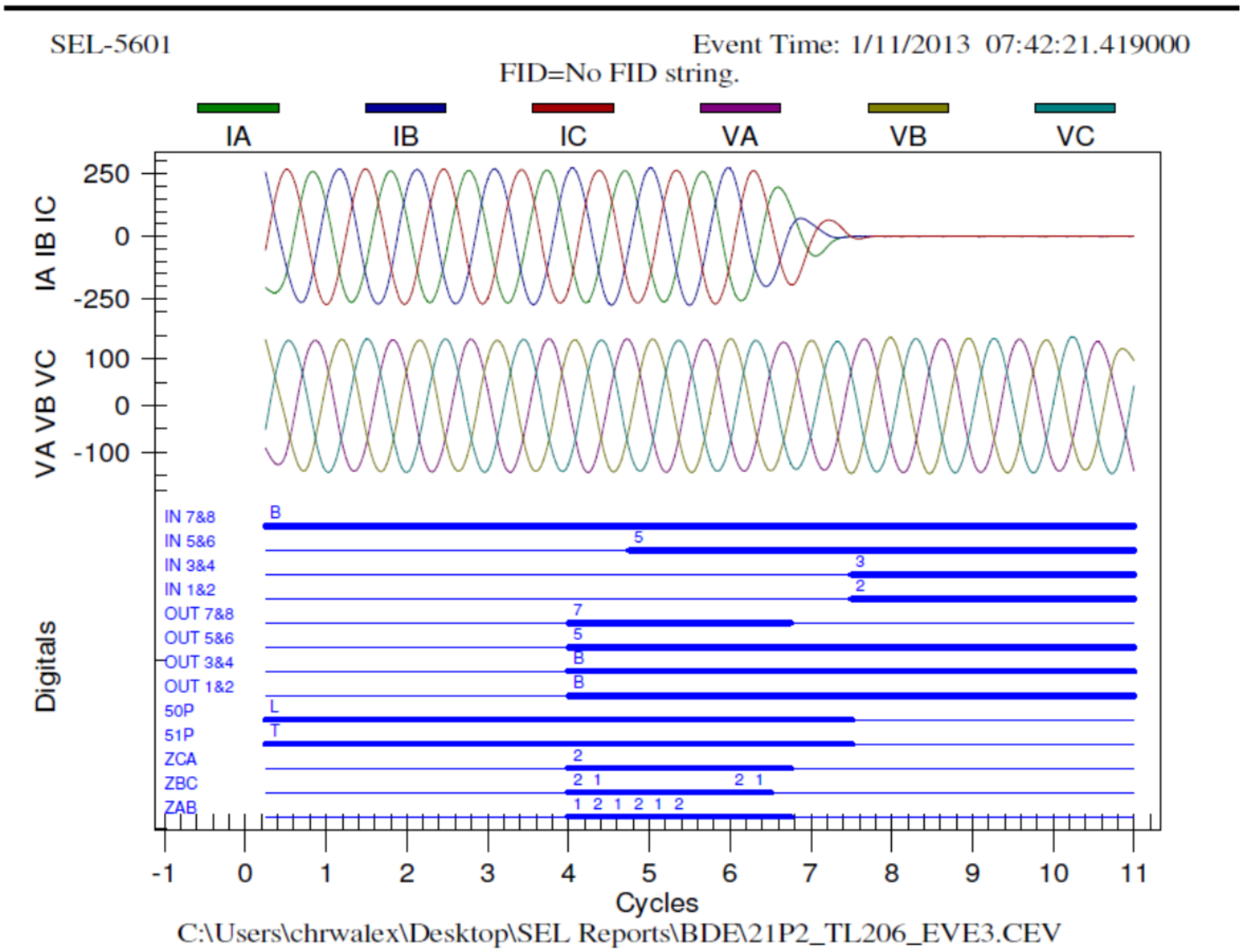

Figure 2-14: TL206 BDE SEL 321 Report for the Trip at 0742 Hours

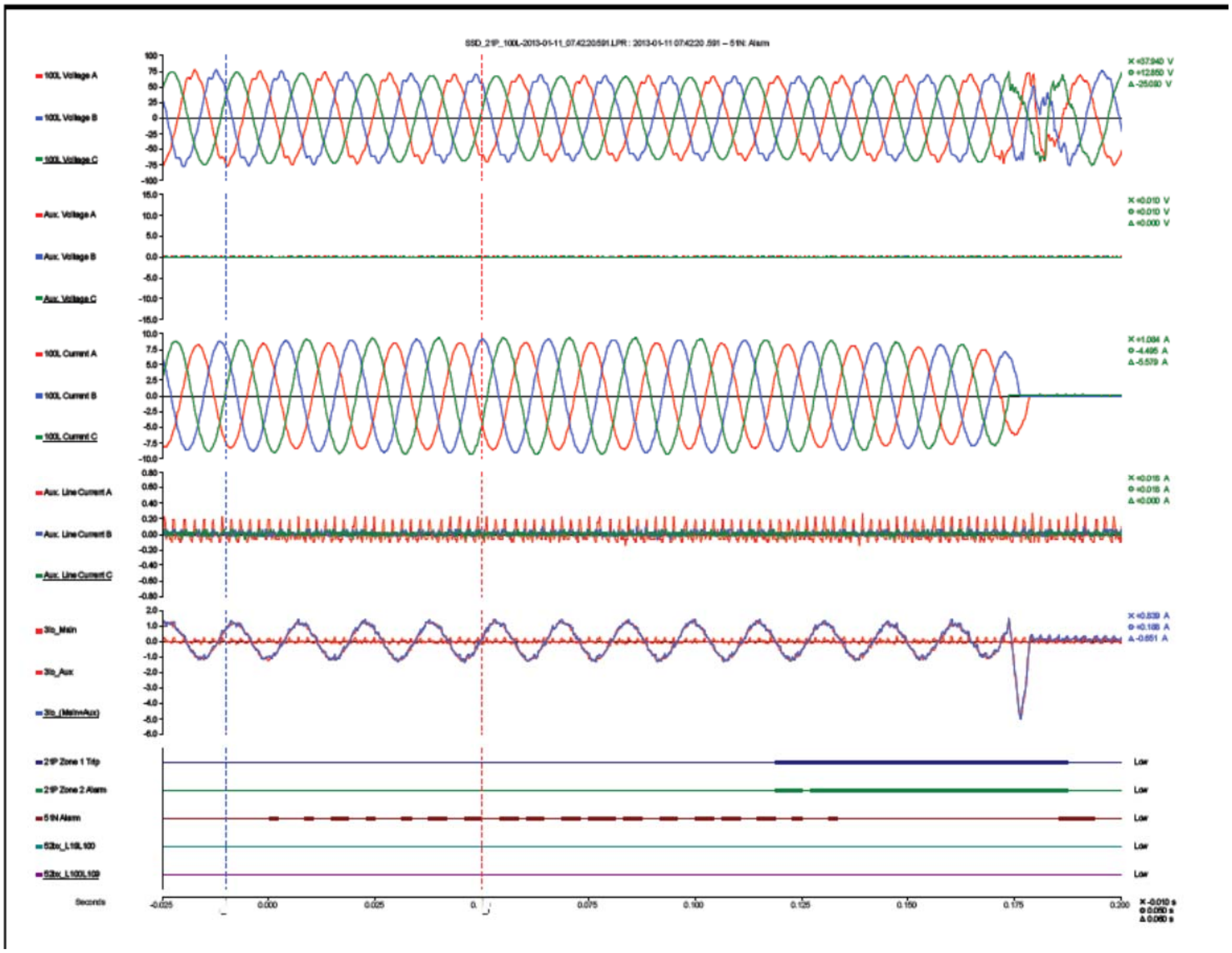

Figure 2-15: LPRO2100 100L SSD Report for the Trip at 0742 Hours

2.4.3 Further Actions Required

- The recommended firmware upgrades should be implemented in the LPRO2100 relays. Testing should be done on the relays following the firmware upgrades to verify that the relays will no longer operate for these events. This can be performed by testing the relays with the file captured on January 11 as the input to control the test set.

- The application of appropriate settings for the load encroachment feature on all SEL 321 relays should be done to prevent operation during off-frequency events. A review of SEL's final recommendation report (pending) should also be carried out. A setting of 100 ohms primary for all lines is recommended based on the protection settings for the longest line on the system, TL206. This setting will accommodate a load of 529 MVA before blocking. The angles settings are PLAF=90, NLAF=-90, PLAR=90, NLAR=270. This approach is preferred over the setting of the 50PP1 current monitor as it is independent of minimum fault levels.

- The reclosing on 100L at Sunnyside should be re-evaluated and co-ordinated with Newfoundland Power such that, upon loss of voltage along the 138 KV loop and the tripping of 100L, the loop is opened at an appropriate location to ensure that a reasonable amount of load is re-energized upon reclose. This will help to prevent a repeat occurrence of the re-energization event as happened on January 11. If this cannot be coordinated then reclosing should be turned off.

- Application of frequency monitoring to capture abnormal frequency events such as occurred on this day should be considered for installation in various 230 KV stations - one in an Eastern station, another in Bay d'Espoir and one in a Western station.

- Further investigation into the tripping of TL236 at Oxen Pond should be conducted to ensure that the permissive overreaching logic is working properly on the P2 protection (SEL) relays.

- A detailed load flow and transient stability analysis should be conducted in concert with the comprehensive review of the sequence of events to gain a full understanding of the events.

- In conjunction with the study above, guidelines should be developed and implemented for optimum reactive power dispatch and levels of Avalon loading, in the event that similar circumstances develop in the future. This should also include a review of the operation of the Optimum Power Flow (OPF) application in the EMS.

- In light of the jumper issue that resulted in the fault and trip TL201 and a separation of the East/West power systems there should be a review of the standards applied for transmission line jumper length.

3.0 POWER SYSTEM RESTORATION

The following sections provide an overview of the restoration periods following the 0742 and the 0851 events.

3.1 0742 hours to 0851 hours

After the trip of transmission line TL201 from the Western Avalon to the Hardwoods terminal stations at 0742 hours due to the line to ground fault, there was a power outage to a large portion of the eastern Avalon, east of Western Avalon terminal station, including St. John's and the surrounding areas. In addition the Central/West Coast system frequency became very high resulting in trips of numerous transmission lines/stations and the loss of the generating plants at Cat Arm, Upper Salmon, Granite Star Lake and the Exploits with major customer outages, including most Central and Western customers. The system eventually islanded into three separate areas with each supplied from the Bay d'Espoir, Hinds Lake and Deer Lake Power plants. The main system was separated west and east of the Stony Brook terminal station which lost all connections to generation. While a large part of the system was without power, there were customers still with power in several areas including:

- The Burin Peninsula, the Sunnyside and Come by Chance area (including the North Atlantic Refinery), the VBN terminal station, and the Avalon Peninsula loads supplied by the 138 KV and 66 KV at Western Avalon, all supplied via the Bay d'Espoir generation. (There were also some Newfoundland Power customers still supplied from NP's own hydro generating plants.)

- The Howley and White Bay area, the GNP (north of Parsons Pond to Bear Cove following the reclose of TL239) and the Baie Verte Peninsula/Springdale areas, all supplied via the Hinds Lake plant.

- The towns of Pasadena and Steady Brook, Deer Lake Power and Corner Brook Pulp and Paper all supplied by the Deer Lake Power plant.

The sequence of events in restoring the power system following the trip of TL201 is contained in Appendix A-4.

Restoration commenced with the closing of the breakers associated with transmission lines TL204 and TL231 at the Bay d'Espoir end. It should be noted that at this time, the equipment statuses at the RTU in Stony Brook were not being updated due to router issues between the EMS and the RTU. The indications for the ECC operator were that all 230 KV line breakers at Stony Brook were closed. In fact, only TL204, TL231 and TL235 breakers (B1L35, B1L04 and

B1L31) at Stony Brook were closed. Upon closure of TL231 at BDE at 0748 hours, the Stony Brook 230 KV and 138 KV busses were energized picking up some loads in the Grand Falls area and South Brook only, as the line breakers associated with TL205 and TL232 were open at Stony Brook (unknown to the ECC operator). TL235 was also energized via TL231, but tripped again due to issues with STB breaker B1L31 which tripped two phases and reclosed again (see Stony Brook DFR trace, Figure 3-1). The Bay d'Espoir and Hinds Lake plants were still separated and supplying two isolated electrical systems now with Stony Brook energized from Bay d'Espoir. The issues with the Stony Brook RTU status update failure continued to complicate the restoration process as the telemetry and equipment statuses were not being updated for this station.

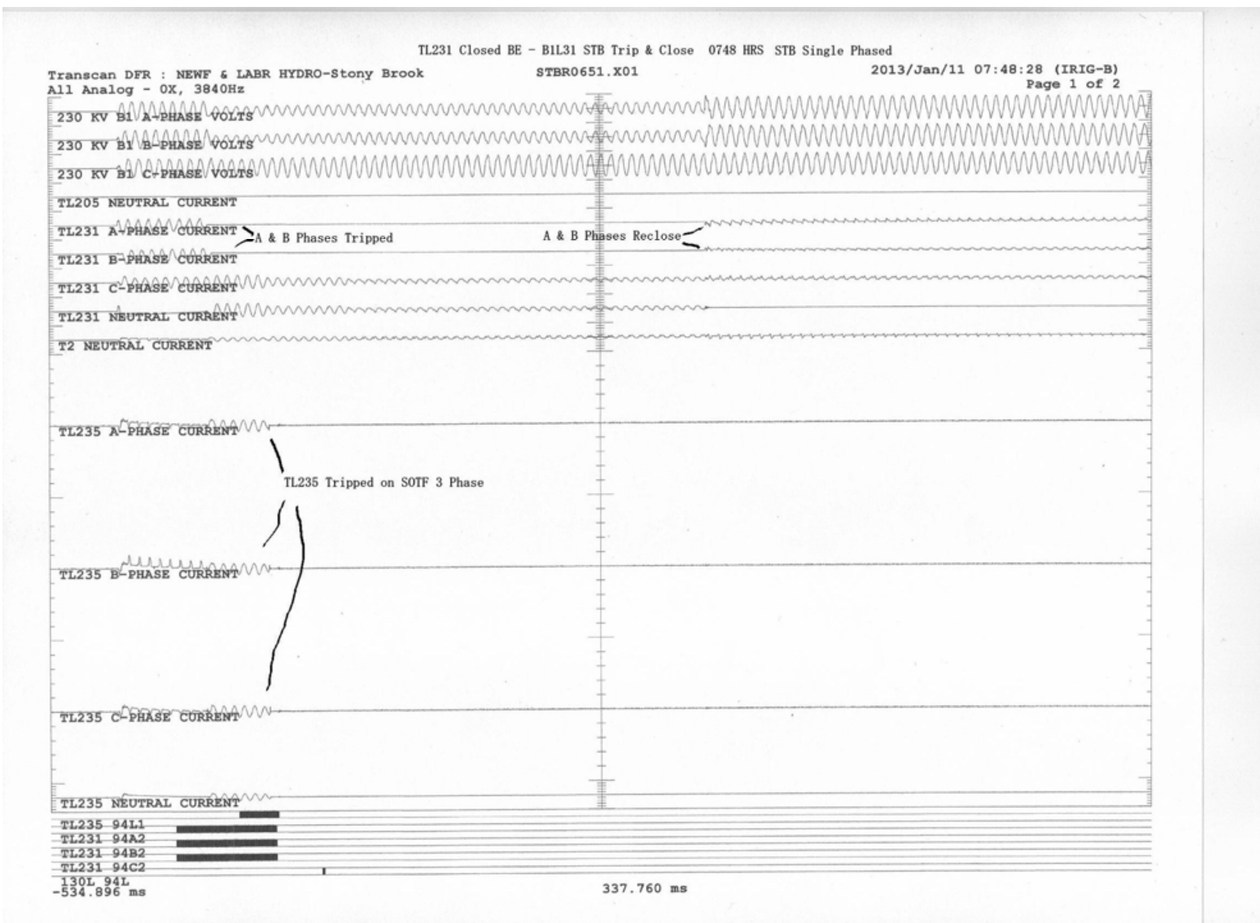

Figure 3-1: Stony Brook DFR Trace at 0748 Hours Showing STB B1L31 Trip/Close

At 0755 hours TL201 from Western Avalon to Hardwoods was restored following an unsuccessful attempt at 0751 hours. At 0756 hours TL236 from Hardwoods to Oxen Pond was restored. TL201 was initially loaded to approximately 25 MW. The load supplied had been increased to 260 MW by 0842 hours but by 0851 hours it reduced to 225 MW. A disturbance at 0842 hours resulted in a trip of all four capacitor banks at Come by Chance and a significant amount of Avalon load loss. This appears to be due to NP issues at their Molloys Lane substation.

Beginning at 0754 hours, the ECC operator, in attempts to restore the Western area, closed line TL205 from Stony Brook to Buchans, at Buchans, and TL228 from Buchans to Massey Drive, at both ends. These lines were still not energized after closure, as generation supply was still not connected at both ends, Massey Drive and Stony Brook.

Just prior to 0800 hours, the breaker B1L22 was closed at Springdale (through the synchrocheck relay). This restored the 138 KV loop and the Bay d'Espoir and Hinds Lake plants were tied together for approximately three seconds before an internal problem in the breaker B1L22 at Springdale caused a fault and the breaker tripped again, clearing the fault with no clearing required at the remote Stony Brook end.

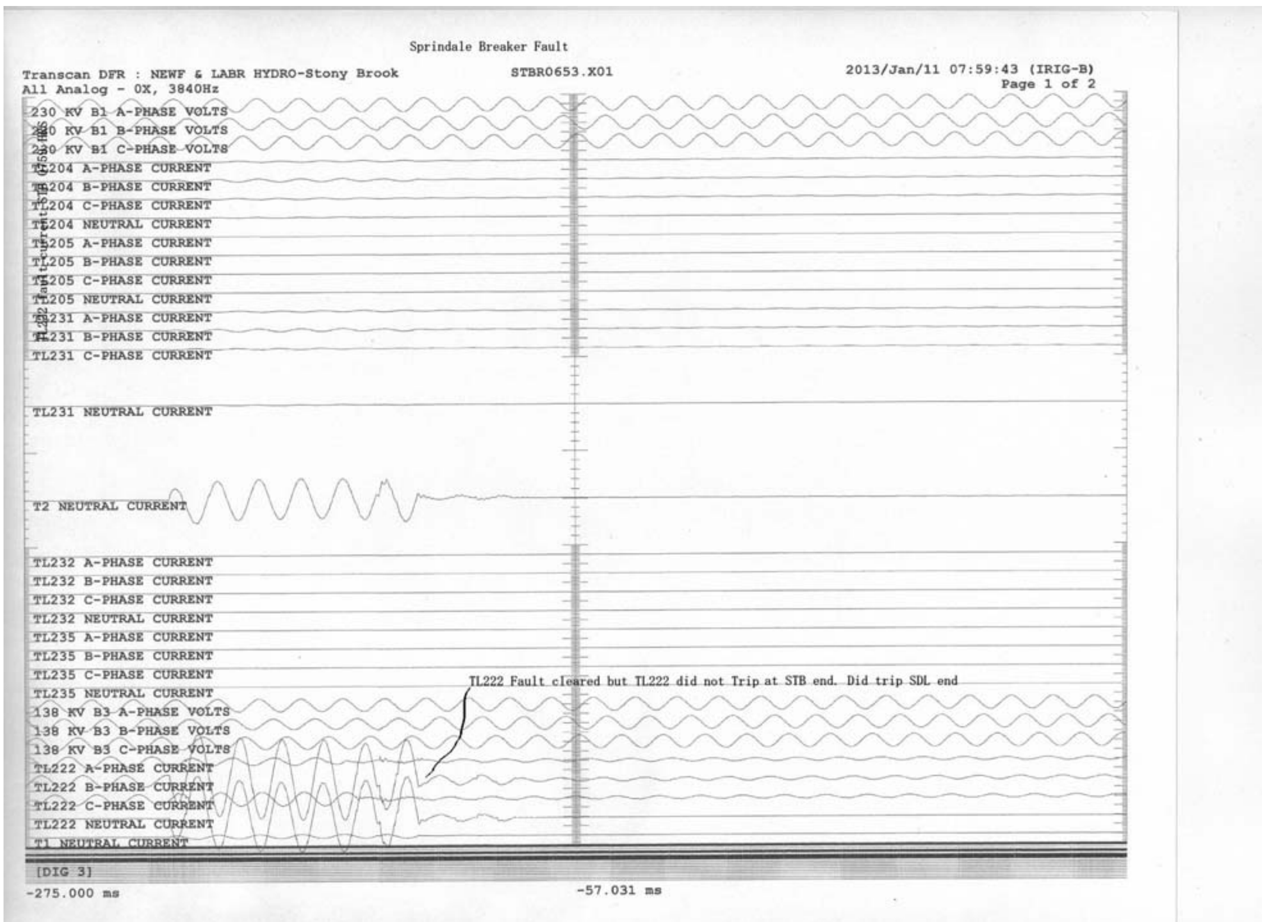

Figure 3-2: Stony Brook Trace at 0759 Hours Showing SPL Breaker B1L22 Fault

At 0800 hours the ECC Operator restored transmission line TL248 from Deer Lake to Massey Drive. At the time indications to ECC were that the 230 KV lines into Stony Brook were closed.

However, they were not and the load at Massey Drive was picked up and supplied from the Hinds Lake plant only. Also picked up at this time were TL228 from Massey Drive to Buchans, TL211 from Massey Drive to Bottom Brook and TL205 from Buchans to Stony Brook, but with no load. The initial loading on TL248 was approximately 50 MW. The restoration of this load at the Massey Drive terminal station caused a significant system upset and resulted in an interruption to customers on the GNP in St. Anthony, Roddickton and Main Brook and to customers from Wiltondale to Parsons Pond, all due to an underfrequency trips. There were numerous underfrequency and voltage alarms indicating the instability of the system as the Hinds Lake plant was overloaded and operating well below 60 Hertz (unknown to the ECC operator). Based on digital fault recorder measurements and the RPM meter output from Hinds Lake, the frequency was around 49 Hz during the time Massey Drive load was picked up for a period of 10 minutes. Figure 3-3 shows the Hinds Lake frequency as taken from the unit RPM output. The voltage on the 230 KV system was being supported by line charging from the unloaded 230 KV lines at a level of around 200 KV. Beginning at 0805 hours the ECC closed additional 230 KV breakers on the islanded Hinds Lake system picking up TL233 from Buchans to Bottom Brook and TL232 from Buchans to Stony Brook but with no additional load. The low frequency caused considerable overexcitation of system equipment, particularly with transformers, however the low system voltage caused by the overloading was offsetting in helping to mitigate the overexcitation impact on equipment.

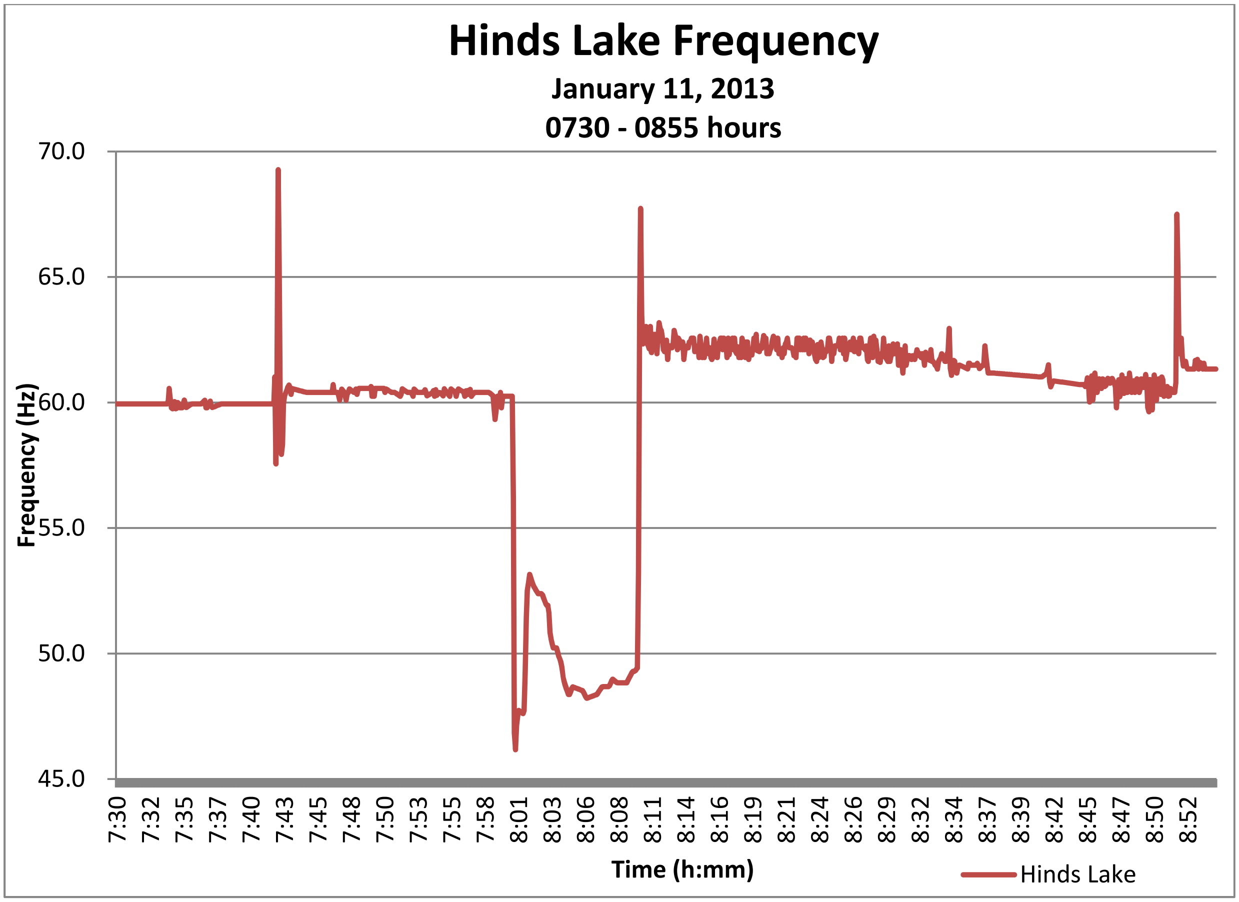

Figure 3-3: Hinds Lake Frequency (From Unit RPM Output)

At 0810 hours, in an effort to off-load the system, the ECC Operator opened the two transformer breakers at Massey Drive (B2T2 and B3T3) interrupting the customer load there. This sudden load loss of load (approximately 40 MW) resulted in some voltage recovery and with the frequency still around 50 Hz, resulted in even more overexcitation of the transformers, resulting in the operation of Buchans T1 and Massey Drive T2 transformer differential protections. The overexcitation effects on the transformers just prior to trip is apparent by the wave distortion displayed in the Buchans DFR trace, Figure 3-4, for both the voltage and the current channels. The subsequent lockout operation of 86T1 at Buchans tripped breakers B1L05 and B1L28 (no lines were de-energized) followed by lockout operation of 86T2 at Massey Drive 3.5 cycles later. The latter operation tripped the 230 KV bus at Massey Drive, de-energizing all the 230 KV lines west of Stony Brook again. Transmission line TL248 also tripped at Deer Lake via the transfer trip from Massey Drive.

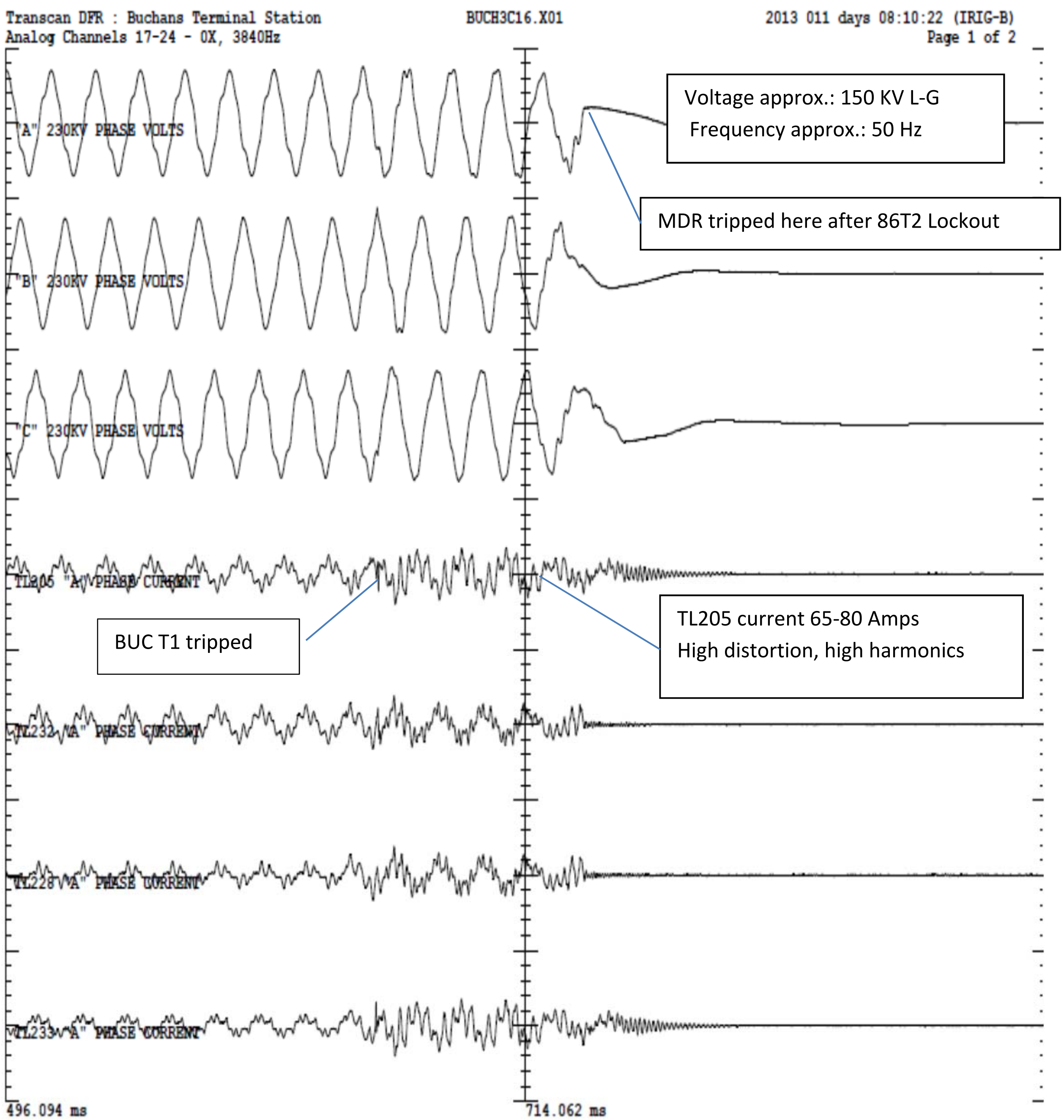

Figure 3-4: Buchans DFR Traces at 0810 hours Indicating Overexcitation Prior to BUC and MDR Lockouts

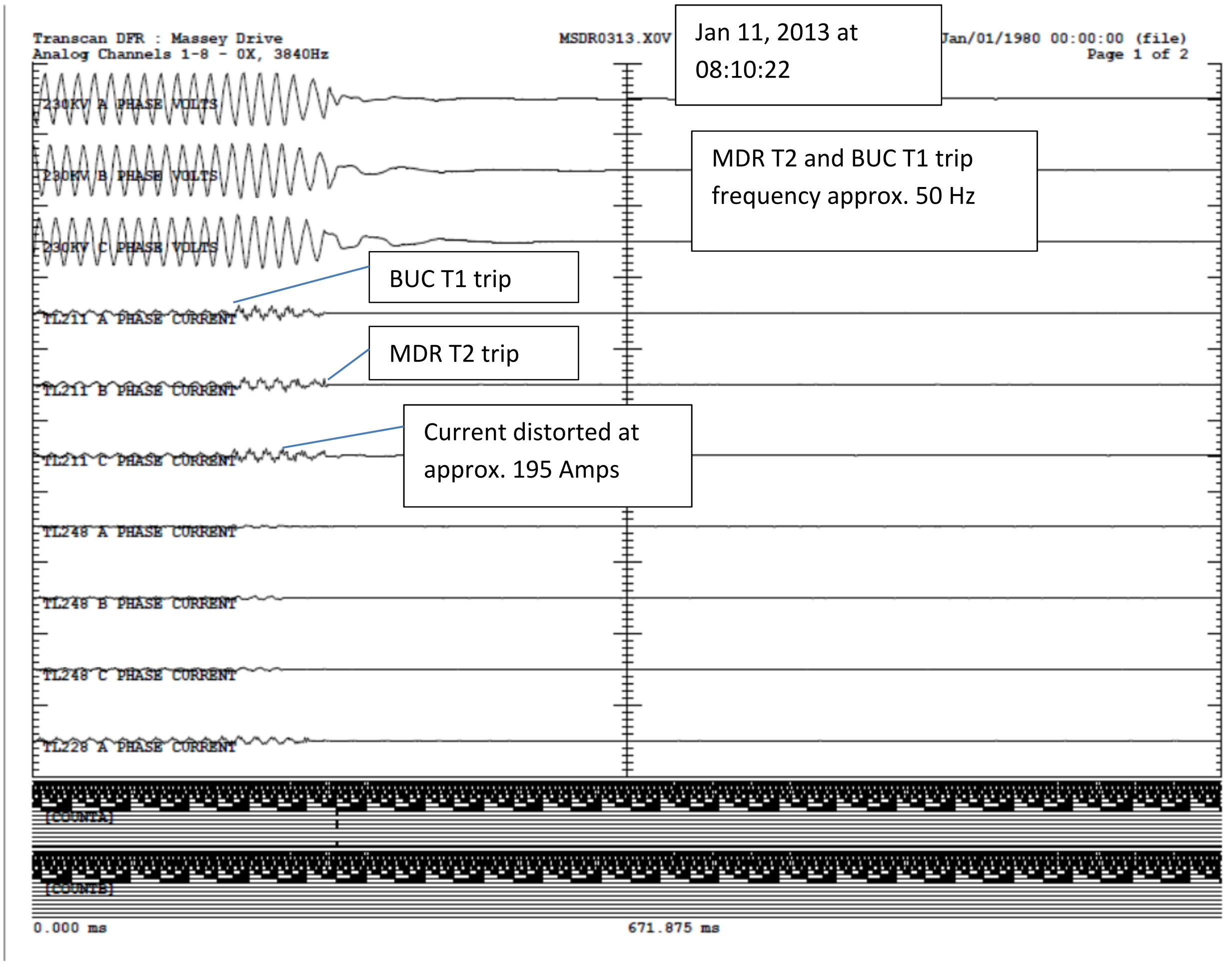

Figure 3-5: Massey Drive DFR Traces at 0810 Hours Indicating Overexcitation Prior to BUC and MDR Lockouts

By 0830 hours the ECC Operator had restored customers in St. Anthony, Roddickton and Main Brook by reconnecting to the grid. This occurred after a failed start of the St. Anthony Diesel Plant. It appears that a diesel unit did finally start and synchronize at 0835 hours, however it tripped again shortly afterwards.

At 0837 hours the communications had been reestablished to Stony Brook RTU which confirmed the status the breakers and the bus voltages at this station.

At 0844 hours breaker B1L22 was closed again at Springdale (through the 25W synchrocheck relay). No problem occurred with the breaker on this closure. The loop was restored and the Bay d'Espoir and Hinds Lake plants were tied together. Restoration efforts continued without incident from this time up to the time of the second trip of TL201 at 0851 hours.

At 0851 hours TL201 tripped and unsuccessfully reclosed at the Western Avalon end only, causing the loss of 225 MW of load and another outage to St. John's and surrounding area. The line trip was again presumed to be caused by the C phase jumper issue on Structure 210.

Following are charts of voltage (Figure 3-6), frequencies (Figure 3-7), and line MWs (Figure 3-8) at key points on the system during the period from 0730 hours to 0855 hours. It should be noted that in the second chart the frequency for each location is clipped to minimum and maximum values of 58 Hz and 62 Hz, respectively. This is due to the limitations of the measurement system.

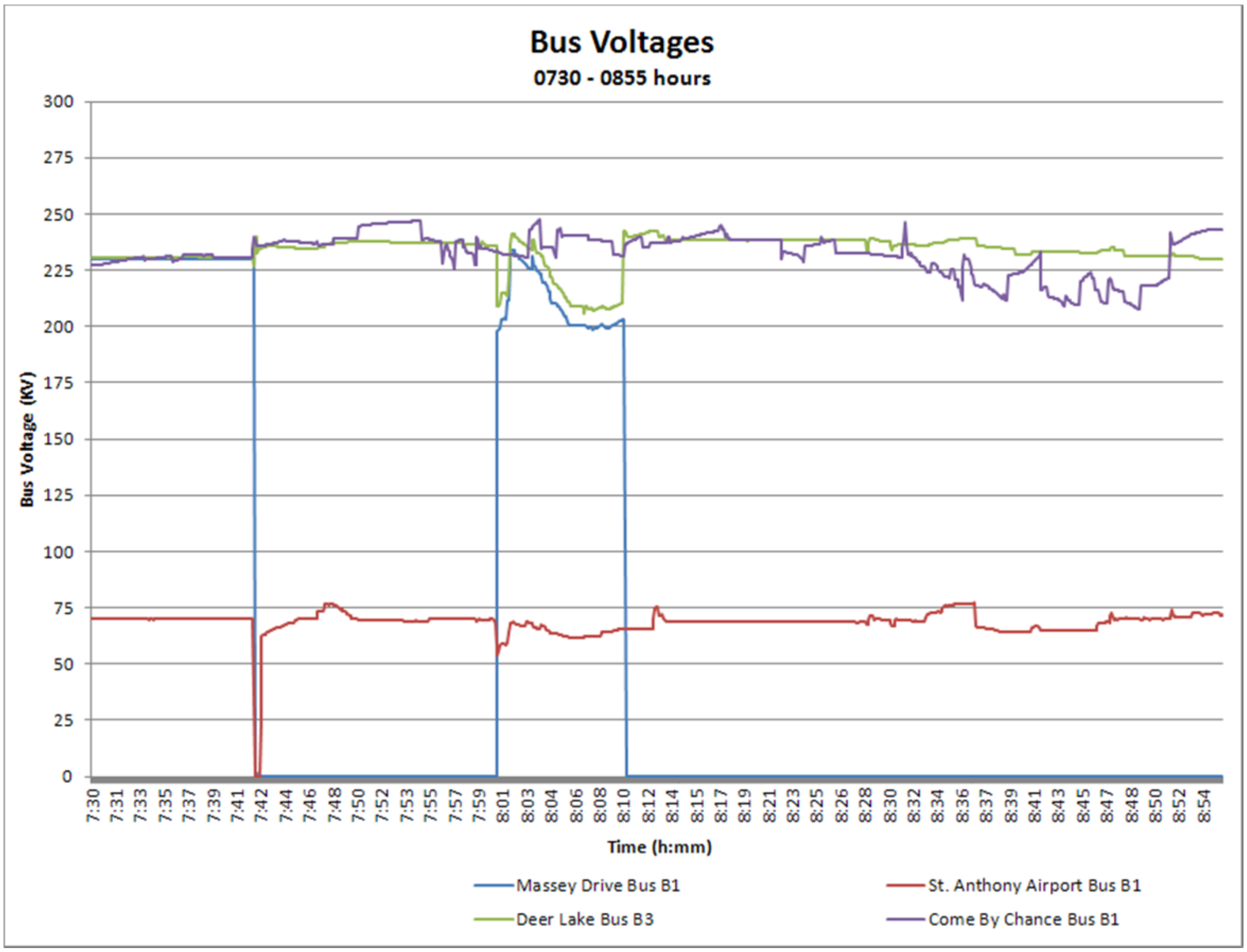

Figure 3-6: System Voltages from 0730 to 0854 Hours

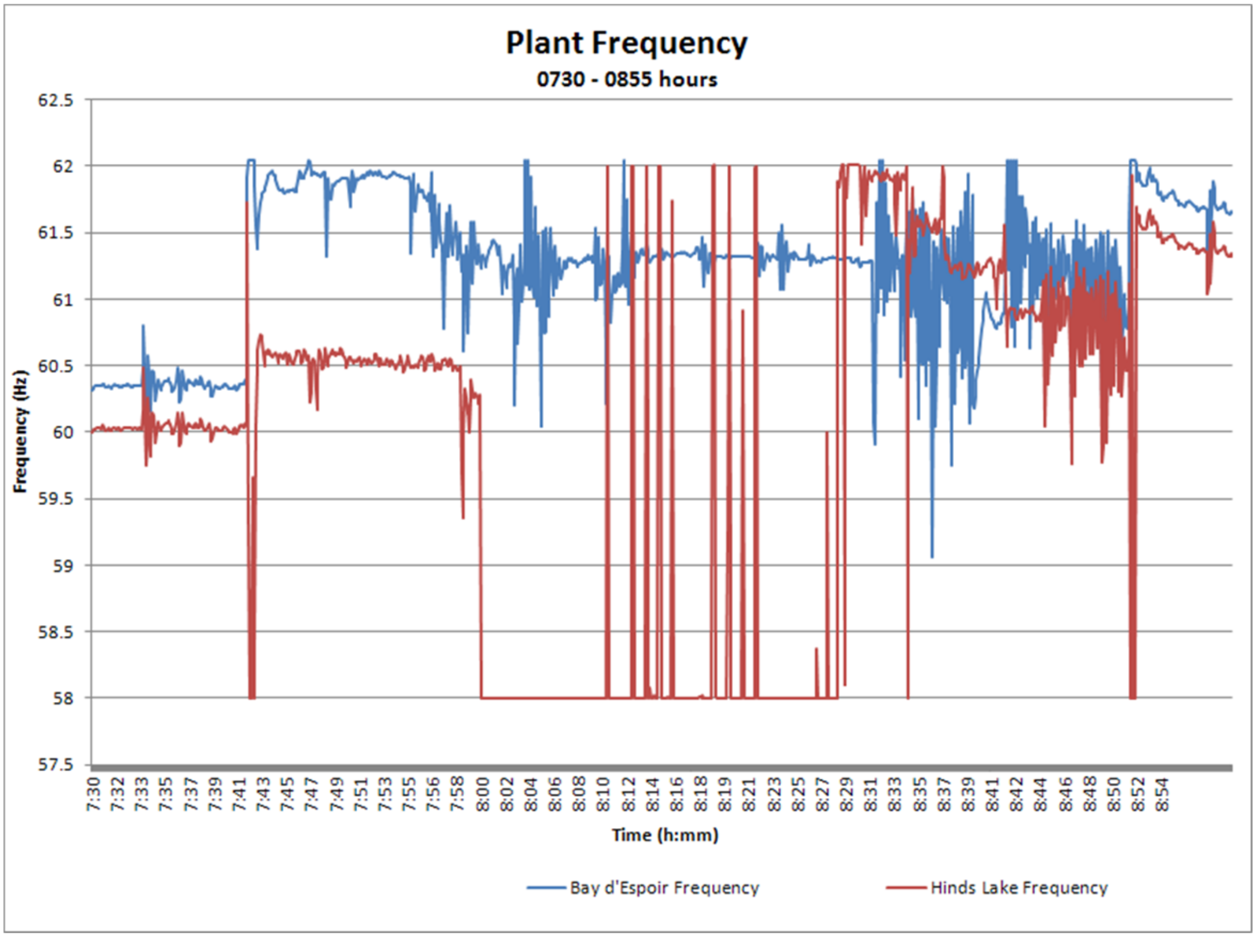

Figure 3-7: Bay d'Espoir and Hinds Lake Frequencies (Clipped) from 0730 to 0854 Hours

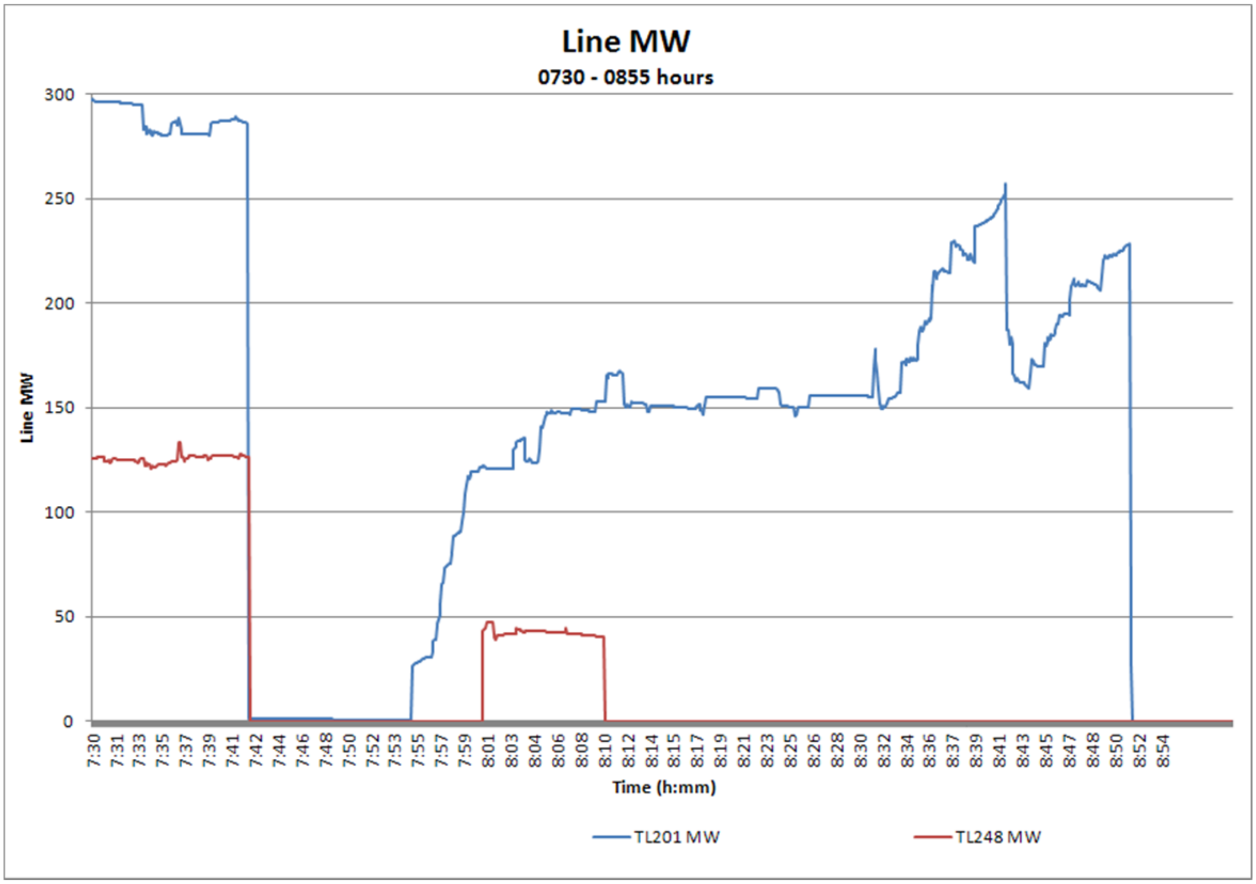

Figure 3-8: TL201 and TL248 MW from 0730 to 0854 Hours

3.1.1 Additional Observations

- At 0748 hours, when TL231 was closed at BDE to re-energize STB, the P2 protection (Schweitzer distance) operated on TL231 at STB sending a three phase trip signal to the breaker B1L31 (L05L31 was already tripped from the incident at 0742 hours). With reference to previous Figure 3-1, B1L31 tripped only on two phases - A and B. The 230 KV bus at STB remained energized via C phase only for approximately 47 cycles until the A and B phases reclosed. C phase failed to open due to problems with the C phase breaker circuit. During later testing, the C phase trip coil circuit was showing open (no continuity) initially, but after several breaker operations it was shown to be closed or continuous. The non-continuity issue is believed to have cleared during the ‘wiping’ of the C phase auxiliary contact during the operational testing. This contact is in series with the trip coil of the breaker. Also revealed during testing was that C phase failed to open via the trip relay signals and instead tripped on phase disagreement protection.

  In addition, with the three phase trip from the line protection and the 94L2 operation, reclosing should have been cancelled by the protection circuit design. However the 94L2 does not operate into the T relay to trip TC1 circuits but rather into the TC2 circuit which failed to trip three phase. The 94L2 should also trip the T relay and prevent reclosing from occurring even with the opening of only two phases.

The SEL 321 also operated unexpectedly. The relay operated Zone 1 on all three phases even though the frequency was not extremely high, at approximately 61.9 Hz, and the load was picked up behind the relay.

- At 0748 hours, TL235 (STB to GFL FRC) tripped three phase due to operation of the P1 protection (Optimho switch on to fault, SOTF). This protection is believed to have operated due to the pickup of the line with all transformers at the GFL FRC end connected and the opening of the two phases on B1L31 immediately following the pickup. The SOTF was enabled immediately following the pickup because the voltage decreased to less than 70 per cent of nominal on the opening of the B1L31 phases A and B with the inrush to the transformers above the current level detector pickup value. If B1L31 had opened 3 phases it most likely would not have operated.

  TL235 protection also sent a transfer trip to GFL FRC to trip the low side breakers on transformers T1, T2, and T3. Only breaker 252T-3 tripped. On subsequent checks it was discovered that 252T-2 had issues with a bent auxiliary switch arm which may have prevented its operation. However, there were no issues discovered with breaker 252T-1. The transfer trip was only present for approximately four cycles due to the clearing via the SOTF. This may have been insufficient time to ensure tripping of the low side breakers. The addition of a timer in the trip outputs of TL235, to ensure adequate trip time is given to the breaker trip coils, should be considered.

- When the ECC operator picked up TL231 at BDE and energized the STB terminal station with load on the 138 KV lines, in addition to the unloaded 230 KV lines TL204 and TL235, the station status was uncertain due to the ongoing issue with the non-updating status the RTU caused by the router buffer overflow. Given the actual state of the system, a more normal approach would be to isolate the loads and the lines in the STB station followed by the pickup of the lines and loads individually. A protocol or guideline should be developed as to how to proceed when such situations occur. Given what transpired later on, possibly taking no action to re-energize equipment when statuses cannot be verified might be the better course until the situation is rectified.

- At 0751 hours the Hardwoods station was picked up by closing breaker B1L01 at HWD. This was immediately followed by the tripping of TL201 by the P2 protection (Optimho

SOTF). With TL206, TL217, TL218 and TL242 still open from the previous incidents, the voltage at HWD was depressed due to the transformer inrush current on pickup. Once the breaker was closed the SOTF was activated and operated due to the voltage depression and inrush current. A subsequent closure at 0755 hours did not see such a large voltage depression as the inrush current was a little less, most likely due to the point at which breaker closure occurred on the voltage waveform. If TL206 had been put in-service prior to the closure of B1L01 the voltage depression would most likely not have been as significant and the SOTF may not have operated. If the SOTF operation had persisted, isolating the transformers at HWD and picking up each individually would be an option.

- At 0759 hours when TL222 from Stony Brook to Springdale was closed at Springdale, momentarily connecting the BDE system to the HLK system for approximately three seconds, the LPRO2100 protection at SPL operated due to a fault. The breaker B1L22 at SPL tripped but the breaker on TL222 at STB, B3L22, did not trip nor did the line protection at STB operate. However, the fault cleared in six cycles with the opening of the SPL B1L22 breaker. The fault can be seen on the STB DFR trace in Figure 3-2, previously referenced. Based on this information and the LPRO relay report at Springdale which operated and tripped, the fault was predicted to be in the SPL B1L22 breaker and most likely related to resistors, based on an experience in the past with this type of oil circuit breaker (138 KV GE KSO). The resistors were suspected to have been damaged during the closing motion and fallen off, faulting inside the tank with the fault clearing on opening. Subsequent detanking of the breaker and checks confirmed the presence of damaged resistors which were indeed found at the bottom of the tank.

- At 0800 hours breaker B3L48 at MDR was closed, picking up Massey Drive loads and transmission lines TL205, TL211 and TL228 from the Hinds Lake plant. This caused Hinds Lake to become overloaded and to operate at a frequency of approximately 50 Hz. This lower frequency and overload caused a lower voltage on the 230 KV bus at Massey Drive, in the range of 200 to 210 KV, even with the line charging from the unloaded 230 KV lines. This underfrequency caused significant overexcitation of equipment, especially at the transformers. A frequency of 50 Hz results in an overexcitation of 20 per cent which is well outside the normal continuous design range of 10 per cent. However, the impact was offset by the lower voltage of about 10 percent. The overexcitation effect can be seen from the Massey Drive and Buchans DFR traces (see previous Figures 3-4 and 3-5) just before the Massey Drive 87T2 differential operation and 86T2 lockout which tripped the 230 KV lines and busses.

The overexcitation was mitigated somewhat by the operation of the Hinds Lake exciter volts per hertz monitor which functioned to keep this ratio within limits at the Hinds Lake unit. This protects the unit by decreasing the terminal voltage of the machine when the frequency decreased, as is evident in Figure 3-9 (a and b) which indicate the frequency and voltage at the unit at this time. The ratio of volts per hertz is being controlled at a maximum of approximately 1.07.

Figure 3-9a: Hinds Lake Terminal Voltage from 0745 to 0815 Hours

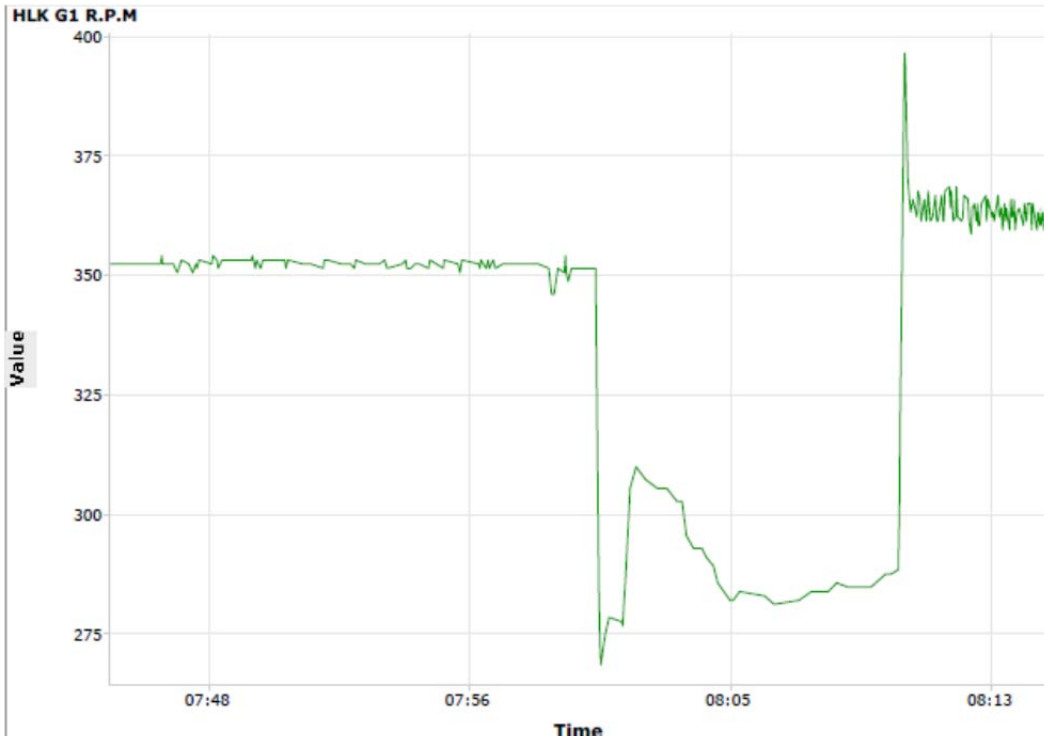

Figure 3-9b: Hinds Lake Frequency from 0745 to 0815 Hours (from RPM Transducer)

The operation of the Buchans and the Massey Drive transformer differential protection occurred around 0810 hours. Prior to this, between 0802 and 0804 hours, additional lines (TL233 and TL232) were energized. At 0810 hours the Massey Drive load was tripped by the ECC operator, to offload the Hinds Lake unit. This resulted in an immediate increase in the 230 KV voltage and caused the frequency at the Hinds Lake unit to increase. As the frequency increased so did the voltage which was being controlled by the exciter volts per hertz monitor. This caused an increase in the overexcitation on the system at this time resulting in the transformer differentials to operate, first at Buchans, followed in about three cycles at Massey Drive. The trip of Buchans T1 caused breaker openings but no line trips. The 87 relays on Buchans T1 and Massey Drive T2 are Alstom MBCH12 which do not use harmonic restraint and are more prone to overexcitation operation than the harmonic restraint differential types. During overexcitation, as is evident from the sine wave distortion prevalent in the DFR traces, there is significant harmonic content on the higher than normal line charging currents which is reflective of the excitation currents in the transformers. With the high level of overexcitation of the transformers, the threshold pickups of the MBCHs were exceeded and the relays operated at around 0810 hours. Although the differentials (87T1 at BUC and 87T2 at MDR) are misoperations, they misoperated during system conditions beyond what would be expected in most contingencies and their operation to trip the

230 KV transmission, given the severe underfrequency, was desirable and helped protect the system equipment.

- At 0851 hours TL201 faulted C phase again due to the jumper issue. Based on the Western Avalon DFR trace and the SEL 321 report, Figures 3 -10 and 3-11 respectively, the fault resistance was in the 100 ohm range and higher. The Schweitzer P2 Zone 1 marginally operated to see the fault as indicated by the momentary pickup in Figure 3-11. Neither of the Hardwoods protections, P1 nor P2, operated to clear the fault because of the high resistance value. It is thought that the Western Avalon end operated due to the effect of the load which assisted in the tripping at this end but did not at the Hardwoods end. The fault was cleared with the three phase trip of the Western Avalon end as the line was being operated radially at the time.

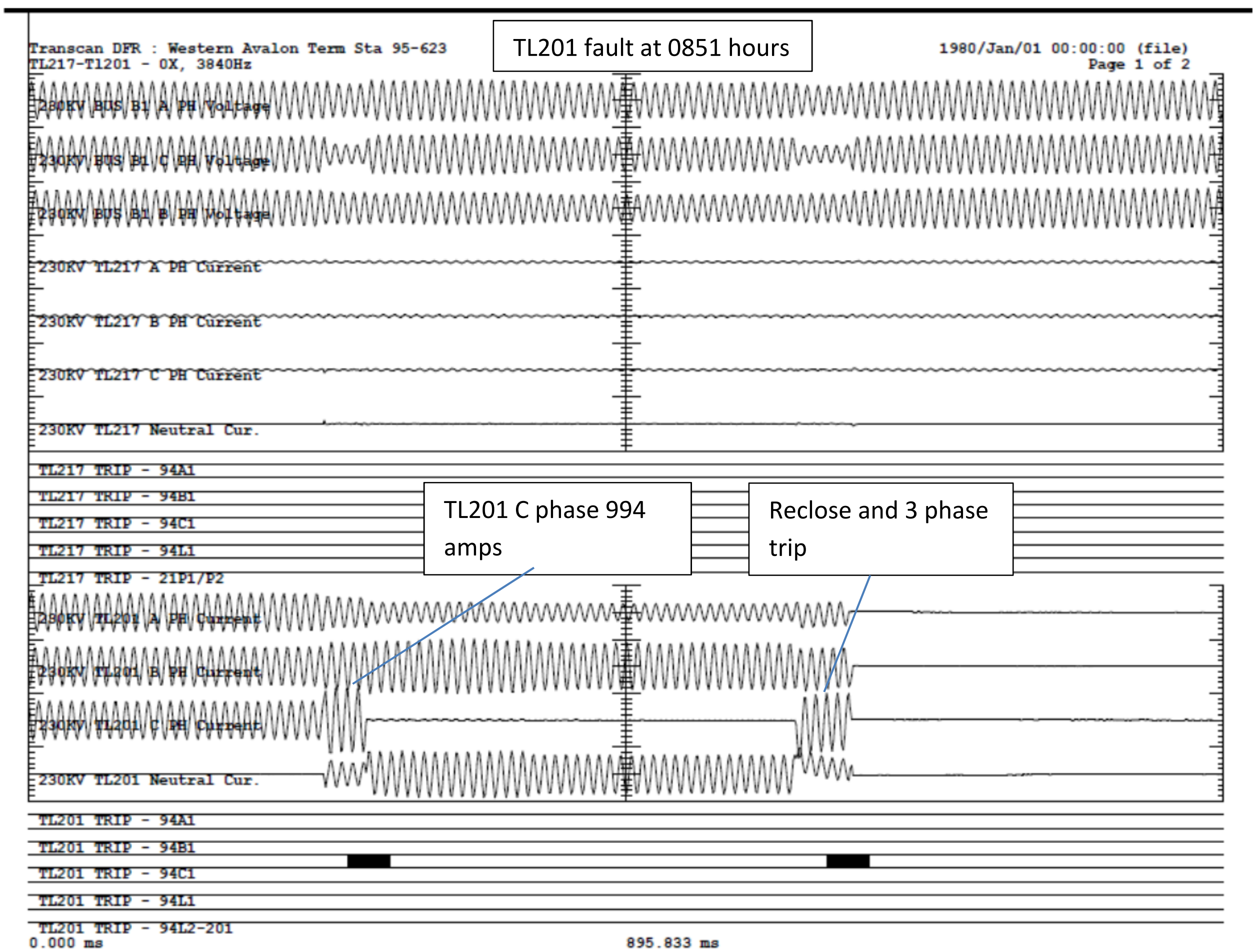

Figure 3-10: Western Avalon DFR Trace at 0851 Hours Showing TL201 Fault and Trip

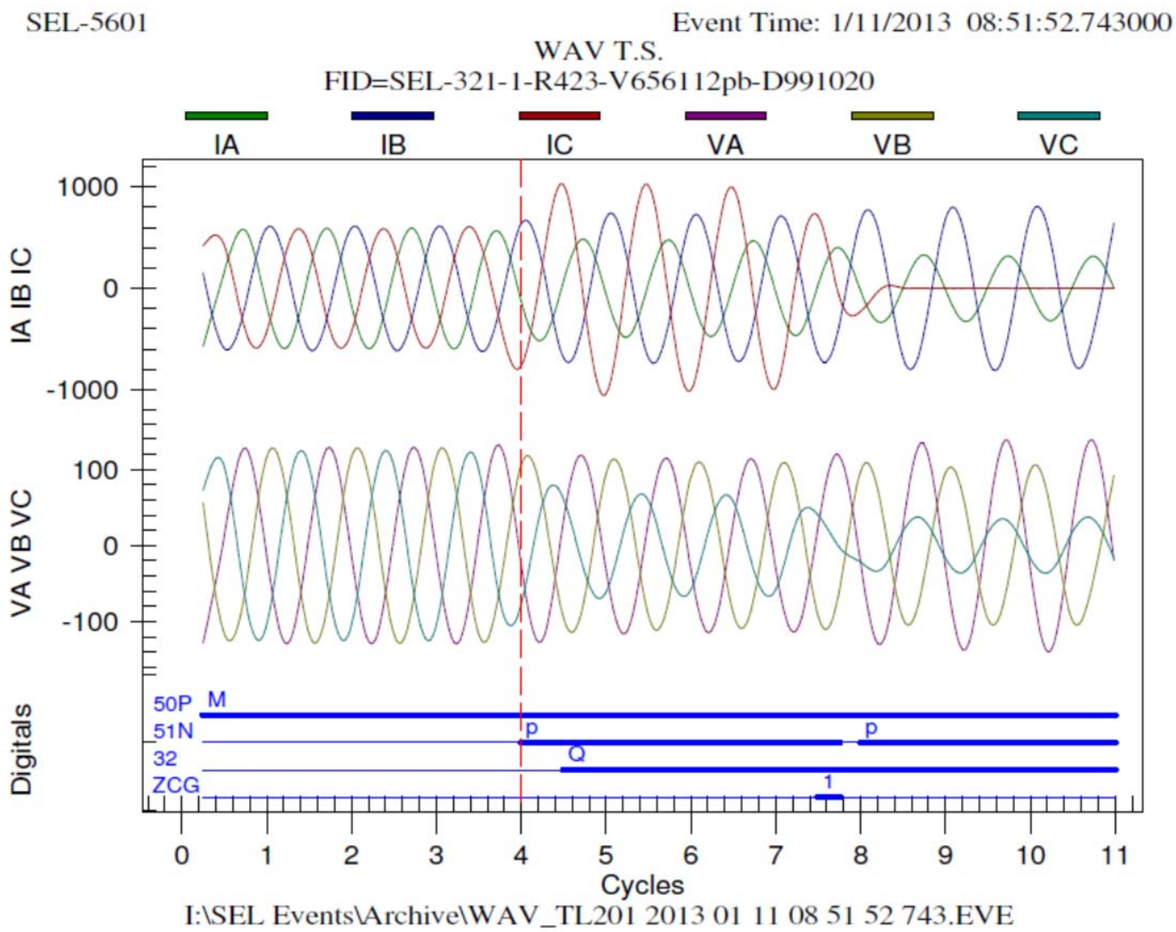

Figure 3-11: Western Avalon TL201 SEL Report 0851 Hours TL201 Fault & Trip

- There were several instances during this restoration period where capacitor banks at Come by Chance were put back in service almost immediately upon tripping due to the under or overvoltage conditions. The manufacturer has recommended that a time delay of at least five minutes prior to re-energizination to allow for time to discharge. Timers should be installed in the control circuits for these banks to block closure until at least five minutes have elapsed from the time of breaker opening.

3.1.2 Actions Taken

- Breaker B1L31 at Stony Brook was checked and found to be not tripping on C phase. This was corrected and the breaker was left in an operating condition. There were issues identified with the 3 phase tripping conversion circuit which permitted reclosing with two phases open which also need to be addressed.

- The non-tripping issues at the low side breakers on the Grand Falls transformers, T1 and T2, following receipt of the transfer trip associated with the trip of TL235, were investigated. Breaker 252T-2 was found to have a bent auxiliary switch arm. This was subsequently repaired. No reason for the non-operation of the 252T-1 was found but it is speculated that it was related to the very short tripping pulse given to the breakers. Application of a timer, to extend this tripping pulse, should be considered.

- Breaker B1L22 at Springdale was inspected internally due to the suspected internal fault. There was resistor damage on the interrupters with debris found on the bottom of the tank. The breaker was taken out of service and is currently undergoing replacement.

- As noted previously, the C phase jumper on TL201 Structure 210 was shortened and replaced.

- The RTU router buffer overflow problem was resolved and implemented for the Stony Brook terminal station. This should eliminate the station non-status update issues as occurred on this day, thereby giving the ECC operator accurate information for use in performing the proper system restoration.

3.1.3 Further Actions Required

- With regards to the tripping of breaker B1L31 at STB at 0748 hours, further investigation is required into why the SEL 321 operated when the station was energized. A request has been sent to Schweitzer to determine if they have any suggestions. If the problem is not addressed by Schweitzer then the relay should be fully tested to ensure it is operating properly. In addition, the load encroachment feature should be applied to this relay even though the problems are not suspected to have originated from a memory/frequency tracking issue.

  Since the breaker closed after tripping two phases, there should be a review of the three pole conversion circuitry for this line, as well as for all line protections, to ensure that the correct logic is applied to provide for three pole trip conversion on the tripping of two phases.

  The 94L2 three phase trip relay should trip the T relay to operate the TC1 and cancel reclosing. Other circuits should be checked to ensure that the 94L2 trips the T relay in this manner.

- A timer should be added to extend the duration of the transfer trip signal from the STB TL235 protection which picks up the 85X at GFL FRC and provides for a direct trip of the three low side breakers 252T-1, 252T-2 and 252T-3 at GFL FRC.

- Based on the damage found internally in breaker B1L22 at Springdale, other 138 KV KSO breakers on the system should be tested or inspected for resistor damage.

- Consideration should be given to developing a protocol or guideline for the ECC operators to follow which addresses how to proceed when incorrect or questionable data occurs in the EMS as experienced at the STB station during restoration following the disturbance at 0742 hours. As noted previously, no action until data confirmation is received might be the best approach, realizing it will be a judgment call in many cases by the operator.

- Consideration and study should be given to the application of underfrequency relaying on the Hinds Lake generator and other hydro units to trip when extreme underfrequency levels are reached and maintained on the system or islanded areas, such as occurred on January 11. A level in the order of 54 Hz with a suitable timer might be appropriate. An alarm indicating an imminent trip would form part of the strategy to alert the operator to take action where possible. The existing underfrequency alarm which was prevalent in the SOE during the Hinds Lake islanding and overloading was from an underfrequency relay at Hinds Lake which is used to increase the frequency above 59 Hz by pulsing the unit when the frequency falls below 59 HZ. This alarm was too frequent and pervasive, not really providing enough information to determine the severity of the situation. An alarm should be established which monitors the frequency and displays with the actual frequency level, similar to voltage levels for the various busses.

- Timers should be installed in the control circuits of the Come by Chance capacitor banks to block closure until at least five minutes have elapsed from the time of breaker opening. This would allow for the manufacturer's recommended discharge time.

3.2 System Restoration Following the Second Trip of TL201 at 0851 hours

Following the trip of TL201 at 0851 hours, the 230 KV supply east of Western Avalon was interrupted again, including St John's and surrounding areas. Holyrood Units 1, 2 and 3 were out of service. Transmission lines TL217 (WAV to HRD), TL218 (HRD to OPD), and TL242 (HRD to HWD) were also still out of service. The NP 138 KV loop from WAV to HRD and HRD B7T5 were open. The HRD 230 KV and 138 KV busses were de-energized with busses B12, B15 and B8 locked out. The Oxen Pond and Hardwood terminal stations were de-energized. All capacitor banks at Come by Chance were out of service.

The Bay d'Espoir generating station was operating, connected to the Hinds Lake plant via the 138 KV loop from Stony Brook to Howley, but open at the Deer Lake 230 KV. Areas being supplied were the Connaigre Peninsula, the Sunnyside and Come by Chance area (including NARL), the VBN terminal station, the Burin Peninsula, the remaining Avalon load, the Grand Falls area, Springdale area, Baie Verte peninsula, Howley, White Bay, and the GNP north of Parsons Pond. Customers in Steady Brook and Pasadena were being supplied by Deer Lake Power's generation. Other pockets of customers in various areas were in service (supplied by NP's generation).

The Central and West Coast power system remains interrupted following the trip at 0810 hours. Stony Brook was energized via transmission lines TL204 and TL231 (BDE to STB). All 230 KV busses west of Stony Brook were de-energized. Transmission lines TL209 and TL248 were open. Breakers associated with transmission lines TL205, TL211, TL228, TL232, and TL233 were closed but de-energized. The MDR Transformer's 66 KV breakers were open with Corner Brook and surrounding areas out of service. Transformers MDR T2 and BUC T1 were locked out. Cat Arm, Upper Salmon, Granite, Star Lake, and the Exploits generation were all off-line**.** Deer Lake Power was operating islanded.

At 0853 hours (see the sequence of events contained in Appendix A-5) the ECC continued in its restoration efforts with the starting of the St. Anthony diesel plant and the opening of TL242 at Hardwoods, followed by the opening of breaker L05L33 at Buchans at 0857 hours. The latter was in preparation to energize TL205 from Stony Brook. Unknown to the ECC, was that breaker L05L33 (Buchans only) was only opened on two phases with B phase remaining closed (or closing again immediately after opening). This led to a single phasing condition and some very confusing operations and trips on the system at this time which continued for a period of 25 minutes during the subsequent restoration period.

3.2.1 230 KV Single Phasing Event at Breaker L05L33 at Buchans

At 0858 hours breaker L05L31 at Stony Brook was closed by the ECC, energizing TL205 and also energizing, single phase through L05L33 (B phase), Buchans lines TL228, TL232, TL233 and the Bottom Brook terminal station (see Figure 3-12). Also energized at this time (single phase) were the 230 KV busses at Massey Drive via transmission line TL211. At this point loads were energized at Bottom Brook via the 138 KV bus and lines TL214 (supplying the Doyles and Port Aux Basques area) and TL250 (supplying the Burgeo area). No loads were single phased or energized at Buchans nor Massey Drive as they were isolated due to the lockout of Buchans T1 and the open 66 KV breakers at Massey Drive. Very high voltages were experienced on the 230 KV system due to the single phasing condition (see Figure 3-13). Voltages measured on the Bottom Brook DFR were 222 KV line to ground on B phase.

After approximately four seconds, Buchans line TL205's P2 (Schweitzer) ground overcurrent (51N) protection operated (Figure 3-14), sending trip signals to breaker B1L05 which was already open and L05L33. The B phase of breaker L05L33 still did not trip.

Seventeen cycles (0.28 seconds) later, L05L33 breaker failure lockout 86BF/L05L33 operated, followed by the tripping of Massey Drive breaker B1L28 one cycle later via TL228 - P1 (Optimho) SOTF protection. The Massey Drive 230 KV busses B1 and B5 remained energized, single phase from TL211. Buchans breaker L32L33 tripped one cycle later, de-energizing TL232.

The single phasing continued on for approximately 15 seconds, at which point Bottom Brook line TL250 tripped via its SEL 311 distance protection, de-energizing the Burgeo loads that were connected up to this time. After another 1.7 seconds, TL214 at Bottom Brook tripped via a transfer trip from Doyles which was initiated by the operation of the lockout 86T2 at Doyles. Doyles T2 (NP transformer 66/12.5 KV) protection operated, most likely due to the operation of the ground overcurrent protection picking up the trip relay 94T2 which trips the 86T2. The 86T2 lockout at Doyles also operated the high speed ground switch on TL214 and opened the NP 66 KV disconnect on T2. The opening of the disconnect T2-A on the high side of T2 initiates the opening of the ground switch.

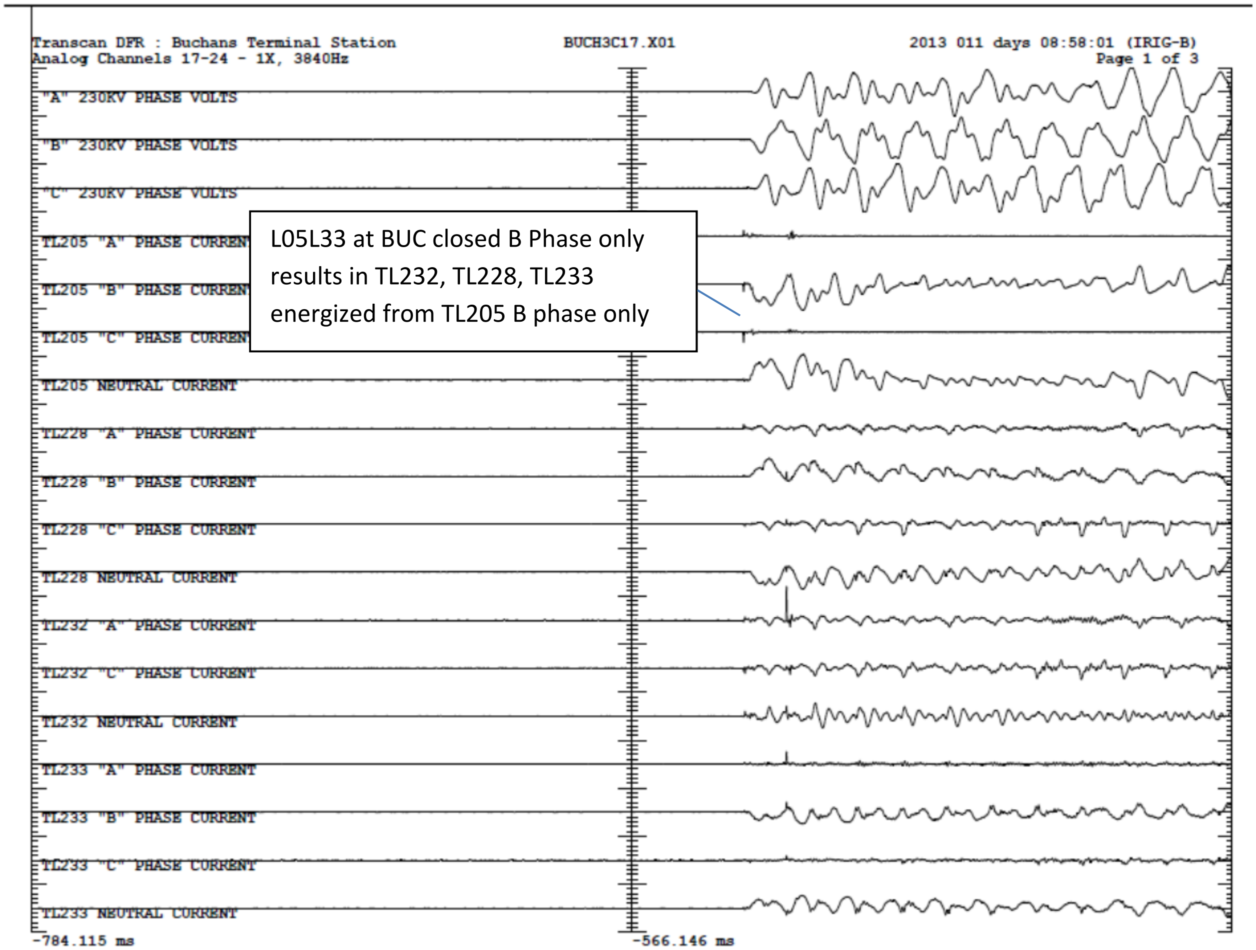

Figure 3-12: Buchans DFR Trace at 0858 Hours Showing the Start of Single Phasing

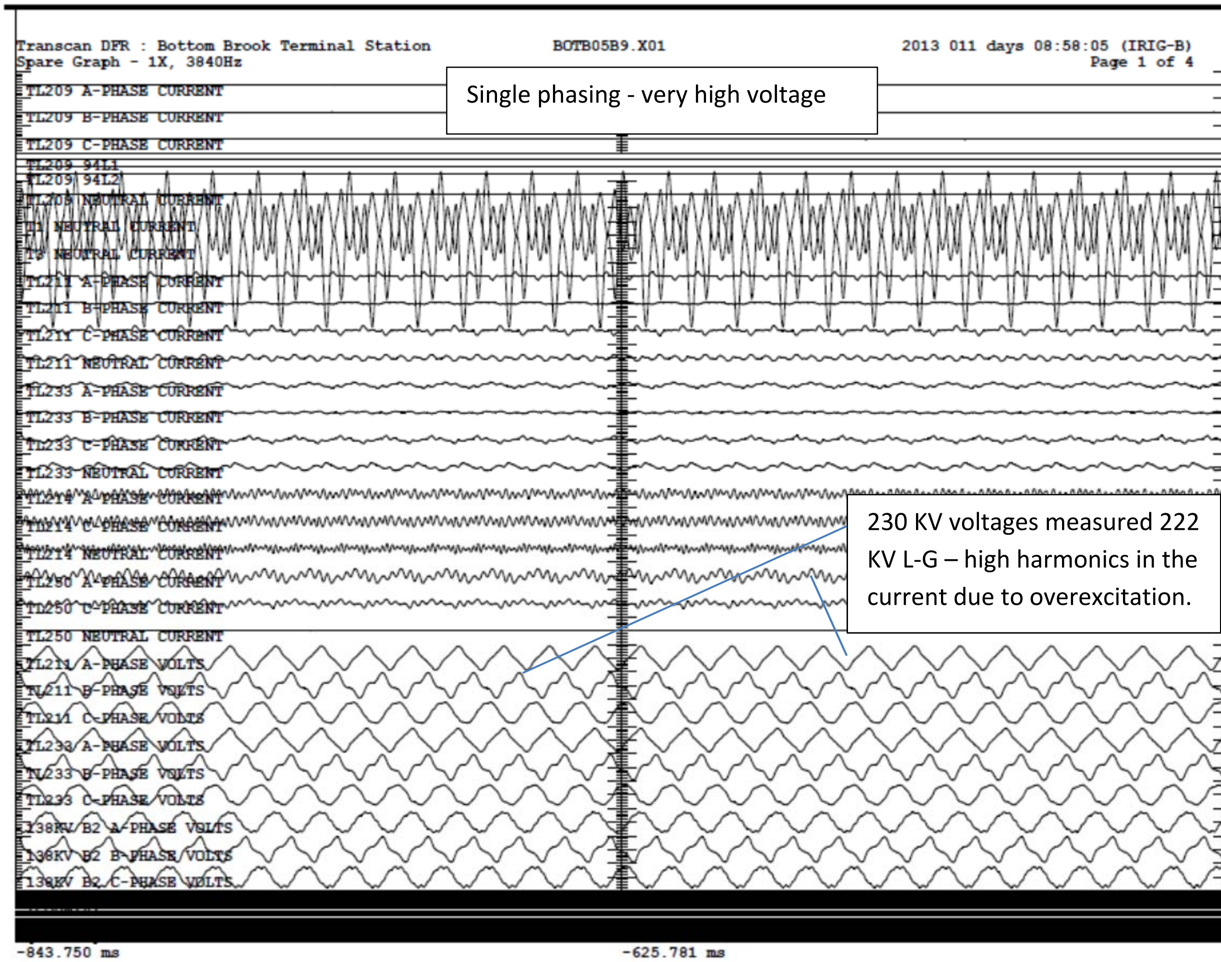

Figure 3-13: Bottom Brook DFR Trace at 0858 Hours Showing Very High Voltage During Single Phasing

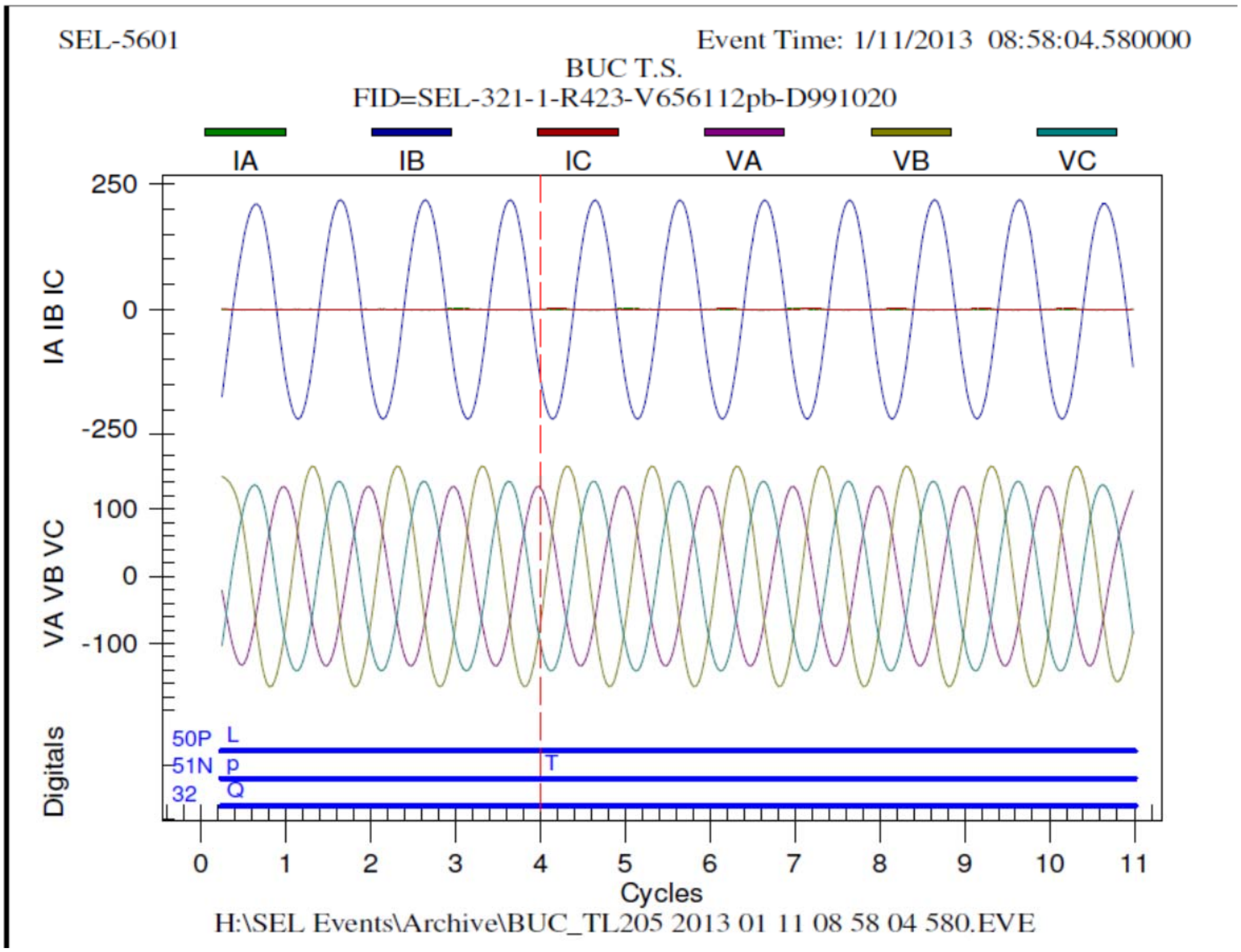

Figure 3-14: Buchans TL205 SEL Relay Report at 0858 Hours – 51N Operation

At 08:58:31 (approximately 12 seconds after tripping) TL250 reclosed but tripped again on line ground distance protection. Also around the same time, Bottom Brook breaker L11L33 tripped three phase via TL233 - P2 (Schweitzer) ground overcurrent (51N) protection. At this time L09L33 was already open. The tripping of L11L33 de-energized the Bottom Brook station and TL211 along with the Massey Drive 230 KV busses B5 and B11. At this time only TL233, now open at the Bottom Brook end, was energized single phase via Buchans L05L33 - B phase.

During the next 10 minutes the ECC closed and opened some breakers on the lines at Massey Drive, Buchans and Bottom Brook, all during the single phasing condition. The actions neither energized nor de-energized any equipment, i.e. at Massey the ECC operator opened breaker B5L28 and closed breaker B3T3, and at Buchans, opened breaker L28L32 and closed B1L28, only to open it again a little later. At Bottom Brook the ECC operator closed B2L14. Also, beginning in this period at 09:04:33, Buchans TL233 - P2 (Schweitzer) 51N protection operated approximately 100 times, recorded by the system SOE, sending trips to both line breakers

B1L05 and L05L33 which were already open, except for B phase on L05L33 which still failed to trip.

At 9:10:04, the ECC operator closed breaker L09L33 at Bottom Brook. This energized TL209 - B phase only, from TL233 along with Stephenville transformer T3, energizing the 66 KV supply to Newfoundland Power. Both T3 low side breakers tripped in about 0.5 seconds, disconnecting the supply to NP, followed by the tripping of Bottom Brook breaker L09L33 three cycles later via TL209 - P1 (Optimho) protection on SOTF which de-energized TL209 again.

At 9:12:56, the ECC operator again closed L09L33 at Bottom Brook, energizing TL209 - B phase only, and picking up Stephenville T3 again, this time with the low side breakers open. This caused some very high voltages on the 230 KV and overexcited the transformer. After approximately 17 seconds, breaker L09L33 at Bottom Brook tripped via TL233 - P2 (Schweitzer) line ground overcurrent (51N) protection, de-energizing TL209 and Stephenville T3.

At 09:22:58 C phase of Buchans breaker L05L33 closed and 09:23:34 there was a closure of A phase (see Figure 3-15), most likely due to loss of air, ending the single phasing condition and energizing TL233 on all three phases. This closing now permitted the ECC to begin a more normal restoration of the West Coast system.

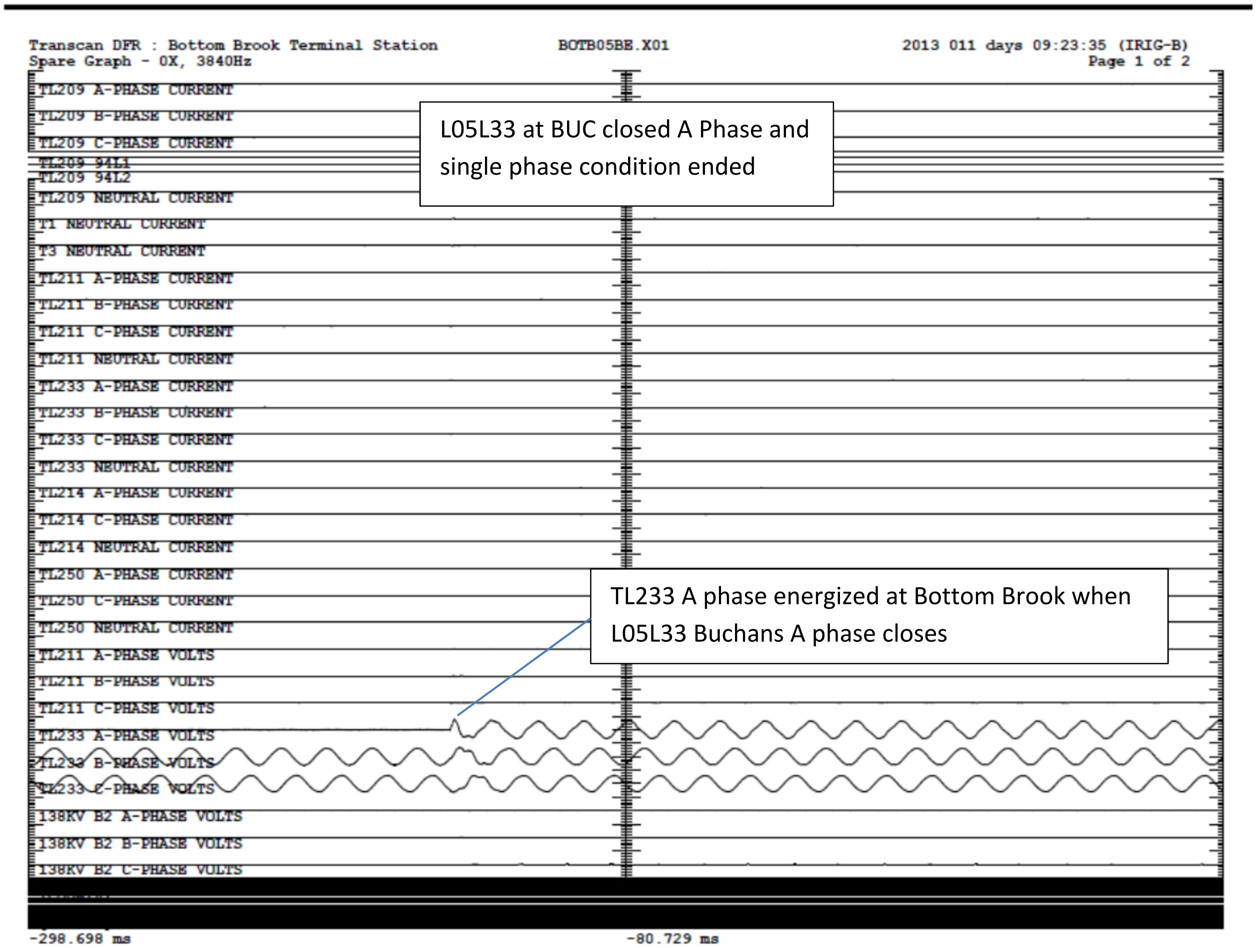

Figure 3-15: Bottom Brook DFR Trace at 0923 Hours Showing BUC L05L33 Closed Three Phase

3.2.2 Continuation of the Restoration Period (Post Single Phasing)

During and after the abnormal single phasing condition, the ECC operator continued with the restoration of the system, as seen from the sequence of events in Appendix A-5. The following highlights some of the major events during the restoration:

- At 0859 hours the Hawkes Bay diesels were put on line.
- At 0907 hours, Western Avalon breaker L01L37 was closed, returning line TL201 to service and energizing the Hardwoods and Oxen Pond terminal stations. By 0910 hours, it was loaded to over 60 MW and, by 0936 hours, to 216 MW.
- At 0909 hours the first unsuccessful attempt of four to energize TL242 from Hardwoods was made. The Holyrood end of the line was open. The line was energized by closing breaker B2L42 but faulted B-C phases and tripped on both line protections in four

cycles. The location of this fault and the other three subsequent faults were indicated by the protections to be very close to the Holyrood end. Location distances with a range from 26.59 km to 33.03 km were recorded by the protection relay fault locators at Hardwoods. The line is approximately 27 km long. Subsequent line patrols did not show any issues with the line.

- At 0916 hours the Hardwoods gas turbine was put online. The unit generated up to a level of 17 MW before tripping at 0939 hours. The unit was put on line and tripped several times during the restoration period.

- At 0918 hours breaker B2L26 at Deer Lake was closed, energizing TL226 and restoring supply to customers from Wiltondale to Parsons Pond after tripping previously at 0807 hours due to underfrequency.

- At 0923 hours, as noted previously, breaker L05L33 at Buchans closed three phase, energizing TL233 on all three phases and ending the abnormal single phasing condition.

- At 0933 hours breaker B11L06 at Bay d'Espoir was closed by the ECC putting line TL206 in-service. It was already closed at the Sunnyside end. The breaker closed on A and C phases only and tripped 85 cycles later most likely on pneumatic disagreement, see Figure 3-16. Come by Chance capacitor banks C1 and C2 also tripped at this time, most likely due to the momentary voltage increase on the 230 KV bus at Come By Chance resulting from the impedance decrease and phase unbalance caused by the closing of the line in parallel with TL202. The 230 KV overvoltage level experienced at Come By Chance was most likely marginally, i.e. at the 110% trip setting, as the third bank in service at this time (C3) did not trip. Shortly after the trips the banks were put back in-service by the ECC.

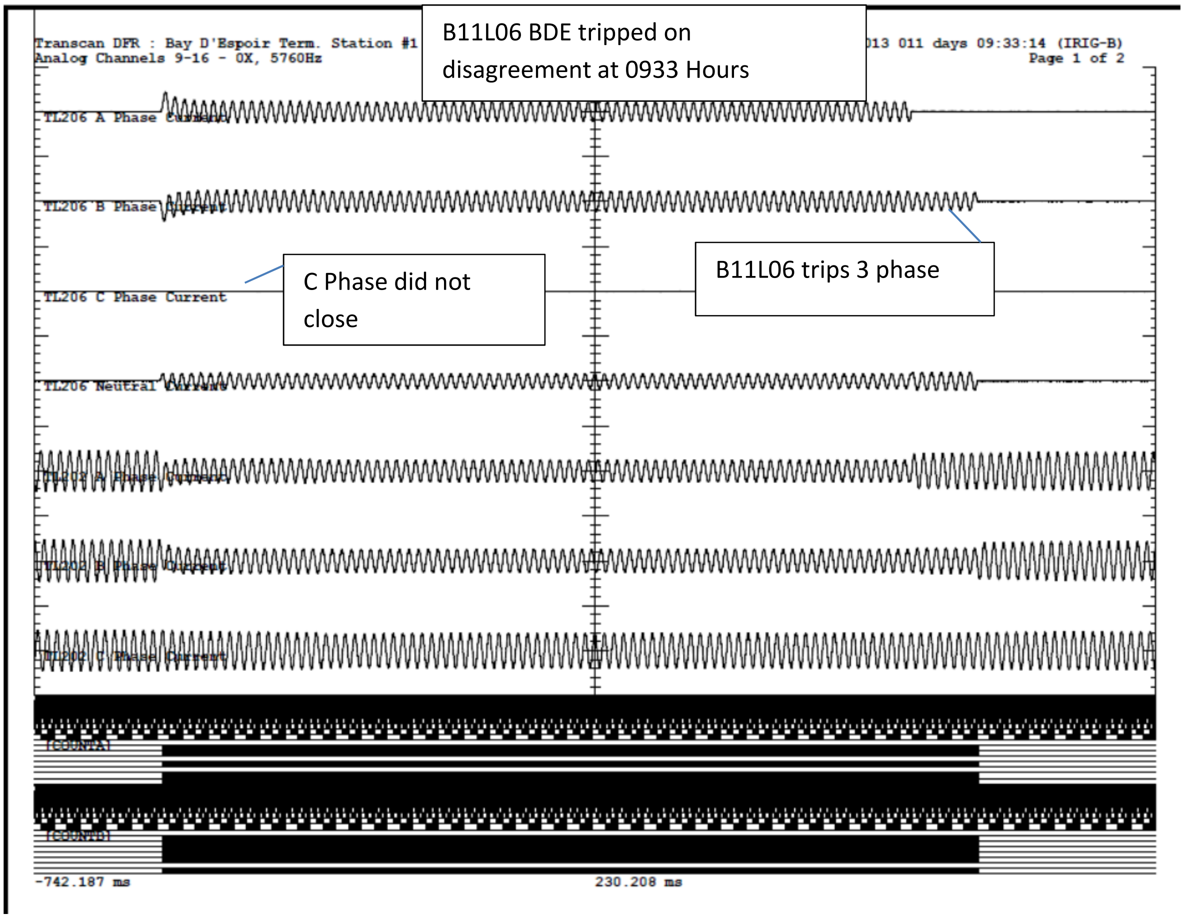

Figure 3-16: Bay d'Espoir DFR Trace at 0933 Hours Showing TL206 Close and Trip

- At 0935 hours breaker L06L34 at Bay d'Espoir was closed by the ECC returning TL206 to service on all three phases. No trips occurred at the in-service capacitor banks in Come By Chance at this time.

- At 0939 hours breaker B1L28 was closed at Massey Drive, energizing the Massey Drive 230 KV bus and NP 66 KV load busses. The Hardwood gas turbine tripped when load was picked up at Massey Drive. An underfrequency had occurred on the system, tripping TL226 in Deer Lake. Transmission line TL226 was re-energized seven minutes later by the ECC.

- At 0944 hours breaker B2T2 at Massey Drive was closed, putting transformer T2 back in-service and paralleling T3.

- At 0946 hours the Hinds Lake plant was connected via the 230 KV line TL248 into Massey Drive.

- At 1008 hours the Granite Canal unit was put on line. The unit was loaded up to 29 MW at 1013 hours.

- At 1023 hours there was a significant load increase followed by a drop of approximately 60 MW in the St. John's area, related to activity at the NP stations at Stamps Lane and Molloys Lane, see Figure 3-17. This led to a system overvoltage and the tripping of capacitor banks C1, C2, C4 at Come By Chance.

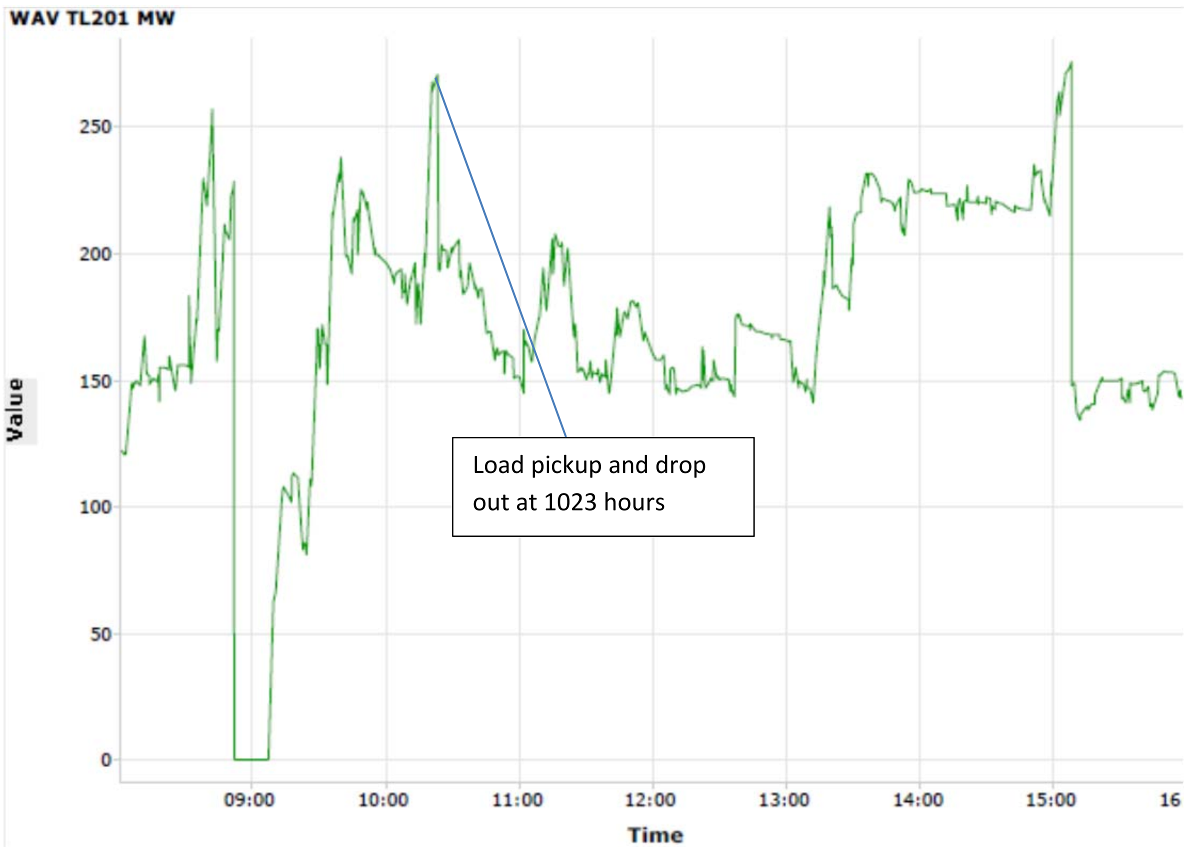

Figure 3-17: TL201 MW Loading from 0800 to 1600 Hours

- At 1057 hours NP breaker 38L-B closed and tripped at Seal Cove. The Holyrood breaker, B7T5, faulted (it was open at the time) when energized from 38L, see Figure 3-18. The lockouts associated with T5 (86T5) and the 66 KV bus (86B6B7) both operated via instantaneous differential protection, transformer and bus respectively. The fault was cleared by breaker B7L38 at Holyrood and by NP 38L-B at Seal Cove.

- At 1116 hours the Bottom Brook breaker B1L09 was closed by the ECC but opened and closed multiple times due to suspected breaker air problems. TL214 and the Doyles station were connected at the time. The breaker ended up open, see Figure 3-19.

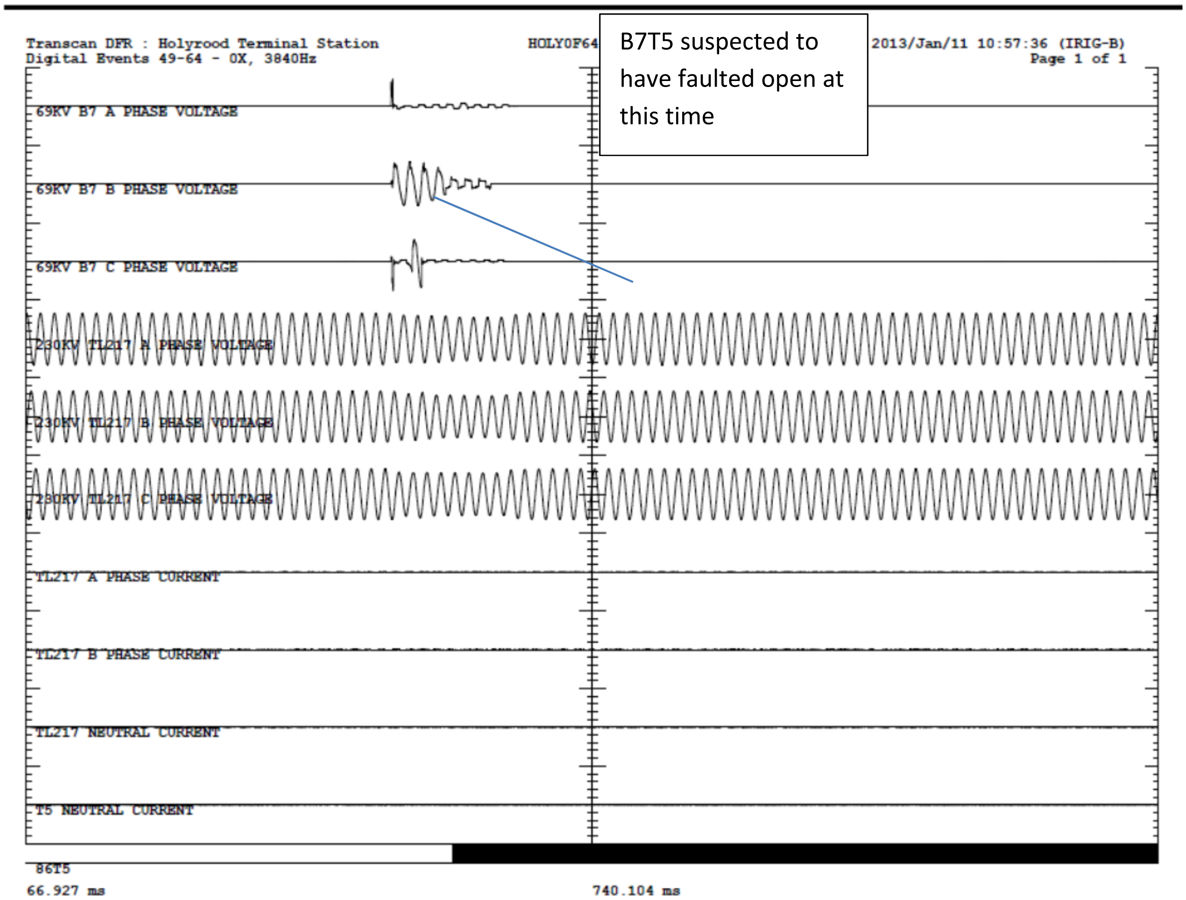

Figure 3-18: Holyrood DFR Trace at 1057 Hours Showing Suspected Fault to Breaker B7T5

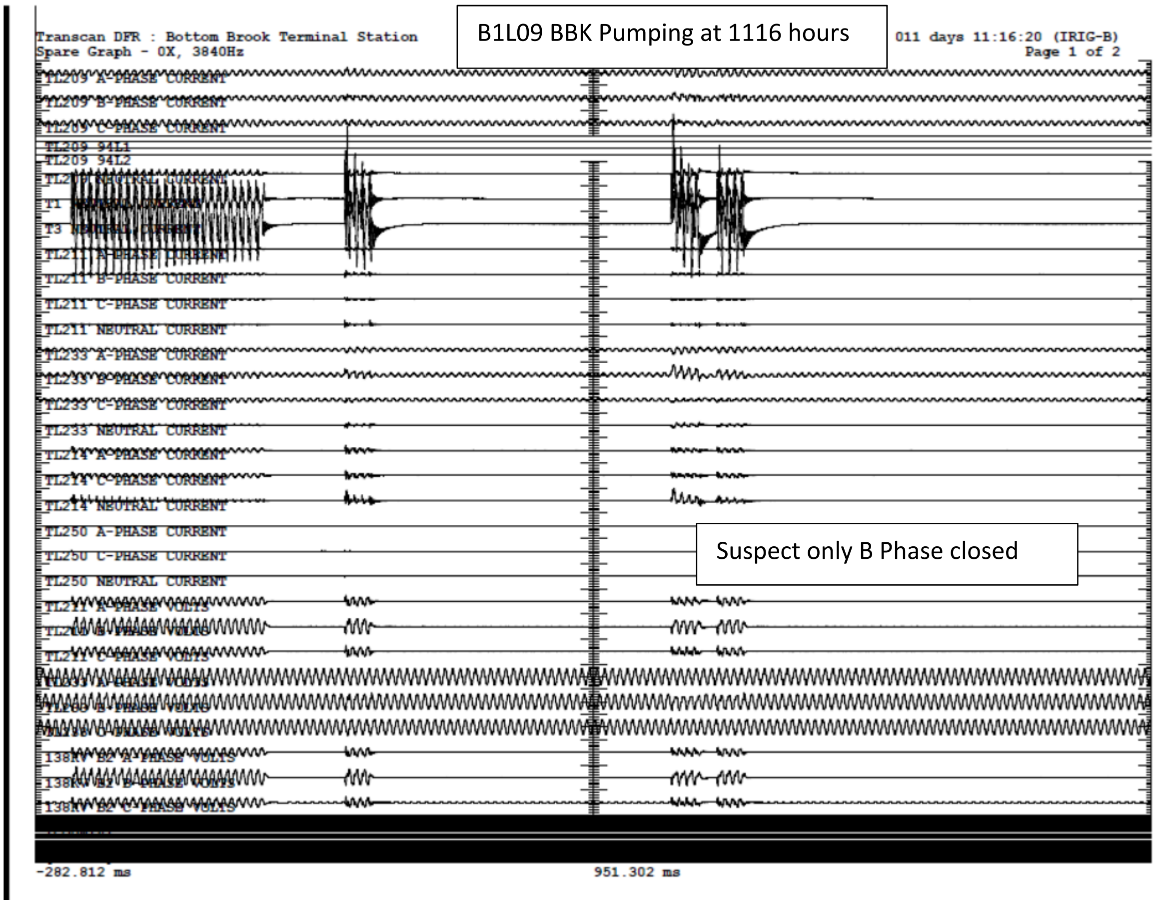

Figure 3-19: Bottom Brook DFR Trace at 1116 Hours Showing BBK Breaker B1L09 Pumping

- At 1119 hours Bottom Brook breaker L11L33 was closed, energizing busses B1, B2, B3, and transmission line TL214 into the Doyles terminal station.

- At 1146 hours the Deer Lake Power and NL Hydro systems were tied together via TL225 at Deer Lake.

- At 1152 hours Massey Drive breaker B4T1 was closed connecting transformer T1 to the Deer Lake Power 66 KV.

- At 1234 hours Holyrood lockouts 86B8B15, 86T5 and 86B6B7 were reset.

- At 1301 hours Doyles lockout 86T2 was reset but operated again approximately one minute later, operating the high speed ground switch - L14AG and sending a transfer trip signal to Bottom Brook to trip TL214. It is suspected that the lockout operated when the NP disconnect T2-A was closed.

- At 1310 hours TL242 was successfully energized from the Hardwoods end.
- At 1311 hours TL214 was re-energized, putting Doyles transformer T1 back in-service.
- At 1316 hours Bottom Brook breaker L11L33 was closed, putting transmission line TL211 in-service. At this time all 230 KV lines in the Western and Central areas were back in-service with the exception of TL247 (Cat Arm to Deer Lake).
- At 1329 hours the Holyrood breaker fail lockout 86BF/B12L17 was reset.
- At 1444 hours the Upper Salmon unit was put online following the reset of lockout 86G/2 at 1439 hours. The unit was loaded to 79 MW at 1502 hours.
- At 1458 hours Holyrood breaker B12L42 was closed, placing TL242 in-service. Transmission line TL217 was still open at Holyrood. Only TL201 was in service to supply the St. John's area loads (220 MW).
- At 1503 hours Holyrood breaker B6T10 was closed. The Holyrood 66 KV busses B6B7 were now energized.
- At 1507 hours Holyrood breaker B12L18 was closed, putting transmission TL218 in-service.
- At 1508 hours Holyrood breaker B12L17 was closed, putting TL217 back in-service and paralleling TL201. Load on both lines totalled 277 MW at this time.
- At 1541 hours Holyrood breaker B12B15 was closed. This energized the Holyrood 230 KV bus - B15 along with transformers T6, T7, T8 and the 138 KV bus - B8.
- At 1544 hours Holyrood breaker B8L39 was closed, putting the NP 138 KV line 39L in-service.
- At 1637 hours Holyrood breaker B7L38 was closed, putting the NP 66 KV line 38L in-service.
- At 1700 hours the Holyrood terminal station ring between B11 and B12 was closed. The Holyrood 230 KV bus B11 was now energized.

- At 1723 hours Holyrood breaker B1B11 was closed, closing the second ring between busses B11 and B12.

- At 1738 hours Holyrood breaker B7T5 was closed, putting transformer T5 in service.

- At 1821 hours Cat Arm breaker L47T1 was closed, putting Cat Arm Unit 1 on line. The unit was loaded to 50 MW at 1900 hours.

- At 1853 hours Cat Arm breaker L47T2 was closed putting Cat Arm Unit 2 on line. The unit was loaded to 60 MW at 1914 hours.

- At 2058 hours Buchans breaker failure lockout 86BF/L05L33 was reset followed by a reset of transformer lockout 86T1 at 2101 hours.

- At 2352 hours Buchans breaker B1L05 was closed, putting transformer T1 back in-service. The time required for personnel to test the transformer and reset the lockout had delayed the re-energization.

- At 2355 hours Buchans breaker B2T1 was closed followed by reclosers BUC-01-R1, BUC-02-R1, and breakers B2L80 and B2L64, fully restoring the station by midnight.

January 12

- At 0010 hours the Star Lake unit was put back online.

- At 0354 hours Holyrood Unit 2 was put back online.

- At 0513 hours Holyrood Unit 3 was put back online.

3.2.3 Additional Observations

- The ECC was faced with widespread outages on the system including the outage to the entire St. John’s region, all the Western area and some outages to the Central area. There were lockouts of all Holyrood units, Cat Arm units, Upper Salmon unit, and a number of lockouts in stations, particularly the Holyrood terminal station, which prevented any lines terminating in Holyrood from being re-energized. With the storm still raging in the Eastern area and impeding travel, personnel were hampered in their response to inspect the station equipment and reset the lockouts.

- The single phasing of Buchans breaker L05L33 upon closure at 0858 hours caused issues such as over and under voltage, lockout operation, additional line tripping, Operator confusion and resulted in additional delays in restoring the system back to normal. When the breaker was opened by the ECC, B phase failed to open even though the breaker indicated open on the EMS status. The reason why the breaker failed to open on B phase and closed uncommanded is not known, however air system problems are suspected. The breaker was taken out of service following this event for an extended period and repaired. There was some damage found on the C phase head and it was replaced. There were auxiliary switches also found to damaged and subsequently replaced. Tests were done on the breaker and the six year preventative maintenance procedures were completed. There were welded contacts found on relay 94L2 from the TL205 trip circuit, resulting in a permanent trip signal to trip coil no. 2 circuit. These were also repaired. In addition, an incorrectly mounted pressure was repositioned.

- The L05L33 breaker failure at Buchans was initiated after the 51N protection operated but failed to clear the condition. The current practice for a breaker failure operation is to trip local breakers but not remote end breakers. Remote end breakers are expected to clear via timed backup protection, in this case the 51N protection on TL205 and TL233 at the Stony Brook and Bottom Brook ends, respectively. This would most likely happen in the case of a fault with a failure to open condition but not for a phase failure to open condition as occurred in this case. For breaker failure operation as experienced here, transfer tripping of the remote breakers on TL205 and TL233 would prevent this condition from persisting by opening and locking out the remote end breakers.

- There were several protection operations during the single phasing events. The TL233 51NL operations were expected given the unbalance on the line. There were many operations of the TL233 protection at Buchans over the 25 minute single phasing period. This caused a severe duty on the protection contacts which may have been energizing and de-energizing trip coils in breaker L05L33 as the contacts picked up and dropped out. In addition, one would have expected the 51NL to operate on TL205 as this relay should have been exposed to more unbalance current than the relay on TL233, however the 51NL on TL233 is set lower (8.2 MVA) than the TL205 setting (47.8 MVA). Other protections, such as the Zone 1 on TL250 and the distance protection on TL209 at Stephenville likely operated due to the abnormal supply issues measured by the protection resulting from the single phasing conditions. The Doyles lockout 86T2 operated at 0858 hours most likely due to the operation of the transformer overcurrent protection on NP transformer T2 (no targets were available) caused by the overexcitation. The reason for the second operation at 1302 hours, just after the lockout was reset, is not known but is suspected to have been caused by the closing of the NP T2-A disconnect or issues with its open status in the protection circuit.

- During this single phasing period the Buchans TL233 protection initiated many transfer trips to the Bottom Brook end. Some of these transfer trip signals were applied for extended periods of several minutes. Also during this period, there were issues in the sequence of events in that the reports missed data at Buchans and repeated events many times at Bottom Brook. Events at Buchans would show two normal states in a row for the same point, missing the abnormal state. This added to the confusion in analyzing this particular event.

- At 1057 hours the Holyrood lockouts 86B6B7 and 86T5 operated when an attempt was made to energize the 66 KV bus B6B7 from NP's line 38L. As breaker B7T5 was open at the time and, given there was a fault as recorded in the DFR trace (see previous Figure 3-18), the fault location is, in all likelihood, on or in the breaker. This was also indicated by the protection operations (in both zones). A and B phases were involved, most likely related to the severe salt contamination. The fault was cleared by 38L protection at NP's Seal Cove station.

- At 1116 hours there was an issue with breaker B1L09 at Bottom Brook when it was closed to energize the station. It 'pumped' multiple times before ending up tripped. This can be seen in the Bottom Brook DFR trace, previous Figure 3-19. It is suspected that it only closed B phase. TL214 and the Doyles station were energized during the pumping operations.

- There were lockouts on the units at Cat Arm and at Upper Salmon during the original load rejection which delayed putting the units online until operators arrived at the plants. The lockouts should not operate for load rejections and appear to be governor related from some of the limited information available with regards to the trips. In addition, at Cat Arm there were station service issues reported by the operators when they arrived at the plant which further delayed getting the units back online. The emergency diesel unit was started but, due to issues with its supply breaker, could not supply the essential loads. Plant personnel experienced problems with the other supplies and station service could not be re-established until a line crew arrived later in the day to establish supply from the Coney Arm 12.5 KV line. The recloser on this line (52SSLR) has to be closed manually due to an ongoing rectifier failure issue. In addition, without load shedding the accommodations, the Coney Arm supply breaker (52SSL) will not stay closed. The accommodations are supplied with an 800 amp single phase service and the breaker trips on neutral overcurrent caused by the imbalance when attempting to pick up the accommodations. Both of these issues had to be overcome before the Coney Arm line could be closed to restore station service to the plant.

- In the design of the Cat Arm plant, black start capabilities from each unit and from the 230 KV were included for such situations as occurred here. The backfeed from the 230 KV was considered but was not attempted due to concerns about high voltage conditions on the 230 KV and the possibility of exposing the station service equipment to these high voltages if attempted. Black start from the units was not considered as this capability has not been confirmed nor are there procedures in place to perform the same.

- There were many operations of the capacitor bank protections due to overvoltage. The banks at Come By Chance have an overvoltage setting of 110% and all have the same trip time of 10 cycles. This caused simultaneous tripping of the banks, such as at 0933 hours, that caused severe voltage swings. Staggering of the settings, 10 cycles apart or so at this level, should be considered to trip banks individually rather than all at the same time. In addition, the capacitor banks at Hardwoods and Oxen Pond were closed by the ECC in an attempt to control the voltage at various times, however they tripped after a while on overvoltage with the varying load. The banks at Hardwoods and Oxen Pond have similar voltage settings except they are staggered on time. The tripping on the overvoltage (107%) was the result of the changing loads on the system with load pickup and drop off during the restoration. One bank, C2 at Hardwoods, appeared to trip more frequently and prematurely. Based on the time settings, bank C2 should have been the second bank to trip when the voltage trip point was exceeded, however it was the first. The protection settings should be checked. The ECC was operating the banks to control the voltage in the region. There were times when the Hardwood gas turbine was on and should have helped control the voltage fluctuations. However, a preliminary review of the gas turbine reactive output profile during the period between 10 am and 2 pm, when it was online, reveals large fluctuations in reaction to the opening and closing of the capacitor banks. Whether this assisted or hampered the control of the voltage is not obvious.

  There were four failed attempts by the ECC to energize TL242 from the Hardwoods end with the Holyrood end open (at 0909, 1027, 1029, and 1041 hours) with a fifth and successful attempt at 1310 hours. This was successful in finally energizing the line but it did jeopardize the TL201 connection into Hardwoods as, for each attempt, the line faulted phase to phase and the fault appeared to be permanent in nature. As the line was open at the Holyrood end this was an effort to initiate the re-energizing the Holyrood station and re-establish station service to the plant via bus B11, as Bus 12 was locked out. Under normal outage conditions this number of attempts, particularly when the line faulted phase to phase, would not be acceptable, but these were far from normal outage conditions and the operator action was justified given the circumstances even though it failed to achieve the re-energizing of the Holyrood station. A subsequent line patrol of TL242 did not reveal any line damage, therefore it is presumed that the faults on the line were caused by the severe salt contamination of the line or station equipment (possibly the open line breakers in the yard).

- At 0933 hours breaker B11L06 was closed at Bay d'Espoir to put TL206 in-service (it was already closed at the Sunnyside end). The breaker only closed two phases of the line to be in parallel with TL202, see DFR trace - previous Figure 3-16. It then tripped on disagreement. This was followed by the overvoltage tripping of two of three in-service capacitor banks at Come By Chance. An attempt was made to close the breaker again at 1422 hours but it again failed to latch closed. It was successfully closed at 1436 hours while in local control.

3.2.4 Actions Taken

- Buchans breaker L05L33 was removed from service. A damaged C phase head and auxiliary switches were replaced. A pressure switch, which was found to be installed incorrectly, was correctly positioned. The six year planned preventative maintenance routine was completed followed by tests and checks on the breaker.

- Also associated with the Buchans breaker L05L33, the defective trip relay 94L2 associated with line TL205 was replaced.

- A line patrol of transmission line TL242 was conducted which did not reveal any issues of a permanent nature on the line.

- Buchans transformer T1 was inspected and tested prior to putting it back in-service following the transformer differential and lockout operation.

3.2.5 Further Actions Required

- Further investigation and testing should be performed on Buchans breaker L05L33 to ensure that the failure to trip B phase, failure to trip on disagreement, and the subsequent closure on loss of air is more completely understood, with repairs as required.

- Further checks on the Buchans TL233 protection, both P1 and P2 trip outputs, into the L05L33 trip coil circuits should be completed to ensure the relay contacts are not damaged due to the numerous operations which occurred during the single phasing conditions.

- Consideration should be given to the addition of remote end tripping of line breakers in the event of breaker failure lockout operations, such as that which occurred on L05L33. The 86BF lockouts should initiate transfer trip to the remote end of the lines.

- The issues with the SOE reporting, i.e., the missed events at Buchans and repeated events at Bottom Brook, should be further investigated.

- Further investigation should be carried out into the determination of the cause of the lockout operations which occurred at Cat Arm and Upper Salmon during the load rejections at 0742 hours. This may include a planned load rejection at each plant to duplicate the conditions which occurred.

- In the future, for all trips of larger generating units, investigations and reports should be completed to determine the cause and whether the plant's systems operated properly. The investigations should include trips due to system related issues. Information such as targets, alarms and logs should be collected and included in the reporting for each event. Any deficiencies should be addressed and corrected.

- Further investigation into the performance issues with the Cat Arm station service supplies should be carried out to determine what needs to be corrected to ensure that station service is available following a trip of the plant. This should include an investigation into whether unit black start capabilities exist and the development of procedures to carry out the same.

- The issues resulting in the delays in restoring station service supply to the Cat Arm plant via the Coney Arm 12.5 KV line (i.e., lack of remote control of the recloser and load imbalance) should be further investigated and corrected, as required.

- Consideration should be given to timer setting changes for the Come By Chance capacitor banks in order to stagger the tripping of the banks for the first level (110%)

overvoltage trip. Currently all banks have 10 cycle trip timers. These could be changed to 10, 20, 30 and 40 cycles for banks C1, C2, C3 and C4, respectively, or some other suitable times.

- The settings for the overvoltage trip (level and timer) at the Hardwoods capacitor bank C2 - 90C2 relay should be checked.

- Consideration should be given to a system voltage study which simulates normal loading scenarios but also abnormal scenarios such as occurred during January 11. Scenarios should include those such as all Holyrood units offline with one line supplying the Avalon - with load restoration, load restoration on the Western system after a major outage, major load rejection, etc. From this study, a suitable operation strategy/guideline should be developed to assist the ECC operators in maintaining system voltages within acceptable limits. The gas turbines and other sources of generation voltage support should also be considered in the study. This study should also address the requirement for the addition of system undervoltage and overvoltage protection and the role the EMS controls might play in the control of the system voltage during abnormal conditions. Application of undervoltage and overvoltage protection schemes should be considered. Currently there is very limited overvoltage protection and virtually no undervoltage protection in service on the system.

- A thorough check should be performed of Breaker B7T5 at the Holyrood terminal station due to the suspected fault at 1057 hours.

- Testing of Bottom Brook breaker B1L09 should be carried out to determine why it ‘pumped’ (closed/open) after the initial closure at 1116 hours.

- Testing of Bay d’Espoir breaker B11L06 should be undertaken to determine why it failed to close on all three phases at 0933 hours.

- The second lockout and ground switch operation at Doyles at 1302 hours should be further investigated. It appears that, after the lockout was reset, there were issues with the NP disconnect T2-A inputs into the lockout circuit. When T2-A was closed the inputs operated and tripped TL214 and applied the high speed ground switch, L14AG. This circuit should be checked during the next planned outage of the station.

4.0 CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER ACTION

4.1 Fault Events and Disturbances

Overall, the events which occurred on January 11, 2013 were marked by many abnormal incidences. There were numerous faults and equipment operations. Many of these operations were expected and correct but there were also many equipment failures, in particular due to protection and high voltage breaker issues which cascaded a single incident into major system wide outages. Many of these issues have been identified and proposals to address them have been recommended. Considerable time has been spent but more time is required to fully address all the issues and to implement the solutions or remedial actions.

As outlined in this report, on this day a severe winter storm with high winds and heavy snowfall had a significant impact on the Island Interconnected power system, resulting in widespread customer outages. At Holyrood severe salt contamination of the equipment insulation in the terminal station yard, driven by the high northerly winds, led to a series of faults and trips in the station and on the lines into the station. The events began at 0413 hours with the trip of Unit 3 while loaded at 68 MW, due to a fault in the terminal station. Unit 3 shut down safely and without damage.

At 0642 hours a single phase fault on Unit 1's breaker B1L17, in the unit transformer T1 protection zone resulted in the high speed clearing of Unit 1 from the system. Unit 2 and 39L also tripped due to the slow clearing of the breaker fault from the 230 KV system, related to issues with the breaker failure protection. Transmission line TL217 tripped on the Western Avalon and Holyrood ends via the line protection when the fault migrated a couple of meters from the breaker B1L17 area into the TL217 transmission line zone. Unit 1 was cleared quickly from the system but unit damage resulted during run down issues following the trip. Unit 2 shut down safely and there were no reports of any damage. The C phase of Breaker B1L17 was damaged and subsequently repaired. The loss of Units 1 and 2 resulted in a system load loss of 250 MW.

At 0648 hours another single phase fault occurred in the zone of protection of transmission line TL217. It was suspected to have originated in the Holyrood station due to the equipment salt contamination. Breaker B12L17 tripped to clear the fault but upon reclose of TL217, it re-faulted phase to phase. Transmission lines TL218 and TL242 tripped at the Oxen Pond and Hardwoods ends respectively, but incorrectly due to overreaching distance protection. However, breaker B12L17 failed to clear this fault and it resulted in a breaker fail protection operation locking out the 230 KV bus B12. During the reclose dead time of TL217 there was a bus fault on the 138 KV bus B8B9 which also tripped and locked out. TL217 was already open at the Western Avalon end from the previous trip at 0642 hours. Therefore when TL218 and TL242 tripped, the fault was supplied by an ungrounded 230 KV system, backenergized from the NP 66 KV through the delta connected transformer T10. Eventually there was a three phase flashover somewhere on bus B12 before clearing. Load loss during this event was 240 MW due to the line tripping and voltage depression.

At 0742 hours, with the Holyrood generating plant and terminal station out of service, the remaining 230 KV line east of the Western Avalon terminal station (TL201) faulted and tripped due to high winds and a jumper issue. This resulted in an outage to St. John’s and the immediate area and a severe overfrequency on the remaining interconnected system east of the Western Avalon terminal station. This was due to loss of the St. John’s area load of 286 MW. The overfrequency caused some digital line protections to misoperate and trip numerous 230 KV and 138 KV lines which resulted in the system separating further into islanded areas. The two 230 KV lines, TL204 and TL231 from Bay d’Espoir to Stony Brook, tripped at the Bay d’Espoir ends and the 138 KV loop from Sunnyside to Stony Brook tripped at the Sunnyside end, all due to the overfrequency condition. This separated the Hydro system into two areas, Eastern and Western, supplied by the Bay d’Espoir and Hinds Lake plants respectively. Other generating units, such as those at Cat Arm, Upper Salmon, and Granite Canal tripped due to line digital protection trips on the lines connecting them. Deer Lake Power separated from the Western system. The 230 KV line, TL248, tripped at Deer Lake and the 138 KV line, TL222, tripped at Springdale on digital protection, further islanding the Hinds Lake plant and de-energizing all the Western and Central 230 KV lines west of Stony Brook. Approximately 10 seconds into the event, a reclose on 100L at Sunnyside terminal station backenergized the 138 KV circuit into Stony Brook, momentarily energizing the 230 KV system west of Stony Brook to Massey Drive. This resulted in many breakers tripping incorrectly on the 230 KV system before 100L tripped again. This was also the time at which an RTU communication issue was experienced at Stony Brook and resulted in the non-updating of equipment status information at this station. This significantly impeded the ECC restoration efforts for a period of approximately one hour.

The result of these events was an outage to the St. John’s region and nearly all of the Central and Western areas except for customers connected via the 138 KV lines from Springdale to Deer Lake including parts of the GNP which were being supplied by the Hinds Lake plant. Total load loss from the system was approximately 700 MW.

4.2 Restoration Events

The restoration efforts were plagued with difficulties from the start. The storm was still prevailing in the Eastern area resulting in additional trips and outages. The reset of the lockout relays at the Holyrood station were delayed due to the storm conditions that impeded travel and prevented appropriate personnel from reaching the stations in a timely manner. In the Western area there were issues with equipment status updates from the Stony Brook terminal station and significant breaker issues which resulted in abnormal system operating conditions and presented significant challenges for the ECC operators. The following is an overview of the restoration, concentrating mainly on the abnormal events which occurred.

At 0748 hours the ECC started restoration of the outaged areas with the energization of TL231 at Bay d'Espoir. This energized the 230 KV and 138 KV busses at the Stony Brook terminal station but due to issues with breaker B1L31 at Stony Brook, TL235 (Stony Brook to Grand Falls) tripped. Updates of the Stony Brook equipment status and telemetry were not available due to the communications issue from the RTU to the ECC and complicated the restoration process in the Western area. In the meantime TL201 was restored at 0755 hours and power was being restored to the St. John's area with bumps and fluctuations causing some voltage disturbances. Weather was still a factor, hampering the availability of personnel and causing additional equipment issues.

At 0800 hours the ECC restored TL248 from Deer Lake to Massey Drive, energizing Massey Drive and picking up some Corner Brook load along with transmission lines TL211, TL228 and TL205, all from the Hinds Lake plant. This operation resulted from incorrect status indications at Stony Brook. This caused a significant underfrequency, to approximately 50 hertz, and voltage issues resulting in overexcitation on the system. This condition persisted for approximately 10 minutes until the Massey Drive transformer loads were tripped by the ECC. This temporarily caused increased overexcitation and resulted in the lockout and trips of transformers T1 at Buchans and T2 at Massey Drive which de-energized the 230 KV at Massey Drive and transmission lines TL211, TL228 and TL205 which were all previously energized.

At 0837 hours the communication issue to Stony Brook was corrected and at 0844 hours the Hinds Lake Western islanded area was reconnected to the Bay d'Espoir system via the 138 KV into Stony Brook with the closing of Springdale breaker B1L22.

At 0851 hours TL201 faulted and tripped again causing another outage to the St. John's area and the loss of approximately 225 MW of load.

At 0853 hours restoration attempts in the Western area continued with the closing of TL205 at Stony Brook which resulted in the single phasing and high voltage on the system due to a breaker issue at L05L33 at Buchans. There were multiple trips and alarms over a 25 minute period before the single phasing condition cleared. This was very confusing to the ECC and delayed restoration efforts.

At 0907 hours TL201 was energized and restoration of the St. John's area proceeded again. By 0930 hours the load was approximately 200 MW on TL201. TL206 was back in service at 0935 hours. There were issues with voltage control with trips the capacitor banks and the Hardwoods gas turbine as blocks of load were picked up.

At 0939 hours restoration was also progressing in the Western area with TL228 and Transformer T3 in service at Massey Drive and the reconnection of this station (via TL248) to Deer Lake and Hinds Lake at 0946 hours.

The loading on the system continued to increase while attempts to put TL242 in service to re-energize the Holyrood 230 KV resulted in several faults and trips. At 1057 hours a fault is suspected to have occurred at the Holyrood 66 KV breaker B7T5 when energized and resulted in a lockout. Conditions were getting back to normal on the Western system by noon with most load busses re-energized and Deer Lake Power reconnected. Cat Arm was not back online at this time due to station service issues.

By 1330 hours the Holyrood lockouts were reset, including the B12L17 breaker failure lockout. At 1458 hours the Holyrood 230 KV bus B12 was energized via TL242. This was followed by TL218 and at 1508 hours TL217 was put in service paralleling TL201.

The Cat Arm units were both back online by 1853 hours.

The Buchans transformer - T1 was put back in service at 2352 hours following the lockout operation earlier in the day and the station was fully in service by midnight.

Holyrood Units 2 and 3 were back online at 0354 and 0513 hours on January 12, respectively.

There were many other operations and events during the day which are not summarized above, however the preceding should provide an indication of the numerous challenges that were faced during this very abnormal day. The number and severity of events made the analysis very difficult, in addition to providing for a very challenging set of circumstances for the ECC and other personnel.

There is additional work required to complete the analysis of the incidences and to gain a full understanding of exactly what occurred. However, based on the analysis done to date, the following section summarizes the recommendations for further action which have been grouped into areas of responsibility.

4.3 Recommendations for Further Action by Area

4.3.1 Transmission and Rural Operations (TRO)

1. There were many issues with breakers, particularly the 230 KV class, during these events. A review of the preventative maintenance schedules and procedures for these breakers should be carried out to ascertain whether they are being carried out adequately. In addition, this review should address whether or not they are adequate for the age of the breakers. One issue is the failure to trip which is related to the auxiliary contact in the trip circuits and may be mitigated by the exercising of the breakers. A schedule for this 'exercising' should be developed and monitored, possibly with the assistance of EMS data which reports the opening and closing of the breakers, to identify 'dormant' breakers.

2. Although inspection of the suspected station faulted area for the Holyrood Unit 3 trip at 0413 hours was performed following the fault, a more thorough inspection of the area should be performed during a scheduled outage, to ensure that no damage exists and to confirm the fault mechanism. The area of concern is from the unit's transformer bushings to the unit breakers.

3. The maintenance program pertaining to the application of the RTV coating on the Holyrood station equipment should be reviewed. The review should also address the extent of the equipment involved, as the current coverage appears to be associated with the unit breakers only.

4. The indications associated with the Holyrood Unit 1 disconnect should be checked during opening, as there appears to be no "in transit" position but rather two "opens". The auxiliary cam switches which provide for the indication need to be checked.

5. Testing should be carried out on line 39L protection, in particular the 51N relay as it appears that the disk is not fully resetting.

6. A more thorough inspection of the equipment associated with the 138 KV bus - B8 (A phase) at the Holyrood terminal station should be performed to determine the location of the bus fault that resulted in the bus lockout.

7. A thorough inspection of the external area of B12L17 should be conducted to look for evidence of an external fault on B and C phases in the TL217 line protection zone. Particular emphasis should be on B phase, the phase of B12L17 which failed to clear.

8. Further testing and inspection of breaker B12L17 is required to determine why the breaker failed to clear the fault on B phase. In addition, the problem with the erratic status indication of B12L17 should be investigated, beginning with examination and testing of the auxiliary contacts used for the indication. If no evidence of an external fault is found on B phase in the area of the breaker and it’s CT, an internal inspection of the B phase contacts and operating mechanism should be performed, as it suggests that B phase faulted, tripped and re-struck internally before being cleared via the breaker failure operation of B12T10.

9. Function testing of the 94TS/T1 Unit 1 transformer backup protection contacts in the breaker failure (B1/TF) and breaker failure lockout (86/BF - B1L17) circuits should be performed to ensure the timer is set and operating correctly to trip the breaker failure lockout.

10. Based on the damage found internally in breaker B1L22 at Springdale, other 138 KV KSO breakers on the system should be tested or inspected for resistor damage.

11. Further investigation and testing should be performed on Buchans breaker L05L33 to ensure that the failure to trip B phase, failure to trip on disagreement, and the subsequent closure on loss of air is more completely understood, with repairs as required.

12. A thorough check should be performed of Breaker B7T5 at the Holyrood terminal station due to the suspected fault at 1057 hours.

13. Testing of Bottom Brook breaker B1L09 should be carried out to determine why it ‘pumped’ (closed/open) after the initial closure at 1116 hours.

14. Testing of Bay d’Espoir breaker B11L06 should be undertaken to determine why it failed to close on all three phases at 0933 hours.

15. The second lockout and ground switch operation at Doyles at 1302 hours should be further investigated. It appears that, after the lockout was reset, there were issues with the NP disconnect T2-A inputs into the lockout circuit. When T2-A was closed the inputs operated and tripped TL214 and applied the high speed ground switch, L14AG. This circuit should be checked during the next planned outage of the station.

16. Further checks on the Buchans TL233 protection, both P1 and P2 trip outputs, into the L05L33 trip coil circuits should be completed to ensure the relay contacts are not damaged due to the numerous operations which occurred during the single phasing conditions.

17. The settings for the overvoltage trip (level and timer) at the Hardwoods capacitor bank C2 - 90C2 relay should be checked.

18. The issues resulting in the delays in restoring station service supply to the Cat Arm plant via the Coney Arm 12.5 KV line (i.e., lack of remote control of the recloser and load imbalance) should be further investigated and corrected, as required.

4.3.2 Thermal Generation

19. Plant management should review the instructions for recording protection targets after unit trips to ensure that they are recorded by the operator before they are reset. Protection panel cards should be updated and made available to the operator for recording the targets as required.

20. During the next scheduled maintenance outage of Unit 3, a function test of the 87GT3 relay should be performed to ensure that the relay targets flag when the relay operates into the lockout.

21. The plant SOE indicates operation of the Unit 3 generator lockout 86-2 but no lockouts were reported in the system SOE at this time. Therefore, the system SOE for this point and the other Unit 3 lockouts should be operation tested.

22. Internal plant trip reports for all unit trips should be completed by plant personnel and distributed to ensure that all systems worked as designed.

4.3.3 PETS - Protection & Control Engineering

23. The lockouts from Unit 1 and 2 which trip the unit breakers, should be added into the Holyrood breaker fail scheme design of the terminal station for the required breakers. A review of all breaker fail designs schemes on the system should be conducted to ensure that all schemes are adequate, in that they have the correct initiating inputs such as the lockouts, and trip the required breakers in the event of a breaker failure.

24. In conjunction with the recommendation to install CT's on both sides of the Holyrood terminal station 230 KV breakers, a new protection design philosophy should be developed with overlapping protection zones to cover all new installations.

25. The application of appropriate settings for the load encroachment feature on all SEL 321 relays should be done to prevent operation during off-frequency events. A review of SEL's final recommendation report (pending) should also be carried out. A setting of 100 ohms primary for all lines is recommended based on the protection settings for the longest line on the system, TL206. This setting will accommodate a load of 529 MVA before blocking. The angles settings are PLAF=90, NLAF=-90, PLAR=90, NLAR=270. This approach is preferred over the setting of the 50PP1 current monitor as it is independent of minimum fault levels.

26. Consideration should be given to the application of trip coil monitors at all breakers which have remote alarming features. The monitors would indicate issues with the circuits. Currently only local monitoring exists using panel lights. SEL has a trip coil monitor which might be suitable.

27. The Zone 2 protection reaches on TL218, TL242 and TL217 need to be increased to ensure that they operate for faults at the remote terminal end. The second zone timers for TL218 and TL242 should also be decreased from 60 cycles to 18 cycles.

28. Previous reviews by Henville Consulting have recommended Zone 1 and Zone 2 protection setting changes for the Eastern lines in addition to setting changes for other line relaying. These should be revisited and implemented as soon as possible.

29. Further investigation into why the Come by Chance 230 KV Capacitor bank, C4, tripped during the fault is required. The 94C4 operated to trip breaker B2C4 at 06:42:06, however this was at a time that the bank was required.

30. The Zone 1 distance protection settings on TL218 and TL242 (presently set at 88% and 82% of line lengths, respectively) should be decreased to a suitable level. A maximum 75% setting is recommended to ensure the protection does not overreach as occurred during these events. Previous studies have recommended a maximum setting of 80%.

31. Consideration should be given to the application of definite time overvoltage protection on the Hardwoods and Oxen Pond capacitor banks, with a trip time of approximately 5 cycles for the first bank and an added 5 cycles or so for each other bank (i.e., second bank at 10 cycles, third at 15 cycles, fourth at 20 cycles). This will permit for staggered tripping but still allow for the tripping of all banks in less than one second for severe overvoltages.

32. The recommended firmware upgrades should be implemented in the LPRO2100 relays. Testing should be done on the relays following the firmware upgrades to verify that the relays will no longer operate for these events. This can be performed by testing the relays with the file captured on January 11 as the input to control the test set.

33. The reclosing on 100L at Sunnyside should be re-evaluated and co-ordinated with Newfoundland Power such that, upon loss of voltage along the 138 KV loop and the tripping of 100L, the loop is opened at an appropriate location to ensure that a reasonable amount of load is re-energized upon reclose. This will help to prevent a repeat occurrence of the re-energization event as happened on January 11. If this cannot be coordinated then reclosing should be turned off.

34. Application of frequency monitoring to capture abnormal frequency events such as occurred on this day should be considered for installation in various 230 KV stations - one in an Eastern station, another in Bay d'Espoir and one in a Western station.

35. Further investigation into the tripping of TL236 at Oxen Pond should be conducted to ensure that the permissive overreaching logic is working properly on the P2 protection (SEL) relays. This protection tripped the Oxen Pond end during the 0742

hour event (trip of TL201). This was a nuisance trip of little significance at the time but could result in something of consequence in the future.

36. With regards to the tripping of breaker B1L31 at STB at 0748 hours, further investigation is required into why the SEL 321 operated when the station was energized. A request has been sent to Schweitzer to determine if they have any suggestions. If the problem is not addressed by Schweitzer then the relay should be fully tested to ensure it is operating properly. In addition, the load encroachment feature should be applied to this relay even though the problems are not suspected to have originated from a memory/frequency tracking issue.

    Since the breaker closed after tripping two phases, there should be a review of the three pole conversion circuitry for this line, as well as for all line protections, to ensure that the correct logic is applied to provide for three pole trip conversion on the tripping of two phases.

    The 94L2 three phase trip relay should trip the T relay to operate the TC1 and cancel reclosing. Other circuits should be checked to ensure that the 94L2 trips the T relay in this manner.

37. A timer should be added to extend the duration of the transfer trip signal from the STB TL235 protection which picks up the 85X at GFL FRC and provides for a direct trip of the three low side breakers 252T-1, 252T-2 and 252T-3 at GFL FRC.

38. Consideration and study should be given to the application of underfrequency relaying on the Hinds Lake generator and other hydro units to trip when extreme underfrequency levels are reached and maintained on the system or islanded areas, such as occurred on January 11. A level in the order of 54 Hz with a suitable timer might be appropriate. An alarm indicating an imminent trip would form part of the strategy to alert the operator to take action where possible.

39. Consideration should be given to the addition of remote end tripping of line breakers in the event of breaker failure lockout operations, such as that which occurred on L05L33. The 86BF lockouts should initiate transfer trip to the remote end of the lines.

40. Consideration should be given to timer setting changes for the Come By Chance capacitor banks in order to stagger the tripping of the banks for the first level (110%) overvoltage trip. Currently all banks have 10 cycle trip timers. These could be

changed to 10, 20, 30 and 40 cycles for banks C1, C2, C3 and C4, respectively, or some other suitable times.

41. Timers should be installed in the control circuits of the Come by Chance capacitor banks to block closure until at least five minutes have elapsed from the time of breaker opening. This would allow for the manufacturer's recommended discharge time.
42. The analysis of these events has highlighted the value of having two different types of protections from two different manufacturers applied on the transmission lines. This philosophy should be considered for all new or upgraded protection applications.

4.3.4 PETS – Electrical Engineering

43. Many of the breakers in the Holyrood station are proposed to be replaced in the near future as part of the Muskrat Falls DC infeed upgrade requirements. New breakers and associated equipment shall be specified with insulation creepage distances suitable for use in highly contaminated environments. For breakers with ceramic type insulation, creepages of 31 mm per KV or greater are recommended.

44. With the acquisition of the new breakers, CTs should be specified on both sides of the breakers to provide for overlapping protection zones. Faults such as the one that occurred on B1L17 will then be cleared high speed, without reliance on the time delayed breaker failure protection.

4.3.5 PETS – Transmission & Distribution Engineering

45. In light of the jumper issue that resulted in the fault and trip TL201 and a separation of the East/West power systems there should be a review of the standards applied for transmission line jumper length.

4.3.6 System Operations and Energy Systems

46. Customers were subjected to significant undervoltage conditions, outside normal limits for several minutes, with the trip of both Holyrood units simultaneously. The procedures pertaining to ECC operator action required during abnormal voltage conditions should be reviewed to ensure they are adequate in maintaining customer supply voltages within acceptable limits.

47. Consideration should be given to developing a protocol or guideline for the ECC operators to follow which addresses how to proceed when incorrect or questionable data occurs in the EMS as experienced at the STB station during restoration following the disturbance at 0742 hours. As noted previously, no action until data confirmation is received might be the best approach, realizing it will be a judgment call in many cases by the operator.

48. The issues with the SOE reporting, i.e., the missed events at Buchans and repeated events at Bottom Brook, should be further investigated.

49. Further investigation and discussion is required regarding the overvoltage condition which occurred, in particular as to why the additional 160 MW load on the NP system was shed following the trip of Holyrood terminal station.

4.3.7 System Operations and Planning

50. A detailed load flow and transient stability analysis should be conducted in concert with the comprehensive review of the sequence of events to gain a full understanding of the events.

51. In conjunction with the study above, guidelines should be developed and implemented for optimum reactive power dispatch and levels of Avalon loading, in the event that similar circumstances develop in the future. This should also include a review of the operation of the Optimum Power Flow (OPF) application in the EMS.

4.3.8 System Operations, Planning and PETS – P&C Engineering

52. Consideration should be given to a system voltage study which simulates normal loading scenarios but also abnormal scenarios such as occurred during January 11. Scenarios should include those such as all Holyrood units offline with one line supplying the Avalon - with load restoration, load restoration on the Western system after a major outage, major load rejection, etc. From this study, a suitable operation strategy/guideline should be developed to assist the ECC operators in maintaining system voltages within acceptable limits. The gas turbines and other sources of generation voltage support should also be considered in the study. This study should also address the requirement for the addition of system undervoltage and overvoltage protection and the role the EMS controls might play in the control of the system voltage during abnormal conditions. Application of undervoltage and

overvoltage protection schemes should be considered. Currently there is very limited overvoltage protection and virtually no undervoltage protection in service on the system.

53. Surge and Trouble Reports should be prepared by System Operations for all disturbances as they provide valuable information regarding the system equipment, identifying issues which may result in larger problems at a later time. They also provide for a valuable tool for personnel, particularly new employees, to become more familiar with all aspects of the system and the equipment over time. These Surge and Trouble Reports should be reviewed and monitored by all stakeholders to ensure that all investigations are complete and recommendations are completed in a timely manner.

4.3.8 Hydro Generation

54. Further investigation should be carried out into the determination of the cause of the lockout operations which occurred at Cat Arm and Upper Salmon during the load rejections at 0742 hours. This may include a planned load rejection at each plant to duplicate the conditions which occurred.

55. In the future, for all trips of larger generating units, investigations and reports should be completed to determine the cause and whether the plant's systems operated properly. The investigations should include trips due to system related issues. Information such as targets, alarms and logs should be collected and included in the reporting for each event. Any deficiencies should be addressed and corrected.

56. Further investigation into the performance issues with the Cat Arm station service supplies should be carried out to determine what needs to be corrected to ensure that station service is available following a trip of the plant. This should include an investigation into whether unit black start capabilities exist and the development of procedures to carry out the same.

APPENDIX A

Sequence of Events Tables

APPENDIX A-1

Sequence of Events – For Event Starting at 0642 hours

Sequence of Events – For Event Starting at 0642 hours

TIME	Duration (cycles)	Location	Notes
Holyrood (HRD) Unit No.3 tripped at 0413 hours. From the analysis the most likely cause was a B phase to ground fault on the 230 KV in the Holyrood Terminal Station between the unit transformer and unit circuit breakers detected by the unit transformer protection. Note that the time is SOE system time, unless otherwise noted. The actual breaker clearing times may be different as SOE breaker times use auxiliary contacts. Some clearing times are taken from DFR's or protection relay reports.			
06:42:05:839	0	HRDTS	LG fault C-Phase on B1L17 at the HRD TS (HRD DFR Time)
06:42:05:896	3	HRDGS	Unit 1 lockout (86-2) operated. (Most likely via Unit 1 87GT1).
06:42:05.945	6	HRDTS	Unit 1 cleared via unit breakers B1L17 and B1B11 - 3 phase. (HRD DFR Time)
06:42:06.004	10	HRDGS	Unit 1 lockout (86-3) operated. The unit shut down.
At this point HRD Unit No. 1 is offline and isolated with the unit breakers open. The Unit 1 disconnect (B1T1) was still closed. B1L17 C-Phase is still faulted line to ground between the B1L17 breaker pole and the B1L17 CT.			
06:42:06.282	27	WAV	Line distance protection relays operated on 230 kV transmission line TL217 (Western Avalon to Holyrood) at Western Avalon (WAV). Both P1 and P2 ground distance protection Zone 2's operated on time backup.
06:42:06.334	30	WAV	Circuit Breakers L03L17 and B1L17 opened 3 phase at WAV. (HRD DFR Time)
At this point transmission line TL217 is open at WAV. TL217 is still closed at HRD. B1L17 C-Phase is still faulted line to ground between the B1L17 breaker pole and the B1L17 CT. No protection operation occurred on the HRD end of TL217 at this point as the fault is behind the protection zone.			
06:42:06.549	43	HRDTS	Protection operation 94L-30L on the 138 kV transmission line 39L (Bay Roberts to Holyrood). It is suspected to have tripped on timed ground protection - 51N.
06:42:06.665	50	HRDTS	Backup phase overcurrent protection operated on HRD Unit No. 1 unit transformer - 51T1 (A & C Phases). Operation is due to fault location.
06:42:06.706	52	HRDTS	Breaker B8L39 opened at HRD.
06:42:06.854	61	CBC	94C4 protection operated
06:42:06.881	63	CBC	Breaker B2C4 Open (Capacitor Bank C4 has tripped).
At this point, the 138 kV connection between Western Avalon and Holyrood is open. B1L17 C-Phase is still faulted line to ground between the B1L17 breaker pole and the B1L17 CT. The fault now migrates from the breaker side of the CT to the line side of the CT.			
06:42:06:915	64	HRDTS	The fault migrated to the other side of the CT in TL217 line zone. (HRD DFR Time)
06:42:06.947	66	HRDTS	TL217 P1 Zone 1 ground distance protection C-Phase HRD operated. The P2 (SEL relay) protection did not operate.
06:42:06.973	68	HRDTS	Breaker B12L17 HRD opened C phase and cleared the fault. (HRD DFR Time)
06:42:06.981	69	HRDGS	Generator No. 2 lockout (86-3) operated. (This was most likely via the unit's backup voltage restrained overcurrent relays - 51V/G2).
06:42:07.027	71	HRDTS	Unit 2 tripped via unit breakers B2B11 and B2L42. (HRD DFR Time)

TIME	Duration (cycles)	Location	Notes
At this point HRD Unit No. 2 is offline and isolated with the unit breakers open. The Holyrood Plant is now entirely offline with no generators available.			
06:42:07.712	112	HRDTS	Circuit Breaker B12L17 reclosed C-Phase at Holyrood with reclosing time set at 40 cycles. TL217 closed at HRD but open at WAV. (HRD DFR Time)
06:42:08.528	161	HRDTS	Generator No. 1 unit disconnect switch B1T1 indicated open.
06:42:09.441	216	HRDTS	Generator No. 1 unit disconnect switch B1T1 indicated open. (second indication)
The unit disconnect switch opened on Unit No.1. This was 2.5 seconds after the lockout operated on the generator. The switch indicated open twice.			

APPENDIX A-2

Sequence of Events – For Event Starting at 0648 hours

Sequence of Events – For Event Starting at 0648 hours

TIME	Duration (cycles)	Location	Notes
At this point, Generators No. 1, No. 2 and No. 3 had all been tripped at the Holyrood Plant. Transmission line TL217 was open three phase at the WAV end and closed at the HRD end. 39L was open at HRD.			
06:48:41:344	0	HRDTS	C Phase to ground fault on TL217 in or very near to the station. (HRD DFR Time)
06:48:41.370	1.5	HRDTS	Line distance protection operation on TL217 at HRD. (C-Phase Z1 ground distance both P1 & P2 protections) Fault suspected to be in the HRD station, SEL P2 indicates 0.38 km from the station.
06:48:41:437	6	HRDTS	Breaker B12L17 HRD tripped C Phase. Fault cleared and reclosing started on TL217. (HRD DFR Time)
At this point, TL217 was opened on C-Phase at Holyrood and the fault cleared.			
06:48:41:566	13	HRDTS	A Phase fault in 138 KV bus B8 zone. 87B8B9 bus differential operated A and C phases. (HRD DFR Time)
06:48:41.619	16	HRDTS	Lockout 86B8B15 operated via 87B8B9.
06:48:41.624	17	CBC	Breaker B1C1 opened – appears to be via the capacitor bank controller.
There was a fault on HRD Bus B8 which caused the lockout to trip Bus B15. Transmission line 39L was open before this fault. The fault occurred during the reclose period of TL217.			
06:48:41.653	18	HRDTS	B8 bus fault cleared via breakers B13B15 and B12B15. (HRD DFR Time)
At this point the 138 kV section of the HRD terminal station is isolated from the grid and locked out.			
06:48:42.138	48	HRDTS	Breaker B12L17 reclosed C phase at HRD. C phase re-faulted involving B phase resulting a B-C-ground fault. (HRD DFR Time).
06:48:42.162	49	HRDTS	Line distance protection P2 phase and ground operation on TL217 HRD. (B to C phases - tripping 3 phase)
06:48:42.166	49	HRDTS	Line distance protection P1 operated B-C to ground on TL217 HRD. 94B1 operated followed by 94L1, 94A1, 94C1.
06:48:42.189	50.6	HRDTS	TL217 B phase fault current interrupted temporarily (2 cycles) via B12L17. (HRD DFR Time).
06:48:42.203	51.5	HRDTS	TL217 C phase fault current interrupted, breaker B12L17 opened A and C phases. (HRD DFR Time).
06:48:42.204	52	HWD	Line distance protection P2 operation on TL242 HWD. (B to C Phase – Zone 1)
06:48:42.204	52	OPD	Line distance protection P2 operation on TL218 OPD. (94A2, 94B2, 94C2, 94L2 operated)
06:48:42.219	52.5	HRDTS	TL217 B Phase re-faulted. B phase failed to remain cleared. The B phase current re-struck (Suspect that B12L17 B phase is closed). (HRD DFR Time).
06:48:42.256	54.7	HWD OPD	TL242 HWD and TL218 OPD ends open 3 phase. HRD TL217 B phase current level decreases from 1,300 A to 40 A. LG fault on the 230 KV delta system supplied only from 66 KV. (HRD DFR Time)

<table>
<tr><th>TIME</th><th>Duration (cycles)</th><th>Location</th><th>Notes</th></tr>
<tr><td colspan="4">TL217 reclosed C Phase at HRD and re-faulted C and B phases to ground. TL217 HRD, TL218 OPD, and TL242 HWD protection operated and initiated three phase trips on all three of these lines. B12L17 HRD tripped A & C phases successfully but B phase fault re-struck after 2 cycles. Once TL218 and TL242 tripped at the remote ends the fault was being supplied by the 66 KV supply from 38L and T10 230 KV delta winding.</td></tr>
<tr><td>06:48:42.273</td><td>55.7</td><td>HRDTS</td><td>After approximately one cycle C phase faulted somewhere in the station on bus B12 or bus B12 connected equipment. The C phase voltage nearly collapsed to zero. Simultaneous faults, one on TL217 B phase and one on C phase in station. Fault current was only at approximately 230 A. (HRD DFR Time)</td></tr>
<tr><td>06:48:42.312</td><td>58</td><td>HRDTS</td><td>230 KV A phase flashed over to ground somewhere in the HRD station. 3 phase fault on the delta system but faults most likely in different locations.</td></tr>
<tr><td colspan="4">At this point, transmission lines TL218 and TL242 are open. There are no 230 kV or 138 kV connections to the HRD station. The Newfoundland Power 66 kV connection between Hardwoods (HWD) and HRD is still in service - 38L into HRD. The 230 KV supply is only from the 66 KV via 38L and T10 feeding a 230 KV 3 phase fault, current approximately 230 A.</td></tr>
<tr><td>06:48:42.804</td><td>88</td><td>HRDTS</td><td>Line distance protection operation P1 on TL217. Optimho SOTF (three phase).</td></tr>
<tr><td>06:48:43.123</td><td>107</td><td>HRDTS</td><td>Breaker Failure Lockout 86BF/B12L17 operated on breaker B12L17.</td></tr>
<tr><td>06:48:43.154</td><td>109</td><td>HRDTS</td><td>Breaker B12T10 open at HRD. (SEL TL218 Events report)</td></tr>
<tr><td>06:48:43.181</td><td>113</td><td>HRDTS</td><td>Breaker B12L42 open at HRD. (Three Phase)</td></tr>
<tr><td>06:48:43.213</td><td>115</td><td>HRDTS</td><td>Breaker B6T10 open at HRD.</td></tr>
<tr><td>06:48:43.229</td><td>116</td><td>HRDTS</td><td>Breaker B12L18 open at HRD.</td></tr>
<tr><td colspan="4">At this point, the 230 KV Bus B12 and breaker B12L17 have been isolated at HRD via a breaker failure operation. Prior to the breaker failure, the indication of B12L17 was erratic indicating that there may have been issues with the auxiliary contacts. Initial load loss was approximately 60 MW but this was followed by line openings in the NP St. John’s 66 KV system which led to the loss of approximately another 160 MW and a severe overvoltage on the St. John’s 66 KV system to the order of 80 KV.</td></tr>
<tr><td>06:48:58.967</td><td>14.8 (sec)</td><td>Ridge Road</td><td>NP 32L (RRD to OPD) tripped with an approximate 130 MW load loss. (NP SOE data time) Other NP St. John’s 66 KV lines opened just prior to this.</td></tr>
<tr><td>06:48:59:048</td><td>14.9 (sec)</td><td>CBC</td><td>B1C2, B2C4, B2C3 Capacitor Bank breakers tripped on protection.</td></tr>
<tr><td>06:49:03.149</td><td>19.0 (sec)</td><td>HWD</td><td>B8C2 Capacitor Bank breaker tripped on protection, Overvoltage assumed.</td></tr>
<tr><td>06:49:03:313</td><td>19.2 (sec)</td><td>HWD</td><td>B7C1 Capacitor Bank breaker tripped on protection, Overvoltage assumed.</td></tr>
<tr><td>06:49:05.356</td><td>21.0 (sec)</td><td>OPD</td><td>B2C2 Capacitor Bank breaker tripped on protection, Overvoltage assumed.</td></tr>
<tr><td>06:49:04.067</td><td>22.8 (sec)</td><td>Seal Cove</td><td>Circuit breaker SCV-38L-B tripped on overvoltage. This tripped 38L at the Seal Cove end. (NP SOE data time). At this point the entire Holyrood station (230 KV, 138 KV and 69 KV) is de-energized.</td></tr>
<tr><td>06:50:01.345</td><td>80.1 (sec)</td><td>OPD</td><td>B5C1 Capacitor Bank breaker tripped on protection.</td></tr>
<tr><td colspan="4">Holyrood Terminal station supplies are tripped and the terminal station is totally de-energized. 230 KV busses B12 and B15 and the 138 KV bus B8 are locked out. TL217, TL218 and TL 242 are tripped at both ends, and 38L is tripped at the remote end. The load remaining in the St. John’s area of approximately 100 MW was being supplied by TL201 and any NP generation online.</td></tr>
</table>

APPENDIX A-3

Sequence of Events – For Event Starting at 0742 hours

Sequence of Events - For Event Starting at 0742 hours

TIME	Duration seconds (cycles)	Location	Notes
At this time Holyrood Units 1, 2 and 3 are out of service. TL217 (WAV to HRD) is out of service, TL218 (HRD to OPD), TL 242(HRD to HWD), the NP 138 KV loop from WAV to HRD is open, and B7T5 at HRD is open. HRD 230 KV and 138 KV busses are de-energized. All load (approximately 285 MW) east of WAV is being supplied via TL201 (WAV to HRD) and NP Avalon generation.			
07:42:16.213	0	TL201	C phase LG fault occurred on TL201, Structure 210 approximately 49.9 km from WAV end. (DFR Time)
7:42:16.280	0.067 (4)	WAV	C phase TL201 WAV cleared on P1 (Optimho) protection only. (DFR Time)
7:42:16.328	0.115 (7)	HWD	C phase TL201 HWD cleared on P1 & P2. (DFR Time)
7:42:16.352	0.139 (8)	HWD	A & B phases of TL201 at HWD tripped via P1 protection. WAV A & B phase remained closed. TL201 now tripped three phase at the HWD end. (DFR Time)
TL201 is opened three phase with approximately 285 MW of load shed from the system. The frequency on the system west of Western Avalon began to increase quickly.			
07:42:16.436	0.223 (13)	HWD	Transfer Trip sent from TL236 HWD (HWD supply from NP)
07:42:16.440	0.227 (13.6)	OPD	Transfer Trip received TL236 OPD (OPD supply from NP)
07:42:16.565	0.352 (21)	CBC	All capacitor banks (C1, C2, C3, C4) tripped. Loss of 137.5 MVAR.
07:42:16.661	0.448 (27)	OPD	TL236 tripped at the Oxen Pond end. P2 Zone 2 permissive operated. (DFR Time)
07:42:16.904	0.69 (41)	WAV	TL201 reclosed successfully at the WAV end. (DFR Time)
07:42:18.691	2.478 (149)	WAV	TL201 faulted again C phase. (SEL Report Time)
07:42:18.774	2.561 (153)	WAV	TL201 tripped 3 phase at the WAV end. P1 and P2 protections operated. (SEL Report Time)
At this time there is no 230 KV transmission energized east of Western Avalon and all HRD units are out of service. The Sunnyside 230 KV voltage was recorded at 259.5 KV prior to the trip of the capacitor banks at CBC. The frequency is increasing on the remaining system to a maximum of around 65 Hz.			
07:42:20.244	4.03	CAT	Breakers L47T1 and L47T2 tripped at Cat Arm. This caused the Cat Arm generation (at 120 MW) to be removed from the grid. TL247 P2 protection (SEL 321 distance relay) Zone 1 misoperated due to the high system frequency.
07:42:20.339	4.126	BDETS	TL204 (BDE–STB) tripped on the BDE end via breakers B4B5 and B5B6. TL204 P2 protection (SEL 321 distance relay) Zone 1 misoperated due to the high system frequency.
07:42:20.386	4.173	BDETS	TL231 (BDE – STB) tripped on the BDE end via breaker B6B10. Breaker B5B6 was already opened. TL231 P2 protection (SEL 321 distance relay) Zone 1 misoperated due to the high system frequency.
07:42:20.891	4.678	SSD	Breakers L109T4, L19L100, L100L109 opened. This opened the 138 KV loop between STB and SSD on one end. The LPRO2100 Distance relays on 100L and 109L both misoperated due to the system frequency issue.

TIME	Duration (seconds)	Location	Notes
At this point in time the system is split into two areas. BDE to STB 230 KV connections are open and the 138 KV loop SSD to STB is open. BDE plant with USL and Granite generation is supplying the Eastern system into SSD. Cat Arm is tripped from the system and HLK (with the Deer Lake Power plant and Exploits generation) is supplying the Western system into MDR and back to STB (including loads into the Gander area) via the 230 KV lines and the 138 KV STB to DLK loop (Exploits generation is also connected into STB). The Western system frequency begins to decrease while the eastern System frequency is still increasing.			
07:42:21.298	5.085	DLK	TL226 tripped at the DLK end via B2L26. This interrupted customers north of Deer Lake to Parsons Pond. The TL226 LPRO2100 distance relay misoperated due to the system frequency issue.
07:42:21.343	5.130	SPD	TL222 tripped at Springdale via breaker B1L22. This opened the 138 KV loop between Stony Brook and Deer Lake. The TL222 LPRO2100 distance relay misoperated due to the system frequency issue.
07:42:21.434	5.221	STB	TL222 tripped at Stony Brook via breaker B3L22. This interrupted customers at South Brook. The TL222 LPRO2100 distance relay misoperated due to the system frequency issue.
At this point in time the system is still split into two areas. In addition, customers north of Deer Lake to Parson's Pond and at South Brook are interrupted and the 138 KV loop from STB to DLK is open.			
07:42:21.457	5.244	USL	TL263 tripped at Upper Salmon via L34L63. This caused the Granite Plant (35 MW) to be removed the grid. TL263 protection (SEL321 distance relay) Zone 1 misoperated due to the high system frequency.
07:42:21.464	5.251	BDE and USL	TL206 tripped on the BDE end via L06L34 and B11L06. TL206 P2 protection (SEL 321 distance relay) Zone 1 misoperated due to the high system frequency. TL234 at USL tripped at the Upper Salmon station via L34T1. TL234 protection (SEL 321 distance relay) Zone 1 misoperated due to the high system frequency. This removed the Upper Salmon generation (80 MW) from the grid.
07:42:21.749	5.536	SLK	Star Lake L80T1 tripped. This removed the Star Lake generation from the grid. There was an 86T group lockout alarm.
At this point in time the generation is lost at Granite and Upper Salmon and TL206 is open at BDE on the Eastern connected system. Star Lake is tripped from the Western connected system.			
07:42:22.047	5.834	DLK	TL239 tripped at Deer Lake via breakers L39T2 and B1L39. This interrupted all customers on the GNP. The TL239 LPRO2100 distance relay misoperated due to the system frequency issue.
07:42:22.068	5.855	STB	TL210 opened on the Stony Brook end via B3L10. The TL210 LPRO2100 distance relay misoperated due to the system frequency issue.
At this point in time all customers on the GNP including those in the Bonne Bay Area are outaged.			
07:42:22.120	5.907	MDR	Transformer T1 tripped via B4T1 due to underfrequency (57.5 Hz) and Reverse Power (3.6 MW) relaying. This separated Deer Lake Power's lines from the grid at Massey Drive.
07:42:22.468	6.255	DLK	Line TL225 tripped at the Deer Lake end via B2L25. The TL225 LPRO2100 distance relay misoperated due to the system frequency issue.
Deer Lake Power is operating separated from the grid. Hinds Lake and Exploits Generation is still connected to the 230 KV through via 138 KV into Deer Lake and 230 KV Deer Lake to Massey Drive (TL248).			

TIME	Duration (seconds)	Location	Notes
07:42:22.646	6.433	DLK	Line TL248 tripped at Deer Lake via breaker B3L48. HLK generation separated from 230 KV. TL248 Protection (SEL 321 distance relay) Zone 1 misoperated due to the low system frequency.
07:42:22.687	6.474	DLK	Line TL247 tripped at Deer Lake via breaker B3L47. The line was already open at the other end (Cat Arm plant).
At this point in time the 230 KV system west of STB is outaged including STB, BUC, MDR, BBK , SVL busses and all 138 KV lines on the 138 KV loop STB to SSD. The Hinds Lake Plant has become separated from the 230 KV grid and is supplying customers in the Howley-White Bay area and customers from Indian River to Springdale. It is likely that the Exploits generation has also tripped at this point.			
07:42:24.053	7.784	Bear Cove	TL256 tripped at Bear Cove via breaker B1L56. Indications are of an undervoltage trip. The GNP had already been interrupted at this point as TL239 had already tripped.
07:42:26.101	9.888	SSD	100L reclosed at Sunnyside via breaker L19L100 and picked up the 138 KV loop from SSD into STB and energized momentarily the STB 230 KV bus and all 230 KV lines west of STB. Customers were picked up at STB, BUC, MDR, BBK, SVL, DLS and the SSD to STB 138 KV loop customers for 10 cycles before 100L tripped again. (STB DFR Time)
07:42:26.160 To 07:42:26.246	9.947 To 10.033	STB BUC BBK MDR BBK	TL232 and TL205 both tripped due to operation of the P1 protection (Optimho SOTF) due to the momentary re-energization of the 230 KV from a very weak infeed and picking up load. Breakers L04L32, B1L32, L05L35 and L05L31 tripped. Also at this time, the STB RTU is unable to update the EMS of the status changes of the conditions at STB due to buffer overflow problems with the routers between the EMS and STB. This status update problem persisted until 08:51:36. TL205 and TL232 are not reported open to EMS as well as other subsequent status changes following, causing some confusion to the operator as to the system status. TL205, TL228, TL232 and TL233 tripped via operation of the P1 protection (Optimho SOTF) due to the momentary re-energization & load pickup. Breakers L28L32, B1L28, and L05L33, B1L05, L32L33 tripped. TL233 tripped via operation of the P1 protection (Optimho SOTF) due to the momentary re-energization & load pickup. Breakers L11L33 and L09L33 tripped. TL228 tripped due to operation of the P1 (Optimho SOTF) due to the momentary re-energization & load pickup. Breaker B1L28 tripped. TL209 tripped due to operation of protection (Optimho SOTF) due to the momentary re-energization & load pickup. Breaker B1L09 tripped. (94L1 operated 52 cycles before B1L09 indicated open in SOE).
07:42:26.247	10.034	SSD	100L tripped again at Sunnyside via breaker L19L100. This followed the previous 100L reclose. (STB DFR Time)
07:42:27.029	10.816	BBK	Bottom Brook B1L09 indicated open.

TIME	Duration (seconds)	Location	Notes
At this point in time, following a 10 cycle momentary partial energization, the 230 KV system west of STB is still outaged including STB, BUC, MDR, BBK , SVL busses and all 138 KV lines on the 138 KV loop STB to SSD. The Hinds Lake Plant is still separated from the 230 KV grid and is supplying customers in the Howley-White Bay area and customers from Indian River to Springdale. The BDE plant is supplying the Eastern connected load (approximately 200 MW). Loads east of WAV in St. John's and area are interrupted. Also at this time, the STB RTU is unable to update the EMS of the status changes of the conditions at STB due to buffer overflow problems with the routers between the EMS and STB. This status update problem persisted until 08:37.			
07:42:30.536	14.323	DLP	The Corner Brook Frequency Converter tripped via breaker 252T.
07:42:34.320	18.107	DLK	TL239 re-closed via breaker B1L39 at Deer Lake. This restored GNP customers from Parsons Pond to Bear Cove – supplied by generation at the Hinds Lake plant.
07:42:54.064	37.851	MDR	Indications of the CBPP Co-Gen trip.

APPENDIX A-4

Sequence of Events – Restoration Period Starting at 0742 hours to 0851 hours

Sequence of Events – Restoration Period Starting at 0742 hours to 0851 hours

Following the trip of TL201, the 230 KV supply east of Western Avalon is outaged, including St John's and surrounding areas. Holyrood Units 1, 2 and 3 are out of service. TL217 (WAV to HRD) is out of service, TL218 (HRD to OPD), TL242 (HRD to HWD), the NP 138 KV loop from WAV to HRD are open and HRD B7T5 is open. The HRD 230 KV and 138 KV busses are de-energized with busses B12, B15 and B8 locked out. The Oxen Pond and Hardwood stations are de-energized. All capacitor banks at Come by Chance have tripped. Bay D'Espoir is operating supplying load to the Connaigre Peninsula, Sunnyside, NARL, the VBN terminal station, the Burin Peninsula and the remaining Avalon supplied from the 138 KV and 66 KV at Western Avalon. Other pockets of customers in various areas also have supply (supplied by NP's Avalon generation).

The Central/West Coast power system has also been outaged. All 230 KV busses including Stony Brook and west are de-energized. All 230 KV lines west of Bay D'Espoir are open. Cat Arm, Upper Salmon, Granite and Star Lake, Exploits generation are all off-line.

Hinds Lake plant is operating islanded, separated at the Deer Lake 230 KV and Springdale 138 KV, supplying the GNP north of Parsons Pond to Bear Cove via TL239, the Baie Verte Peninsula and Springdale.

STB status indication note: The status indication issue from Stony Brook is still ongoing with some breaker indications incorrect. Stony Brook TL205 and TL232 breakers are indicating closed but are open. TL222 breaker B3L22 is indicating open but is closed. B3L10 is correctly indicating open. All other breakers are correctly indicating closed.

This sequence of events covers the period of restoration up to the time that TL201 tripped again at 0851 hours.

TIME	Duration	Location	Notes
07:47:40.239	0	SAP	Capacitor banks C1 and C3 put back in service.
07:48:27.582	47 sec	BDE	TL231 (BDE-STB) re-energized by ECC picking up Stony Brook station from BDE via breaker B6B10 (B1L31 closed at STB). STB T1, T2, TL235 (STB – GFL FC), TL222 (South Brook), 130L (STB-GFL) and 133L (STB-BFL) were picked up. TL204 (STB-BDE) was also back-energized (TL204 open on BDE end). Approximately 140 MVA picked up. (STB DFR TIME)
07:48:27.724	47 sec	STB	TL231 tripped 2 phases (A&B) via breaker B1L31. TL231 SEL 321 P2 protection distance elements 3 phase misoperated. B1L31 C phase failed to trip. Loads connected single phased. (STB DFR TIME)
07:48:27.811	47 sec	STB	TL235 tripped 3 phase via breaker B1L35. TL235 Optimho P2 protection misoperated on SOTF. Transfer trip sent to GFL FRC. (STB DFR TIME)
07:48:27.919	47 sec	GFL FC	Breaker 252T-3 opened. 252T-1 and 252T-3 GFL FC failed to open.
07:48:27.950	47 sec	STB	130L (STB-GFL) tripped via protection. (STB DFR TIME)
07:48:28.506	48 sec	STB	B1L31 reclosed A & B phases. Single phasing condition ended. STB energized 3 phase. (STB DFR TIME)
07:49:06.317	1 min 26 sec	BDE	Breaker B5B6 closed by the ECC. TL204 now in service supplying load to STB.
07:50:01.760	2 min 21 sec	BDE	Breaker B4B5 closed by the ECC. Ring closed at BDE.

At this time, transmissions lines TL204 and TL231 have been closed at the BDE and STB ends. Both lines indicated correctly as closed on the mapboard. When the line was picked up at BDE it restored South Brook customers via TL222 and NP customers in Grand Falls and Bishop's Falls via 130 L and 133L. 130L breaker B3L130 was closed but tripped shortly after STB was picked up. However it was still indicating closed. Some NP loads along the 138 KV loop were believed to have been energized on pick up, based on a measured load level of 140 MVA but then tripped again.

STB EMS status to ECC which were indicating closed but were actually open are breakers: L05L31, L05L35, B1L32, L04L32, B1L35 and B3L130. B3L22 is indicating open but is closed. All other breaker status should have been correct. The telemetry (e.g., bus voltages) is also incorrect.

The western and central region is still outaged except for the loads supplied by the Hinds Lake islanded area with the South Brook and NP loads supplied via STB and Bishops Falls station. (NP 132L-B and 136L-B at BFS opened at 07:48:27).

TIME	Duration	Location	Notes
07:50:15.789	3 min	WAV	Breaker L01L37 closed by the ECC. TL201 re-energized but still open at HWD end.
07:51:23.141	4 min	HWD	Breakers B1L36 and B2L42 opened by the ECC - via a group breaker open command.
07:51:50.386	4 min	HWD	B1L01 closed but tripped immediately via TL201 Optimho SOTF due to high inrush currents and momentarily low 230 KV voltages.
07:53:15.840	6 min	BBK	Breaker B1L11 opened by the ECC - via a group breaker open command.
07:54:06.020	7 min	BUC	Breaker B1L05 closed by the ECC. Unknown to the operator at this time is that TL205 was still open at the STB end – TL205 not energized (STB EMS status issues).
07:55:03.114	8 min	BUC	Breaker B1L28 closed by the ECC. TL228 not energized.
07:55:06.643	8 min	HWD	Breaker B1L01 closed by the ECC. This restored TL201 from WAV to HWD. The 66 KV bus picked up. There were no other 230 KV lines into the station at this point.
07:55:52.139	8 min	MDR	Breaker B1L28 closed by the ECC. This closed TL228 from BUC to MDR, however the line was not energized.
At this time, TL201 has been restored from Western Avalon to Hardwoods, restoring the Hardwoods station. The line was initially loaded to 25 MW and increased to 150 MW at 08:05 hours. There were no other energized 230 KV lines at Hardwoods or Oxen Pond. TL228 is closed but unenergized from Buchans to Massey Drive. TL205 is closed at the Buchans end but remained unenergized because unknown to the ECC Operator at this time, TL205 is still open at the STB end (STB EMS status issues).			
07:56:06.747	9 min	HWD	Breaker B1L36 closed by the ECC. TL236 energized from HWD.
07:56:45.004	9 min	OPD	Breaker B1L36 closed by the ECC. This restored TL236 from HWD to OPD. The OPD 66 KV is energized.
At this time the Oxen Pond station has been restored via TL236 from Hardwoods. The line was initially loaded to 7 MW and increased to approximately 50 MW at 08:05 hours.			
07:57:41.267	10 min	CBC	Capacitor bank C3 put back in service.
07:59:09.435	12 min	DLK	Breaker B2L26 closed by the ECC. This restored TL226 from Deer Lake to Parsons Pond. At this point the customers are still being supplied via the Hinds lake Plant which is operating islanded. DLK TL248 and TL225 are open. TL222 SPL is also open.
07:59:18.669	12 min	CBC	Capacitor bank C2 put back in service.
At this time capacitor banks C2 and C3 are back in service at CBC and TL226 has been restored from Deer Lake to Parsons Pond. All NP customers west of Stony Brook are still without power. Hinds Lake Plant is operating islanded, separated at Springdale and Deer Lake.			
07:59:39.680	12 min	SPL	Breaker B1L22 closed by the ECC. This closed the loop (via the 25W) and tied the Hinds Lake and BDE Plants together – momentarily.
07:59:42.923	12 min	SPL	Breaker B1L22 opened again at Springdale – separating the Hinds Lake and BDE plants again. Breaker B1L22 faulted internally, opening to clear the fault. TL222 SPL distance protection 21NZ1 operated clearing fault in 6 cycles. TL222 STB did not trip but fault was cleared from STB end by SPL breaker opening.
08:00:40.780	13 min	DLK	Breaker B3L48 closed by the ECC. TL248, MDR station, TL228, TL211, TL205, BUC energized from the Hinds Lake plant. Bottom Brook loads were not picked up.

TIME	Duration	Location	Notes
At this time the Massey Drive and Buchans terminal stations are energized (with load) via TL248, supplied from the islanded Hinds Lake plant. The pickup of the Massey Drive load has caused Hinds Lake to overload and resulted in underfrequency and low voltage on the islanded system with numerous voltage and underfrequency alarms, in addition to customer interruption on the GNP. There is approximately 40 MW on TL248 at this point and 80 MW plus on Hinds Lake. The frequency is low, probably around 50 Hz. Both TL205 and TL228 are energized with TL205 open at Stony Brook.			
08:00:41.666	13 min	DLK	Breaker B2L26 tripped via an underfrequency protection operation caused by picking up MDR load and overloading Hinds Lake. .
08:00:45.479	13 min	RWC	Breaker B1L57 tripped at Roddicton via frequency (81) protection. Most likely a result of picking up TL248 and the Massey Drive load.
08:00:49.890	13 min	SDP	Line 2 Recloser SA2-R1 opened at St. Anthony via undervoltage and underfrequency protection.
08:00:52.671	13 min	SDP	Line 1 Recloser SA1-R1 opened at St. Anthony via undervoltage and underfrequency protection.
08:00:56.055	13 min	SDP	Line 3 Recloser SA3-R1 opened at St. Anthony via undervoltage and underfrequency protection.
08:00:56.059	13 min	SDP	Breaker B1T1 opened at St. Anthony via undervoltage and underfrequency protection.
At this time all customers in St. Anthony, Roddickton and Main Brook and all customers north of Deer Lake (to Parson's Pond) have been interrupted. The system continued experience significant frequency issues to the Hinds Lake plant overload.			
08:02:55.798	15 min	SAP	Capacitor bank C2 put back in service.
08:03:15.327	16 min	CBC	Capacitor bank C4 put back in service.
08:03:26.908	16 min	BUC	Breaker L05L33 closed by the ECC. TL233 BUC-BBK energized but with no load.
At this time TL233 is also energized to Bottom Brook via TL248/TL228 and the Hinds Lake Plant.			
08:04:03.750	17 min	PPT	Reactor R1 taken out of service.
08:04:06.920	17 min	CBC	Capacitor bank C2 tripped at CBC.
08:04:25.102	17 min	BUC	Breaker L28L32 closed by the ECC. (B1L28 was already closed at this point) TL232 is energized from the BUC end. The STB end of TL232 was still open.
At this time all 230 KV lines west of Stony Brook except TL209 (BBK to SVL) are back-energized from Deer Lake via Hinds Lake plant. TL205 and TL232 are open at Stony Brook. An underfrequency condition is still prevalent on the islanded Hinds Lake system.			
08:05:22.712	18 min	CBC	Capacitor bank C2 put back in service.
08:05:55.231	18 min	BBK	Breaker L11L33 closed by the ECC. This closed the loop TL211 to TL233. No additional lines were picked up. Bottom Brook load (bus B1) is not picked up.
08:06:46.926	19 min	MDR	Transformer breaker B2T2 opened by the ECC. This an attempt to reduce the load at the station. The load transferred to transformer T3.
08:07:20.890	20 min	DLK	Breaker B2L26 was closed but opened immediately. The underfrequency trip did not reset and still applied to the breaker due to the ongoing condition.
08:07:35.439	20 min	DLK	Breaker L39T2 closed by the ECC. (TL239 was already energized at this point)
08:08:39.785	21 min	PPT	Reactor R2 taken out of service.
08:09:37.000	22 min	SDP	Blackstart of St. Anthony Diesel plant initiated by the ECC.

TIME	Duration	Location	Notes
08:10:20.708	23 min	MDR	Transformer breaker B3T3 opened by the ECC. This was an attempt to reduce the load at the station. 40 MW was off loaded from Hinds Lake.

At this time the ECC had closed an additional line breaker at Bottom Brook closing the loop into Buchans. There was an unsuccessful close attempted on B2L26. The ECC opened the transformer breakers associated with MDR T2 and T3 removing the load from the station and the lowering Hinds Lake plant loading. The 230 KV bus voltage was only at approximately 200 KV just prior to when the load was removed. The removal of load caused an immediate voltage increase and this, with the underfrequency persisting, caused more transformer overexcitation resulting in operation of some transformer differential relays and operation of the transformer lockouts on T2 at Massey Drive and T1 at Buchans (a description follows).

TIME	Duration	Location	Notes
08:10:22.621	23 min	BUC	Transformer lockout 86T1 operated due to 87T1 (MBCH12) caused by overexcitation due to underfrequency and voltage recovery on load tripping.
08:10:22.663	23 min	BUC	Buchans breakers B1L28, B1L05 and B2T2 all tripped by 86T1 operation caused by 87T1. TL's 211, 228, 233, 205 and 232 are still energized by TL248 and Hinds Lake. (Breakers tripped at different times with BUC DFR Time indicating isolation of T1 from the 230 KV at 663 msec.)
08:10:22.679	23 min	MDR	Transformer lockout 86T2 operated due to 87T2 (MBCH12) caused by overexcitation due to underfrequency and voltage recovery on load tripping.
08:10:22.708	23 min	MDR	Massey Drive breakers B1L48, B1L28 and B5L11 all tripped by 86T2 operation caused by 87T2. The low side breakers had already been opened by the ECC. (Breakers tripped at different times, 708 msec given as B1L48 trip time).
8:10:22:796	23 min	DLK	Deer Lake B3L48 breaker tripped via transfer trip from Massey Drive on tripping of B1L48 MDR.
08:10:23.997	23 min	MDR	Massey Drive disconnect B5T2 opened by 86T2 operation. (There was another open indication 2.5 seconds later).
08:10:25.124	23 min	SAP	Capacitor banks C1, C2, C3 all tripped (59 – overvoltage)
08:10:28.551	23 min	BUC	Buchans disconnect B1T1 opened by 86T1 operation. (There was another open indication 3.0 seconds later)

At this time, transformers BUC T1 and MDR T2 have tripped and locked out. Stations (MDR, BUC and BBK) and all 230 KV lines west of STB have become de-energized again. Hinds Lake is still islanded supplying approximately 40 MW, separated at the Deer Lake 230 KV and Springdale 138 KV, supplying the GNP north of Parsons Pond via 138 KV (with St. Anthony Airport T.S. load tripped), the Baie Verte Peninsula and Springdale. All three capacitor banks have tripped at the St. Anthony airport.

On the eastern Bay D'Espoir plant system, TL201 is still being loaded and is at approximately 150 MW supplying Hardwoods and Oxen Pond via TL236. Stony Brook is energized via the 230 KV lines TL204 and TL231 supplying some 138 KV loads, including South Brook and Bishop's Falls.

TIME	Duration	Location	Notes
08:10:30.018	23 min	HWD	Capacitor bank C2 put back in service.
08:11:51.224	24 min	HWD	Capacitor bank C2 tripped via overvoltage protection.
08:13:02.872	26 min	PPT	Reactor R2 put back in service.
08:13:26.127	26 min	PPT	Reactor R1 put back in service.
08:15:05.473	28 min	MDR	CBK 50\60Hz protection lockout received.
08:24:31.700	37 min	BBK	Bottom Brook breaker B1L11 closed by the ECC. TL211 still de-enegized.
08:26:01.348	39 min	MDR	Massey Drive breaker B1L28 closed by the ECC. TL228 is still de-energized.

TIME	Duration	Location	Notes
08:28:03.360	41 min	SDP	Breaker B1T1 closed by the ECC.
08:28:33.721	41 min	MDR	Massey Drive breaker B5L11 closed by the ECC. TL211 is still de-energized.
08:28:48.238	41 min	SDP	Line 2 recloser SA2-R1 closed by the ECC.
08:28:59.416	41 min	SAP	Capacitor bank C2 put back in service.
08:29:24.663	42 min	RWC	Breaker B1L57 closed by the ECC.
08:30:39.545	43 min	SDP	Line 3 recloser SA3-R1 closed by the ECC.
08:30:58.192	43 min	SAP	Capacitor Bank C3 put back in service.
At this time the customers at St. Anthony, Roddickton and Main Brook have been restored via the grid (Hinds Lake generation only). It appears that the start of the diesel plant was unsuccessful to now. Line breakers are closed at Massey Drive, however, at this time, MDR, BUC and BBK are still de-energized.			
08:31:26.795	44 min	MDR	DLP Line 16 (MDR to CBP&P)) breaker opened.
08:31:39.096	44 min	HWD	Capacitor bank C2 put back in service.
08:31:39.893	44 min	OPD	Capacitor bank C2 put back in service.
08:31:50.066	44 min	MDR	DLP Line 17 (MDR to CBK FRC) breaker opened.
08:31:51.480	44 min	CBC	Capacitor bank C2 tripped (protection trip).
At this time DLP has separated the Mill from Massey Drive via the line breakers on Lines 16 and Line 17. Transformer T1 had already tripped at 07:42. The 66 KV Bus B4 MDR is still energized via DLP Line 1.			
08:31:59.911	44 min	OPD	Capacitor bank C2 was taken out of service by the ECC.
08:33:20.429	46 min	SAP	Capacitor bank C1 was put back in service.
08:33:46.012	46 min	OPD	Capacitor bank C2 was put back in service.
08:34:21.025	47 min	SDP	Two recloses on recloser SA3-R1.
08:34:36.625	47 min	SDP	Unit breaker B3G6 closed.
08:35:09.532	48 min	OPD	Capacitor bank C1 was put back in service.
08:36:09.719	49 min	CBC	Capacitor bank C2 was put back in service.
At 0837 hours the first updated readings from the Stony Brook RTU were received. STB telemetry and breaker indications were now correctly displaying on the EMS at the ECC.			
08:37:04.730	50 min	SAP	Capacitor banks C1, C2, C3 all tripped (59 – overvoltage)
08:37:42.034	50 min	HWD	Capacitor bank C1 put back in service.
08:39:35.494	52 min	CBC	Capacitor bank C1 put back in service.
08:41:18.087	54 min	PPT	Reactor R1 was taken out of service.
08:42:01.587	55 min	SDP	Unit breaker B3G6 opened.
It appears that G6 at the St. Anthony diesel plant synchronized at 08:35 hours – only to trip again 5 minutes later.			
08:42:06.840	55 min	CBC	Capacitor banks C1, C2, C3, C4 all tripped (protection trip).
There was a disturbance that tripped the banks at Come By Chance at this time. TL201 had been loaded to approx. 260 MW but 80 MW of load was lost. NP reported tripping at Molloy's Lane substation. The Come By Chance voltage appeared to be normal prior to the trip of the banks (233 KV) but reduced to 216 KV for a sustained period following the trip of the banks.			
08:43:57.503	56 min	OPD	Capacitor bank C1 was put back in service.

TIME	Duration	Location	Notes
08:44:51.776	57 min	SPL	Breaker B1L22 was closed by the ECC. This closed the loop (via the 25W) and tied the two plants at Bay d'Espoir and Hinds Lake together.
At this time the Hinds Lake and Bay d'Espoir plants are tied together through the 138 KV loop.			
08:45:07.886	58 min	CBC	Capacitor bank C4 put back in service.
08:45:08.565	58 min	BUC	Breaker L32L33 closed by the ECC. Line not energized.
08:46:20.129	59 min	SAP	Capacitor bank C2 put back in service.
08:47:11.245	1 hour	CBC	Capacitor bank C2 put back in service.
08:47:17.823	1 hour	SAP	Capacitor bank C3 put back in service.
08:47:30.932	1 hour	SDP	Line 1 Recloser SA1-R1 closed by the ECC.
08:47:33.578	1 hour	HWD	Hardwoods turbine End B started.
08:48:26.702	1 hour 1 min	HWD	Breaker B2L42 closed by the ECC. TL242 energized but open at Holyrood.
08:49:39.318	1 hour 2 min	CBC	Capacitor bank C3 put back in service.
08:51:52.767	1 hour 4 min	WAV	Fault on TL201 C phase, assumed to be Structure 210 jumper issue. P1 Protection (Optimho) ground distance operated C-G tripping 94C1. P2 Protection (Schweitzer) operated C-G tripping 94C2 approx. 2.4 cycles later.
08:51:52.799	1 hour 4 min	WAV	Breaker L01L37 tripped C phase. Hardwoods end did not trip.
08:51:53.045	1 hour 4 min	CBC	Capacitors banks C2, C3 and C4 tripped on protection. (Overvoltage most likely).
08:51:53.423	1 hour 4 min	WAV	C phase reclosed at WAV. (39 cycles dead time from WAV DFR)
08:51:53.487	1 hour 4 min	WAV	P1 Protection (Optimho) ground distance C-G tripping 94C1.
08:51:53.531	1 hour 4 min	WAV	L01L37 Tripped 3 phase. HWD end remained closed. Load loss on TL201 was 225 MW.
At 08:51 hours a line to ground fault on TL201 caused it to trip and separate the Avalon (east of Western Avalon) from the rest of the system again. There was 225 MW on TL201 at the time of the trip.			

APPENDIX A-5

Sequence of Events – Restoration Starting at 0851 hours

Sequence of Events – Restoration Starting at 0851 hours

<table>
<tr><th>TIME</th><th>Duration</th><th>Location</th><th>Notes</th></tr>
<tr><td colspan="4">Following the trip of TL201 at 0851 hours, the 230 KV supply east of Western Avalon is outaged again, including St John's and surrounding areas. Holyrood Units 1, 2 and 3 are out of service. TL217 (WAV to HRD), TL218 (HRD to OPD), and TL242 (HRD to HWD) have tripped, the NP 138 KV loop from WAV to HRD is open and B7T5 HRD is open. The HRD 230 KV and 138 KV busses are de-energized with busses B12, B15 and B8 locked out. The Oxen Pond and Hardwood terminal stations are de-energized. All capacitor banks at Come by Chance have tripped.

The Bay d'Espoir generating station is operating connected to Hinds Lake plant via the 138 KV loop from Stony Brook to Howley, but open at the Deer Lake 230 KV. Areas being supplied are the Connaigre Peninsula, Sunnyside, NARL, the VBN terminal station, the Burin Peninsula, the remaining Avalon load via the 138 KV and 66 KV at Western Avalon, Grand Falls area, Springdale area, Baie Verte peninsula, Howley, White Bay, and the GNP north of Parsons Pond. Other pockets of customers in various areas have supply (supplied by NP's generation). Transmission line TL226 from Deer Lake is tripped.

The Central and West Coast power system remains outaged following the trip at 0810 hours. All 230 KV busses west of Stony Brook are de-energized. Transmission lines TL209 and TL248 are open. Transmission lines TL205 (open STB), TL211, TL228, TL232 (open STB), and TL233 breakers are closed but de-energized. The MDR Transformer's 66 KV breakers are open with Corner Brook and surrounding areas outaged. Transformers MDR T2 and BUC T1 are locked out. Cat Arm, Upper Salmon, Granite, Star Lake, and the Exploits generation are all off-line. Deer Lake Power is operating islanded.

Line Breaker Status STB, BUC and MDR:
STB closed: B1L31, B2L04, B3L133, B3L22
BUC closed: L28L32, L32L33, L05L33
BBK closed: B1L11, L11L33, B2L14, B2L14, B3L50
MDR closed: B1L28, B5L11

Note re: STB status indication: The status indication issue from Stony Brook is corrected. All status and telemetry are now correct.

This sequence of events covers the period of restoration from 0851 hours.</td></tr>
<tr><td>08:53:36.590</td><td>0</td><td>SDP</td><td>Breaker B3G6 closed</td></tr>
<tr><td>08:54:17.611</td><td>41 sec</td><td>SDP</td><td>Breaker B3G5 closed</td></tr>
<tr><td>08:54:24.323</td><td>48 sec</td><td>HWD</td><td>Breaker B2L42 opened by the ECC</td></tr>
<tr><td>08:55:03.645</td><td>1 min 27 sec</td><td>SDP</td><td>Breaker B3G2 closed</td></tr>
<tr><td>08:55:39.651</td><td>2 min 3 sec</td><td>SDP</td><td>Breaker B3G4 closed</td></tr>
<tr><td>08:55:39.651</td><td>2 min 3 sec</td><td>SDP</td><td>Breakers B3G5, B3G6 open</td></tr>
<tr><td>08:55:46.616</td><td>2 min 10 sec</td><td>SDP</td><td>Breaker B3G4 open</td></tr>
<tr><td>08:56:28.613</td><td>2 min 52 sec</td><td>SDP</td><td>Breaker B3G3 closed</td></tr>
<tr><td>08:56:50.596</td><td>3 min 14 sec</td><td>SDP</td><td>Breaker B3G5 closed</td></tr>
<tr><td>08:56:57.651</td><td>3 min 19 sec</td><td>SDP</td><td>Breaker B3G1 closed</td></tr>
<tr><td>08:57:10.660</td><td>3 min 34 sec</td><td>SDP</td><td>Breaker B3G4 closed</td></tr>
<tr><td>08:57:24.622</td><td>3 min 48 sec</td><td>SDP</td><td>Breaker B3G3 open</td></tr>
<tr><td>08:57:37.218</td><td>4 min 1 sec</td><td>BUC</td><td>Breaker L05L33 opened by the ECC. As B1L05 was already open, this was intended to open TL205 at the BUC end. B phase on L05L33 remained closed, unknown to the operator.</td></tr>
<tr><td>08:58:00.744</td><td>4 min 14 sec</td><td>STB</td><td>Breaker L05L31 closed by the ECC. This energized one phase at the MDR and BBK 230 KV busses and the 138 KV at BBK.</td></tr>
</table>

TIME	Duration	Location	Notes
At this point the ECC begins to re-energize the 230 KV system by picking up TL205 from STB. Unknown to the operator is that L05L33 at BUC is closed B-phase and it resulted in the single phase energization of lines TL228, TL232, TL233 and TL211. Extremely high voltages were experienced at MDR, BBK and BUC. Load was connected through BBK in DLS, PAB and the Burgeo areas.			
08:58:04.587	5 min	BUC	TL205 - P2 (Schweitzer) protection 51N operated (94A2, 94B2, 94C2, 94L2). Trips sent to L05L33 which failed to open B phase. B1L05 was already open. L05L33 Breaker Fail initiated.
08:58:04.875	5 min	BUC	86BF/L05L33 operated. Trips sent to B1L05 (already open) and L32L33.
08:58:04.890	5 min	MDR	Breaker B1L28 tripped via P1 (Optimho) SOTF. MDR 230 KV is still energized by TL211.
08:58:04.907	5 min	BUC	Breaker L32L33 tripped via 86BF/L05L33. TL232 is de-energized.
08:58:19.517	5 min	BBK	Breaker B3L50 tripped via SEL 311 protection Zone 1, AB elements - single phasing caused a misoperation.
08:58:20.092	5 min	DLS	94T2 (NP 66 KV transformer) operated. T2 overcurrent protection operates into 94T2. Suspect operated by transformer T2 overcurrent due to overexcitation. NP recloser had already indicated tripped several seconds prior.
08:58:21.131	5 min	DLS	86T2 operated. Suspect operated through auxiliary timer initiated by 94T2. Transformer T2 overcurrent remained operated due to overexcitation due to high voltage caused by the single phasing.
08:58:21.218	5 min	BBK	Breaker B2L14 tripped via transfer trip from DLS, initiated by the 86T2.
08:58:23.481	5 min	DLS	High Speed GND Switch L14 AG closed initiated by the 86T2 operation.
08:58:25.069	5 min	DLS	High Speed GND Switch L14 AG opened.
08:58:27.396	5 min	DLS	High Speed GND Switch L14 AG closed.
08:58:28.946	5 min	DLS	High Speed GND Switch L14 AG opened (Ground switch opens after T2 High Speed disconnect T2-A opened).
08:58:31.474	5 min	BBK	Breaker B3L50 re-closed.
08:58:31.639	5 min	BBK	TL233 P2 (Schweitzer) protection 51N operated 94L2 due to single phasing via L05L33 BUC. L09L33 already open.
08:58:31.658	5 min	BBK	TL250 SEL 311 protection Zone 1 BC elements operated 94L2. Single phasing caused misoperation.
08:58:31.669	5 min	BBK	Breaker L11L33 tripped 3 phase by TL233 P2 protection. L09L33 is already open.TL211, and MDR and BBK 230 KV busses were de-energized. TL233, “B” phase only, energized from BUC.
08:58:31.695	5 min	BBK	Breaker B3L50 tripped via 94L2. SEL 311C Zone 1, BC phase.
08:58:34.326	5 min	HBY	Breaker G2T3 closed
08:58:35.322	5 min	HBY	Breaker G2T3 opened
08:59:03.328	5 min	HBY	Breaker G1T3 closed
08:59:28.339	6 min	HBY	Breaker G2T3 closed
09:00:14.626	7 min	SDP	Breaker B3G2 open
09:00:21.665	7 min	SDP	Breaker B3G1 open
09:00:39.723	7 min	MDR	Breaker B5L11 opened by the ECC.
09:01:13.675	8 min	MDR	Breaker B3T3 closed by the ECC. No load picked up as MDR 230 KV was de-energized.
09:01:26.134	8 min	PPT	Recloser L41R1 closed by the ECC.
09:01:52.161	8 min	MDR	Breaker B1L28 closed by the ECC. MDR 230 KV still de-energized.
09:03:46.311	10 min	SSD	Breaker L109T4 closed by the ECC.

TIME	Duration	Location	Notes
09:03:51.411	10 min	HRD	Disconnect B3T3 opened.
09:04:14.238	11 min	BUC	Breaker L28L32 opened by the ECC. No lines dropped or picked up.
09:04:29.502	11 min	SSD	Breaker L19L100 closed by the ECC
09:04:33.304	11 min	BUC	Beginning at this time there were about 100 operations of the TL233 P2 (Schweitzer) protection at Buchans. Both line breakers were already tripped except for B phase. These trips stopped at 09:22:58.352 hrs.
09:05:11.080	12 min	SAP	Breaker B1C1 closed by the ECC.
09:05:13.000	12 min	BUC	Breaker B1L28 closed by the ECC. TL228 is still de-energized.
09:05:21.884	12 min	HRD	Disconnect B2T2 opened.
09:07:10.121	14 min	WAV	Breaker L01L37 closed by the ECC. TL201 is energized. The Hardwoods end is already closed.
TL201 is back in service with both Hardwoods and Oxen Pond stations re-energized.			
09:07:16.000	14 min	BUC	Breaker B1L28 opened by the ECC (no SOE indication).
09:08:27.895	15 min	BBK	Breaker B2L14 closed by the ECC. TL214 not energized.
09:09:38.895	16 min	HWD	Breaker B2L42 closed by the ECC. HRD end open.
09:09:38.955	16 min	HWD	Breaker B2L42 tripped in 4 cycles. TL242 had faulted B-C phase. P1 and P2 phase distance operated. SOTF tripping 3 phase. Fault distance P1 26.59 and P2 27.75 km, indicating very close to HRD.
09:09:42.803	16 min	MDR	Breaker B1L28 opened by the ECC. MDR and TL228 already de-energized.
09:10:04:320	17 min	BBK	Breaker L09L33 closed by ECC (time from the BBK DFR). TL209 and SVL single phased.
09:10:04.805	17 min	SVL	Breaker L405T4 tripped via TL209 94-1 relay. Suspect 21Z1 (KD4) TL209 SVL operated caused by single phasing.
09:10:04.808	17 min	SVL	Breaker B2T3 tripped via TL209 94-1 relay. Suspect 21Z1 (KD4) TL209 SVL operated caused by single phasing.
09:10:04.853	17 min	BBK	Breaker L09L33 tripped 3 phase by TL209 P1 (Optimho) SOTF protection.
09:10:30.663	17 min	SDP	Breaker B3G4 opened.
09:10:45.239	17 min	CBC	Breaker B1C1 closed by the ECC.
09:12:06.642	19 min	SDP	Breaker B3G5 opened.
09:12:49.161	19 min	STB	Breaker B3L10 closed by the ECC. TL210 energized.
09:12:56.477	19 min	BBK	Breaker L09L33 closed by the ECC. TL209 is energized B phase from TL233 via L05L33 which is still closed - B phase only. B1L09 already open. SVL T3 is picked up with no load as the low side breakers are open. The single phasing condition produced extremely high voltages, overexciting SVL transformer.
09:13:04.960	20 min	CBC	Breaker B2C3 closed by the ECC.
09:13:13.241	20 min	BBK	Breaker L09L33 tripped (3-phase protection trip by TL233 - P2 Schweitzer on 51N protection). TL209 and SVL are unenergized.
09:16:26.441	23 min	HWD	Breaker G1T5 closed by the ECC.
09:18:38.170	25 min	DLK	Breaker B2L26 closed by the ECC. TL226 energized to Parsons Pond.
09:18:57.187	25 min	SVL	Breaker L405T4 closed by the ECC. SVL not energized.
09:22:54.969	29 min	BUC	Breaker L05L33 C phase closed. B and C phases closed. Only TL233 energized two phases. (BBK DFR Time)
09:22:58.352	29 min	BUC	TL233 P2 (Schweitzer) protection 94L2 back to normal permanently.

TIME	Duration	Location	Notes
09:23:34.855	30 min	BUC	Breaker L05L33 A phase closed. All 3 phases now closed on TL233. (BBK DFR Time)
L05L33 is closed 3 phase. TL233 (open at BBK) is energized 3 phase from TL205 and the system begins to get back to normal.			
09:24:00.608	31 min	CBC	Breaker B2C3 opened by the ECC.
09:25:18.795	32 min	CBC	Breaker B1C2 closed by the ECC.
09:27:19.341	34 min	CBC	Breaker B1C1 closed by the ECC.
09:28:30.936	35 min	OPD	Breaker B5C1 closed by the ECC.
09:33:13.480	40 min	BDE	Breaker B11L06 closed by the ECC momentarily picking up TL206 (already closed at SSD end). The breaker closed only on A&C phases, and tripped again after 85 cycles most likely on disagreement. (BDE DFR Time)
09:33:13.752	40 min	CBC	Breakers B1C1, B1C2 tripped, protection trips, most likely due t over voltage protection at the 110% level (94C1 and 94C2 operated).
09:33:40.256	40 min	OPD	Breaker B2C2 closed by the ECC.
09:33:42.022	40 min	CBC	Breaker B2C4 closed by the ECC.
09:33:59.066	40 min	HWD	Breaker B7C1 closed by the ECC.
09:34:03.197	41 min	CBC	Breaker B1C2 closed by the ECC.
09:35:35.666	42 min	BDE	Breaker L06L34 closed by the ECC.
TL206 is now in in service - parallel with TL202.			
09:36:10.664	43 min	STB	Breaker B1L32 closed by the ECC. TL232 is energized to BUC.
09:37:28.994	44 min	BUC	Breaker L28L32 closed by the ECC. TL228 is energized.
TL232 is now in service in parallel with TL205.			
09:39:28.128	46 min	MDR	Breaker B1L28 closed by the ECC.
MDR 230 KV Bus and 66 KV busses B2 and B3 are now energized. Load is picked up through T3.			
09:39:31.953	46 min	HWD	Breaker B5G1 tripped (trip of the gas turbine).
09:39:33.108	46 min	DLK	Breaker B1L26 tripped due to underfrequency at 58 Hz (suspect load pickup at MDR).
09:39:33.270	46 min	MDR	Lockout 86T2 reset.
09:39:55.698	46 min	MDR	Breaker B1L48 closed by the ECC.
09:40:34.464	47 min	DLK	Breaker B3L48 closed by the ECC. HLK unit connected via the 230 KV into MDR.
09:40:49.419	47 min	HWD	Breaker B7C1 tripped
09:40:51.334	47 min	OPD	Breaker B5C1 tripped
09:40:53.528	47 min	MDR	Breaker B1L48 opened by the ECC. The HLK unit is disconnected from the MDR 230 KV.
09:40:53.622	47 min	DLK	Breaker B3L48 tripped via transfer trip from MDR.
09:40:59.173	47 min	SAP	Breaker B1C3 opened by the ECC.
09:43:15.083	50 min	MDR	Disconnect B5T2 closed by the ECC.
09:43:37.703	50 min	MDR	Breaker B2T2 closed by the ECC. T2 back in service.
MDR T2 is back in-service.			
09:44:39.927	51 min	MDR	Breaker B1L48 closed by the ECC.
09:44:50.047	51 min	HWD	Breaker B7C1 closed by the ECC.
09:46:16.920	53 min	DLK	Breaker B2L26 closed by the ECC. TL226 energized.

TIME	Duration (min:secs)	Location	Notes
TL226 is re-energized resuming supply to customers from Wiltondale to Parsons Pond.			
09:46:29.451	53 min	DLK	Breaker B3L48 closed by the ECC.
HLK is connected via 230 KV into MDR.			
09:46:57.501	53 min	DLK	Breaker B3L47 closed by the ECC.
09:47:18.000	54 min	CAT	ECC attempted start on G2. G2 is still locked out.
09:48:44.844	55 min	HLK	Control gates lowered by the ECC.
09:49:09.997	56 min	USL	Breaker L34L63 closed by the ECC. Line TL263 to GCL is energized.
TL263 is energized.			
09:49:25.475	56 min	DLK	Breaker B3L47 opened by the ECC (following failed start on CAT G2).
09:49:30.608	56 min	USL	Breaker L34T1 closed by the ECC. T1 energized.
09:49:55.000	56 min	GCL	ECC attempted start on G1.
09:50:13.780	57 min	USL	Breaker B1T2 closed. Station service re-energized.
09:54:35.497	1 hour 1 min	CBC	Breaker B2C3 opened by the ECC.
10:03:23.718	1 hour 10 min	STB	Breaker B1L130 closed by the ECC. 130L energized.
10:06:55.248	1 hour 13 min	CBC	Breaker B1C2 opened by the ECC.
10:08:10.000	1 hour 15 min	GCL	Breaker B1G1 closed. Unit on line.
Granite Canal unit is online. Unit loaded to 29 MW at 10:13 hrs.			
10:11:03.079	1 hour 18 min	CBC	Breaker B1C1 closed by the ECC
10:14:17.169	1 hour 21 min	STB	Breaker B1L35 closed by the ECC. TL235 energized.
TL235 is energized.			
10:14:59.266	1 hour 21 min	STB	Breaker L05L35 closed by the ECC.
10:15:11.331	1 hour 22 min	HWD	Breaker B7C1 opened by the ECC.
10:17:06.046	1 hour 24 min	HWD	Breaker B8C2 closed by the ECC.
10:19:38.046	1 hour 26 min	HWD	Breaker B7C1 closed by the ECC.
10:20:22.570	1 hour 27 min	CBC	Breaker B1C2 closed by the ECC.
10:20:37.807	1 hour 27 min	OPD	Breaker B5C1 closed by the ECC.
10:21:47.656	1 hour 28 min	SDP	Breaker B3G6 closed.
10:22:07.624	1 hour 29 min	SDP	Breaker B3G2 closed.
10:22:59.671	1 hour 29 min	SDP	Breaker B3G5 closed.
10:23:09.603	1 hour 30 min	CBC	Breakers B1C1, B1C2, and B2C4 tripped.
Load pickup by NP followed by a load trip of approximately 60 MW resulted in a system overvoltage and tripping of capacitors C1, C2, and C4 at Come by Chance.			
10:23:14.325	1 hour 30 min	HBY	Breaker G2T3 tripped (unit overspeed).
10:23:15.396	1 hour 30 min	HWD	Breaker B8C2 tripped.
10:23:26.334	1 hour 30 min	HBY	Breaker G1T3 tripped (air box PSI fault).
10:24:38.788	1 hour 31 min	CBC	Breaker B2C3 closed by the ECC.
10:25:04.659	1 hour 32 min	SDP	B3G4 closed

TIME	Duration	Location	Notes
10:27:13.528	1 hour 34 min	HWD	Breaker B2L42 closed by the ECC. HRD end still open.
10:27:13.559	1 hour 34 min	HWD	Breaker B2L42 tripped in 4 cycles. TL242 faulted BC phase. P1 and P2 phase distance operated. SOTF tripping 3 phase. Fault distance P1 27.01 and P2 26.52 km, indicating very close to HRD.
10:29:27.270	1 hour 36 min	HWD	Breaker B2L42 closed by the ECC. HRD end open.
10:29:27.323	1 hour 36 min	HWD	Breaker B2L42 tripped tripped in 4 cycles. TL242 faulted A-C phase. P1 and P2 phase distance operated. SOTF tripping 3 phase. Fault distance P1 35.75 and P2 30.35 km, indicating very close to HRD. (3-phase protection trip)
10:31:34.335	1 hour 38 min	HBY	Breaker G2T3 closed.
10:33:13.596	1 hour 40 min	BBK	Breaker L09L33 closed by the ECC. TL209 Energized. SVL station re-energized. L405T4 already closed. SVL diesel shuts down.
10:38:11.443	1 hour 45 min	HWD	G1T5 closed (Gas turbine online)
10:40:15.455	1 hour 47 min	HWD	G1T5 tripped (Gas turbine offline when switching to generate)
10:41:37.612	1 hour 48 min	HWD	Breaker B2L42 closed by the ECC. HRD end open.
10:41:37.664	1 hour 48 min	HWD	Breaker B2L42 tripped tripped in 4 cycles. TL242 faulted AB phase. P1 and P2 phase distance operated. SOTF tripping 3 phase. Fault distance P1 33.03 and P2 27.69 km, indicating very close to HRD.
10:43:16.202	1 hour 50 min	OPD	Breaker B5C1 opened by the ECC.
10:45:16.298	1 hour 52 min	BBK	Breaker B1L09 closed by the ECC. B1, B3, TL214, and TL211 energized briefly.
10:45:17.043	1 hour 52 min	BBK	Breaker B1L09 tripped. Suspect problems with air system on breaker (no protection indication).
10:48:00.944	1 hour 55 min	HWD	G1T5 closed (Gas turbine online).
10:49:46.333	1 hour 56 min	HBY	Breaker G2T3 opened (plant shutdown – potentially due to loss of DC).
10:54:29.620	2 hours 1 min	SDP	B3G3 closed.
10:56:55.662	2 hours 3 min	SDP	B3G1 closed.
10:57:36.000	2 hours 4 min	NP SCV	NP closed breaker SCV 38L-B, energizing HRD B7 from 66 KV via 38L. HRD B7T5 already open (NP SOE Time).
10:57:36.576	2 hours 4 min	HRD	Lockouts 86B6B7 and 86T5 operated. 87B6/B7 A&B phases instantaneous bus differential & 87T5 A&C phases transformer differential operated. B7T5 already open, suspect fault on breaker B7T5 bushings.
Holyrood breaker B7T5 faulted (open at the time) when energized from 38L.			
10:57:36.665	2 hours 4 min	HRD	Breakers B7L2 and B7L38 tripped.
10:57:36.974	2 hours 4 min	HRD	Breaker B6L3 tripped.
10:57:43.540	2 hours 4 min	HRD	Disconnect B11T5 opened due to 86T5 operation.
11:01:57.456	2 hours 8 min	HWD	G1T5 tripped (while raising GT setpoint).
11:03:13.348	2 hours 10 min	HBY	Breaker G2T3 closed.
11:06:47.967	2 hours 13 min	SAP	Breaker B1C1 opened by the ECC.
11:08:10.406	2 hours 15 min	DLP	Breaker B4L25 closed by DLP Operator.
11:08:12.243	2 hours 15 min	DLP	Breaker B4L25 tripped.
11:10:31.379	2 hours 17 min	HWD	Breaker B8C2 closed by the ECC.
11:11:52.493	2 hours 18 min	HWD	Breaker B8C2 tripped (protection operation).

TIME	Duration	Location	Notes
11:14:10.219	2 hours 21 min	OPD	Breaker B5C1 closed by the ECC.
11:14:44.526	2 hours 21 min	OPD	Breaker B5C1 opened by the ECC.
11:15:06.152	2 hours 22 min	DLK	Breaker B2L25 closed by the ECC.
11:15:06.850	2 hours 22 min	OPD	Breaker B5C1 closed by the ECC.
11:15:12.629	2 hours 22 min	SDP	Breaker B3G6 opened.
11:15:49.449	2 hours 22 min	DLK	Breaker B2L25 opened by the ECC.
11:16:21.345	2 hours 23 min	BBK	Breaker B1L09 closed initially by the ECC and then opened/closed 4-5 times. Suspect problems on breaker air system. TL214 and DLS 66 KV energized and de-energized also at this time.
11:16:40.490	2 hours 23 min	DLP	Breaker B4L25 closed by DLP Operator.
11:16:42.607	2 hours 23 min	DLP	Breaker B4L25 tripped.
11:19:16.323	2 hours 26 min	BBK	Breaker L11L33 closed by the ECC.
Bottom Brook busses B2 and B3, transmission line TL214 and DLS 66 KV are energized.			
11:21:05.612	2 hours 28 min	SDP	Breaker B3G1 opened.
11:22:42.317	2 hours 29 min	BUC	Breaker B1L28 closed by the ECC. BUC 66 KV is not energized, B1T1 open due to T1 lockout operation.
11:23:13.447	2 hours 30 min	HWD	G1T5 closed (GT online).
11:25:04.048	2 hours 32 min	BBK	Breaker L11L33 opened by the ECC.
11:26:10.196	2 hours 33 min	BBK	Breaker L11L33 closed by the ECC.
11:28:10.180	2 hours 35 min	BBK	Breaker B1L09 closed initially by the ECC and then open/closed 2 times. Suspect air system issues with the breaker.
11:30:48.621	2 hours 37 min	SDP	Breaker B3G1 closed.
11:42:00.666	2 hours 49 min	DLK	Breaker B2L25 closed by the ECC.
11:46:27.501	2 hours 53 min	DLP	Breaker B4L25 closed by DLP Operator (DLP now synced back to the system).
Deer Lake Power is connected to NL Hydro system at the 66 KV at Deer Lake.			
11:49:40.941	2 hours 56 min	CBC	Breaker B1C2 closed by the ECC.
11:49:49.751	2 hours 56 min	BBK	B3L50 closed by the ECC.
TL250 is energized.			
11:52:02.340	2 hours 59 min	MDR	B4T1 closed by the ECC.
Massey Drive 66 KV bus B4 is connected to Hydro system supplying DLP.			
11:53:29.126	3 hours	MDR	Breaker L16B-MD closed by DLP.
11:53:43.511	3 hours	MDR	Breaker L17B-MD closed by DLP.
12:03:23.127	3 hours 10 min	GFC	Breaker 252T-3 closed by local operator.
12:05:36.534	3 hours 12 min	OPD	Breaker B5C1 opened by the ECC.
12:06:06.351	3 hours 13 min	GBK	Recloser GB1-R1 closed by the ECC.
12:07:39.183	3 hours 14 min	OPD	Breaker B5C1 closed by the ECC.
12:09:32.352	3 hours 16 min	HWD	Breaker B7C1 opened by the ECC.
12:13:23.284	3 hours 20 min	GBK	Recloser GB5-R1 closed by the ECC.
12:19:56.274	3 hours 26 min	SAP	Breaker B1C1 closed by the ECC.
12:23:14.610	3 hours 30 min	SDP	Breaker B3G6 closed.
12:25:06.000	3 hours 32 min	NP	GRT-G-B closed (Greenhill GT on).

TIME	Duration	Location	Notes
12:25:26.599	3 hours 32 min	SDP	Breaker B3G1 closed.
12:33:17.624	3 hours 40 min	STB	Breaker L04L32 closed by the ECC. Both lines already energized.
12:34:08.456	3 hours 41 min	HRD	Lockout 86B8B15 reset.
12:34:24.781	3 hours 41 min	HRD	Lockout 86T5 reset.
12:35:35.049	3 hours 42 min	HRD	Lockout 86B6B7 reset.
Holyrood Lockouts 86B8B15, 86T5 and 86B6B7 were reset.			
12:38:12.317	3 hours 45 min	HWD	Breaker B7C1 closed by the ECC.
12:43:15.510	3 hours 50 min	BBK	Breaker B1L09 closed. The breaker closed successfully while station in local control.
12:45:01.188	3 hours 52 min	BBK	Breaker B1L11 opened by the ECC. B1 BBK and TL211 still energized.
12:45:18.984	3 hours 52 min	BBK	Breaker L11L33 opened by the ECC. TL211 de-energized.
12:46:01.797	3 hours 53 min	MDR	Breaker B5L11 closed by the ECC. TL211 energized from MDR.
13:01:44.918	4 hours 8 min	DLS	86T2 reset.
13:02:18.348	4 hours 9 min	CAT	Switch G1T1 opened (perhaps by local operator).
13:02:37.775	4 hours 9 min	DLS	94T2 trip. Operated by T2 overcurrent protection, trips recloser (already open) and operated time delayed into 86T2. Suspect DLS NP disconnect T2-A closed.
13:02:38.786	4 hours 9 min	DLS	86T2 operated.
13:02:38.806	4 hours 9 min	BBK	Transfer trip (85-TL214) received BBK.
13:02:38.869	4 hours 9 min	BBK	Breaker B2L14 tripped via transfer trip on TL214.
TL214 tripped causing an outage to DLS and PAB.			
13:02:41.168	4 hours 9 min	DLS	High speed GND Switch L14 AG closed due to 86T2 operation.
13:02:42.752	4 hours 9 min	DLS	High speed GND Switch L14 AG opened.
13:02:45.096	4 hours 9 min	DLS	High speed GND Switch L14 AG closed.
13:02:46.685	4 hours 9 min	DLS	High speed GND Switch L14 AG opened. Opens when NP T2-A opens.
13:04:28.185	4 hours 11 min	CBC	Breaker B1C2 opened by the ECC.
13:10:29.535	4 hours 17 min	HWD	Breaker B2L42 closed by the ECC. TL242 energized, open at HRD end.
TL242 is energized from the Hardwoods end only.			
13:11:45.792	4 hours 18 min	BBK	Breaker B2L14 closed by the ECC.
TL214, DLS T1 and DLS 66 KV are energized again.			
13:15:23.660	4 hours 22 min	CBC	Breaker B1C1 closed by the ECC.
13:16:00.695	4 hours 23 min	BBK	Breaker L11L33 closed by the ECC. TL211 closed both ends.
At this point all 230 KV lines in the Western and Central areas are back in service with the exception of TL247 (CAT to DLK).			
13:17:18.445	4 hours 24 min	BBK	Breaker B1L11 closed by the ECC. Ring closed at BBK.
13:17:37.439	4 hours 24 min	CBC	Breaker B2C4 closed by the ECC.
13:17:54.043	4 hours 24 min	HWD	Breaker B8C2 closed by the ECC.
13:20:00.010	4 hours 27 min	WAV	Breaker L01L03 closed by the ECC.
13:20:28.605	4 hours 27 min	OPD	Breaker B5C1 opened by the ECC.
13:20:46.844	4 hours 27 min	HWD	Breaker B8C2 tripped (protection trip).

TIME	Duration	Location	Notes
13:26:45.000	4 hours 33 min	MDR	CB frequency converter lockout was returned to normal.
13:28:14.005	4 hours 35 min	OPD	Breaker B5C1 closed by the ECC.
13:29:49.000	4 hours 36 min	HRD	Breaker failure lockout 86BF/B12L17 reset.
Holyrood breaker fail lockout B12L17 is reset.			
13:35:35.220	4 hours 42 min	HWD	Breaker B8C2 closed by the ECC.
13:36:47.784	4 hours 43 min	SLK	G1 anomalies returned to normal.
13:38:16.115	4 hours 45 min	DLP	Breaker 252T closed locally.
13:39:45.352	4 hours 46 min	HBY	Breaker G2T3 opened.
13:48:01.907	4 hours 55 min	DLK	Breaker B3L47 closed by the ECC.
TL247 is closed at the Deer Lake end only.			
13:48:49.000	4 hours 55 min	BUC	Recloser BUC-02-R1 opened.
13:49:00.000	4 hours 56 min	BUC	Recloser BUC-01-R1 opened.
13:51:17.912	4 hours 58 min	HWD	Breaker B8C2 tripped (protection trip).
13:54:21.474	5 hours 1 min	HWD	Breaker G1T5 opened.
13:57:27.364	5 hours 4 min	HBY	Breaker G2T3 closed.
14:04:49.426	5 hours 11 min	DLP	Breaker 252 closed locally.
14:12:56.394	5 hours 19 min	HRD	Lockout 86-3/G1 reset.
14:13:56.426	5 hours 20 min	HRD	Lockout 86-2/G1 reset.
14:17:43.848	5 hours 24 min	DLP	Breaker 152T closed locally.
14:35:12.773	5 hours 42 min	HRD	Breaker B7L38 closed by the ECC.
14:35:37.960	5 hours 42 min	HRD	Breaker B7L38 opened by the ECC.
14:36:25.289	5 hours 43 min	BDE	Breaker B11L06 closed. PH2 in local.
14:39:28.596	5 hours 46 min	USL	Lockout 86G/2 reset.
14:44:18.667	5 hours 51 min	USL	Breaker G1T1 closed by the ECC.
USL G1 is online. The unit is loaded to 79 MW at 15:02 hrs.			
14:50:56.860	5 hours 57 min	CBC	Breaker B1C2 closed by the ECC.
14:55:48.614	6 hours 2 min	CBC	Breaker B1C1 opened by the ECC.
14:58:11.701	6 hours 5 min	HRD	Breaker B12L42 closed by the ECC. Already closed at HWD end.
TL242 is in service. HRD bus B12 is energized. TL217 is still open at the HRD end. TL201 is supplying HWD. TL201 load is 220 MW.			
14:58:22.344	6 hours 5 min	CBC	Breaker B1C1 closed by the ECC.
15:01:26.026	6 hours 8 min	HWD	Breaker B8C2 closed by the ECC.
15:02:41.731	6 hours 9 min	HRD	Breaker B12T10 closed by the ECC.
15:03:10.671	6 hours 10 min	HRD	Breaker B6T10 closed by the ECC.
HRD 66 KV B6B7 is energized.			
15:06:17.011	6 hours 13 min	HRD	Breaker B7L2 closed by the ECC
15:07:23.179	6 hours 14 min	HRD	Breaker B12L18 closed by the ECC. Already closed OPD end.
TL218 is in service.			
15:08:04.076	6 hours 15 min	HRD	Breaker B12L17 closed by the ECC. Multiple (5) open/closes. TL217 closed both ends.
TL217 is in service supplying the St. John's region in parallel with TL201. The load on both lines totals 277 MW.			

TIME	Duration	Location	Notes
15:10:08.173	6 hours 17 min	HWD	Breaker B8C2 opened by the ECC. High Voltage on the 66 KV.
15:12:52.399	6 hours 19 min	HRD	Disconnect B11T5 closed by the ECC. T5 not energized and B11 still de-energized.
15:21:22.035	6 hours 28 min	HWD	Breaker B8C2 closed by the ECC. Low Voltage limit exceeded.
15:30:47.723	6 hours 37 min	HWD	Breaker B8C2 open via overvoltage protection.
15:32:45.872	6 hours 39 min	HRD	Lockout 86-1/G2 reset.
15:32:45.904	6 hours 39 min	HRD	Lockout 86-3/G2 reset.
15:32:45.924	6 hours 39 min	HRD	Lockout 86-2/G2 reset.
15:34:23.967	6 hours 41 min	HWD	Breaker B8C2 closed by the ECC.
15:41:11.962	6 hours 48 min	HRD	Breaker B12B15 closed by the ECC.
HRD 230 KV bus B15, transformers T6, T7, T8 and 138 KV bus B8 are all energized.			
15:42:38.235	6 hours 49 min	HWD	Breaker B8C2 opened via voltage protection.
15:44:18.515	6 hours 51 min	HRD	Breaker B8L39 closed by the ECC.
NP line 39L is in service.			
15:44:59.384	6 hours 51 min	HBY	Breaker G1T3 closed by the ECC.
15:47:02.877	6 hours 54 min	HWD	Breaker B8C2 closed by the ECC.
15:54:23.571	7 hours 1 min	SAP	Breaker B1C1 opened by the ECC.
15:54:32.180	7 hours 1 min	HWD	Breaker B8C2 opened via overvoltage protection.
16:26:27.771	7 hours 33 min	HRD	Breaker B3L18 closed by the ECC.
16:37:39.071	7 hours 46 min	HRD	Breaker B7L38 closed by the ECC.
NP line 38L is in service.			
16:56:14.483	8 hours 3 min	HWD	Breaker G1T5 closed by the ECC
16:56:44.061	8 hours 3 min	HRD	Breaker B2L42 closed by HRD operator – 5 indications are recorded.
16:58:26.094	8 hours 5 min	HWD	Breaker B8C2 closed by the ECC.
16:59:27.364	8 hours 6 min	HRD	Breaker B6L3 closed by the ECC.
17:00:53.077	8 hours 7 min	HRD	Breaker B2B11 closed by HRD operator.
The HRD T.S. ring between B12 and B11 and HRD 230 KV bus B11 are energized.			
17:10:48.653	8 hours 17 min	CBC	Breaker B2C3 opened by the ECC.
17:14:15.757	8 hours 21 min	PRV	Breaker G1T1 closed.
17:22:43.909	8 hours 29 min	HRD	Breaker B1L17 closed by HRD operator.
17:23:33.262	8 hours 30 min	HRD	Breaker B1B11 closed by HRD operator.
The HRD T.S. second ring between B11 and B12 is closed.			
17:38:56.294	8 hours 45 min	HRD	Breaker B7T5 closed by the ECC.
HRD transformer T5 is in service.			
18:10:56.620	9 hours 17 min	CAT	Lockout 86G/1 reset.
18:16:16.439	9 hours 23 min	CAT	Disconnect G1T1 closed by CAT operator.
18:21:45.765	9 hours 28 min	CAT	Breaker L47T1 closed. G1 is online.
Cat Arm Unit 1 is online. The unit is loaded to 50 MW at 1900 hrs.			
18:42:06.776	9 hours 49 min	CAT	T-L47T2 normal. The alarms and events reported G2 lockout to normal however no G2 lockout was recorded?
18:47:44.009	9 hours 54 min	HRD	Breaker B2B11 opened.

TIME	Duration	Location	Notes
18:48:02.790	9 hours 55 min	HRD	Breaker B2B11 closed.
18:48:09.360	9 hours 55 min	HRD	Breaker B2L42 opened.
18:48:20.193	9 hours 55 min	HRD	Breaker B2L42 closed.
18:48:25.006	9 hours 45 min	HWD	Breaker G1T5 tripped. GT tripped on vibration alarm.
18:48:45.544	9 hours 55 min	HRD	Breaker B3L18 opened.
18:48:56.909	9 hours 55 min	HRD	Breaker B3L18 closed.
18:49:51.866	9 hours 56 min	CBC	Breaker B2C3 closed by the ECC.
18:53:14.440	10 hours	CAT	Breaker L47T2 closed. G2 is online.
Cat Arm Unit 2 is online. The unit is loaded to 60 MW at 1914 hrs.			
19:05:36.996	10 hours 12 min	HWD	Breaker G1T5 closed.
19:06:54.653	10 hours 13 min	SDP	Breaker B3G3 opened.
19:07:04.395	10 hours 14 min	HBY	Breaker G1T3 opened. Plant shut down by the ECC.
19:07:05.412	10 hours 14 min	HBY	Breaker G2T3 opened. Plant shutdown by the ECC.
19:07:11.253	10 hours 14 min	CBC	Breaker B1C1 opened by the ECC.
19:12:35.661	10 hours 19 min	SDP	Breaker B3G4 opened. Plant shutdown by the ECC.
19:13:35.659	10 hours 20 min	SDP	Breaker B3G2 opened. Plant shutdown by the ECC.
19:15:15.678	10 hours 22 min	SDP	Breaker B3G5 opened. Plant shutdown by the ECC.
19:16:01.813	10 hours 23 min	STA	Breaker B1C3 closed by the ECC.
19:16:33.675	10 hours 23 min	SDP	Breaker B3G6 opened. Plant shutdown by the ECC.
19:41:51.012	10 hours 48 min	HWD	Breaker G1T5 tripped. GT tripped on vibration alarm.
19:41:43.831	10 hours 48 min	CBC	Breaker B1C1 closed by the ECC.
20:03:24.006	11 hours 10 min	SVL	Breaker B2T3 closed by the ECC.
20:11:07.003	11 hours 18 min	HWD	Breaker G1T5 closed.
20:31:03.518	11 hours 38 min	HWD	Breaker G1T5 tripped. Unit tripped on vibration alarm.
20:49:21.032	11 hours 56 min	HRD	Breaker B3B13 closed.
20:49:33.068	11 hours 56 min	HRD	Breaker B3B13 opened.
20:52:00.455	11 hours 59 min	HRD	Breaker B3B13 closed.
20:52:06.851	11 hours 59 min	HRD	Breaker B3B13 opened.
20:52:12.956	11 hours 59 min	HRD	Breaker B3B13 closed.
20:58:30.008	12 hours 5 min	HWD	Breaker G1T5 tripped. Unit tripped on vibration alarm.
20:58:30.088	12 hours 5 min	BUC	Lockout 86BF/L05L33 reset.
21:01:09.956	12 hours 8 min	BUC	Lockout 86T1 reset.
22:09:44.529	13 hours 16 min	HWD	Breaker G1T5 opened.
22:52:23.064	13 hours 59 min	BUC	Disconnect B1T1 opened.
23:25:10.003	14 hours 32 min	BUC	Breaker B1L28 opened by the ECC.
23:25:45.060	14 hours 32 min	BUC	Disconnect B1T1 closed.
23:52:01.229	14 hours 59 min	BUC	Breaker B1L05 closed by the ECC.
BUC transformer T1 is energized.			
23:55:09.575	15 hours 2 min	BUC	Breaker B2T1 closed by the ECC.

TIME	Duration	Location	Notes
23:58:07.000	15 hours 5 min	BUC	Recloser BUC-01-R1 closed.
23:58:49.000	15 hours 5 min	BUC	Recloser BUC-02-R1 closed.
00:00:12.693	15 hours 7 min	BUC	Breaker B2L80 closed by the ECC.
00:00:50.877	15 hours 7 min	BUC	Breaker B2L64 closed by the ECC.
BUC station is fully in service.			

APPENDIX B

Schweitzer Engineering Limited

Explanation of SEL 321 Protection Misoperation due to Over/Under Frequency

January 11, 2013

newfoundland labrador hydro
a nalcor energy company

MEMO

TO: K. GOULDING, R. LEGGO, A. LAU

FROM: R. COLLETT

SUBJECT: PRELIMINARY EVENT ANALYSIS - JANUARY 11, 2013 0742

DATE: JANUARY 18, 2013

CC: P. HUMPHRIES, P.THOMAS, J. FLYNN, J. MATCHEM

Introduction and Background

At the request of System Operations, a preliminary analysis was undertaker by the System Planning Department to investigate an instability event on January 11, 2013 at 0742. This event involved what is assumed to be a single-phase fault on TL201 that ultimately resulted in the loss of supply to over 600 MW of load.

The study involved load flow and transient stability analysis using Version 32 of PSS®E software from Siemens PTI.

Sequence of Events

The following is an overview of significant events from January 11 provided by System Operations based on preliminary analysis:

- At 0413 hours on January 11 there was a localized trip of Unit 3 at Holyrood. Preliminary indications are that there was an issue with a boiler drum level.
- At 0642 hours on January 11 there was a trip of Holyrood Unit No. 1, TL217 (Western Avalon end only, although it appears that the HRD end tripped and reclosed), Holyrood Unit No. 2, and line 39L.
- At 0648 hours on January 11 there was a Holyrood 138 KV station lockout, breaker failure operation associated with breaker B12L17, and line protection operations on TL 242 (Holyrood - Hardwoods) and TL218 (Holyrood – Oxen Pond). At this time it is uncertain as to

whether there were faults on the latter two lines of if they tripped in response to issues on the station sides of the breakers at HRD.

- At 0742 hours on January 11 there was a trip on TL201 (Western Avalon - Hardwoods). With TL217 already out of service this resulted in a significant system upset/instability and trips of numerous lines and generating units west of the Avalon Peninsula. Preliminary indications are that there was a single phase fault on TL201.
- At 0851 hours on January 11 there was another trip on TL201. Again there was indication of a single phase fault in the same location as the fault at 0742 hours. This line outage resulted in another significant impact to customers, reversing much of the restoration effort that had taken place since the first trip at 0742 hours.

System Conditions

Based on the detail provided above as well from SCADA data from Hydro's Energy Management System (EMS), models were developed to reflect system conditions at the time of the 0742 event. The conditions are summarized as follows:

- System Generation: 942 MW
- Gross Avalon Load: 391 MW
- St. John's Area Load: 252 MW
- Status of Holyrood Plant: Out of Service
- Status of TL201: In Service
- Status of TL217: Out of Service
- Status of TL218: Open at HRD End
- Status of TL242: Open at HRD End
- Status of 38L: Out of Service
- Status of 39L: Out of Service
- Status of HWD Gas Turbine: In Service as Generator, 5 MW Output

Load Flow Analysis

The load flow model developed for this analysis is illustrated in Figure 1. As indicated, the only supply to the St. John's area is via TL201 with reactive support for loads provided by capacitor banks at Hardwoods and Oxen Pond. It should be noted that power factors for loads in the St. John's area were modified to match 230 kV voltage measurements from EMS data.

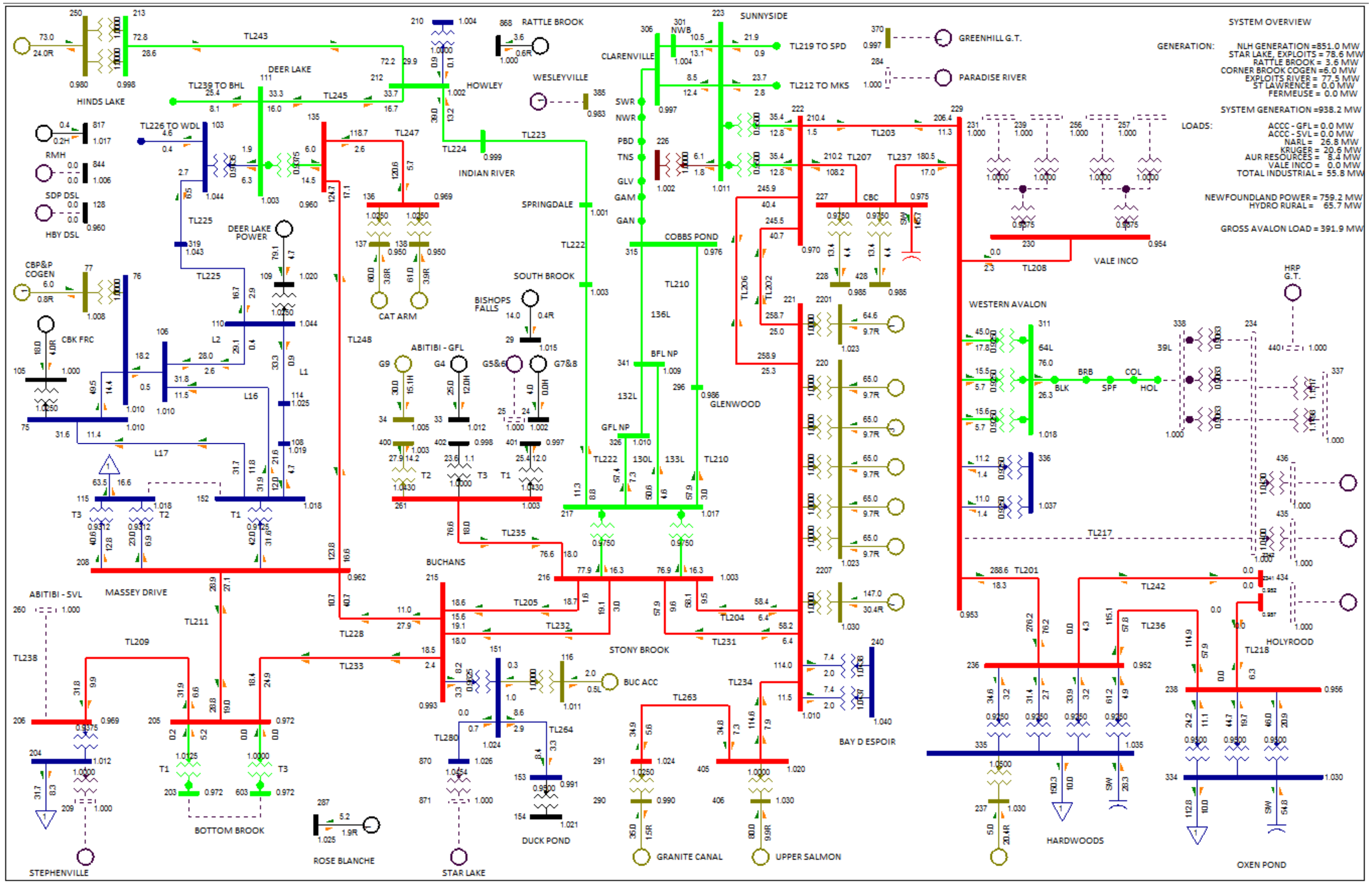

Figure 1 – Load Flow Plot – System Condition January 13, 0742

Transient Stability Analysis

Transient stability analysis was performed to investigate the system response to a single line-to-ground (SLG) fault on TL201. The dynamic simulation was performed based on the following sequence of events which represent a failed reclose:

1. t = 1.000 seconds – SLG Fault near middle of TL201
2. t = 1.083 seconds – Open One Phase HWD B1L01
3. t = 1.100 seconds – Open One Phase WAV L0103 and L01L37
4. t = 1.600 seconds – Close One Phase WAV L0103 and L01L37
5. t = 1.650 seconds – Trip TL201

The results of this analysis as are follows:

1. The SLG fault on TL201 resulted in the tripping of the line. This trip resulted in the isolation of load in St. John's area. This resulted in the interruption of 287 MW flow on TL201 at Western Avalon Terminal Station.

2. Voltages at Come-by-Chance Terminal Station become elevated due to the sudden loss of load. As illustrated in Figure 2. The overvoltages presented below would result in the tripping of the Come-By-Chance capacitor banks.

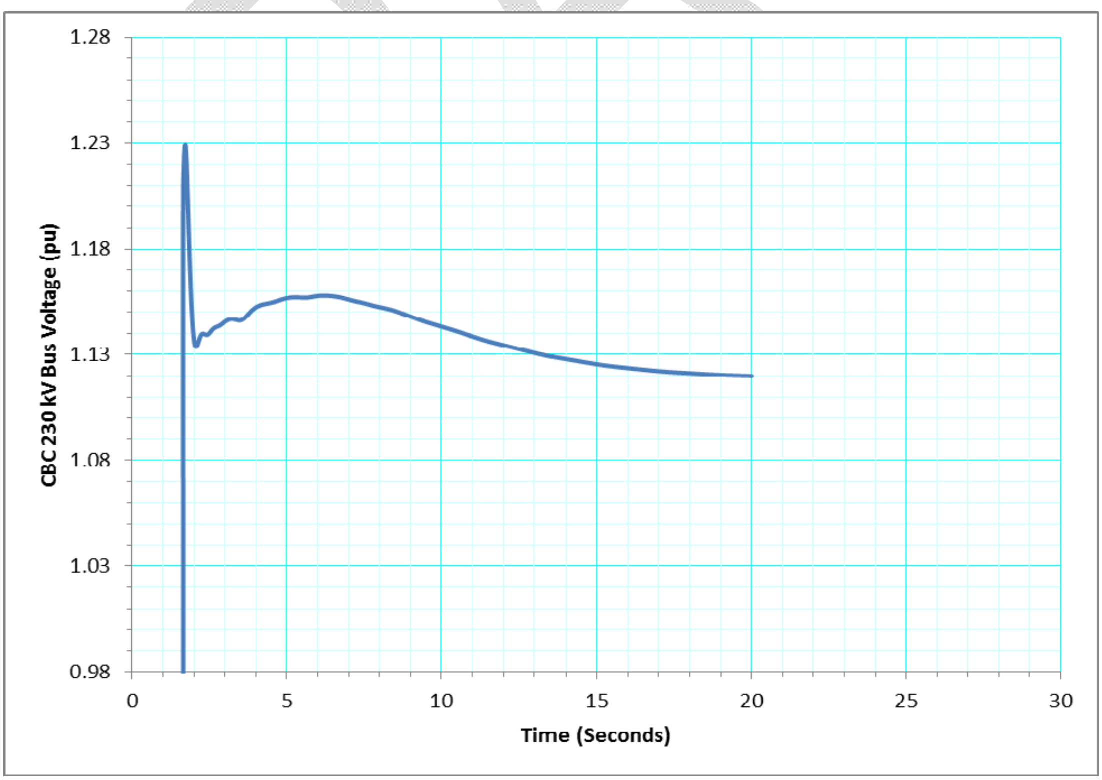

Figure 2 – CBC 230 kV Bus Voltage Following SLG Fault on TL201

3. The loss of load results in a significant increase in system frequency. As illustrated in Figure 3, the simulated frequency reaches a maximum value in excess of 65.1 Hz. It should be noted, however, that the simulation does not include the modelling of overfrequency protection that would result in the tripping of units. The tripping of units would reduce the magnitude of the overfrequency condition.

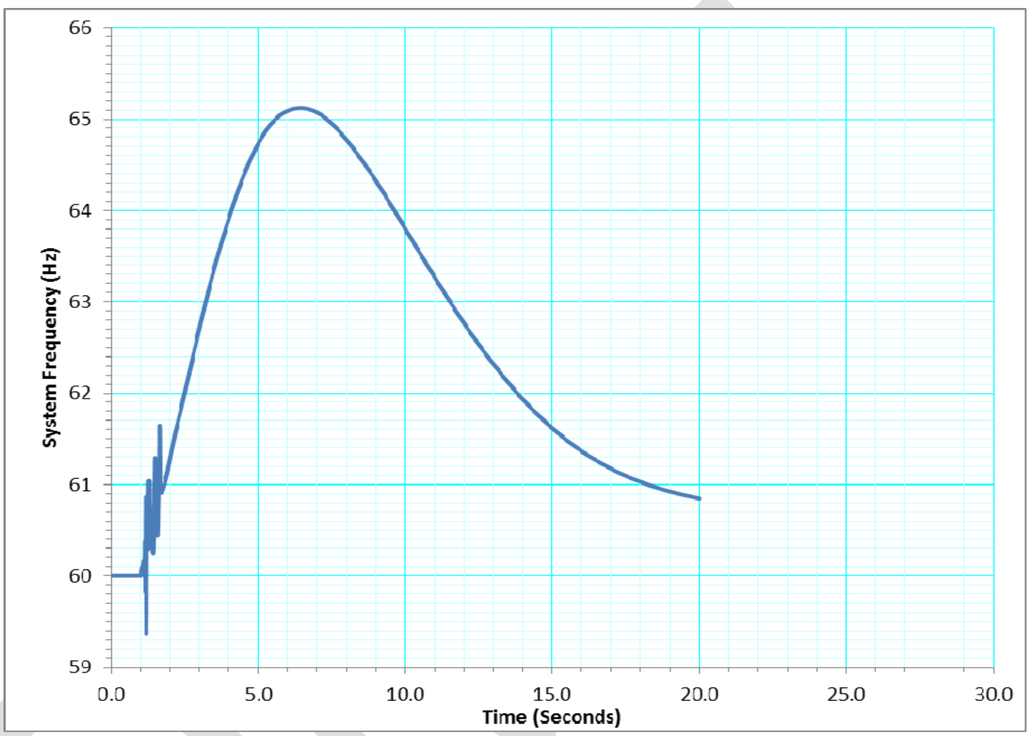

Figure 3 – CBC 230 kV Bus Frequency Following SLG Fault on TL201

4. Despite the loss of load, the simulation indicates that angular stability is maintained for the units across the system. This is illustrated in Figure 4.

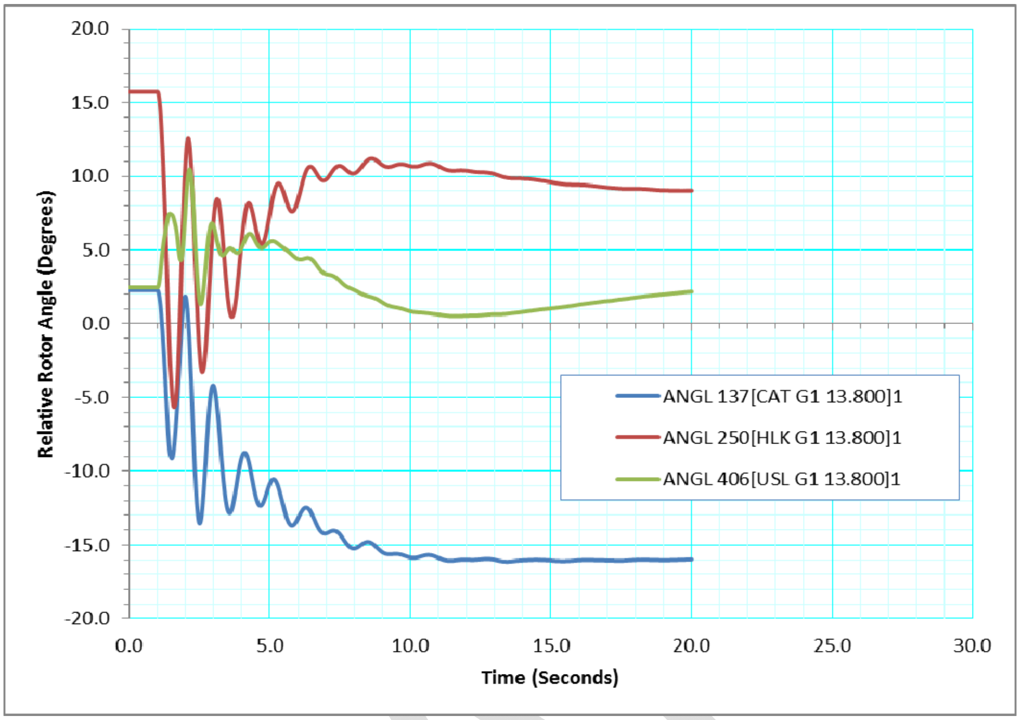

Figure 4 – Machine Angular Stability Following SLG Fault on TL201

Conclusion

Based on the preliminary analysis described above, the SLG event on TL201 resulted in sudden interruption of the flow over 280 MW at WAV. This sudden loss of load resulted in overvoltage and overfrequency conditions across the system. While a comprehensive analysis of the Sequence of Events is required for a detailed understanding of the disturbance, it is clear from this preliminary analysis that the system conditions would have triggered responses from protective devices across the system. Without these protective measures, the system frequency would have exceeded 65 Hz and voltages on select 230 kV buses would have exceeded 1.10 per unit.

It is therefore recommended that a detailed load flow and transient stability analysis be conducted in concert with the comprehensive review of the Sequence of Events to gain a full understand of the event.

Regards,

R. Collett

Rob Collett

Senior System Planning Engineer

APPENDIX C

Preliminary Stability Study

0742 Event

System Planning Department

Explanation of SEL 321 Relay operation at Newfoundland and Labrador Hydro

Background

On the 11th of January 2013 several SEL 321 relay's phase distance elements operated while there was no fault on the power system. Fig.1 is an oscillographic capture of the voltages, currents and digitals as recorded by the relay at the time of the operation. From this we can see that the power system did not experience a fault at the time of the relay operation.

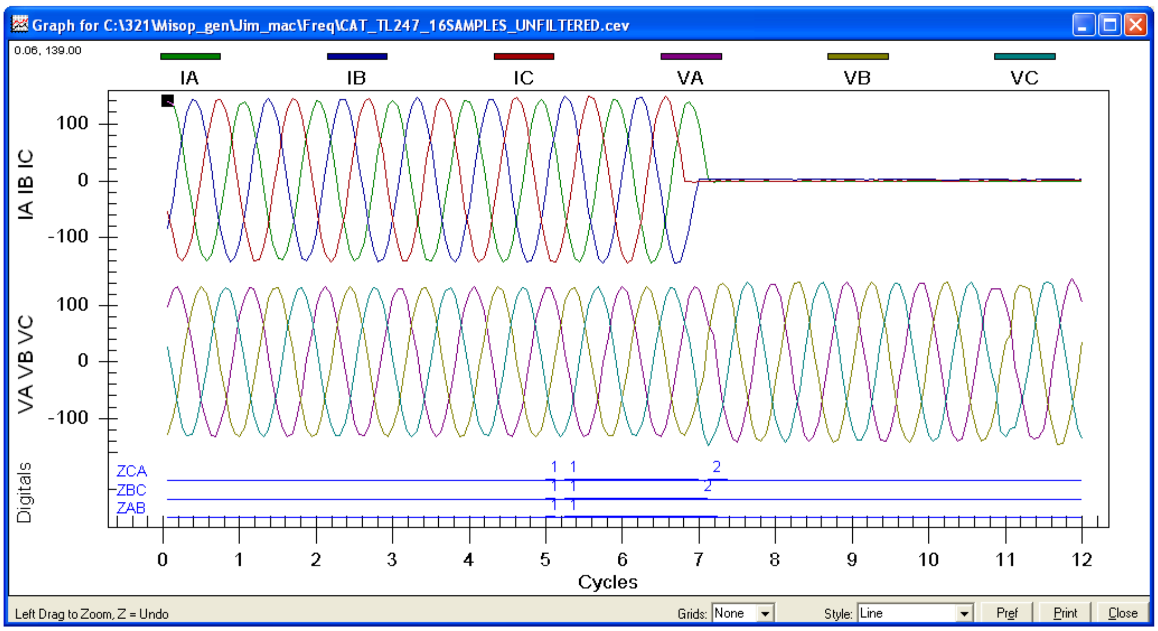

Fig.1 Oscillographic record extracted from SEL 321-3 relay, the oscillography shows the voltages, currents and digitals at the time of the relay operation. From this record we can see that all three phase-to-phase elements (ZAB, ZBC and ZCA) asserted.

The following is an explanation as to why the relay operated and also offers a solution on how to prevent the relay from operating for such conditions in the future.

Analysis

At the time of the relay operation the relay's tracking frequency was out of synchronism with that of the power system frequency. What this means is that the relay is designed to sample the primary power system quantities (voltage and current) at 16 samples per cycle (spc), however at the time of the relay operation the relay was not sampling the primary system at this rate, this can be seen when examining the A-phase voltage, as shown in Fig.2.

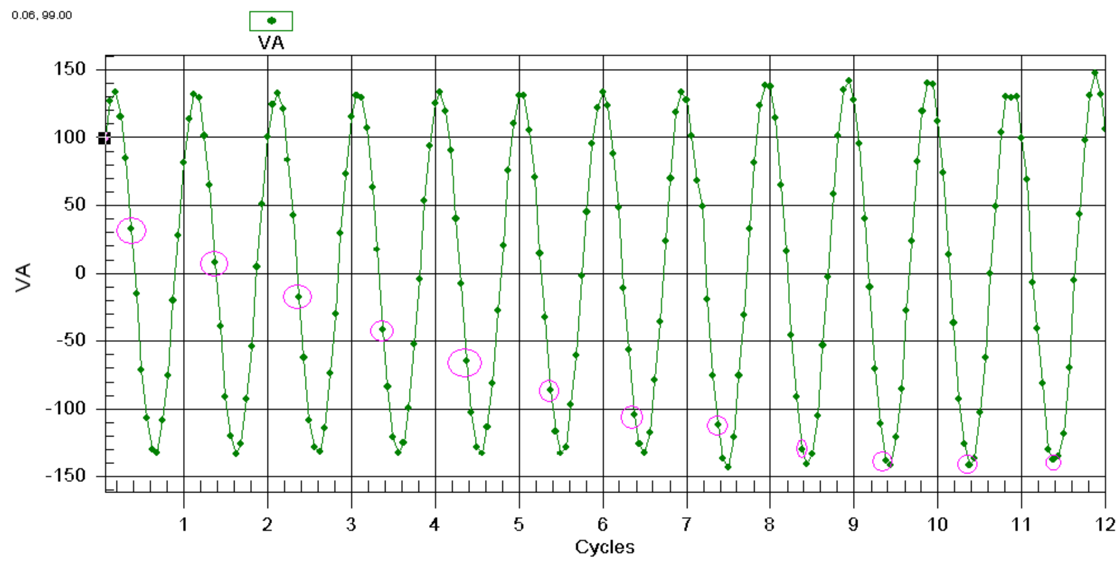

Fig.2. Is an oscillographic plot of the "A-phase" voltage, the oscillography indicates when the wave form was sampled by the relay.

The reason that the relay was not sampling the power system at 16 spc can be due to a few reasons;

- One could be that prior to the relay operation the power system experienced a sudden loss of a significant load or generation source. The result of which is rapid change in the system frequency. For the loss of a significant load, the system frequency will rapidly increase to a newer higher frequency or in the case of losing generation, results in a rapid decrease to a lower frequency. The relay frequency tracking algorithm is designed such that a sudden jump in the power system frequency does not result in the relay jumping to the new frequency but slewing to the new frequency as show in Fig. 3 (a) and (b). The relay frequency slews to the new rate using the following algorithm:

$$freq\_relay_k = freq\_relay_{k-1} + \frac{1}{8} \cdot (freq\_measure_k - freq\_relay_{k-1})$$

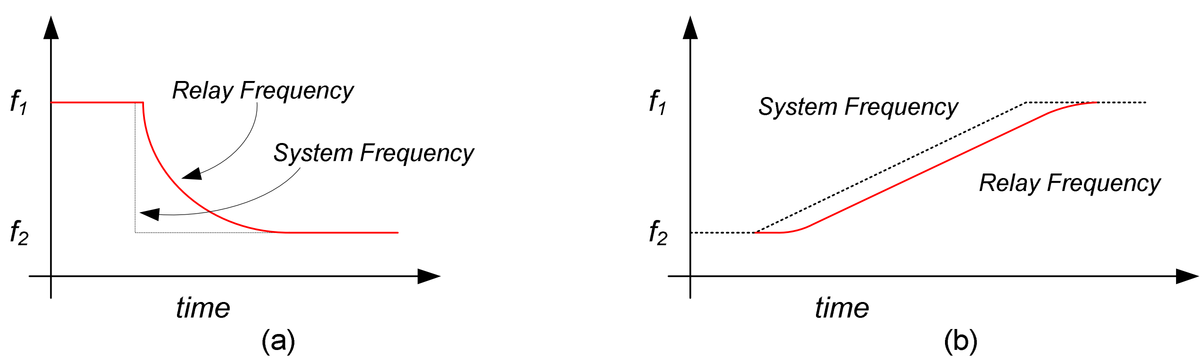

Fig.3. show the response of the relay frequency tracking algorithm for a (a) step in the power system frequency (b) for a ramp in t he system frequency.

- A second possibility is that the relays time processing unit (TPU) fails, if this occurs the relay will slew to the nominal frequency and issue an alarm. As the relay issued no alarm condition when the relay operated this possibility can be disregarded.
- A third reason is that the system frequency was changing too fast for the relay frequency tracking algorithm to keep up with the power system, stated different the df/dt of the power system was greater than the tracking ability of the algorithm. The SEL 321 frequency tracking algorithm is capable of tracking a df/dt rate of 30Hz/sec. The power system rate of change of frequency was far below this and therefore this possibility can be ignored.
- A fourth possibility is that the system frequency is outside the bonds of the relay operating range , at the time of the operation the power system frequency was is the region of 55.7 Hz. The SEL 321-3 has a frequency tracking range of 55 - 63 Hz. The 321-1 has a frequency tracking range of 55 – 65 Hz.

One could be inclined to think that the relays phase distance elements misoperated because the relay was not frequency tracking the power system frequency correctly, this is however not quite correct. Recall the 1st generation micro processor distance relays did not employ frequency tracking and where either self polarized or cross polarized, these relays would not have operated under this condition (this will be show later using the positive sequence impedance calculation), because the frequency of the operate quantity (the line replica voltage drop (δV)) and the polarizing quantity will remain at the same frequency with respect to each other. The reason for the SEL 321 relay misoperating is that the frequency of the operating quantity (δV)) and the polarizing quantity (the positive sequence memory voltage ($V1_{MEM}$)) where not the same. The difference between the 1st generation micro processor relay and the SEL-321 is that the SEL 321 uses positive sequence memory voltage to polarize the distance element. To explain why the positive sequence memory voltage resulted in the operation of phase distance elements the positive sequence memory voltage will be analyzed more closely.

Positive sequence Memory Polarization

The SEL321-3 relay uses positive sequence voltage for the memory voltage of the distance elements a simplistic schematic of the memory voltage circuit is shown in Fig.4

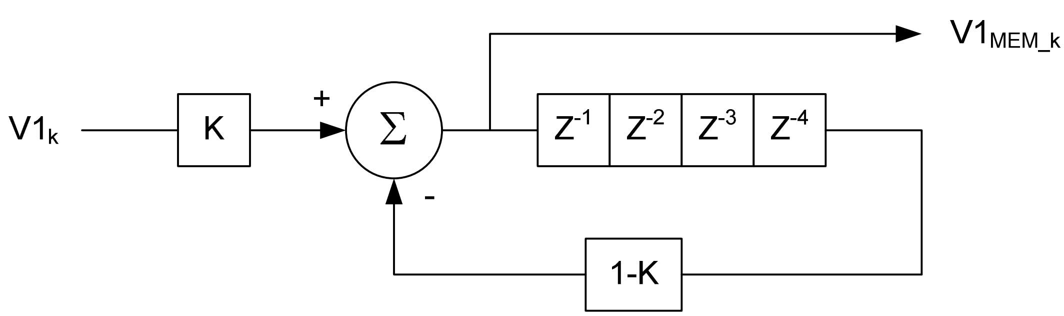

Fig.4. Simplistic schematic representation of the SEL 321 memory voltage algorithm.

The memory voltage (V1MEM_k) is composed of using a fraction of the present positive sequence memory voltage ($k \cdot V1_k$) and subtracting this from a fraction of the memory voltage from a ½ a cycle earlier ($(1-k) \cdot V1_{MEM\_k-4}$). This is equivalent to adding a fraction of the present positive sequence voltage ($k \cdot V1_k$) to a fraction of the memorized positive sequence memory voltage from one cycle ago ($(1-k) \cdot V1_{MEM\_k-1cycle}$). If you look at Fig.5 this becomes clear. It can be seen that the sample at (k-4) and at (k-1cycle) have the same magnitude but are 180 degrees out of phase with each other (of opposite sign). Therefore we are adding quantities that are in phase with each other.

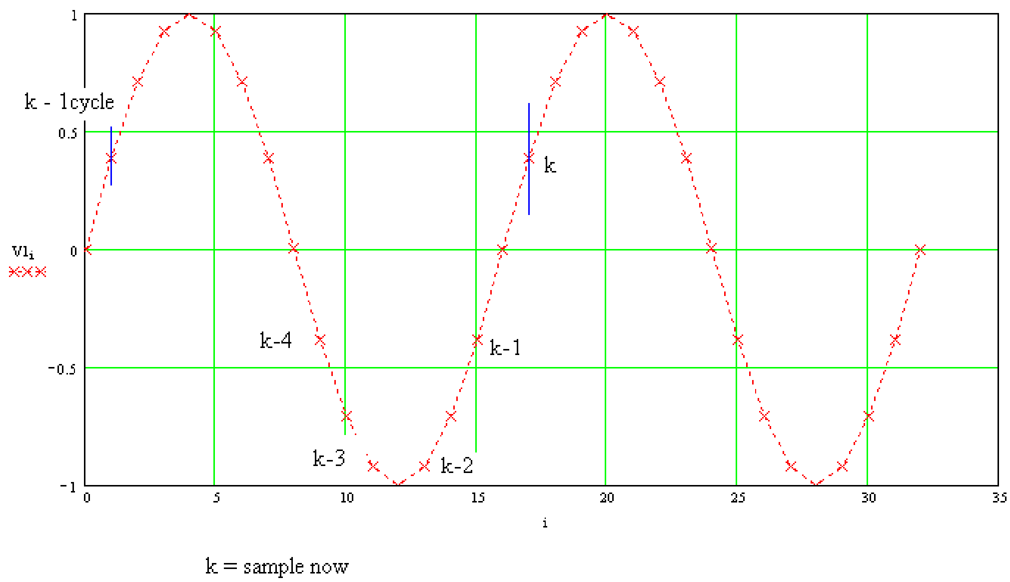

Fig.5. Illustrating the symmetry of using data that is a ½ cycle old and that being 1 cycle old.

In the SEL 321-3 relay the coefficients have been chosen so that this gives the memory voltage a response time of approximately 20 cycles. That means that if the relay experiences a change in the positive sequence voltage, the memory voltage would take 20 cycles to respond to this value. For example if the relay experienced a close in three phase fault to the relay terminals and the positive sequence voltage decreased to zero the positive sequence memory voltage could keep the relay polarized (directionalized) for a further 20 cycles, enable relay to trip for a forward fault or restrain the relay from operating for a reverse fault and allowing the appropriate protection or backup protection to clear the fault. In this particular case that means even if the relay frequency algorithm did track to the system frequency immediately the memory voltage would have only reached this new frequency after 20 cycles!

As mentioned previously the SEL 321mho distance elements are made up by comparing the line replica impedance voltage drop (δV) against the polarizing voltage ($V1_{MEMk}$) and since these two quantities are not at the same frequency the impedances calculated by the relay is incorrect. From the relay's oscillography data it is not possible determine with 100% certainty what the polarizing voltage of the relay was at the time of the operation. However using the relay oscillography data and knowing when the distance elements asserted and the response time of the memory voltage algorithm, it is possible to back calculate what the relays memory voltage may have been. Using the calculated memory voltage, and the oscillography obtained from the relay it is possible to use a mathematical model of the relay and determine the response of the relay under the specific system condition. Following are the results obtained using the above mentioned method.

The phase-to-phase distance elements

In order for the zone 1 phase-to-phase distance elements to operate the following conditions have to be met;

- The calculated impedance must be less than the zone 1 setting,
- The forward directional element must assert (either 32QF or all three denominator terms MABD, MBCD and MCAD must be greater than 0.5)
- The load encroachment element must not be asserted, (if load encroachment is not enabled this element is de-asserted by default)
- The out-of-step blocking logic must not be asserted if the out-of-step logic is enabled.

Since the relay had neither the out-of-step nor the load encroachment logic enabled, let concentrate on the other two enabling requirements of the zone 1 distance elements (ZAB1, ZBC1 and ZCA1). Before we consider the impedance calculation (m-calculation) let's determine if the directional elements indicated the fault as being forward. As we mentioned the forward directional element is enable if either the 32QF element asserts (negative sequence directional element) or if all three denominator terms where greater than 0.5. The equations for the denominator terms are as follow:

$$MABD = Re\left(IAB \cdot e^{jZ1ANG} \cdot VAB_{MEM}{}^{*}\right)$$

$$MBCD = Re\left(IBC \cdot e^{jZ1ANG} \cdot VBC_{MEM}{}^{*}\right)$$

$$MCAD = Re\left(ICA \cdot e^{jZ1ANG} \cdot VCA_{MEM}{}^{*}\right)$$

Fig.6 is a plot of the denominator terms using the calculated memory voltage;

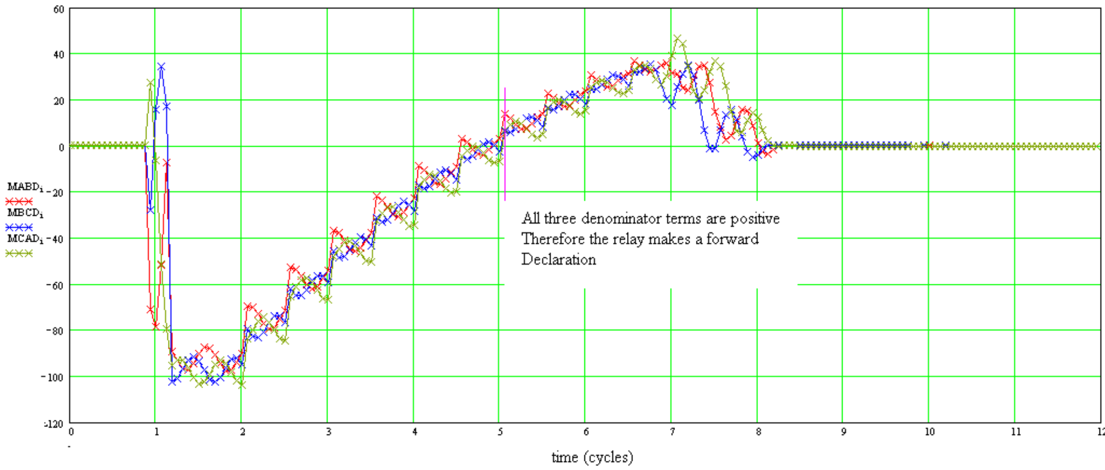

Fig.6 Plot of the denominator terms (directional term), from this plot it can be seen that at cycle 5.125 all three terms become greater than 0.5 and the relay declares the fault as forward.

From Fig.6 we can see that the denominator terms become positive greater than 0.5 at about 5.125 cycles. Fig.7 is a plot of the m-calculations of the phase-to-phase distance elements the equations for the phase to phase elements is as follows:

$$MAB = \frac{Re(VAB \cdot VAB_{MEM}^{*})}{MABD}$$

$$MBC = \frac{Re(VBC \cdot VBC_{MEM}^{*})}{MBCD}$$

$$MCA = \frac{Re(VCA \cdot VCA_{MEM}^{*})}{MCAD}$$

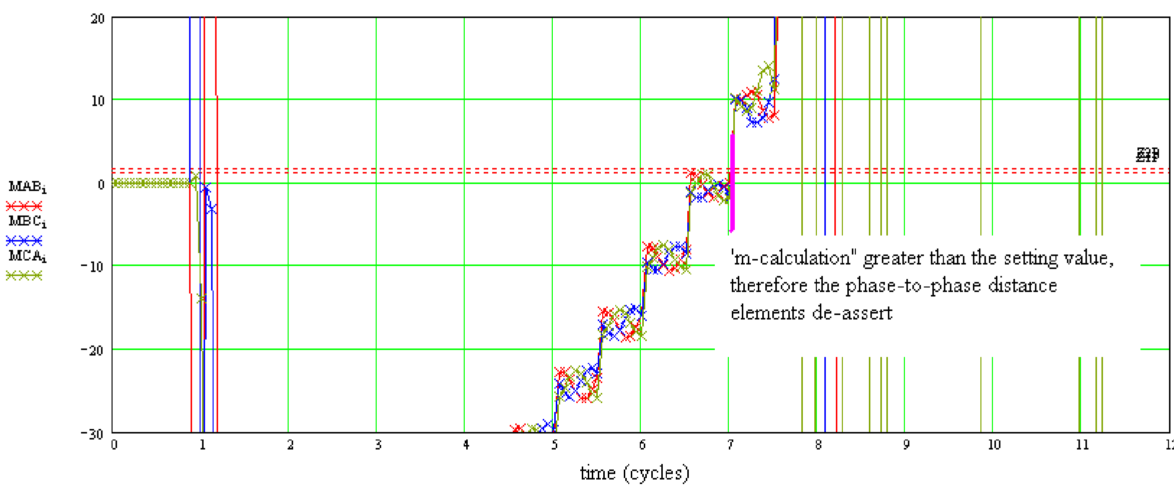

Fig.7. Plot of the “m-calculations” of the phase-to-phase distance elements.

If we examine Fig.6 and 7 we see that at time 5.125 cycles the denominator calculation for all three phase-to-phase distance elements becomes greater than 0.5 and at the same time the m-calculations for all three phase loops is less than the set values (Z1P , Z2P). Therefore at time 5.125 cycles all three distance elements assert their output, (this can be seen when examining the oscilographic record shown in Fig.1). At time of 7 cycles the 'm-calculation' impedance value is greater than the set value and all three distance elements de-assert, this can again be confirmed by the oscillographic record.

This now explains why the relay operated, but the question now remains how do we set the relay to prevent it from operating for such a condition again?

Proposed Solution

As stated previously the reason for the distance elements operating is that the operating and polarizing quantities where not at the same frequency and this resulted in the operating quantity rotating with respect to the restrain quantity. Also recall that one of the conditions to allow the phase-to-phase distance elements to operate is that the load encroachment element must not be asserted. Load encroachment calculates the positive sequence impedance of the load using the instantaneous positive sequence voltage and current (this means that the voltage and currents are at the same frequency with respect to each other). A plot of the positive sequence impedance is shown in Fig.8

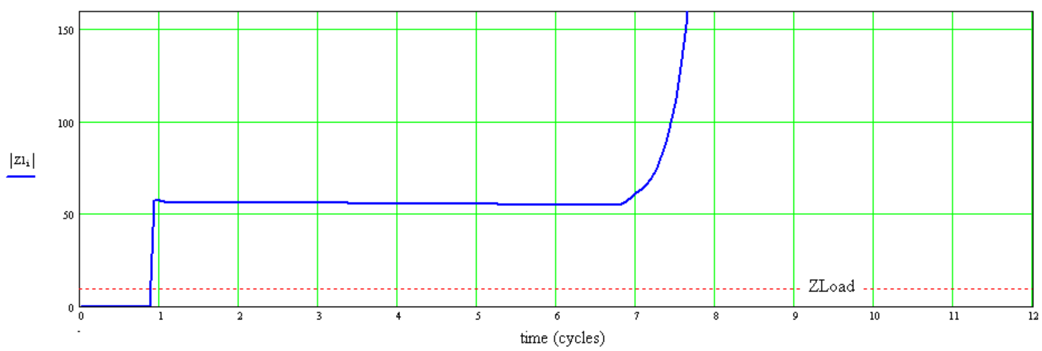

Fig.8 Plot of the positive sequence impedance magnitude.

Fig.8 shows that even if the relay is not tracking the system frequency correctly, the positive sequence impedance retains its correct value (within reason) because the positive sequence voltage and current will have the same error and by dividing these two quantities with each other that have the same relative errors, the errors basically cancel each other and the positive sequence impedance is preserved.

Therefore by enabling the load encroachment element in the relay the load encroachment element will prevent the phase-to-phase distance elements from operating under similar condition. The proposed setting for this system is as follows:

ELE =Y,

ZLF = 10

ZLR = 10

PLAF = 90

NLAF = -90

PLAR = 90

NLAR = 270

With these setting the relay would have prevented the distance elements form asserting, however it must be pointed out that with these settings the load encroachment element will not block the relay for operating for any genuine phase-to-phase fault and the reason for this is that the phase-to-phase distance elements are a subset of the load encroachment element as shown in Fig. 9.

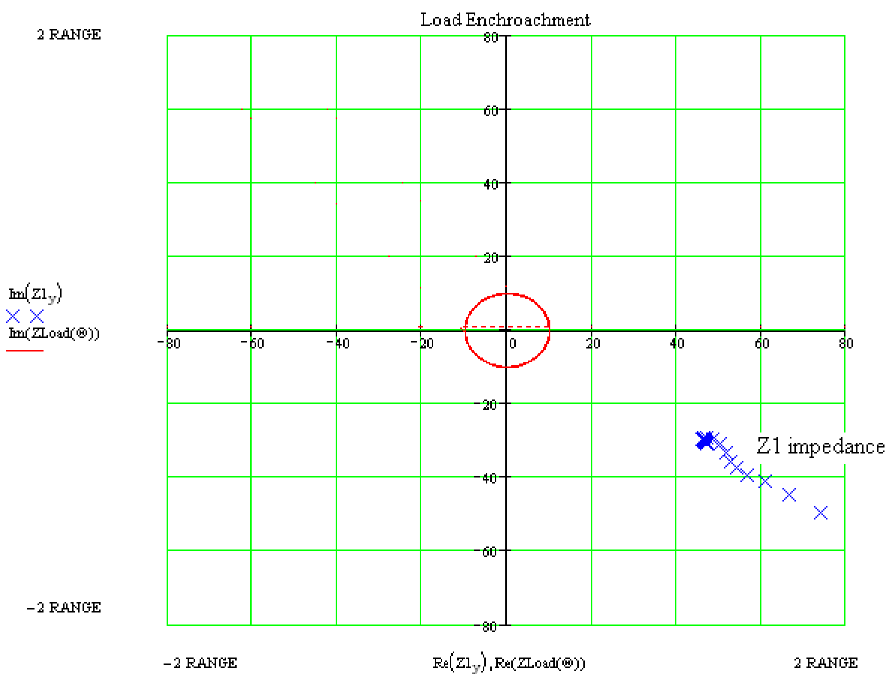

Fig.9 Plot of the load encroachment element characteristic, and the positive sequence impedance, note that the phase-to-phase distance elements fall within the load encroachment element.

Summary

The SEL 321-3 phase-to-phase distance elements operated due to a difference in frequency between the operating and polarizing quantities of these elements. If the load encroachment element had been enabled it would have prevented the relay from operating under these conditions.

newfoundland labrador
hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

September 30, 2013

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

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: An Application by Newfoundland and Labrador Hydro (Hydro) pursuant to Subsection 41(3) of the Act for approval of the Restoration of Unit 1 Turbine and Generator at the Holyrood Thermal Generating Station

Enclosed please find the original and eight copies of Hydro's Holyrood Unit 1 January 11, 2013 Failure Root Cause Analysis final report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Thomas Johnson – Consumer Advocate
Dean Porter – Poole Althouse

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Newfoundland and Labrador Hydro

Holyrood Unit 1 Failure - January 11, 2013

Root Cause Analysis: Final Report

Prepared By (Lead Investigator): Sean Mullaney

Date: 2013/09/30

Reviewed By: [illegible]

Date: 2013/09/30

Approved By: Greg Read for A. Marche

Date: 2013/09/30

Approved By: Terry LeDrew

Date: 2013/09/30

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Table of Contents

1. Summary

On January 11, 2013, severe weather conditions caused an electrical fault in the Holyrood Terminal Station, which caused Holyrood Units 1 and 2 to trip offline. While Unit 2 coasted down normally and without incident, Unit 1 experienced high vibration due to a loss of oil lubrication for approximately three minutes during the coast down. All five journal bearings and other components were later found to be damaged. When lubricating oil was restored after three minutes, it resulted in localized fires at some of the damaged, hot bearing locations. The fires were extinguished by plant personnel. There were no injuries.

Root cause analysis was completed by a team of internal and external personnel with expertise in the equipment function and root cause analysis theory. The TapRooT® root cause analysis techniques were applied for this investigation.

Three causal factors were identified:

1. The established maintenance test procedures did not adequately validate the system function, for the direct current (DC) lubrication oil pump, which serves as a contingency for bearing lubrication when two alternating current (AC) pumps are unavailable.

2. During the incident, the station service system voltage was insufficient to start the second alternating current (AC) lubricating pump, due to the system wide voltage depression experienced after the electrical fault in the Holyrood Terminal Station.

3. The direct current (DC) lubrication oil pump started based upon the loss of both AC pumps, but it did not maintain adequate lubrication to the bearings due to an undetected motor speed issue.

Root causes and corrective actions were determined for each causal factor. Most corrective actions pertain to strengthening internal operating and maintenance procedures and specifications for third party maintenance. Several of the corrective actions have already been implemented and the remainder has been assigned.

Following are the key lessons learned from this incident:

A. The overall system function must be considered when developing and reviewing equipment functional test procedures. In this case, established maintenance test procedures verified that the Holyrood Unit 1 DC Lube Oil Pump was operating but failed to verify that it was providing the system's overall function of delivering sufficient lubricating oil to the bearings. OEM recommended test procedures may not be adequate for ensuring full functionality of equipment and systems.

B. Technical specifications for third party maintenance contracts must be sufficiently detailed to ensure that equipment performance criteria and suitable maintenance testing and adjustments are clearly and thoroughly specified. In this case, the DC pump maintenance specification did not adequately specify the performance criteria and adjustments, and a pump was returned to service that was not able to perform.

C. Equipment specifications and system design must include fail safe design for both black-out and <u>brown-out</u> conditions. In this case, there was a brown-out condition such that the station service voltage was too low for the South AC Pump to start.

These lessons learned will be shared broadly by the investigation team with Holyrood plant personnel, Hydro’s engineering personnel in the Project Execution and Technical Services Division, applicable third party consultants and contractors, and other operating units within Nalcor Energy.

2. Initial Conditions / Initiating Event

On January 11, 2013, severe weather conditions including high winds and heavy, wet snow occurred on the Avalon Peninsula. At 06:42 AM, an electrical fault occurred on C phase of the 230 kV Breaker B1L17 in the terminal station, one of two unit breakers for Holyrood Unit 1 generator. Holyrood Units 1 and 2 tripped offline in response to the electrical fault in the Holyrood Terminal Station. Unit 1 experienced higher than normal vibration levels as it coasted down, with fires at various bearing locations along the unit’s rotational shaft.

Protection systems for Holyrood Units 1 and 2 operated, opening the unit breakers for both generators and removing them from operation. Once removed from operation, the unit’s control system is designed to coast the rotating unit down to a rest position. Then a turning gear motor is engaged to turn the unit shaft at two revolutions per minute (RPM) to prevent shaft deflection until the unit has fully cooled down (four days in duration).

The removal of the generating units and other transmission system voltage support equipment resulted in a severe depression in system voltage to approximately 80% of normal voltage levels (See Figure 1).

Prior to the failure event two alternating current (AC) lube oil pumps that provide lubrication for the turbine-generator journal bearings were in operation on Unit 1. These pumps are commonly referred to as the North and South AC Pumps. The North AC Pump is powered directly from the generating unit (unit service) and is designed to come offline with the unit. The South AC Pump is powered by the plant station service which is fed from the terminal station.

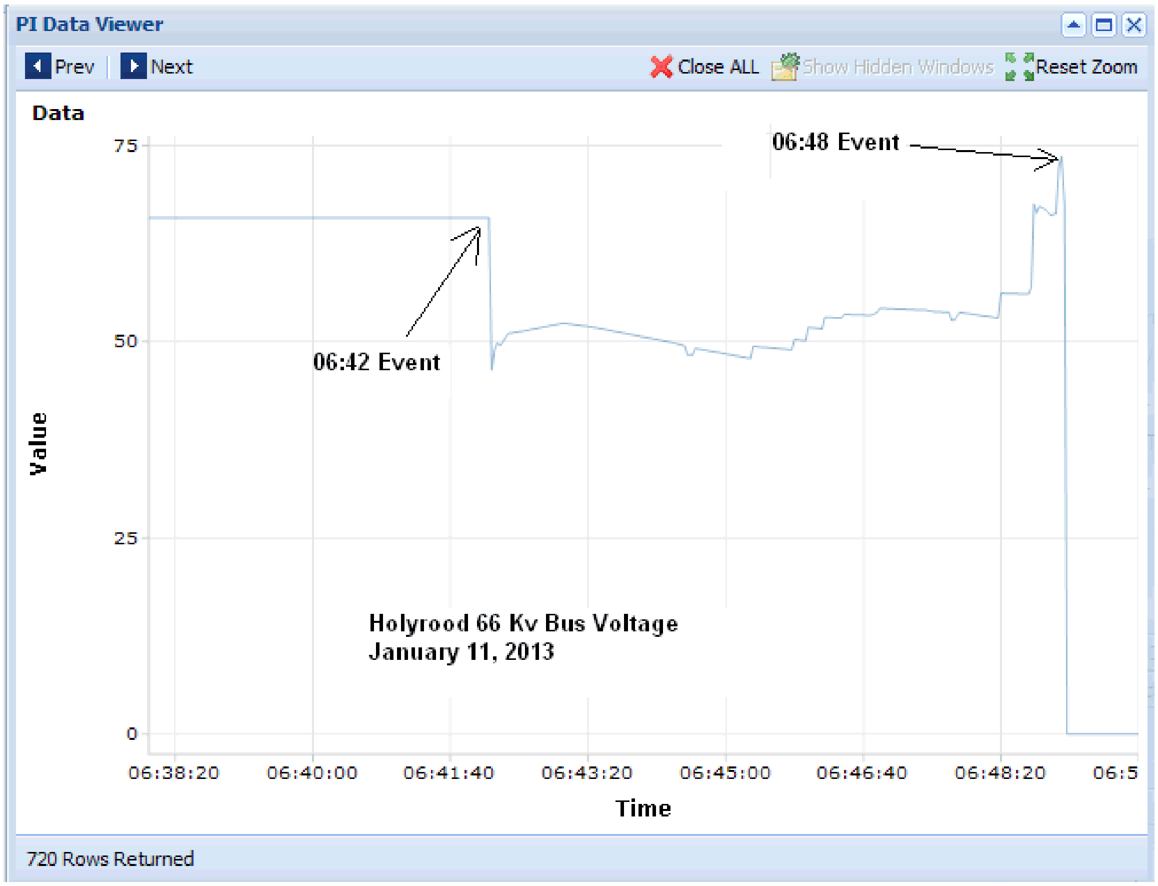


Figure 1: Voltage depression experienced in the Holyrood Terminal Station during January 11, 2013 06:42 fault event

3. Incident Description

Once disconnected from the grid, Unit 2 coasted down without issue, as designed. However, Unit 1 experienced higher than normal vibration levels as it coasted down. The Unit 1 generator bearing vibration levels increased to 217 and 272 microns on the inboard and outboard bearings respectively, prior to failure. Normal vibration levels are in the range of 50-90 microns. A horizontal flame emanated from the inboard bearing.

A fire was also experienced in the generator front standard. The turbine crossover pipes were observed to be shaking during the failure event.

Appendix A contains a report from Alstom Power, outlining the initial observations based on the “as found” condition of Unit 1 following the January 11 event. Following this initial assessment, the unit was disassembled for a more detailed inspection and condition assessment of the individual components. This inspection revealed damage to all five bearings and journals along the turbine-generator shaft. The turbine-generator rotor assembly had moved 3.5 mm horizontally towards the generator. The shims under the generator feet were found to have been dislocated due to the excessive vibration. Other unit components were damaged as well.

Holyrood Units 1 and 2 each have three separate lubricating pumps for supplying oil to the bearings and generator seals. There are two AC pumps and a direct current (DC) pump. The North AC Pump is the primary pump and it draws electrical power directly from the unit’s generator. The South AC Pump is a secondary pump that draws power from the station service, which is fed from the Island Interconnected System via the Holyrood Terminal Station. The DC Pump is a third line of defense for the supply of lubricating oil, and it draws power from dedicated battery banks located in the Holyrood powerhouse.

When Unit 1 was removed from operation in response to the terminal station electrical fault, the North AC Pump consequentially shut down. The South AC Pump tripped offline due to the voltage depression that was experienced during the terminal station electrical fault (See Figure 1). It did not restart with the loss of the North AC Pump, as is expected when the station service supply is available. The DC Pump started in response to the loss of the AC pumps and the resultant drop in lubricating oil pressure. However, it did not deliver sufficient lubricating oil to the generator bearings. The lack of sufficient lubricating oil continued for a period of approximately three minutes and fourteen seconds. With the plant completely shut down, many alarms and process upsets were being reviewed and assessed. Plant personnel manually started the 600 V emergency diesel generator D1, which removed the station service supply from the grid and established supply from the diesel generator. This resulted in the South AC Pump starting, recovering sufficient lubricating oil pressure. (See Figure 2 below for plant Distributed Control System {DCS} trends which illustrate this sequence of events.)

The fires experienced at the Unit 1 turbine-generator bearings were the result of restoration of lubricating oil to the damaged hot bearings and seals, following the three minute and fourteen second period during which the unit rotated without adequate lubrication.

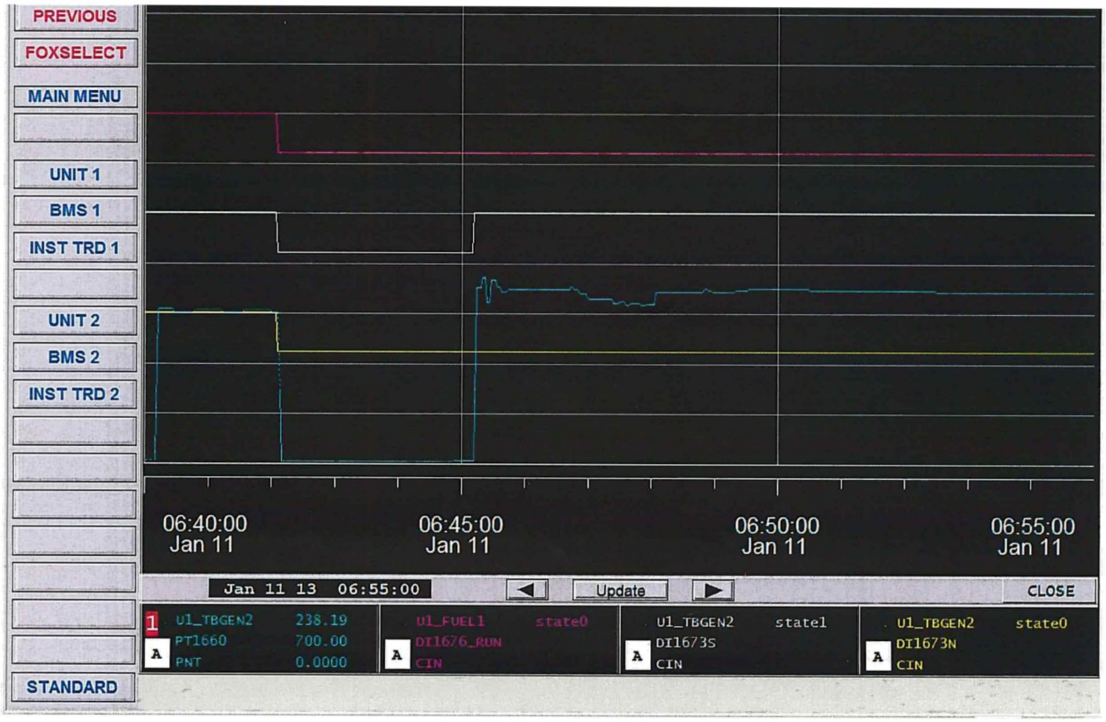


Figure 2: Status of Unit 1 Lube Oil Pumps and Lubricating Pressure during January 11, 2013 event. PT1660 (blue) is lubricating oil pressure at the front standard of the unit. DI1676_RUN (magenta) is the run/stop status of the DC lube oil pump. (The DC pump's run status is triggered by a normally closed contact that opens to indicate run/start. Its running indication is opposite of both AC pumps North and South. i.e. run is indicated after the state change, the portion of the trend that is lower vertically.) DI1673s (white) is the run/stop status of the AC lube oil pump South. DI1673N is the run/stop status of the AC Lube Oil pump North. Upon loss of AC pumps, the lube oil pressure crashes, despite the fact that the DC lube oil pump started. Pressure is restored three minutes and fourteen seconds later after manual start of emergency diesel restores power to AC lube oil pump South.

4. Immediate Corrective Actions

Plant personnel extinguished all fires at the Unit 1 bearing locations and ensured that all issues relating to safety and further equipment damage were mitigated.

5. Root Cause Investigation

A detailed investigation was initiated on January 17, 2013 to determine the underlying root causes of the damage to Unit 1. An investigation team and peer reviewers were identified early and consisted of internal and external personnel with expertise in the equipment function and root cause analysis theory. The TapRooT® root cause analysis techniques were applied for this investigation. This work involved several phases and iterations of information gathering, testing, and analysis of test data to determine the sequence of events, define the causal factors[1], analyze the root causes and develop corrective actions. The investigation is now complete.

6. Causes and Corrective Actions

Three causal factors were identified during the TapRooT® analysis:

1. Inadequate DC Pump Test Procedures;
2. Inadequate System Voltage; and
3. DC Powered Lubricating Pump Not Operating Correctly.

The SnapCharT® in Appendix B provides a visual representation of the sequence of events and illustrates how each causal factor related to the incident. The three causal factors are identified on this SnapCharT® as “CF”.

Following is a description of each causal factor, the root causes and the recommended corrective actions.

<u>Causal Factor #1: Inadequate DC Pump Test Procedures</u>

The investigation revealed that the established maintenance test procedures for the DC Pump did not adequately validate the system function. The established procedures were:

- *Procedure 0324, Turb/Gen Operation – Cold Startup of Unit #1 and #2 from a Major or Minor Overhaul*
    - o This procedure is used by plant personnel for unit startup
    - o An excerpt as it relates to lubricating pumps is located in Appendix C

- *Turbine and Auxiliaries Weekly Checks*
    - o This check sheet is used by plant personnel to test the DC Pump weekly
    - o An actual completed check sheet from January 10, 2013 is included in Appendix D.

While both of these tests included verification that the DC Pump is operable, neither test required verification that the DC Pump actually delivered lubricating oil to the

[1] A causal factor is a mistake or equipment failure that, if corrected, could have prevented the incident from occurring or would have significantly mitigated its consequences.

bearings. As a result, an existing capacity issue with the operation of Unit 1 DC Pump, with respect to delivery of lubricating oil to the bearings, was not detected during unit startup and weekly online function tests.

Root Causes

With respect to causal factor #1, the following root causes were identified using the TapRooT® methodology:

1. **Human Performance Difficulty: Human Engineering: Human-Machine Interface, Displays for monitoring Turbine-Generator Lubricating Pressure Needs Improvement.**

2. **Human Performance Difficulty: Management System: Standards Needs Improvement**

Appendix E includes a copy of an excerpt from the General Electric (GE) original equipment manufacturer (OEM) turbine generator manual, provided to Hydro when the units were originally installed and commissioned in 1969. The section titled PUMP TEST AND AUTOMATIC STARTING states:

> *Provisions are made to test the AC and DC motor pumps which are on "stand-by". An orifice and solenoid valve is included with each starting pressure switch and a "run" pressure switch is included for each pump. The "run" pressure switch senses pressure between the pump discharge connection and its isolating discharge check valve. The test is performed by pushing the pump test pushbutton and energizing the test solenoid valve. The solenoid valve is an open-closed design and causes oil to flow from the header to drain through the orifice in the starting pressure switch sensing line. The orifice drops the oil pressure sensed by the starting pressure switch and causes the switch to close and start the motor pump. As soon as the pump is running, its discharge pressure will rise to normal pressure and the "run" pressure switch will close, lighting the "run" signal lamp. Releasing the test push button closes the solenoid valve and the automatic start pressure switch opens. The motor is stopped by turning the motor control SBI switch or equivalent to the "stop" position.*

The components involved in the tests referenced above (test solenoid valve, starting pressure switch, etc.) are located in the Unit 1 lube oil tank on the first floor of the Holyrood plant. The turbine generator assembly is located on the third floor of the plant, 34 vertical feet above the tank. The test as per the GE manual is confirming that the pressure switch will sense a drop of pressure in the starting pressure switch sensing line and accordingly call for the South AC Pump or DC Pump to start, depending on the test being performed. Once started, a "run" signal lamp is illuminated for a given pump.

The *Turbine and Auxiliaries Weekly Checks* check sheet and the *Turb/Gen Operation – Cold Startup of Units 1 and 2 from a Major or Minor Overhaul* procedure, used by plant personnel, addressed these OEM recommendations. The test procedures, as written, were confirming the starting circuitry of the pumps (similarly to the OEM test, to come in to operation based on loss of lube oil pressure in the lube oil tank), but did not include a step to confirm that adequate lubricating oil was being delivered to the bearings on the turbine-generator shaft.

Corrective Actions

1. It is recommended to design and install a new DCS display to indicate status of existing electronic oil pressure transmitters that are installed directly in the front standard of the turbine-generator assembly on the third floor. The weekly online test should be modified to require plant personnel to use this DCS display to monitor the lubrication oil pressure during tests of the South AC Pump and DC Pump, and to log a copy of the pressure trend with the test sheet.

    - **This corrective action is complete!** The DCS display is in service and test procedures have been revised. The test form and a sample DCS screen shot are located in Appendix F.

2. It is recommended to create two new test procedures for testing the South AC Pump and DC Pump on a weekly basis as well as prior to all return to service.

    - **This corrective action is complete!** The following new procedures, located in Appendix G, have been created and added to the plant procedures database:
        - *Procedure #1076, Unit 1 and 2 – AC Standby and DC Turbine Lubricating Oil Test – Weekly;*
        - *Procedure #1077, Unit 1 &2 Turbine AC/DC Lube Oil Pumps Test Procedure -Return to Service*.

<u>Causal Factor #2: Inadequate System Voltage</u>

During the incident, station service system voltage available to the Unit 1 South AC Pump was insufficient to start the pump, due to the system wide voltage depression experienced after the Holyrood Terminal Station fault and resulting loss of system voltage support.

Root Cause

With respect to causal factor #2, the following root cause was identified using the TapRooT® methodology:

Equipment Difficulty: Design: Design Specifications, Problem Not Anticipated

The Unit 1 South AC Pump's starting circuitry is located in Motor Control Center (MCC) E1, which is an essential services MCC. It is backed up by the 600 V emergency diesel generator D1. In a no-voltage or black start condition, under-voltage protective relaying calls for D1 to start and re-energize or re-establish appropriate voltage to the motor loads of MCC E1. On the morning of January 11, 2013, the Holyrood Terminal Station experienced what is referred to as a brown-out, or a severe and sustained voltage depression (See Figure 1). This brown-out condition had a dual effect with respect to MCC E1: (1) the system voltage which is normally supplied was at a level below which the starting coil for the Unit 1 South AC Pump is rated to close; and (2) the voltage level was insufficiently low for the under voltage relays to call for a start of emergency diesel D1.

Corrective Actions

1. It is recommended to install new coils in the motor starters of MCC-E1, with an improved low voltage tolerance compared to the original starter coils.

    - **This corrective action is complete!** New coils, with a 50% improvement in low voltage tolerance, have been procured and installed.

2. It is recommended to examine the present under-voltage scheme that calls for the starting of the emergency diesels that back up the plant essential services MCC's, with consideration of protection from a brown-out as well as a black-out condition.

    - This corrective action has been assigned to Hydro's Protection and Controls Engineering personnel. Design enhancements to prevent a similar occurrence are currently being evaluated.

<u>**Causal Factor #3: DC Powered Lubricating Pump Not Operating Properly**</u>

The DC Pump started based upon the loss of both the North AC Pump and the South AC Pump, but did not maintain adequate lubrication to the bearings.

Root Causes

With respect to causal factor #3, the following root causes were identified using the TapRooT® methodology:

1. Human Performance Difficulty: Procedures, Situation Not Covered

At an undetermined point in time prior to the failure event (prior to April 2009, as the plant DCS historian data only goes back that far), the adjustable resistor in the field circuit of the DC lube oil pump motor (located in the motor's electrical starter cabinet) was moved, thereby decreasing electrical resistance. In a shunt wound DC motor, decreasing resistance in the field circuit decreases the motor's speed. As found and tested after the January 11, 2013 incident, the motor was rotating at approximately 2800 RPM, as compared to a rated speed of 3500 RPM. The maintenance procedures did not include a check of the DC motor speed. As a result, the slow speed was not detected.

2. Equipment Difficulty: Quality Control Needs Improvement

A problem with the rotational speed of the Unit 1 DC Lube Oil Pump motor was identified during the root cause investigation. The motor was sent to Pennecon Energy for an independent analysis. Pennecon Energy identified and corrected two issues affecting speed: (1) the brush boxes were offset; and (2) the motor neutral plane was improperly adjusted. The technical details of these issues are more fully described in the *Investigation of DC Lubrication System* report located in Appendix H.

The speed issues were a result of maintenance of the DC motor performed by a third party service provider. The Unit 1 DC lube oil pump motor was returned to the plant following third party maintenance and was placed in service with these issues present. The service contract specification did not address the specific required adjustments to ensure motor performance. There is a need for enhanced quality control with respect to the contracting of third party maintenance work for DC motors. The service contract for motor maintenance is presently due for renewal. Specific requirements and expertise in working on DC motors will be a requirement in the new tender package.

Corrective Actions

1. It is recommended to create a new maintenance standard requiring motor speed to be verified after any intervention with the DC lubrication system. If maintenance is performed on any component of the system (pump, DC motor, electrical starter, etc.) by plant staff or by a third party service provider, the motor and pump speed should be verified to be correct, prior to the system being made available and released for service.

    - **This corrective action is complete!** A new maintenance procedure has been created: *MSD176: Rotational Speed Check of 258 V DC Motor Emergency Lube Oil Pump*. The new procedure is located in Appendix I.

2. It is recommended to improve the technical specification for the third party provision of motor maintenance services to include specific requirements for adjustment of DC motors.

- This corrective action has been assigned to Hydro's Electrical Engineering personnel. The improvements to the technical specification will be incorporated into the tender document when the maintenance services are tendered later in 2013.

Unit 1 DC Motor Amperage and System Pressure Cycling Issue

During the course of the investigation, an issue arose with the operation of the DC Pump during testing. The pump motor amperage and oil pressure are expected to be constant when the oil lubrication system is in steady state operation. But, during testing, the motor amperage and oil pressure exhibited a cycling behavior. Following a series of additional testing, it was determined that the cycling behavior related to the test conditions. There is no cycling problem when the pump is in service. Hence, the cycling issue was ruled out as having any relevance to the root cause analysis. The technical description of this testing and analysis in located in Appendix J.

7. Lessons Learned

Following are the key lessons learned from this incident:

1. The overall system function must be considered when developing and reviewing equipment functional test procedures. In this case, established test procedures verified that the Holyrood Unit 1 DC Lube Oil Pump was operating but failed to verify that it was providing the system's overall function of delivering sufficient lubricating oil to the bearings. OEM recommended test procedures may not be adequate for ensuring full functionality of equipment and systems.

2. Technical specifications for third party maintenance contracts must be sufficiently detailed to ensure that equipment performance criteria and suitable testing and adjustments are clearly and thoroughly specified. In this case, the DC pump maintenance specification did not adequately specify the performance criteria and adjustments, and a motor was returned to service that was not able to perform.

3. Equipment specifications and system design must include fail safe design for both black-out and brown-out conditions. In this case, there was a brown-out condition such that the station service voltage was too low for the South AC Pump to start.

These lessons learned will be shared broadly by the investigation team with Holyrood plant personnel, Hydro's engineering personnel in the Project Execution and Technical Services Division, applicable third party consultants and contractors, and other operating units within Nalcor Energy.

8. Investigation Team

- Sean Mullowney, P. Eng. - Lead Investigator / Electrical Investigator
  Electrical Design Engineer
  Project Execution & Technical Services (PETS)
  Newfoundland and Labrador Hydro

- Todd Collins, P. Eng. - Mechanical Investigator
  Mechanical Design Engineer
  Project Execution & Technical Services
  Newfoundland and Labrador Hydro

- Christian Thangasamy, M. Eng., P. Eng. - Plant Investigator / TapRooT® coach
  Plant Mechanical Engineer
  Holyrood Thermal Generating Station
  Newfoundland and Labrador Hydro

- Tobie Comtois - Plant Investigator / IBEW Rep.
  Electrical Maintenance Department
  Holyrood Thermal Generating Station
  Newfoundland and Labrador Hydro

- Greg Read, P. Eng. - Team Lead
  Program Manager
  Project Execution, Regulated
  Newfoundland and Labrador Hydro

- Ken Turnbill - TapRooT® Work Session Facilitator
  System Improvements Inc.

9. Peer Review / Approval

An internal peer review of the root cause analysis has been completed and feedback has been incorporated into the report. An external peer review is pending and any feedback may be incorporated into a final revision of the report. The peer reviewers are:

- Howard Richards, P. Eng.
  Chair, Root Cause Analysis Technical Council
  Newfoundland and Labrador Hydro
  Peer Reviewer - TapRooT® Process

- Herb Sirois
  FM Global
  Peer Reviewer - Technical

- Michel Burbaud
  FM Global
  Peer Reviewer - Independent / Cold Eyes

Final review and approval of this report has been executed by:

- Terry LeDrew, P. Eng.
  Plant Manager, Thermal Generation
  Holyrood Thermal Generating Station
  Newfoundland and Labrador Hydro

- Alberta Marche, P. Eng.
  Manager, Project Execution Regulated
  Newfoundland and Labrador Hydro

APPENDIX A

Alstom Power Holyrood Unit 1
Inspection Report January 15, 2013

Nalcor Holyrood Unit 1 Turbine and Generator Inspection Report January 15, 2013

POWER | ALSTOM

Holyrood Unit 1

Observations as found – January 15, 2013

The following documents the condition of the Unit 1 turbine and generator as found after the unanticipated event of January 11, 2015.

The unit had not been touched since the trip. Powder from the fire extinguisher used to put out a fire on the #1 bearing remained on the turbine.

Vibration Effects

The effects of vibration could be seen in many places around the unit as follows:

- #2 control valve pin had walked loose
- Insulation from cross-over piping expansion joint on floor on both sides of LP hood
- Safety covers had come loose from many flanges
- Dirt had migrated from under gantry tracks towards the turbine on both the left and right sides
- Instrumentation covers had shook loose
- Covers had opened under bushing box
- Loose screw was noted inside doghouse
- Damage to vacuum breaker was noted
- Carbon dust was found on mezzanine level under collectors
- Loose insulation found on top of cross-over pipe

Generator Shims

The shims on the generator base had moved and buckled indicating that they had come loose enough to move during the event. Keys and hold down bolts appeared to be intact. See photos below:

Figure 1 Generator Shim – LHS Turbine End

Figure 2 Generator Shim – RHS Collector End

Oil Deflectors

Outer oil deflector clearance was measured on the #3 and #4 bearings. On both bearings there was no clearance on the bottom. On #3 the upper clearance was 0.180" and on #4 the upper clearance was 0.160". Normal for these bearings would be about 0.005" at the bottom and 0.020" at the top. Oil deflector damage had occurred. Also it appeared that the journals were sitting more than 0.100" low. This could indicate damaged bearings.

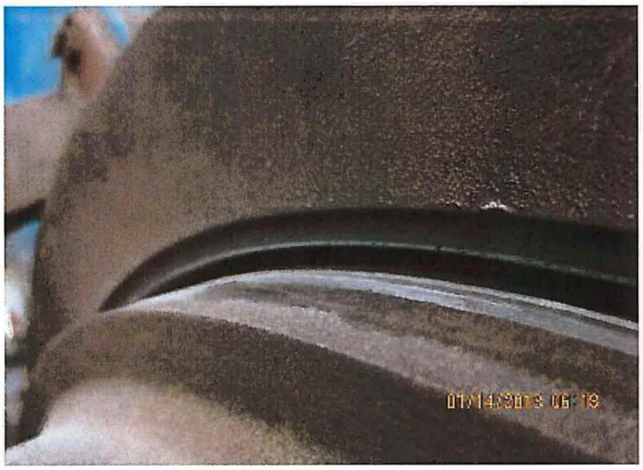


Figure 3 Bearing #4 – upper oil deflector clearance

Figure 4 Bearing #4 – lower oil deflector clearance

B-Phase

The B-phase bus duct on the mezzanine level appeared to have been distressed. On this duct only, the liners at each coupling had migrated out from under the connector rings. See Photos below.

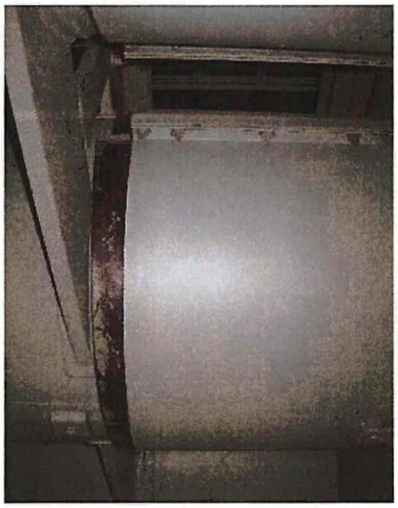


Figure 5 B-PhaseDuct

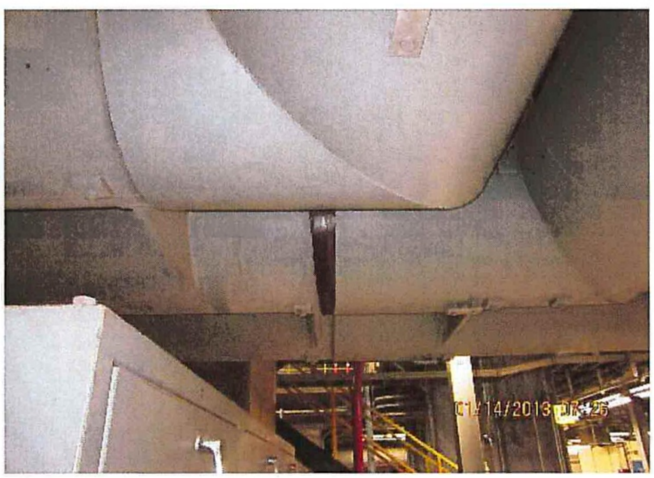


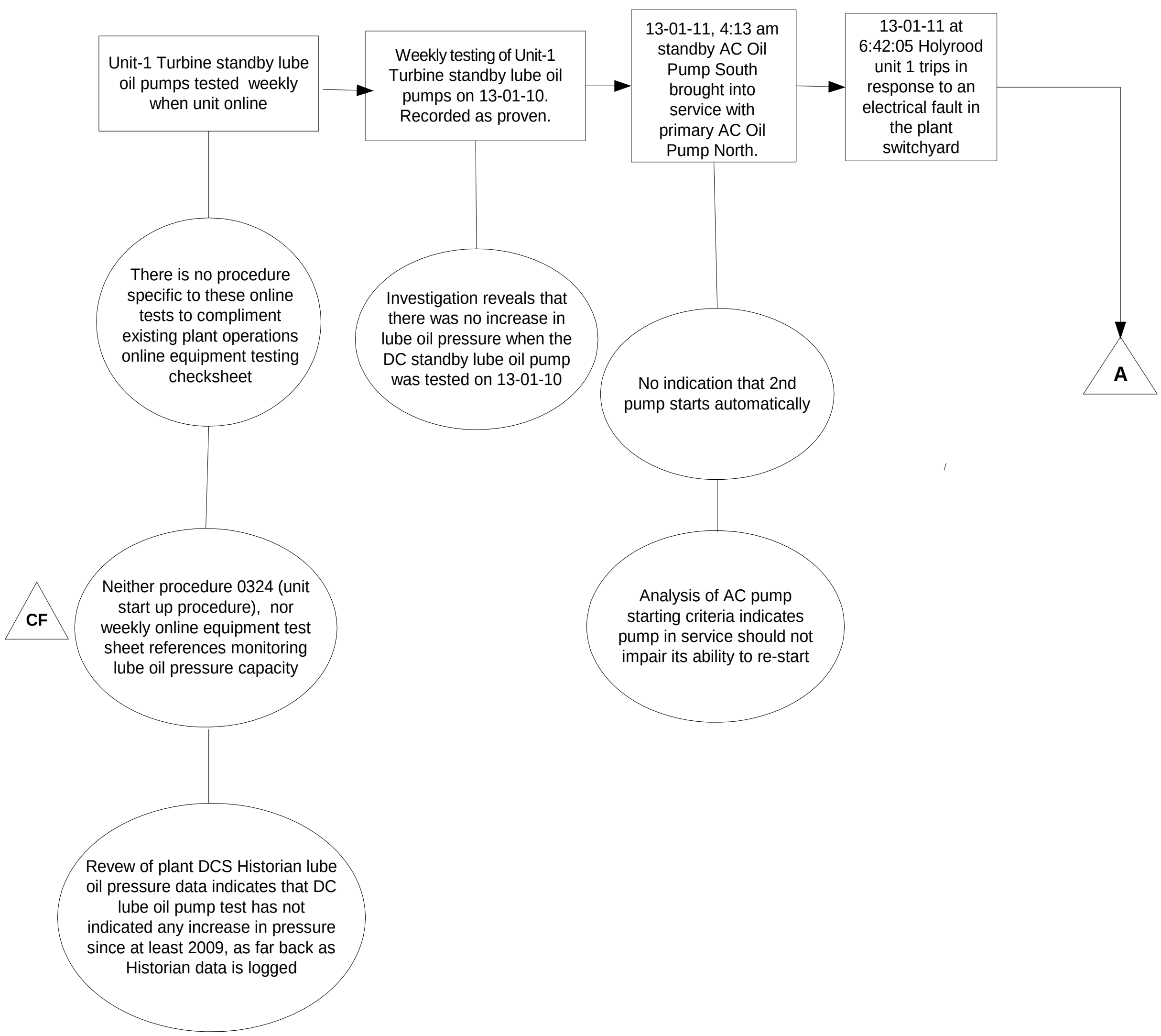
Figure 6 B-Phase Duct

Note: These findings are based on visual inspection only and further more detail investigation may lead to additional findings.

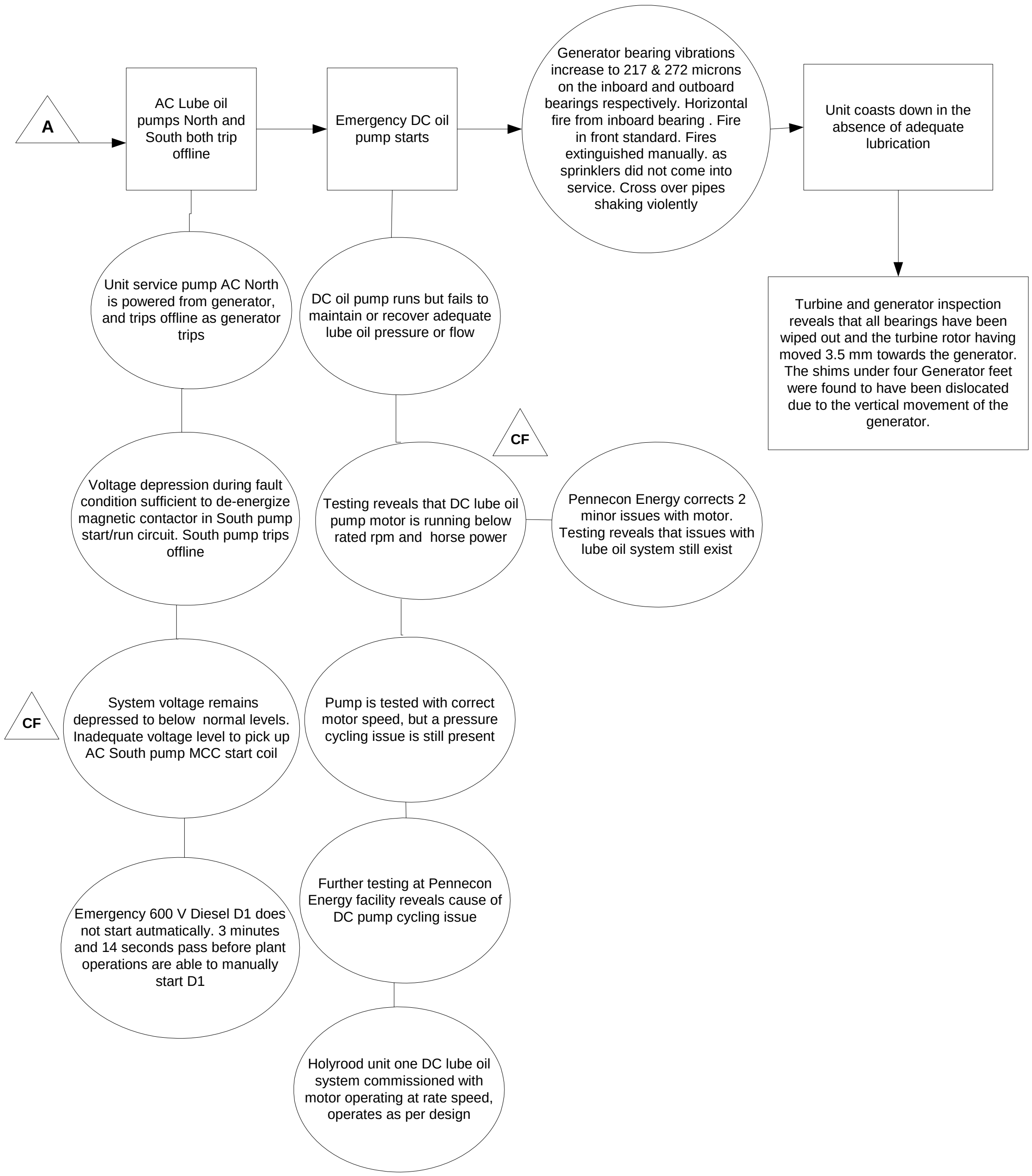
APPENDIX B

Holyrood Unit 1 Failure Analysis SnapCharT®

Holyrood January 11, 2013 U1 Failure Root Cause Analysis Snap Chart



Holyrood January 11, 2013 U1 Failure Root Cause Analysis Snap Chart, Continued



APPENDIX C

Excerpt from Holyrood Unit Startup Procedure #0324

(a) Travelling screens and screen wash pump selector switch placed in AUTO.
(b) Turn OFF C.W. pump motor heater.
(c) Open fully the condenser outfall valves and the partition valves.
(d) Select the C.W. pump discharge valve to 'AUTO'.
(e) When the pump is started and the discharge valve moves to the "cracked" position, select "manual" and slowly open valve keeping watch on condenser for leaks. Place valve selector switch in "AUTO" when valve is fully open.
(f) After two (2) hours the partition valves may be closed.

NOTE: The partition valves are opened and the C.W. discharge lines are flushed after lengthy shut down to avoid plugging condenser tubes with mussels that may have grown in the discharge pipe.

(g) Vent condenser by throttling outfall valve and opening condenser vents until water issues from vents.

3. Turbine Generator cooling system to be placed in service.

(a) Open cooling water (sea water from C. W. System) inlet valve to cooler and vent coolers.

NOTE: The inlet valve to cooler should be left closed until the C. W. system has been flushed and placed in service, to prevent plugging.

(b) T. G. head tank should be at normal level and the level control valve placed in "AUTO" on W.D.P.F. console.
(c) Start T.G. pump with discharge valve closed and slowly pressurize system.
(d) Vent T. G. coolers, Hydrogen coolers, Turbine lube oil tank coolers and Boiler feed pump coolers.

4. Generator

(a) Verify that turbine lube oil reservoir is full and the Bowser has been cleaned.
(b) Pressurize generator casing with air to 15 to 30 kPa.
(c) AC oil pump can now be started and depending on the position of the three-way supply valve (located in the lube oil tank) oil will be supplied to the bearings and generator seals or to generator seals only.
(d) With oil flowing to bearings and seals; perform tests of the oil pumps as follows:

(1) Leave the D.C. oil pump breaker open.
(2) North A.C. oil pump in operation and south in "AUTO".
(3) Stop NORTH pump. Check that south A.A. pump starts automatically.
(4) Place North A.C. oil pump in "AUTO" and stop South A.C. pump. Check that North starts automatically.

(5) Close breaker on D.C. oil pump and place in "AUTO". Stop A.C. oil pumps. Check that D.C. pump starts automatically.
(6) Start one A.C. oil pump and place the other A.C. pump in "AUTO". Shut down D.C. pump and place in "AUTO".

(e) The turbine may be placed on turning gear.

NOTE: It is recommended that the turbine be on turning gear eight (8) hours prior to pre-warming.

(f) Carbon dioxide is now admitted to the generator to purge the air. CO_2 is admitted to the bottom of the generator through the CO_2 distribution pipe and air in the generator is discharged to atmosphere through the Hydrogen feed pipe. The admission of CO_2 is controlled by valve C42 and C45 always maintaining between 15 and 30 kPa generator pressure during purging. CO_2 shall be admitted to the generator until the percentage of CO_2 in the discharge (vent) pipe is in excess of 70%.

(g) Hydrogen may now be admitted through the top of the generator through the hydrogen distribution pipe and the carbon dioxide-air mixture is discharged to atmosphere through the CO_2 feed pipe. The admission of hydrogen (H2) to the generator is controlled with valve H-26, maintaining a generator pressure 15 to 30 kPa. Hydrogen shall be admitted until the gas mixture discharged is in excess of 90%.

(h) The generator can be pressurized to operating pressure of 320 kPa and the seal oil booster system placed in service. As the pressure increases the purity should increase to exceed 95%.

(i) Hydraulic fluid pumping system start-up.
1. Verify turbine in tripped condition.
2. Check hydraulic fluid tank level.
3. Check coolers in service.
4. Open by-pass valve and start hydraulic fluid pump.
5. Close by-pass slowly - pressurizing system.
6. Place 2nd pump in stand-by.

5. Low Pressure Feedwater System

Note: Refer to Procedure #'s POP-003, POP-015, POP-016, POP-032, POP-053, POI-01/02/03 and POI-13

The Deaerator should be filled and steam open to coil allowing the water to heat up. After this is achieved, do not use RFW pump to put water in the boiler.

1. Ensure that there is an adequate water level in both the RFW tanks and in the Hotwell.
2. Ensure Hotwell water is checked by the Lab for chlorides, Condensate Polisher Regeneration chemicals, etc. (Lab) before and after the CW (salt water) system is placed in service as per Procedure POP-015.
3. Ensure Extraction pumps have proper oil levels.
4. Close all known vents and drains on the LP Feed system. Refer to dry lay-up instructions POI-001/002//003 as required.
5. Check the DA rundown and DA recirculation are closed when filling DA.
6. Ensure Extraction Pump Seal Water is in service.
7. Ensure Hotwell make-up and Surplus Stations are in service. Align set point and process of Hotwell Level Control at normal operating level and place in auto.
8. Check the 4kv starter Breakers for proper operating position.
9. Check the discharge valves are opened approximately 10% on both Extraction pumps before starting Extraction pumps.
10. Open suction Valves to both Extraction pumps.
11. Ensure that the Condensate Polisher has been rinsed down. Refer to POP-053 Putting a Condensate Polisher in line.
12. Ensure that the Condensate Polisher plant is at '0%' percent before starting Extraction pump.
13. Ensure that the Low Load Recirc Valve is in the open position.
14. Ensure Extraction Pump Motor Cooling Water is in service (Unit #3 only).
15. Start the Condensate Extraction Pump as per Procedure POP-032.
16. Start hydrazine/ammonia pump if required, and slowly open Deaerator (Fill) Control Valve to fill D.A. if required, **maintaining a slow rate of fill**, while monitoring the Hotwell level at the same time as per Procedure POP-003. Check for leaks and at normal level 70%, the steam coil may be opened partially.
17. Open the Pegging Steam supply to the Deaerator, if hot, prior to adding water.
18. Slowly open the pump discharge valve and allow the system to purge and fill with water.
19. Check system periodically after start up for anything that is not

APPENDIX D

Holyrood Unit Turbine and Auxiliaries Weekly Checks, January 10, 2013

11693 Hyd
199.99 Bearing

File #102.01.35/12
Revision #: 2
Rev. Date: Dec 20, 2012

To be completed weekly every Wednesday when Units are on or in Stand-By mode.

Scope: To ensure Turbine & Generator runs down with oil to the bearings and generator seals. Also ensuring alarms work on Unit 3 bearing oil tank.

TURBINE AND AUXILIARIES WEEKLY CHECKS

Test	Unit	Check	Alarms Rec'd
Standby AC Oil Pump Test	Unit #1 U.C.B.	✓	Alarms Rec'd Y / N
	Unit #2 U.C.B.	✓	Alarms Rec'd Y / N
	Notes:		
Emergency D.C. Oil Pump Test	Unit #1 U.C.B.	✓	Alarms Rec'd Y / N
	Unit #2 U.C.B.	✓	Alarms Rec'd Y / N
	Notes:		
Standby Hydraulic Fluid Pump Test	Unit #1 U.C.B.	✓	Alarms Rec'd Y / N
	Unit #2 U.C.B.	did not start on test	Alarms Rec'd Y / N
	Notes:		
Emergency Seal Oil Pump Test	Unit #1 Skid		Alarms Rec'd Y / N
	Unit #2 Skid		Alarms Rec'd Y / N
	Unit #3 Skid		Alarms Rec'd Y ✓ / N
	Notes:		
Oil Tank Level (Low Level -4) **Gauge Hi/Lo Test** (High Level +4)	Unit #3 M.O.T.		Alarms Rec'd Y ✓ / N
	Notes:		Level Indication ______
Front Standard Emergency Governor Test (Oil Trip & Lock Out)	Unit #3 F.S.		Alarms Rec'd ~~Y / N~~
	Notes: Not performed due to light integrity issues with [illegible]		
Auxiliary Oil Pump (A.O.P.) Test	Unit #3 M.O.T.		Alarms Rec'd Y ✓ / N
	Notes:		
Emergency Bearing Oil Pump (DC Flushing) Test	Unit #3 M.O.T.		Alarms Rec'd Y ✓ / N
	Notes:		
AC Flushing Oil Pump Test	Unit #3 M.O.T.		Alarms Rec'd Y ✓ / N
	Notes:		

Completed By: Terry Barnable
Shift Supervisor: Don Malone

Date: 13 / 01 / 16
YY MM DD
Shift: C

H:\Holyrood\Forms\Operations Forms\Turbine&Auxiliaries-Wkly Checks.xls

APPENDIX E

Excerpt from General Electric Turbine – Generator Manual

MAIN LUBE OIL TANK AND LUBE SYSTEM
(Motor Pumps)

TANK ASSEMBLY

The lube oil tank is a compact, simple design. Elimination of the turbine shaft-driven centrifugal oil pump also eliminates the booster pump priming system for the shaft pump as well as the need for a 200 psig lube-hydraulic system pressure. The lube system pressure level is now 65 psi and permits the use of much smaller motor pumps than was possible in the past. Three full-capacity motor pumps are standard - two with AC motors, one with a DC motor. The AC motor pumps normally supply lube oil for the turbine generator. Either pump can supply bearing flow and generator shaft seal flow with the other pump as a standby" or back-up pump.
The DC motor pump is an emergency pump and backs up the two AC pumps.

GRAVITY FLOW HEAT EXCHANGERS

Cooling the lube oil is accomplished by finned tube heat exchangers in the tank. The bearing drains return to the lube tank through a single pipe connection.
Three gravity flow, finned tube heat exchanger units are mounted in a series - flow arrangement in a compartment inside the rank. The returning lube oil passes into the compartment through the heat exchangers and through an orifice plate dam back into the main reservoir of oil. The lube oil in the tank will be about 120°F with the coolers arranged this way. The orifice plate dam is used to provide a level of oil in the cooler compartment to submerge the heat exchanger tubes and establish a uniform flow through the tubes. The finned tubes also are very effective in detraining air and foam.
Each heat exchanger unit is designed with a cooling capacity of 50% of the turbine requirements. Any two units will thus provide adequate cooling capacity, with the third unit as spare capacity. The oil side of each cooler unit is oil tight permitting removal of water boxes on the spare cooler for cleaning and inspection of tubes. Normal cooling water temperature is 95°F max.
The oil pumps are vertical, 20 HP motor-driven centrifugal pumps. Each pump has a suction strainer and is isolated from the lube system header by a check valve in its discharge piping. Two of the pumps have AC motors. One AC pump normally supplies the turbine with lube oil. The other AC pump is on standby or back-up service. Each pump has an automatic start pressure switch which senses pressure in the lube system header. The DC motor pump starting pressure switch is set to actuate at a lower pressure than for the two AC pump switches so that the AC motor pumps normally will take care of the turbine lube oil supply and the DC motor pump will automatically start only on an "emergency basis".

VAPOR EXTRACTOR

A motor driven vapor extractor which includes an oil separator is provided on the tank. The extractor is adjusted to maintain a slight vacuum of about 1"
This vacuum prevents oil vapor from passing out through small openings in the tank structure and wetting external areas of the tank. The extractor also scavenges the turbine generator lube and shaft seal drain piping to remove oil vapors, moisture and any hydrogen which might accidentally pass into the seal drain system oil return to the lube tank. The exhaust from the vapor extractor is piped to a vent which discharges outside the building to atmosphere.

OIL PUMPS

All three pumps discharge into a common header in the tank. Oil for the generator shaft seal system is supplied directly from the header to the hydrogen shaft seal oil unit with its own pressure regulators, filters, etc. Oil for the turbine generator bearings passes through a blocking valve which permits shutting off oil to the bearings during bearing inspection, but still permits the motor pump in service to maintain seal oil pressure at the generator shaft seals. Next the lube oil passes through a diaphragm type, pressure regulating valve which maintains bearing lube oil pressure at 25 psig at turbine centerline and then on to the bearings. 170KPa

PUMP TEST AND AUTOMATIC STARTING

Provisions are made to test the AC and DC motor pumps which are on "stand-by". An orifice and solenoid valve are included with each starting pressure switch and a "run" pressure switch is included for each pump. The "run" pressure switch senses pressure between the pump discharge connection and its isolating discharge check valve. The test is performed by pushing the pump test pushbutton and energizing the test solenoid valve. The solenoid valve is an open-closed design and causes oil to flow from the header to drain through the orifice in the starting pressure switch sensing line. The orifice drops the oil pressure sensed by the starting pressure switch and causes the switch to close and start the motor pump. As soon as the pump is running, its discharge pressure will rise to normal pressure and the "run" pressure switch will close, lighting the "run" signal lamp. Releasing the test pushbutton closes the solenoid valve and the automatic start pressure switch opens. The motor is stopped by turning the motor control SBI switch or equivalent to the "stop" position.
This feature is not only provided for all three motors on a panel at the tank, but provisions are made for connections to the customer's own central Control Panel.

The motor control switches for these pumps should be three-position SB-1 or equivalent switches. The three positions are "run", "auto-start" or "stand-by" and "stop". A spring return from "stop" to "auto-start" should be used to automatically return the control switches to the automatic start condition and maintain the AC and DC pumps as back-up pumps. The motor-pump starters should have seal-in contacts in parallel with the automatic start pressure switch contacts to prevent cycling and also to require the operator to manually stop the pump. The motor control switches should have a "pull to lock out" or similar feature in order to minimize the possibility that the motor control would be accidentally left in the "off" condition. An additional precaution against leaving the motor pump in the "off" condition is to have a green light lighted when the motor control switch is in the "auto-start" position. When the motor control switch is in the "locked out" position, the green light would go off.

TANK CONSOLE

A metal console is located on the top of the tank along one side. The console contains the pressure switches for the pumps, the pump test pushbuttons and solenoid valves, the lube oil tank thermometer and oil level gage. All the electrical devices are wired to terminal strips in the console and space has been designated for customer Connection conduits and wire. Some of the accessories included are: a remote pressure transmitter for lube oil pressure; a low bearing oil pressure switch and a thermocouple for lube oil tank temperature.

OIL CONDITIONER

For filtration purposes, an oil conditioner is included in the lube system. The oil conditioner is used to dehydrate, clean, and polish the oil and includes such equipment as: a vapor extractor; a polishing filter; and a transfer and by-pass pump system, driven by CGE 1 H.P. - 460 V - 1800 RPM motors. The type of oil conditioner used is a Bowser Model (823-P).

PERIODIC OPERATIONAL TESTS SUMMARY

The following operational tests are in addition to the normal observations given in the "Operating Instructions".

Once a Day

1. Operate the main stop valve, reheat stop valve and intercept valves by sequence testing at operator's control panel.

2. Close the extraction check valves equipped with an air operated test mechanism part way by operating the test levers.

Once a Week

1. Observe closure of the main stop valves, intercept valves and reheat stop valves during sequence testing by watching travel of the valve stems.

2. Test the overspeed governor by means of the pushbutton and indicating lights at the operator's control panel. (Maintain load on the unit during this test).

3. Start the stand-by oil pump and the D.C. emergency oil pump by operating the test arrangement provided. This can be done from the control room or at the main oil tank console.

4. Start the stand-by hydraulic fluid pump by operating the test arrangement provided. This can be done from the control room or at the hydraulic fluid power unit.

Once a Month

1. If the unit has been on the line continuously, close the control valves to check for sticking.

2. If the unit has been on load-limit control continuously, operate for a short period of time on the speed governor load control.

Every 3 - 6 Months

1. If the unit is not to be removed from the line, check operation of the overspeed governor by the test logic. Otherwise check by actual overspeeding. This test will verify the capability of all steam valves to close.

Every 6 to 12 Months

1. Check operation of the overspeed governor by overspeeding the turbine.

2. Test the main stop valve, control valves and intercept valve for tightness.

3. Test operation of the vacuum trip.

4. Test operation of the solenoid trip.

APPENDIX F

Check Sheet with New DCS Display Addition

File #102.01.35/12
Revision #: 3
Rev. Date: Mar 27, 2013

To be completed weekly every Wednesday when Units are on or in Stand-By mode.

TURBINE AND AUXILIARIES WEEKLY CHECKS

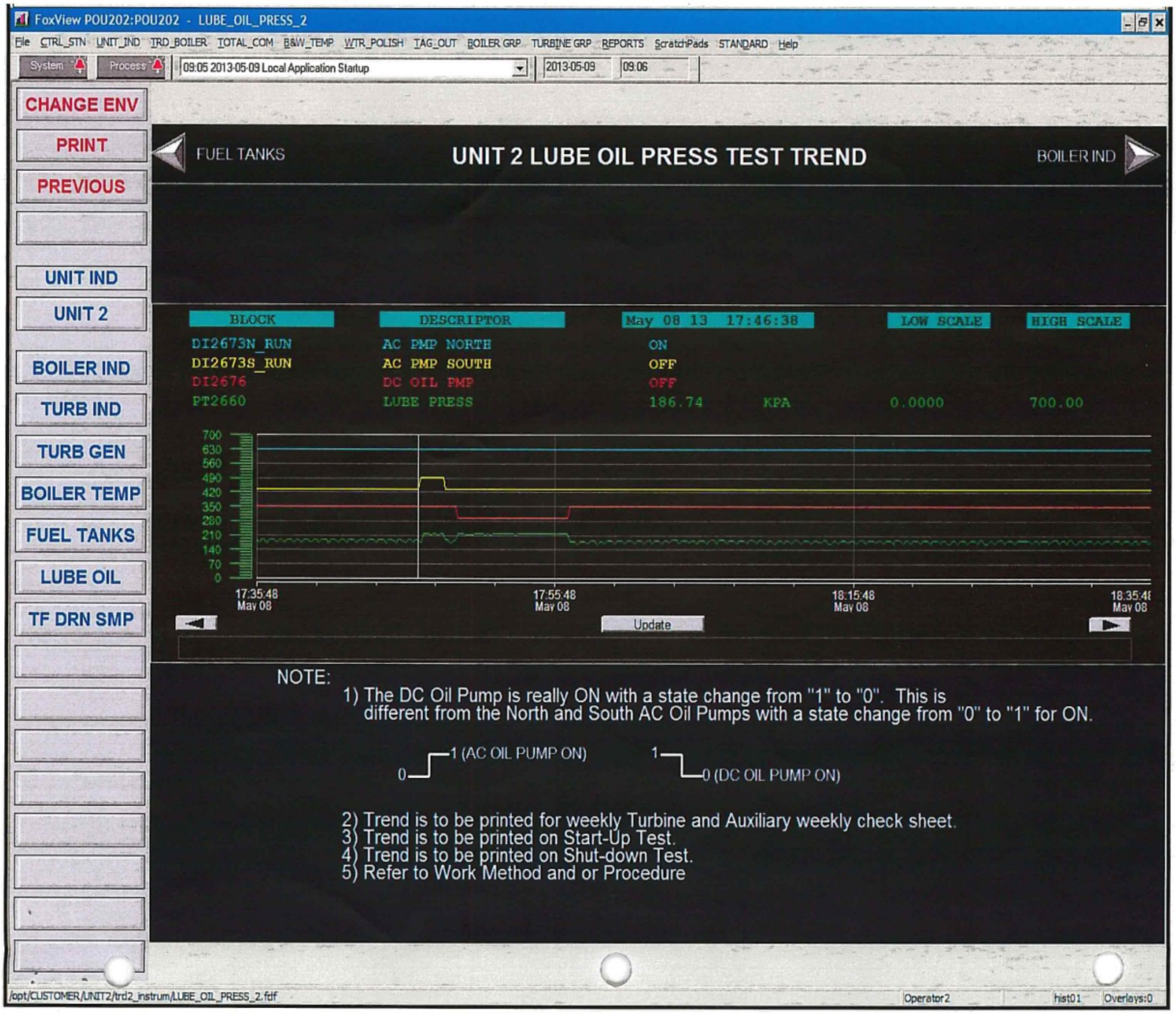
	Unit 1 & 2			
Standby AC Oil Pump Test	Unit #1 U.C.B.		Alarms Rec'd	Y / N
	Unit #2 U.C.B.	✓	Alarms Rec'd	Y / N
	Notes:			
Emergency D.C. Oil Pump Test	Unit #1 U.C.B.		Alarms Rec'd	Y / N
Print permanent trends of lube oil pressure	Unit #2 U.C.B.	✓	Alarms Rec'd	Y / N
	Notes:			
Standby Hydraulic Fluid Pump Test	Unit #1 U.C.B.		Alarms Rec'd	Y / N
Two running due	Unit #2 U.C.B.		Alarms Rec'd	Y / N
to low Pressure	Notes:			
Emergency Seal Oil Pump Test	Unit #1 Skid		Alarms Rec'd	Y / N
	Unit #2 Skid		Alarms Rec'd	Y / N
	Unit #3 Skid		Alarms Rec'd	Y / N
	Notes:			
	Unit 3			
Oil Tank Level (Low Level -4)	Unit #3 M.O.T.		Alarms Rec'd	Y / N
Gauge Hi/Lo Test (High Level +4)	Notes:		Level Indication ______	
Auxiliary Oil Pump (A.O.P.) Test	Unit #3 M.O.T.		Alarms Rec'd	Y / N
	Notes:			
AC Flushing Oil Pump Test	Unit #3 M.O.T.		Alarms Rec'd	Y / N
	Notes:			
Emergency Bearing Oil Pump (DC Flushing) Test	Unit #3 M.O.T.		Alarms Rec'd	Y / N
Print permanent trends of lube oil pressure	Notes:			
Front Standard Emergency Governor Test (Oil Trip & Lock Out)	Unit #3 F.S.		Alarms Rec'd	Y / N
	Notes:			

Completed By: "D" Shift
Shift Supervisor: Glen Kennedy

Date: 13 / 5 / 8
YY MM DD
Shift: D

- Unit 3 Shut down.
- Unit 1 Shut down.

H:\Holyrood\Forms\Operations Forms\Turbine&Auxiliaries-Wkly Checks.xls


FoxView POU202:POU202 - LUBE_OIL_PRESS_2
File CTRL_STN UNIT_IND TRD_BOILER TOTAL_COM B&W_TEMP WTR_POLISH TAG_OUT BOILER GRP TURBINE GRP REPORTS ScratchPads STANDARD Help
System
Process
09:05 2013-05-09 Local Application Startup
2013-05-09
09:06
CHANGE ENV
PRINT
PREVIOUS
UNIT IND
UNIT 2
BOILER IND
TURB IND
TURB GEN
BOILER TEMP
FUEL TANKS
LUBE OIL
TF DRN SMP
FUEL TANKS
UNIT 2 LUBE OIL PRESS TEST TREND
BOILER IND
BLOCK
DESCRIPTOR
May 08 13 17:46:38
LOW SCALE
HIGH SCALE
DI2673N_RUN
AC PMP NORTH
ON
DI2673S_RUN
AC PMP SOUTH
OFF
DI2676
DC OIL PMP
OFF
PT2660
LUBE PRESS
186.74
KPA
0.0000
700.00
700
630
560
490
420
350
280
210
140
70
0
17:35:48 May 08
17:55:48 May 08
18:15:48 May 08
18:35:48 May 08
Update
NOTE:
1) The DC Oil Pump is really ON with a state change from "1" to "0". This is different from the North and South AC Oil Pumps with a state change from "0" to "1" for ON.
0
1 (AC OIL PUMP ON)
1
0 (DC OIL PUMP ON)
2) Trend is to be printed for weekly Turbine and Auxiliary weekly check sheet.
3) Trend is to be printed on Start-Up Test.
4) Trend is to be printed on Shut-down Test.
5) Refer to Work Method and or Procedure
/opt/CUSTOMER/UNIT2/trd2_instrum/LUBE_OIL_PRESS_2.fdf
Operator2
hist01
Overlays:0

APPENDIX G

Plant Operational Procedural Enhancements

Re: 1077 - POP-162 Unit 1 & 2 Turbine " AC/DC lube oil pumps test procedure -" Return to service ".

Request Title: **POP-162 Unit 1 & 2 Turbine " AC/DC lube oil pumps test procedure-" Return to service".**

Document Control Coordinator : Gerard Cochrane

Beverly Kennedy on Sept 20th, 2013 at 02:04 PM

Request Details

Requester: Beverly Kennedy

Details:

Cancellation Message (if applicable):

Request Change Status : Approved

Solution Definition and Development Information

Procedure No: 1077	Entered By: Beverly Kennedy Date: May 29th, 2013 08:52 AM
Title	**POP-162 Unit 1 & 2 Turbine " AC/DC lube oil pumps test procedure-" Return to service".**

Archive Information

Issue Date:	05/29/2013 May 29th, 2013
Distribution:	Manager - Operations, Manager - Work Execution, Operations
Manual/Group:	Maintenance Standards, Plant Operating Procedures
Revision No:	0
Revision Date:	09/23/2013
Prepared By:	Beverly Kennedy
Controller:	Gerard Cochrane
Reviewers:	Gerard Cochrane, Gerard Cochrane, Evan Cabot, Gerard Cochrane, Chris House, Gerard Cochrane, Evan Cabot, Gerard Cochrane
Approved By:	Terry LeDrew/HO/NLHydro

Procedure Scope

This directive describes the procedure for testing the reliability of the Turbine AC & DC lube oil pumps.

Reference Information

GE TIL 914-2 Back-up lube oil system reliability.

EQUIPMENT : AC & DC lube oil pumps.

Re: 1076 - POP-163 Unit 1, 2 and 3 - Turbine Emergency DC lube oil Test -Weekly

Request Title: POP-163 Unit 1 and 2 - AC Standby and DC Turbine Lubricating Oil Test -Weekly Reviewers are Evan, Chris and Gerard

Document Control Coordinator: Gerard Cochrane

Beverly Kennedy on Sept 26th, 2013 at 01:24 PM

Request Details

Requester: Beverly Kennedy

Details:

Cancellation Message (if applicable):

Request Change Status: New Request

Solution Definition and Development Information

Procedure No: 1076	Entered By: Beverly Kennedy Date: May 29th, 2013 08:48 AM
Title	**POP-163 Unit 1 and 2 - AC Standby and DC Turbine Lubricating Oil Test -Weekly**

Archive Information

Issue Date:	05/29/2013 May 29th, 2013
Distribution:	Operations
Manual/Group:	Plant Operating Procedures
Revision No:	0
Revision Date:	
Prepared By:	Beverly Kennedy
Controller:	Gerard Cochrane
Reviewers:	Evan Cabot, Gerard Cochrane, Chris House
Approved By:	Terry LeDrew/HO/NLHydro

Procedure Scope

This directive describes the procedure for testing the reliability of the AC Standby and DC Turbine Lubricating Oil Pumps on a weekly basis

Reference Information

GE TIL 914-2 Back-up lube oil system reliability.

EQUIPMENT : AC Stand-by and Emergency DC lube oil pump.

Procedure Details

Note 1 Unit Control Board (UCB) - is the Operator designated for a particular Unit situated in the Control Room

Note 2 The UCB Operator will have the permanent trend screen displaying on the DCS that shows the Turbine Lube Oil Pressure vs the AC and DC pump starts

1. Turbine on line
2. Battery Chargers On.
3. Check to ensure the DC lube oil pump is in Auto.
4. Check to ensure that the South AC lube oil pump is in Auto.
5. Check that the North AC lube oil pump is in service
6. Before Function Testing have a Field Operator ready to check AC and DC lube oil pumps to confirm that both pumps start in the field, to record lube oil pressure at the Lube Oil Set and Turbine Front Standard as required in the following steps of this procedure. The Field Operator is to report to the Shift Supervisor any unusual noise originating from the motors or pumps when either the AC and DC pump start or when the pumps are running. The Field Operator will also ensure the oil level in the lube oil tank is at normal operating level before and after testing and report to the Shift Supervisor if it is not.
7. With the North AC oil pump running, Record the Lube Oil Pressure at the front standard and check this pressure against the DCS Lube Oil Pressure reading. Note any differences and record.
8. Push the AC Oil Pump test button from the unit control board. Confirm with the Field Operator that the South Pump is running and record the lube oil pressure at the Lube Oil Set. Then record the lube oil pressure at the Turbine Front Standard. Confirm with the UCB Operator that the red "running" light is ON for the South AC oil pump.
9. The UCB Operator will contact the Field Operator to confirm that the North AC oil pump is running and the lube oil pressure is adequate. If so, the UCB Operator can shut down the South AC Oil Pump and place it in Auto
10. Push the DC Oil Pump test button from the unit control board. Confirm with the Field Operator that the DC Oil Pump is running and record the lube oil pressure at the Lube Oil Set. Then record the pressure at the Turbine Front Standard. Confirm with the UCB Operator that the red "running" light is ON for the DC oil pump.
11. The lube oil pressure at the Turbine Front Standard should increase by a minimum of 35

Kpa, with the DC and North AC oil pump running. If not, report this to the Shift Supervisor.

12. Check the pre and post test data.

13. Return DC lube oil pump to auto.

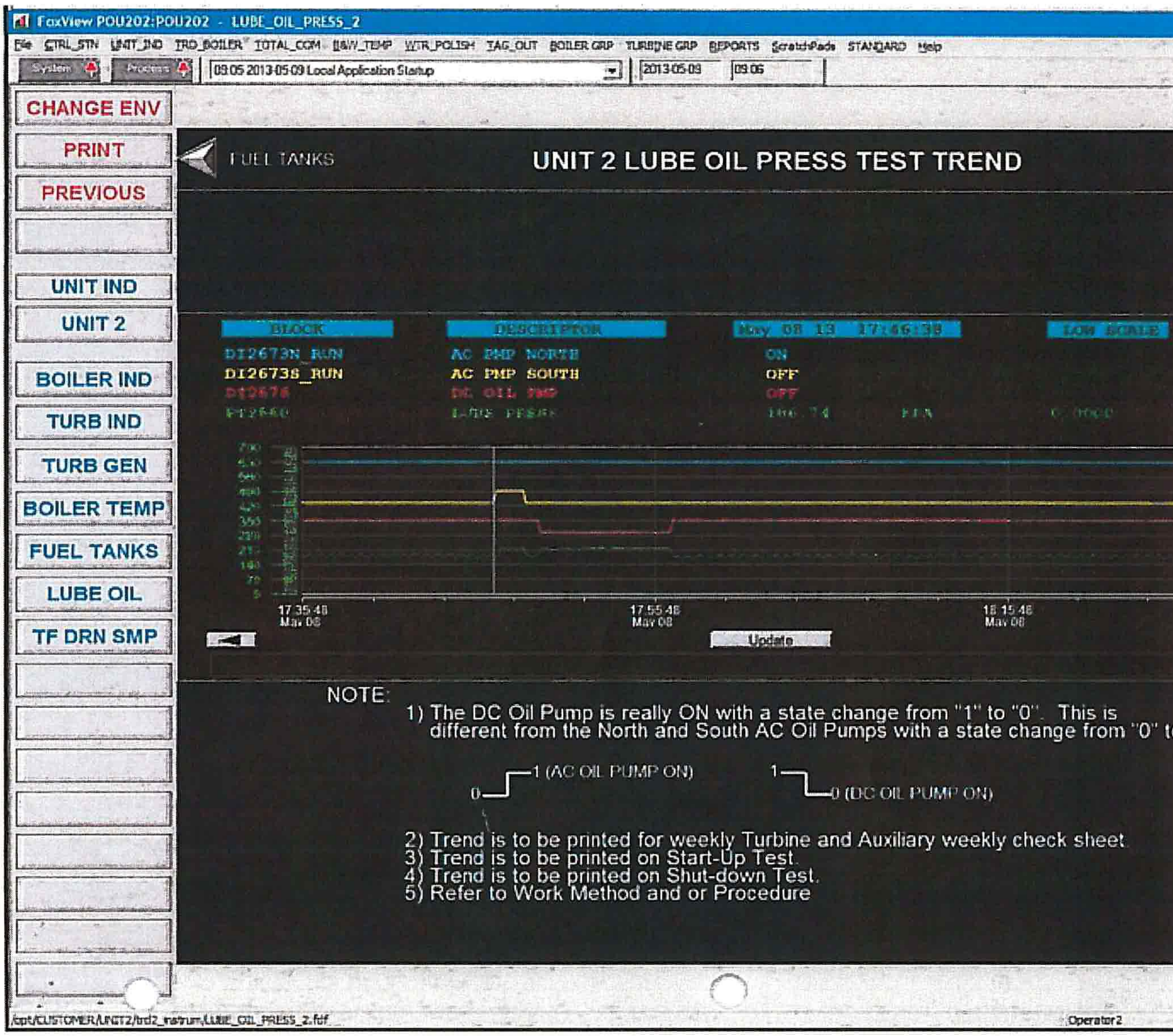
14. Investigate and correct malfunctions.

15. Repeat the test after the issues have been resolved

16. Print the permanent trend showing clearly the Turbine Lube Oil Pressure with the North AC oil pump running, South AC pump and DC pump starts. The trend should show step increases in lube oil pressure with a start of the AC South stand-by pump and with a start of the DC Oil Pump while the North AC oil pump remains in service at all times This sheet shall be submitted to the Manager, Operations. **See sample below.**

17. Record all test information in the unit control board and the shift supervisor's station log books.

SAMPLE


FoxView POU202:POU202 - LUBE_OIL_PRESS_2
File CTRL_STN UNIT_IND TRD_BOILER TOTAL_COM B&W_TEMP WTR_POLISH TAG_OUT BOILER GRP TURBINE GRP REPORTS ScratchPads STANDARD Help
09:05 2013-05-09 Local Application Startup
2013-05-09
09:06
CHANGE ENV
PRINT
PREVIOUS
UNIT IND
UNIT 2
BOILER IND
TURB IND
TURB GEN
BOILER TEMP
FUEL TANKS
LUBE OIL
TF DRN SMP
FUEL TANKS
UNIT 2 LUBE OIL PRESS TEST TREND
BLOCK
DESCRIPTOR
LOW SCALE
DI2673N_RUN
AC PMP NORTH
ON
DI2673S_RUN
AC PMP SOUTH
OFF
17:35:48 May 08
17:55:48 May 08
18:15:48 May 08
Update
NOTE:
1) The DC Oil Pump is really ON with a state change from "1" to "0". This is different from the North and South AC Oil Pumps with a state change from "0" to
0
1 (AC OIL PUMP ON)
1
0 (DC OIL PUMP ON)
2) Trend is to be printed for weekly Turbine and Auxiliary weekly check sheet.
3) Trend is to be printed on Start-Up Test.
4) Trend is to be printed on Shut-down Test.
5) Refer to Work Method and or Procedure
/opt/CUSTOMER/UNIT2/trd2_instrum/LUBE_OIL_PRESS_2.fdf
Operator2

Procedure Details

Unit 1, 2 Turbine AC / DC lube oil pump test procedure- Return to service".

1. Turbine at rest- not on turning gear.

2. Verify that turbine lube oil reservoir is full and full flow filters in service.

3. Verify that the three-way supply oil valve (located in the lube oil tank) is positioned to supply oil to the generator seals and bearings.

4. Pressurize generator casing with air to 15 to 30 kPa.

5. North AC oil pump can now be started.

6. With oil flowing to seals and bearings: perform the following test on both AC oil pumps and DC oil pump as follows:

   (1) Open up the D.C. oil pump breaker and lock out the D.C oil pump pistol grip handle on the unit control board.

   (2) With the North A.C. oil pump in Operation and South AC oil pump in "AUTO".
      a. Record lube oil pressure at front standard.

      b. Record lube oil pump discharge pressure at lube oil tank.

      c. Verify oil flow to all bearings.

      d. Verify "run" red indicating light on UCB for North AC lube oil pump.

   (3) Stop North AC oil pump. Check that South A.C. oil pump starts automatically.
      a. Record lube oil pressure at front standard.

      b. Record lube oil pump discharge pressure at lube oil tank.

      c. Verify oil flow to all bearings.

      d. Verify "run" red indicating light on UCB for South AC lube oil pump.

7. Place North A.C. oil pump in "AUTO" and stop South A.C. oil pump. Place the South AC oil pump pistol grip handle to the full locked-out position. Check that North AC oil pump starts automatically.

8. Close breaker on D.C. oil pump and place in "AUTO". Stop the North A.C. oil pump and place the pistol grip handle to the full lock-out position. Check that D.C. Oil pump starts automatically.

a. Record lube oil pressure at front standard.

b. Record lube oil pump discharge pressure at lube oil tank.

c. Verify oil flow to all bearings.

d. Verify "run" red indicating light on UCB for DC lube oil pump.

Note 1; the minimum lube pressure at the front standard should not be less than 35 kpa on the start of the DC pump.

Note 2: The minimum operating DC lube oil pump pressure at the front standard should not be less than 83 kpa

9. With the battery Chargers in the off position record the following.

    a. The lube oil pressure at the lube oil tank.

    b. The lube oil pressure at the front standard.

Note: With the assistance from maintenance personnel record the following:

    c. Voltage of armature (VDC)

    d. Current of armature (A)

    e. Voltage of field (VDC)

    f. Current of field (A)

    g. Motor speed (rpm)

10. Run the Emergency DC lube oil pump for minimum 25 minutes and record the following:

    a. The lube oil pressure at the lube oil tank.

    b. The lube oil pressure at the front standard.

Note: With the assistance from maintenance personnel record the following:

    c. Voltage of armature (VDC)

    d. Current of armature (A)

e. Voltage of field (VDC)

f. Current of field (A)

g. Motor speed (rpm)

11. Check the pre and post data parameters.

    a. Put the unit start up on hold if any differences are found between pre test and post test parameters.

    b. Investigate and correct malfunctions.

    c. Repeat the test after the issues have been resolved.

    d. If lube oil pressure at the front standard and lube oil tank are in acceptable operating range continue on with the following procedure steps.

12. Place battery Chargers back in service.

13. Start North A.C. oil pump and place the South A.C. oil pump in "AUTO". Shut down D.C. Oil pump and place in "AUTO".

14. The turbine may be placed on turning gear.

15. Record all test information in the unit control board and the shift supervisor's station log books.

APPENDIX H

Investigation of Unit 1 DC Lubrication System

newfoundland labrador
hydro
a nalcor energy company

Newfoundland and Labrador Hydro – a Nalcor Company
Holyrood January 11, 2013 U1 Failure Root Cause Analysis
Investigation of Unit 1 DC lubrication System

Prepared By: Sean Mullowney

Date: June 28/2013

Reviewed By: Greg Reid

Date: July 2, 2013

newfoundland labrador
hydro
a nalcor energy company

Approved By: Terry Le[illegible]

Date: June 28/13

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1. Background

The following report summarizes the work that has been completed to date by the Newfoundland and Labrador Hydro (Hydro) Holyrood Unit 1 Failure Root Cause Analysis Team, as it relates to the issue(s) with the Unit 1 DC lubricating pump system.

Much of this investigative work occurred in the area where Alstom Power and Hydro personnel were working to disassemble and repair the unit. This required careful coordination to ensure the safety of all personnel, as testing commenced.

This commitment to safety necessitated certain delays in the investigative testing, to ensure that no personnel were put in harm's way.

2. Investigation Sequence of Events

The following is a chronological timeline of the investigation, as it unfolded in the days after the January 11th event:

- January 17th – January 29th:
    - Root cause analysis team was formed, and collection of data began. Data included plant DCS (Distributed Control System) Historian alarm data, DCS SOE (Sequence of Events) alarm lists, ECC (Energy Control Center) SOE alarm lists, plant turbine-generator protection/control schematics and interviews with plant operations personnel who were working on January 11$^{th;}$
    - Examination of unit damage was possible during the week of January 21st, as Alstom Power began unit disassembly activities during this week;
    - Data, as well as physical examination of unit components, allowed the team to conclude that, following unit trip at 06:42 on January 11th, the turbine-generator coasted down with the absence of sufficient delivery of lubrication to its bearings;
    - DCS trends confirm loss of both AC lubricating pumps and crash of lube oil pressure following unit trip (see Figure 1 below); and
    - Lubricating oil pressure is re-established three minutes and 14 seconds after unit trip, when manual start of emergency diesel D1 re-establishes power to MCC-E1 (see Casual Factor # 2 in main report).

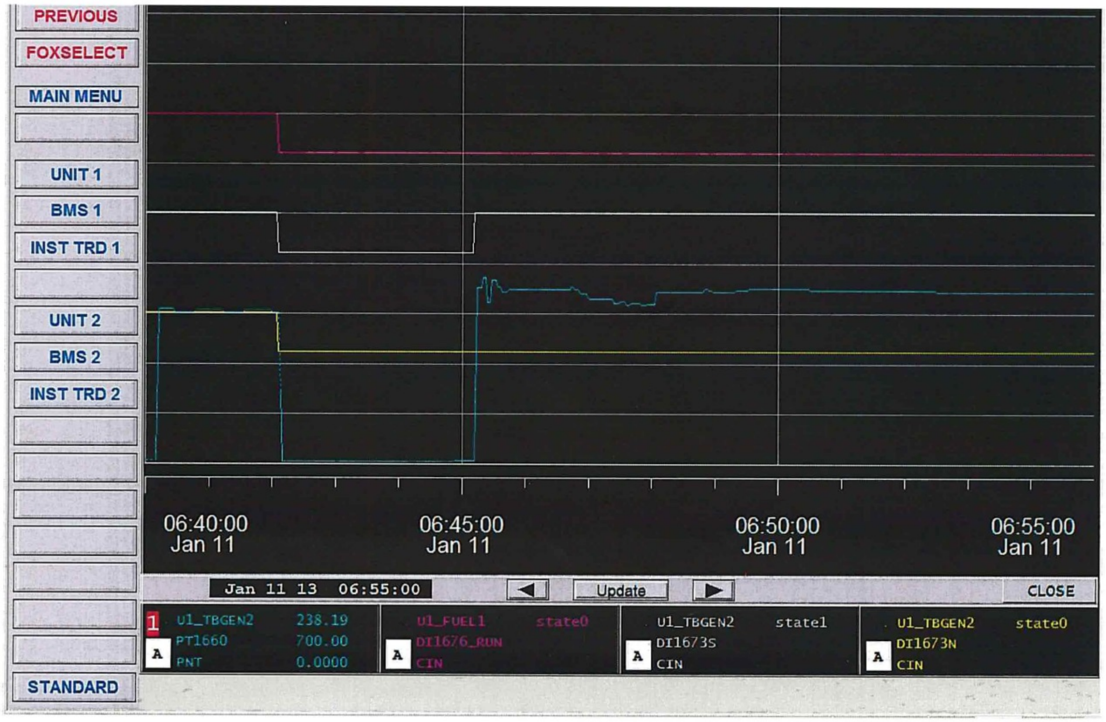


Figure 1: Status of Unit 1 Lube Oil Pumps and Lubricating Pressure during January 11, 2013 event. PT1660 (blue) is lubricating oil pressure at the front standard of the unit. DI1676_RUN (magenta) is the run/stop status of the DC lube oil pump (Note: DC pump's run status is triggered by a normally closed contact that opens to indicate run/start. Its running indication is opposite of both AC pumps North and South {i.e. run is indicated after the state change, the portion of the trend that is lower vertically}). DI1673s (white) is the run/stop status of the AC lube oil pump South. DI1673N is the run/stop status of the AC Lube Oil pump North. Upon loss of AC pumps the lube oil pressure crashes, despite DC lube oil pump starting. Pressure is restored 3 minutes, 14 seconds later after manual start of emergency diesel restores power to AC lube oil pump South.

- February 4th - February 15th:
    - o DCS trend data collected, indicates that DC lubricating oil pump starts in response to loss of AC pumps/falling lubricating pressure but does not aid in recovery of pressure (see Figure 1 above);
    - o Review of DCS Historian data shows that weekly online DC pump test has not shown a pressure increase back as far as November 2009 (as far back as data for present version of Historian is available);
    - o DC starter controls function tested, no component failures found;

- DC lubricating pump motor is decoupled from pump and controls tested (simulation of loss of AC pumps and falling lubricating pressure). Motor starts in response to these triggers (indication that DC motor starter is in working order, supports DCS trend data indication that DC pump started on January 11th);
- DC lubricating pump motor rotation is confirmed to be correct;
- Check valves (valves which allow oil flow in one direction, and seal when pressure is introduced in opposite direction) that are installed in the piping for each lubricating pump (2 AC, 1 DC) are confirmed to be free (i.e. neither stuck open, preventing establishment of oil pressure);
- Piping from each pump to the main lubricating oil header is checked with a boroscope to confirm that there are no blockages in the lines;
- Filters on each pump inlet are checked and confirmed to be free of blockages; and
- DC pump removed from tank, inspected, disassembled, components checked by Alstom Power. No issue(s) found.

- February 27th:

  - Alstom Power has unit disassembly and lubricating system temporary arrangement to a point where test runs of the system with DC and both AC and pumps can commence (i.e. cleaning of lubricating oil tank complete, re-installation of pumps, inspection of oil coolers, temporary jumpers installed around bearing locations, tank refilled with oil).

- Week of March 4th:

  - DC lube oil pump is function tested with temporary lubricating oil piping arrangement to Unit 1 turbine-generator (i.e. generator, turbine rotors, bearing, etc. removed, temporary jumpers installed around bearing locations);
  - Inability to achieve or maintain adequate pressure is noted (see Figure 2 below, a representative test from March 5);
  - Cycling of lubricating pressure and DC motor amperage is noted;
  - Further testing/observation of DC motor starter conducted; and

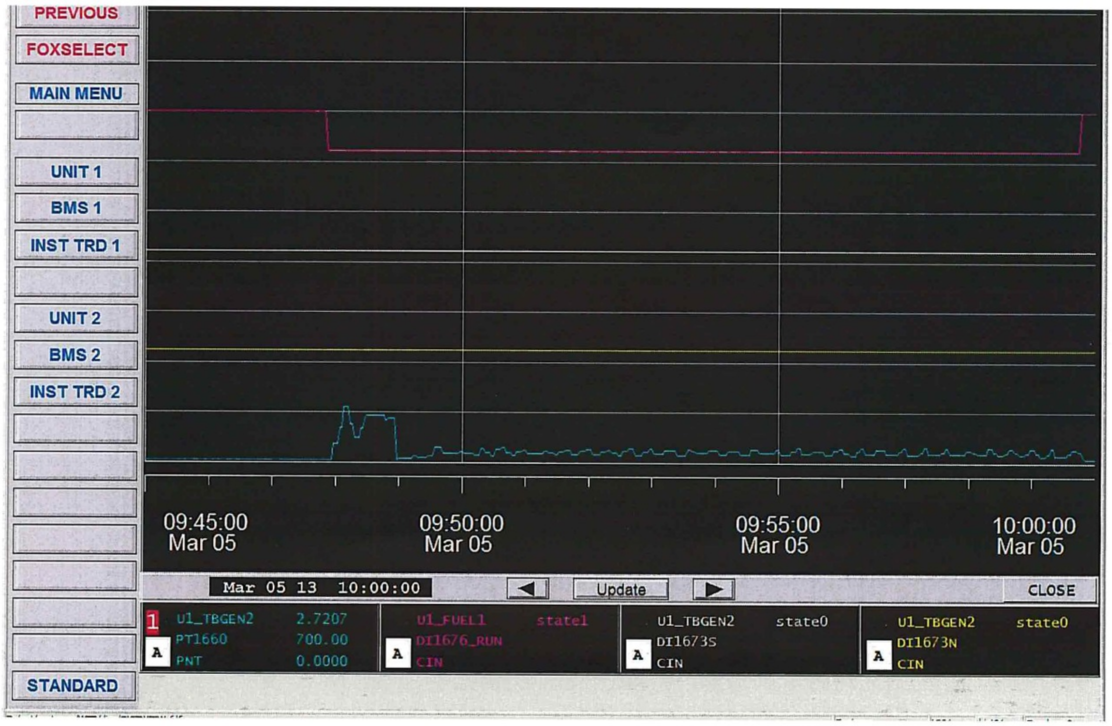


Figure 2: DC lube oil pump test from March 5, 2013. Note the falling magenta line indicates starting of the DC lube oil pump. There is an increase in pressure (blue) for a short time before pressure crashes and cycles

- Test conducted with the feedback to the control valve in the lubricating oil tank removed, to allow the valve to fully open (removing feedback essentially removes valve control action from system). No change in system operation was noted (see Figure 3 below).

- March 11 to April 5th:
  - Measured rotational speed of DC pump motor. Nameplate rated speed is 3,500 RPM (Revolutions Per Minute), measured speed was 2,840 RPM;
  - Unit 2 DC Lube Oil Pump motor was tested and its speed was measured for comparative purposes, to confirm that Unit 1 speed is abnormal;
  - Consulted with external motor resource (Pennecon Energy);
  - Removed Unit 1 DC motor and sent it to Pennecon Energy test shop for independent analysis (see report in Appendix A);

Figure 3: DC lube oil pump test with tank control valve wide open. Magenta is the start/run status of the DC lube oil pump. White is the lube oil pressure in the tank (expect higher value as there is approximately 42 feet of vertical head between the tank and the turbine-generator). Blue is the pressure in the front standard of the turbine-generator. Note the same cyclic pattern in the pressure trend as in Figure 2.

  - Two issues (motor brush boxes slightly off and motor neutral plane adjustment necessary) noted and corrected; and
  - Motor speed at no load now acceptable, Pennecon Energy report declares motor operation to be in line with nameplate specification data.

- Week of April 8th:

  - Motor re-coupled to DC Pump and tested;
  - Motor speed measured and found to be improved (3,160 RPM) but still below nameplate rated speed of 3,500 RPM;
  - Motor amperage and system pressure cycling still present;
  - Adjusted variable resistor in field circuit of motor (present in DC starter) and nameplate speed achieved; and
  - Lubrication oil delivery to turbine-generator bearing locations improved, but pressure and motor amperage cycling issue still present.

- Week of April 23rd:
    - Unit 2 taken offline for eight hours for planned maintenance outage;
    - Connected Unit 1 lube oil pump motor to starter for Unit 2 DC lube oil pump and performed functional test;
    - Motor amperage and system pressure cycling still observed;
    - This test eliminated Unit 1 DC pump electrical starter as cause of cycling issues (i.e. independent starter and power supply, cycling issue still present); and
    - Team focus returned to lube oil tank components.
- Week of April 29th:
    - Unit 1 DC lubricating pump removed from tank and coupled to Unit 1 AC North motor and installed in AC North pump well (system has and continues to operate at full pressure when testing either of the AC pumps, pressure cycling issue unique to DC pump/motor assembly);
    - Pressure and motor amperage (AC North motor with this test) cycling issue present on AC North motor/DC pump combination (see Figure 4 below); and
    - As DC pump is common factor with this test it seems to indicate that casual factor for DC lubrication issues is within pump itself.
- Week of May 6th:
    - Flowserve Engineer brought to site to consult with Hydro Root Cause Analysis team. Flowserve is the Original Equipment Manufacturer (OEM) for the Ingersoll Rand Unit 1 DC pump, and contracted pump service provider for the plant (see Flowserve service report, Appendix B);
    - Decision is made to send Unit 1 DC pump to Flowserve laboratory in Ontario for independent function testing; and
    - DC pump is uncoupled and preparations are made to ship it and an AC pump motor (AC as the test facility does not have the means to run a DC motor of this size).
- Week of May 13th:
    - Informed by Flowserve that, due to previous bookings at their test facility June 5th is earliest they can perform testing on Unit 1 DC pump.

- Week of June 3rd:

  - Flowserve performs testing on Unit 1 DC pump in their laboratory (with water, in the absence of lubricating oil) and informs Hydro that they are unable to replicate the cycling issue that has been experienced with the testing performed on the modified lubrication system for Unit 1 at the Holyrood plant; and

Figure 4: Test of DC Pump when coupled to AC South motor. Note that a test of AC pump South (white) provides normal and stable lube oil pressure (blue). When the AC North motor (yellow) is ran while coupled to the DC pump a similar cyclic pattern is exhibited as when DC motor and pump are ran together.

  - Holyrood plant manager makes contact with Unit 1 OEM to request they provide assistance to tap root team, with a view of reviewing the entire lubrication system from a system design stand point.

- Week of June 10th:

  - GE informs Hydro that a proposal for technical assistance is being prepared.

APPENDIX I

Plant Maintenance Procedural Enhancements

Re 1080 - MSTD-176 Rotational and speed check of 258 Volt DC motor for emergency lube oil pumps

Request Title: **MSTD - 176 Rotational and speed check of 258 Volt DC motor for emergency lube oil pumps. Wayne the procedure was created and needs to be reviewed.**

Document Control Coordinator : Wayne Rice

Beverly Kennedy on Sept 9th, 2013 at 02:31 PM

Request Details

Requester: Beverly Kennedy

Details:

Cancellation Message (if applicable):

Request Change Status : Approved

Solution Definition and Development Information

Procedure No: 1080 Entered By: Beverly Kennedy Date: Sept 9th, 2013 10:46 AM

Title	**MSTD-176 Rotational and Speed Check of 258 Volt DC Motor for Emergency Lube Oil Pumps**

Archive Information

Issue Date:	09/09/2013 Sept 9th, 2013
Distribution:	Electrical Maintenance 'A', Electrical Maintenance Supervisor, Manager - Work Execution
Manual/Group:	Maintenance Standards
Revision No:	0
Revision Date:	09/25/2013
Prepared By:	Beverly Kennedy
Controller:	Wayne Rice
Reviewers:	Wayne Rice, Wayne Rice
Approved By:	Terry LeDrew/HO/NLHydro

Procedure Scope

To ensure that all 258V motors for emergency lube oil pumps are electrically connected for proper rotation and speed, and meet required operating parameters before being coupled.

Note that this procedure pertains to preventive or corrective maintenance interventions by the Electrical Department.

Beyond any maintenance interventions, it is the responsibility of the Operations Department to perform functional checks of plant DC emergency lube oil pumps and associated systems prior to placing a main generating unit in service. While Electrical Maintenance A personnel may assist with these functional checks if requested by the Shift Supervisor, the tests are prescribed and championed by Operations and contained in the applicable Operations procedure.

This Maintenance Standard is not intended to supplant or cover any of the work performed during these functional checks.

Reference Information

Procedure Details

- Any 258 Volt DC motor disconnected with the intent of being eventually reconnected at that same specific location will have its supply and motor leads identified with two(2) color bands (per lead) as follow:

Polarity	Supply	motor
A	Red/white	Red/white
B	Black/Blue	Black/Blue

Note that because many DC equipment leads are often colored, identification of tape bands vs lead color may sometime be difficult, Blue and Black shall be deemed equivalent, so will Red and White.

- Any 258 VDC motor returned from repairs "off-site" or being placed in service for the first time (e.g. new, refurbished, or in-stock replacement) will have the following tests completed and documented before being coupled:

1. 250 VDC Megger and Bridge (micro-ohm) test of Field and Armature;

2. Rotation checked; if the rotation observed is the reverse of that indicated on the nameplate, the polarity (or phasing) of the field must be reversed with respect to that of the armature. Once the wiring changes are completed, repeat the testing to confirm proper rotation. Mark leads to match the new established phasing, as per the table above.

3. Run for ten (10) minutes to verify operation and confirm steady operating speed as per OEM nameplate. Accurate speed measurement can be taken by synchronizing a calibrated strobe light to the cooling fan blades of the DC motor. If the speed of rotation is found to be inadequate, adjust the field rheostat located in the motor starter until the desired speed is attained. All pertinent information and readings, including field and armature data (E and I), will be logged on the PM check sheet or, in the case of a corrective maintenance intervention, recorded on the completed work order and

communicated by email to the Manager - Work Execution, the Manager - LTAP, the Manager - Operations, the Short Term Work Planning & Scheduling (STWPS) Supervisor and the SPA Responsible for the Emergency Lube Oil System;

4. Vibration and bearing temperature test if any sign of abnormal condition is suspected.

- Any 258 VDC motor disconnected but not removed from site will not require any of the specific tests outlined in 2) to 4), provided the electrician in control of the work or the supervisor can verify that the lead markings have not been altered.

APPENDIX J

Unit 1 Lubrication DC Motor Amperage and System Pressure Cycling Issue

<u>**Unit 1 Lubrication DC Motor Amperage and System Pressure Cycling Issue**</u>

Following resolution of the issues affecting motor speed, subsequent test runs of the Unit 1 DC Lube Oil System for Holyrood Unit 1 revealed a motor amperage and oil pressure cycling issue. The technical details of this issue are more completely described in the **Investigation of DC Lubrication System** report located in Appendix G.

The report in Appendix G summarizes the testing that was performed to determine the cause of this cycling issue, up to the point of the submission of the draft root cause analysis report on July 2, 2013.

Further investigation was undertaken during the summer months to gain a full understanding of the cause of this motor amperage and system pressure cycling issue.

The Unit 1 lube oil tank has a capacity of 2514 gallons. With a total vertical height of 57 inches, an inch of oil depth in the tank correlates to approximately 44.1 gallons. The DC lube oil pump has an impeller diameter of 6-7/8", while the AC pump's impeller is 7-3/16" in diameter. During the testing completed on the AC and DC oil pumps this past winter and spring, the oil level in the tank was 28 inches, which correlates to a volume of 1235 gallons. At 28 inches, the DC pump has a suction head (i.e. the elevation difference between the oil level and the center line of the pump suction) of 9.25 inches, as the pump impeller center line is 18.75 inches from the bottom of the tank.

To allow pump testing while the bearings were disassembled, temporary piping arrangements were made to allow a closed loop system. As testing progressed with the DC lube oil pump installed in the Unit 1 lube oil tank with the temporary lubrication system piping arrangement, it consistently pumped at a pressure of 160 kilopascals (kPa) for approximately 50 seconds prior to any cycling issues. After 50 seconds, the discharge pressure temporarily decayed to approximately 145 kPa, and then decayed further and began to cycle at pressures between 96 kPa and 90 kPa.

In an effort to determine the root cause of the pressure cycling issues experienced during these tests, the Unit 1 DC lube oil pump and motor were removed and installed in a testing tank at Pennecon Energy's facility. (Pennecon Energy possesses an appropriate DC test set to power the motor.) During this testing, the discharge line for the pump was routed back into the tank in order to recirculate oil and maintain a consistent tank level. The pump's DC motor was set up to run at the rated speed of 3500 RPM, such that the pump was pumping 210 gallons per minute (GPM) of lube oil, at a pressure of 160 kPa. The pump and motor performed as designed, with no cycling issues.

A second pump was also installed in the tank for the purpose of draining the oil level in a controlled manner. At approximately four inches of oil above the DC pump centerline, it began to exhibit the same cycling behavior as the DC oil pump did during the testing at the plant.

During the testing at the plant, the pump discharged oil at 160 kPa for 50 seconds before losing suction and exhibiting the cycling behavior. The rate of oil flow for the DC pump is 210 GPM. The system capacity for the Unit 1 lubrication piping system is 200 gallons. An oil volume of 210 gallons is equivalent to 4.5 inches of height in the lube oil tank. Hence the pump suction head after 50 seconds was 4.75 inches. The pump still had approximately 0.75 inch of head above the required Net Positive Suction Head[2] (NPSH) of 4 inches. Therefore it regained its pressure to 145 kPa momentarily before losing suction at a tank level of 4 inches.

From this testing it was concluded that the cycling was a result of not meeting the pump NPSH requirements due to the temporary piping arrangement and oil level in the tank during the testing. The temporary piping arrangement was required to accommodate bearing repair work that was being carried out. Temporary bypass arrangements were used, consisting of pans that were open to the atmosphere (as opposed to intact piping with the assembled unit), with drains that connected into the system's lubrication piping. Once the system capacity was reached (200 gallons) with the temporary piping modification in place, the oil was not returning back to the lubrication tank quickly enough to maintain a suction head of greater than 4 inches. As soon as the suction head fell below 4 inches, the pump would lose suction and the cycling behavior would commence.

Due to the larger impeller diameter the AC lube oil pump delivers 275 GPM at a pressure of 160 kPa, without restrictions. At a system capacity of 200 gallons the pump would fill up the system in 43.5 seconds and still have a suction head of 4.75 inches. The required NPSH for the AC lube oil pump is 3 inches. Hence it would continue to pump without cycling because the suction head would not reach the 3 inch level required for it to lose suction. As a result, the AC pump would operate properly during testing.

While the Unit 1 DC lube oil pump and motor were undergoing the testing described above at the Pennecon Energy facility, the Holyrood Unit 2 DC pump and motor (identical system design as Unit 1) was removed from service and installed in Unit 1 position. Following reassembly of Unit 1, the DC motor speed was verified and the DC lubrication system operated as designed.

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[2] The Net Positive Suction Head is the head (elevation difference) value at a specific point (e.g. the inlet of a pump) required to keep the fluid from cavitating.

After the Unit 1 pump and motor testing was completed at the Pennecon Energy testing facility, it was returned to the Holyrood plant and was installed in Unit 2. With motor speed verified, it operated as designed as well.

This testing verified that the causal factor that contributed to the January 11, 2013 Unit 1 failure at Holyrood, with respect to the DC lubrication system, was low motor speed, as described above.

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NEWFOUNDLAND AND LABRADOR HYDRO

January 11, 2013 - Winter Storm Events

Power System Performance Review
Recommendations Resulting from the Analysis
Indicated by Area

Power System Review and Analysis Committee
June 2013
Final

4.3 Recommendations for Further Action by Area

4.3.1 Transmission and Rural Operations (TRO)

1. There were many issues with breakers, particularly the 230 KV class, during these events. A review of the preventative maintenance schedules and procedures for these breakers should be carried out to ascertain whether they are being carried out adequately. In addition, this review should address whether or not they are adequate for the age of the breakers. One issue is the failure to trip which is related to the auxiliary contact in the trip circuits and may be mitigated by the exercising of the breakers. A schedule for this 'exercising' should be developed and monitored, possibly with the assistance of EMS data which reports the opening and closing of the breakers, to identify 'dormant' breakers.

2. Although inspection of the suspected station faulted area for the Holyrood Unit 3 trip at 0413 hours was performed following the fault, a more thorough inspection of the area should be performed during a scheduled outage, to ensure that no damage exists and to confirm the fault mechanism. The area of concern is from the unit's transformer bushings to the unit breakers.

3. The maintenance program pertaining to the application of the RTV coating on the Holyrood station equipment should be reviewed. The review should also address the extent of the equipment involved, as the current coverage appears to be associated with the unit breakers only.

4. The indications associated with the Holyrood Unit 1 disconnect should be checked during opening, as there appears to be no "in transit" position but rather two "opens". The auxiliary cam switches which provide for the indication need to be checked.

5. Testing should be carried out on line 39L protection, in particular the 51N relay as it appears that the disk is not fully resetting.

6. A more thorough inspection of the equipment associated with the 138 KV bus - B8 (A phase) at the Holyrood terminal station should be performed to determine the location of the bus fault that resulted in the bus lockout.

7. A thorough inspection of the external area of B12L17 should be conducted to look for evidence of an external fault on B and C phases in the TL217 line protection zone. Particular emphasis should be on B phase, the phase of B12L17 which failed to clear.

8. Further testing and inspection of breaker B12L17 is required to determine why the breaker failed to clear the fault on B phase. In addition, the problem with the erratic status indication of B12L17 should be investigated, beginning with examination and testing of the auxiliary contacts used for the indication. If no evidence of an external fault is found on B phase in the area of the breaker and it's CT, an internal inspection of the B phase contacts and operating mechanism should be performed, as it suggests that B phase faulted, tripped and re-struck internally before being cleared via the breaker failure operation of B12T10.

9. Function testing of the 94TS/T1 Unit 1 transformer backup protection contacts in the breaker failure (B1/TF) and breaker failure lockout (86/BF - B1L17) circuits should be performed to ensure the timer is set and operating correctly to trip the breaker failure lockout.

10. Based on the damage found internally in breaker B1L22 at Springdale, other 138 KV KSO breakers on the system should be tested or inspected for resistor damage.

11. Further investigation and testing should be performed on Buchans breaker L05L33 to ensure that the failure to trip B phase, failure to trip on disagreement, and the subsequent closure on loss of air is more completely understood, with repairs as required.

12. A thorough check should be performed of Breaker B7T5 at the Holyrood terminal station due to the suspected fault at 1057 hours.

13. Testing of Bottom Brook breaker B1L09 should be carried out to determine why it 'pumped' (closed/open) after the initial closure at 1116 hours.

14. Testing of Bay d'Espoir breaker B11L06 should be undertaken to determine why it failed to close on all three phases at 0933 hours.
15. The second lockout and ground switch operation at Doyles at 1302 hours should be further investigated. It appears that, after the lockout was reset, there were issues with the NP disconnect T2-A inputs into the lockout circuit. When T2-A was closed

the inputs operated and tripped TL214 and applied the high speed ground switch, L14AG. This circuit should be checked during the next planned outage of the station.

16. Further checks on the Buchans TL233 protection, both P1 and P2 trip outputs, into the L05L33 trip coil circuits should be completed to ensure the relay contacts are not damaged due to the numerous operations which occurred during the single phasing conditions.

17. The settings for the overvoltage trip (level and timer) at the Hardwoods capacitor bank C2 - 90C2 relay should be checked.

18. The issues resulting in the delays in restoring station service supply to the Cat Arm plant via the Coney Arm 12.5 KV line (i.e., lack of remote control of the recloser and load imbalance) should be further investigated and corrected, as required.

4.3.2 Thermal Generation

19. Plant management should review the instructions for recording protection targets after unit trips to ensure that they are recorded by the operator before they are reset. Protection panel cards should be updated and made available to the operator for recording the targets as required.

20. During the next scheduled maintenance outage of Unit 3, a function test of the 87GT3 relay should be performed to ensure that the relay targets flag when the relay operates into the lockout.

21. The plant SOE indicates operation of the Unit 3 generator lockout 86-2 but no lockouts were reported in the system SOE at this time. Therefore, the system SOE for this point and the other Unit 3 lockouts should be operation tested.

22. Internal plant trip reports for all unit trips should be completed by plant personnel and distributed to ensure that all systems worked as designed.

4.3.3 PETS - Protection & Control Engineering

23. The lockouts from Unit 1 and 2 which trip the unit breakers, should be added into the Holyrood breaker fail scheme design of the terminal station for the required breakers. A review of all breaker fail designs schemes on the system should be

conducted to ensure that all schemes are adequate, in that they have the correct initiating inputs such as the lockouts, and trip the required breakers in the event of a breaker failure.

24. In conjunction with the recommendation to install CT's on both sides of the Holyrood terminal station 230 KV breakers, a new protection design philosophy should be developed with overlapping protection zones to cover all new installations.

25. The application of appropriate settings for the load encroachment feature on all SEL 321 relays should be done to prevent operation during off-frequency events. A review of SEL's final recommendation report (pending) should also be carried out. A setting of 100 ohms primary for all lines is recommended based on the protection settings for the longest line on the system, TL206. This setting will accommodate a load of 529 MVA before blocking. The angles settings are PLAF=90, NLAF=-90, PLAR=90, NLAR=270. This approach is preferred over the setting of the 50PP1 current monitor as it is independent of minimum fault levels.

26. Consideration should be given to the application of trip coil monitors at all breakers which have remote alarming features. The monitors would indicate issues with the circuits. Currently only local monitoring exists using panel lights. SEL has a trip coil monitor which might be suitable.

27. The Zone 2 protection reaches on TL218, TL242 and TL217 need to be increased to ensure that they operate for faults at the remote terminal end. The second zone timers for TL218 and TL242 should also be decreased from 60 cycles to 18 cycles.

28. Previous reviews by Henville Consulting have recommended Zone 1 and Zone 2 protection setting changes for the Eastern lines in addition to setting changes for other line relaying. These should be revisited and implemented as soon as possible.

29. Further investigation into why the Come by Chance 230 KV Capacitor bank, C4, tripped during the fault is required. The 94C4 operated to trip breaker B2C4 at 06:42:06, however this was at a time that the bank was required.

30. The Zone 1 distance protection settings on TL218 and TL242 (presently set at 88% and 82% of line lengths, respectively) should be decreased to a suitable level. A maximum 75% setting is recommended to ensure the protection does not overreach

as occurred during these events. Previous studies have recommended a maximum setting of 80%.

31. Consideration should be given to the application of definite time overvoltage protection on the Hardwoods and Oxen Pond capacitor banks, with a trip time of approximately 5 cycles for the first bank and an added 5 cycles or so for each other bank (i.e., second bank at 10 cycles, third at 15 cycles, fourth at 20 cycles). This will permit for staggered tripping but still allow for the tripping of all banks in less than one second for severe overvoltages.

32. The recommended firmware upgrades should be implemented in the LPRO2100 relays. Testing should be done on the relays following the firmware upgrades to verify that the relays will no longer operate for these events. This can be performed by testing the relays with the file captured on January 11 as the input to control the test set.

33. The reclosing on 100L at Sunnyside should be re-evaluated and co-ordinated with Newfoundland Power such that, upon loss of voltage along the 138 KV loop and the tripping of 100L, the loop is opened at an appropriate location to ensure that a reasonable amount of load is re-energized upon reclose. This will help to prevent a repeat occurrence of the re-energization event as happened on January 11. If this cannot be coordinated then reclosing should be turned off.

34. Application of frequency monitoring to capture abnormal frequency events such as occurred on this day should be considered for installation in various 230 KV stations - one in an Eastern station, another in Bay d'Espoir and one in a Western station.

35. Further investigation into the tripping of TL236 at Oxen Pond should be conducted to ensure that the permissive overreaching logic is working properly on the P2 protection (SEL) relays. This protection tripped the Oxen Pond end during the 0742 hour event (trip of TL201). This was a nuisance trip of little significance at the time but could result in something of consequence in the future.

36. With regards to the tripping of breaker B1L31 at STB at 0748 hours, further investigation is required into why the SEL 321 operated when the station was energized. A request has been sent to Schweitzer to determine if they have any suggestions. If the problem is not addressed by Schweitzer then the relay should be fully tested to ensure it is operating properly. In addition, the load encroachment

feature should be applied to this relay even though the problems are not suspected to have originated from a memory/frequency tracking issue.

Since the breaker closed after tripping two phases, there should be a review of the three pole conversion circuitry for this line, as well as for all line protections, to ensure that the correct logic is applied to provide for three pole trip conversion on the tripping of two phases.

The 94L2 three phase trip relay should trip the T relay to operate the TC1 and cancel reclosing. Other circuits should be checked to ensure that the 94L2 trips the T relay in this manner.

37. A timer should be added to extend the duration of the transfer trip signal from the STB TL235 protection which picks up the 85X at GFL FRC and provides for a direct trip of the three low side breakers 252T-1, 252T-2 and 252T-3 at GFL FRC.

38. Consideration and study should be given to the application of underfrequency relaying on the Hinds Lake generator and other hydro units to trip when extreme underfrequency levels are reached and maintained on the system or islanded areas, such as occurred on January 11. A level in the order of 54 Hz with a suitable timer might be appropriate. An alarm indicating an imminent trip would form part of the strategy to alert the operator to take action where possible.

39. Consideration should be given to the addition of remote end tripping of line breakers in the event of breaker failure lockout operations, such as that which occurred on L05L33. The 86BF lockouts should initiate transfer trip to the remote end of the lines.

40. Consideration should be given to timer setting changes for the Come By Chance capacitor banks in order to stagger the tripping of the banks for the first level (110%) overvoltage trip. Currently all banks have 10 cycle trip timers. These could be changed to 10, 20, 30 and 40 cycles for banks C1, C2, C3 and C4, respectively, or some other suitable times.

41. Timers should be installed in the control circuits of the Come by Chance capacitor banks to block closure until at least five minutes have elapsed from the time of breaker opening. This would allow for the manufacturer’s recommended discharge time.

42. The analysis of these events has highlighted the value of having two different types of protections from two different manufacturers applied on the transmission lines. This philosophy should be considered for all new or upgraded protection applications.

4.3.4 PETS – Electrical Engineering

43. Many of the breakers in the Holyrood station are proposed to be replaced in the near future as part of the Muskrat Falls DC infeed upgrade requirements. New breakers and associated equipment shall be specified with insulation creepage distances suitable for use in highly contaminated environments. For breakers with ceramic type insulation, creepages of 31 mm per KV or greater are recommended.

44. With the acquisition of the new breakers, CTs should be specified on both sides of the breakers to provide for overlapping protection zones. Faults such as the one that occurred on B1L17 will then be cleared high speed, without reliance on the time delayed breaker failure protection.

4.3.5 PETS – Transmission & Distribution Engineering

45. In light of the jumper issue that resulted in the fault and trip TL201 and a separation of the East/West power systems there should be a review of the standards applied for transmission line jumper length.

4.3.6 System Operations and Energy Systems

46. Customers were subjected to significant undervoltage conditions, outside normal limits for several minutes, with the trip of both Holyrood units simultaneously. The procedures pertaining to ECC operator action required during abnormal voltage conditions should be reviewed to ensure they are adequate in maintaining customer supply voltages within acceptable limits.

47. Consideration should be given to developing a protocol or guideline for the ECC operators to follow which addresses how to proceed when incorrect or questionable data occurs in the EMS as experienced at the STB station during restoration following the disturbance at 0742 hours. As noted previously, no action until data confirmation is received might be the best approach, realizing it will be a judgment call in many cases by the operator.

48. The issues with the SOE reporting, i.e., the missed events at Buchans and repeated events at Bottom Brook, should be further investigated.

49. Further investigation and discussion is required regarding the overvoltage condition which occurred, in particular as to why the additional 160 MW load on the NP system was shed following the trip of Holyrood terminal station.

4.3.7 System Operations and Planning

50. A detailed load flow and transient stability analysis should be conducted in concert with the comprehensive review of the sequence of events to gain a full understanding of the events.

51. In conjunction with the study above, guidelines should be developed and implemented for optimum reactive power dispatch and levels of Avalon loading, in the event that similar circumstances develop in the future. This should also include a review of the operation of the Optimum Power Flow (OPF) application in the EMS.

4.3.8 System Operations, Planning and PETS – P&C Engineering

52. Consideration should be given to a system voltage study which simulates normal loading scenarios but also abnormal scenarios such as occurred during January 11. Scenarios should include those such as all Holyrood units offline with one line supplying the Avalon - with load restoration, load restoration on the Western system after a major outage, major load rejection, etc. From this study, a suitable operation strategy/guideline should be developed to assist the ECC operators in maintaining system voltages within acceptable limits. The gas turbines and other sources of generation voltage support should also be considered in the study. This study should also address the requirement for the addition of system undervoltage and overvoltage protection and the role the EMS controls might play in the control of the system voltage during abnormal conditions. Application of undervoltage and overvoltage protection schemes should be considered. Currently there is very limited overvoltage protection and virtually no undervoltage protection in service on the system.

53. Surge and Trouble Reports should be prepared by System Operations for all disturbances as they provide valuable information regarding the system equipment, identifying issues which may result in larger problems at a later time. They also

provide for a valuable tool for personnel, particularly new employees, to become more familiar with all aspects of the system and the equipment over time. These Surge and Trouble Reports should be reviewed and monitored by all stakeholders to ensure that all investigations are complete and recommendations are completed in a timely manner.

4.3.8 Hydro Generation

54. Further investigation should be carried out into the determination of the cause of the lockout operations which occurred at Cat Arm and Upper Salmon during the load rejections at 0742 hours. This may include a planned load rejection at each plant to duplicate the conditions which occurred.

55. In the future, for all trips of larger generating units, investigations and reports should be completed to determine the cause and whether the plant's systems operated properly. The investigations should include trips due to system related issues. Information such as targets, alarms and logs should be collected and included in the reporting for each event. Any deficiencies should be addressed and corrected.

56. Further investigation into the performance issues with the Cat Arm station service supplies should be carried out to determine what needs to be corrected to ensure that station service is available following a trip of the plant. This should include an investigation into whether unit black start capabilities exist and the development of procedures to carry out the same.

NEWFOUNDLAND AND LABRADOR HYDRO

Remedial Actions

From the January 11, 2013 System Events

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TABLE OF CONTENTS

1 INTRODUCTION

The impact of the events on January 11, 2013 were similar to those experienced on January 4 and 5, 2014, in that they each had system wide customer impacts with significant terminal station problems affecting the Avalon Peninsula. During each event, the Holyrood units were tripped offline, and the restoration time of these units impacted the duration of customer outages. Both had incidents originating at the Holyrood Terminal Station (HRD TS) that involved a failure of the 230 KV breaker, B1L17 but the causes of these breaker failures are unrelated. Following is a summary of each of the events.

2 JANUARY 11, 2013 SYSTEM EVENTS

The system outages on January 11, 2013, were primarily weather related. There were electrical faults experienced in the HRD TS, caused by wet and salt contaminated snow. One of these electrical faults was the result of the failure of the insulation on the 230 KV breaker B1L17. The disturbances in the HRD 230 kV switchyard resulted in the shutdown of all three Holyrood generating units and a trip of one of the two 230 kV transmission lines from the Western Avalon Terminal Station (WAV TS) to the major load centers on the Avalon Peninsula. There was an extended outage to Unit 1 due to mechanical equipment failures and a fire resulting from a bearing lubrication oil system failure. Restoration of the Holyrood plant was greatly hampered by blizzard conditions preventing station maintenance crews from arriving at the station. While crews worked to access the station, there was no power system connection either in or out of the Holyrood Generating Station. This resulted in delays in restarting the units at Holyrood and in supplying customer demand. Station service into the Holyrood plant was not re-established until late in the afternoon on January 11, 2013. The first Holyrood unit did not come online until the next morning (22 hours after the initial trip).

Later in the morning of January 11, 2013, the remaining in-service line out of WAV TS (TL201) faulted and tripped due to a jumper issue. This resulted from the high winds. The loss of this line interrupted the load on the Avalon Peninsula and resulted in a high system frequency in the central and western areas of the Island. The high frequency caused protection relay mis-operations, resulting in multiple transmission line trips, de-energization of terminal stations and the significant loss of generation in these areas. This severely hampered the restoration efforts which were to take place during the remainder of the day. In particular, the terminal stations at Stony Brook, Buchans, Massey Drive, Bottom Brook, Doyles and Stephenville all required re-energization before customer restoration could occur. Further aggravating the situation were RTU communications issues at the Stony Brook terminal station which resulted in additional abnormal events and additional equipment outages during the restoration by Hydro's Energy Control Centre personnel. The last station (Massey Drive) was not restored until the early afternoon hours (more than five hours following the triggering event). In addition, the hydraulic generation was restored throughout the day with the last plant (Cat Arm) not back on line until nearly 19 hours after the initial trip. Some of the delays in the restoration were the result of the time to dispatch crews to the stations. There were also station service issues at Cat Arm which hampered the restoration efforts at this remote station.

3 JANUARY 4 AND 5, 2014 SYSTEM EVENTS

The weather has not been identified as a causal factor in the January 4 and 5, 2014 system events. The initial outage at the Sunnyside Terminal Station (SSD TS) on January 4, 2014, was the result of a failure to transformer T1. A breaker failure at the terminal station escalated this event and resulted in an outage to the 230 kV transmission to the Avalon Peninsula and a trip of all three units at Holyrood. There was a significant loss of generation in the central and western areas (similar to the January 11, 2013 events); however, in this case, the 230 kV lines and terminal stations in these regions remained in service.

Additionally, the issues with RTU communications at Stony Brook or any other individual station did not reoccur. There was however, a loss of the Energy Control Centre's Energy Management System (EMS) for a period of less than one hour during this event. Transmission into the HRD TS was restored in just over an hour, facilitating the re-establishment of station service and earlier restoration of the Holyrood units. The generating units at Holyrood shut down safely during the trip event and were able to be restarted normally, post event. A vibration issue on Unit 1 delayed its return to service and was resolved by a slower than typical start up. The hydraulic generating stations (with the exception of Hinds Lake) were back on line in just over three hours due to crews being dispatched to these sites in preparation of the storm. The unit at Hinds Lake was delayed in starting due to a unit breaker issue.

The second outage at the Sunnyside Terminal Station (SSD TS) on January 4, 2014, occurred during the restoration efforts following the events earlier in the morning. Personnel were in the process of restoring transformer T4 and the transmission supply to the Burin Peninsula when temporary protection modifications adversely affected the 230 kV bus lockout. It was determined that a trip condition associated with the failed transformer T1 was still active, resulting in this trip. This event resulted in another major system disturbance, with the loss of 230 kV transmission from SSD TS to WAV TS and to the Bay d'Espoir Terminal Station, and a trip of some generation in the central and western areas (Cat Arm, Granite Canal, and Units 5 and 6 at Bay d'Espoir). Restoration following this event occurred in an expedient manner. The transmission into the HRD TS was restored in 30 minutes, again facilitating the re-establishment of station service and unit restarting. The hydraulic generating units were restored in less than an hour. The first Holyrood unit was restored in 12 hours and 30 minutes following the initial trip during the morning events at SSD TS.

The outage at the HRD TS during the evening hours on January 5, 2014, occurred when personnel were restoring Unit 1 following the trip on the previous day. A failed breaker at the HRD TS resulted in the shutdown of Holyrood Units 2 and 3 and the trip of the 230 kV transmission line from Western Avalon to Holyrood (TL217). This was primarily a HRD TS event and the impact was largely confined to the Avalon Peninsula. Transmission into the HRD TS was restored in less than an hour, facilitating the re-establishment of station service and the unit restart process. The first Holyrood unit, Unit 2, was restored the next morning (eight hours after the initial trip).

4 MITIGATING ACTIONS TAKEN FOLLOWING THE JANUARY 11, 2013 EVENTS

Following the events on January 11, 2013, a report; *January 11, 2013 Power System Outage Report,* was written. It includes a summary of all the actions taken to the time of its preparation, in addition to presenting numerous recommendations for future action to help avoid or lessen the impact of such events in the future. The recommendations were identified by area of responsibility and covered all the issues which led to the significant power system events on this day, including areas such as:

- Review of preventative maintenance procedures and schedules
- High voltage breaker replacement, inspections and repairs
- Protection and control circuitry - function testing and enhancements
- Digital protective relay firmware and setting changes
- System stability studies
- System voltage/frequency studies and control enhancements
- Development and enhancement of procedures

A number of these recommendations were implemented prior to the end of 2013, some of which helped to mitigate or lessen the customer impact resulting from the January 2014 events. They are summarized as follows:

<u>Action Item(s)</u>

The application of appropriate settings for the load encroachment feature on all SEL 321 relays should be done to prevent operation during off-frequency events. A review of SEL's final recommendation report (pending) should also be carried out. A setting of 100 ohms primary for all lines is recommended based on the protection settings for the longest line on the system, TL206. This setting will accommodate a load of 529 MVA before blocking. The angles settings are PLAF=90, NLAF=-90, PLAR=90, NLAR=270. This approach is *preferred over the setting of the 50PP1 current monitor as it is independent of minimum fault levels.*

The recommended firmware upgrades should be implemented in the LPRO2100 relays. Testing should be done on the relays following the firmware upgrades to verify that the relays will no longer operate for these events. This can be performed by testing the relays with the file captured on January 11 as the input to control the test set.

Discussion

During the events on January 4 and 5, 2014 there was significant customer load loss on the Avalon Peninsula with over frequency conditions resulting on the remainder of the system. However, unlike the events on January 11, 2013, these conditions did not result in protection relay mis-operations, multiple transmission line trips, and the de-energization of terminal stations, thus providing for a much more expedient restoration. The implementation of the relay setting changes indicated above helped to mitigate the impact of the high frequency conditions.

Action Item

An investigation was required into the communication issue which occurred at Stony Brook between the Stony Brook RTU and EMS. During the restoration efforts, the status of this terminal station stopped updating due to a buffer overflow problem with the routers between the EMS and Stony Brook.

Discussion

During the events on January 4 and 5, 2014, as a result of the solution implemented following the investigation above, there were no communication issues affecting specific remote terminal units (RTU's). This helped to avoid potential operator confusion which could have resulted in additional abnormal events and equipment outages.

Following the failure of Unit 1 during the January 11, 2013 event, a root cause investigation was completed into its failure which resulted in recommendations related to the routine testing of the DC lube oil pump operation. Recommendations implemented during and after the investigation ensured the proper operation of the DC lubrication systems during the 2014 event.

Action item(s)

Recommendations were made to design and install new DCS displays and to create new test procedures to ensure the proper operation of the lubricating oil system.

Discussion

During the events on January 4 and 5, 2014, all three generating units tripped and shut down safely using the DC lubricating oil pumps. As a result of the implementation of the recommended changes, the pumps operated as designed and provided sufficient oil to the bearings to enable safe shut down of the units.

In addition to these equipment related recommendations, Hydro strengthened its storm readiness procedures following the January 11, 2013 events. In particular, prior to the events on January 4, 2014, crews were specifically deployed to generating stations that were remote in nature and it was known that travel would be difficult or impossible during a storm. Existing crews were supplemented by having additional staff on site, specifically at the Holyrood Generating Station, prior to the event. Hydro also took into consideration recent operating experience when deploying crews to Granite Canal and Cat Arm. Leading into the January 4, 2014, event, the Granite Canal unit had known vibration issues and Cat Arm had known issues with the station service breakers. By deploying crews to these sites in advance of the weather, any potential issues that arose could be mitigated as quickly as possible. In the case of Cat Arm (and unlike during the events on January 11, 2013), manual switching of the station service breakers prevented the plant from going black and allowed the units to go back in service as soon as the system was restored and capable of having them back online.

Also in relation to storm readiness and lessons learned from the January 2013 event, Hydro ensured that access routes to major facilities would be maintained during the event by ensuring routes were clear prior to the storm, and by having plans in place for keeping routes clear during the storm as required.

There have been a number of other key recommendations completed since the January 2013 events (e.g., breaker repairs and RTV coatings, shortening of transmission line jumpers, additional protection and control modifications, etc.) that may not necessarily have lessened the impact of the events on January 4 and 5, 2014, as they targeted causal factors which were not present during the 2014 events.

Q. Further to the response to PUB-NLH-045, explain in detail when and why Newfoundland Power's mobile gas turbine was located at Holyrood in 2013, how long it stayed there, the function it performed there, whether it successfully performed in this function, and if moved from Holyrood, why was it moved.

A. There was no requirement to initiate a blackstart of the Holyrood plant during the recent system events on January 4 and 5, 2014. Unlike the circumstances that occurred on January 11, 2013, during the recent events the 230 kV transmission lines into the Holyrood Terminal Station (HRDTS) were able to be restored quickly, thus providing for station service requirements. Please refer to Hydro's response to PUB-NLH-045 for additional detail regarding the January 11, 2013 events.

In 2012, Hydro determined (based on an AMEC assessment report) that the Holyrood gas turbine, used for emergency station service and blackstart capability, could no longer be available for use. At this time, Hydro was planning for an addition of a 60 MW (nominal) combustion turbine as part of its generation planning for 2015. In January 2012 it was determined that this unit would be located at Holyrood and configured to provide the required blackstart. In the meantime, Hydro developed a contingency plan to use the Hardwoods gas turbine (HWDGT) to provide blackstart power for the Holyrood Thermal Generating Station (HTGS). However, it was shown that during the events experienced on January 11, 2013, the HWDGT blackstart contingency plan was inadequate, due to its reliance on the Avalon transmission system. In order to utilize the HWDGT for the blackstart of the HTGS, a transmission path is required from the Hardwoods Terminal Station to the HRDTS. On this day, electrical faults had caused trips and lockouts of the HRDTS so no transmission path was available. There were considerable delays in getting the HRDTS restored due to the blizzard conditions that prevented station maintenance crews from arriving at the station.

Hydro took steps towards an alternate HTGS blackstart contingency plan by requesting that Newfoundland Power relocate its mobile generation to Holyrood. An agreement was reached between Hydro and Newfoundland Power to relocate Newfoundland Power's 6.5 MW Mobile Gas Turbine (NP-MGT) and 2.5 MW Portable Diesel (NP-MD3) to Holyrood and connect them to the HTGS to allow for faster restoration of station service and to provide for plant blackstart capability. These mobile units were also configured to provide power to the interconnected power system via the HRDTS.

Engineering design and construction of a grounding system, overhead lines, and a transformer bay were required for the electrical connection to the HTGS. The engineering and construction work were completed, the units were commissioned and on April 24, 2013, a test to provide station service power into the HTGS was successfully completed. It was proven that the generation could provide for essential services critical to life safety and system operations as it allows for the operation of fans to evacuate smoke, the restart of air compressors, operation of cooling water pumps to maintain equipment temperatures, and operation of extraction pumps to manage water chemistry and exhaust hood temperature.

In order to facilitate a blackstart test of the HTGS, a coordinated effort between Hydro and Newfoundland Power was required along with a window of opportunity when no Holyrood units were required for system support. This window presented itself on May 10, 2013. Blackstart tests were performed; however, the tests showed that the mobile units were inadequate in providing full blackstart capability due to the inability to start up a Holyrood unit boiler feedwater pump motor. As a result, Hydro continued to rely on its interim blackstart solution using HWDGT, while the Holyrood combustion turbine application was being advanced.

Following the test, the mobile units were disconnected and returned to Newfoundland Power in late May, 2013 for their annual capital and maintenance program.

Although full blackstart capability was not possible from Newfoundland Power's mobiles, Hydro recognized that this unit could help to secure the supply to essential services at the Holyrood generating station for the winter seasons. It would also provide the significant benefit of keeping much of plant auxiliary equipment operating in a warm state, thereby reducing the start-up time once the transmission supply is restored. Only one of the mobiles was required for this function. Hydro therefore determined that it would request NP-MGT be returned to Holyrood for each winter season until the new 60 MW (nominal) combustion turbine was in place.

In October, 2013 a letter was received from the Board requesting Hydro to take immediate action to ensure all possible options have been considered to provide reliable Holyrood blackstart capability. In November 2013, a report with the options was completed. This was filed with the Board with the preferred option to have a nominal 16 MW diesel plant, onsite, as a blackstart generating solution to be installed and commissioned by February 28, 2014.

In November 2013, Hydro made the request to Newfoundland Power to have NP-MGT re-connected at Holyrood. This unit was subsequently returned to the HTGS location and reconnected on December 30, 2013.