Henville Consulting Inc.

NEWFOUNDLAND AND LABRADOR HYDRO

Protection Systems Impacts on 4 January 2014 Supply Disruptions – External Protection Review

22 March, 2014

Prepared/Authored by:

Charles Henville
Principal, Henville Consulting Inc.

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
C. HENVILLE
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EXECUTIVE SUMMARY

This focus area contributes the protection systems' impact on the disturbances. This portion of the review is prepared by Henville Consulting Inc, a (British Columbia) corporation specializing in the application and setting of protection systems in large power systems. Recognizing that the vast majority of investigative work has been performed by Newfoundland and Labrador Hydro internal staff, this contribution to the investigation is termed "External Protection Review". It identifies protection issues from a high level.

During the system disturbances on 4th and 5th January 2014, the transmission lines and system transformers were operating in many unusual conditions and with unusual system stress. There were some transformer faults and some slow or failed breakers. Under these conditions, there were many protection operations. Not unexpectedly, given the Newfoundland and Labrador Hydro protection systems are applied according to typical North American best practices, most of the operations were correct, desirable, and easily explained. However in some cases there were protection failures or correct operations that were undesirable. This section is an analysis of the most critical protection operations with a view to fully understanding the relationship of protection operations to the system conditions during the disturbances.

Considering that there were many tens of thousands of individual events (as recorded by sequence of events recorders) on 4th and 5th January, the External Protection Review relied heavily on information and preliminary analysis received from internal staff, specifically, Art Bursey and Alex Lau. The investigation started on 30th January 2014 through telephone discussions and email exchanges between Charles Henville and Art Bursey (Senior System Operations Engineer) and Alex Lau (Supervising Engineer, Protection). The process began with a review of draft 1 of the high level sequence of events report and (through discussion with internal staff) identification of the key protection issues that needed resolution. The investigation continued over the next several days with information exchange, leading up to three days of further analysis at Hydro Place with full access to drawings, detailed relay event records, and digital fault recorder records. Additional information was obtained from the internal review team meetings on 9th and 10th February 2014. This report was drafted during these four days.

The key findings with respect to the impact of protection systems are as follows:

1. Most protection systems responded appropriately to problems with primary equipment during the restoration process.
2. Records available from sequence of event recorders, digital fault recorders and modern

digital protection systems were key enablers to analysis of the primary system events and responses of the protection systems. However, complete analysis of some portions of the disturbance is constrained by limited information availability from several legacy protection systems.

3. On 4th January, there were several instances of breaker failures, and one instance of multiple slow breakers for the same fault. These multiple contingencies may have been related to the severe weather conditions on the day of the disturbances, or may be related to age or condition of equipment. Industry best practices do not apply and design protection systems to handle multiple independent contingencies on power systems. Notwithstanding the events on 4th January 2014, such contingencies are normally considered to be non-credible.
4. The failure of breaker B1L03 at Sunnyside substation to clear a short circuit on Sunnyside Transformer T1, combined with the lack of initiation of breaker failure protection for this type of fault led to the system breakup and initial blackout of the Avalon Peninsula area at 9:05 am.
5. A subsequent fire on T1 damaged some of the secondary wiring used for protection purposes that triggered emergency modifications to the wiring of bus B1 protection. These modifications may have impacted the ability of the 230 kV bus B1 protection to clear a 230 kV fault caused by unexpected opening of Sunnyside 230 kV disconnect switch B1T4 during system restoration. This fault had to be cleared by remote transmission (TL202 and TL206) protection systems at Bay D'Espoir (BDE).
6. One of the two remote transmission (TL202) protection systems did not work as expected and two breakers at the BDE terminal of TL202 opened slowly from the initial protection operation. These breakers plus additional breakers were opened after breaker failure protection at Bay D'Espoir operated. The breaker failure protection operations increased the amount of the system breakup, and delayed restoration.

Key protection system recommendations moving forward

1. Three high priority protection related recommendations have been made.

- **High Priority No. 1**: Check and modify where necessary, trip coil No. 2 connections to all applications on a specific 230 kV breaker type. Until this recommendation is implemented, the integrity of the transmission system may be considered at risk in the event of a transmission system short circuit with a single contingency of a protection failure.
- **High Priority No. 2:** Adjust zone 2 protection timer settings on the TL202 and TL206

terminals at Bay D'Espoir. Previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances. This recommendation has been implemented.

- **High Priority No. 3:** Identify which additional simple relay setting changes or modifications recommended in previous studies may be done in advance of planned upgrades to improve the performance of the transmission system protection. Previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances.

2. Five other recommendations deal with actions that may be considered over a longer term. These recommendations mostly involve risk versus reward or cost benefit analysis decisions, and an action plan will need to be developed to implement each of them.

- **Long Term No. 1:** Consider replacing Sunnyside T1 protection at the same time as T1 is replaced. The decision should be made to allow sufficient time to be in service with the replacement T1.
- **Long Term No. 2:** Consider including a protection technician in emergency response personnel. This recommendation should be implemented in coordination with other emergency response plans.
- **Long Term No. 3:** Review applications of breaker failure protection to ensure all transformer protection systems, initiate breaker failure protection for breakers tripped by the transformer protection. Modify where necessary. This review should be completed within one year and any necessary modifications should be completed in within two years.
- **Long Term No. 4:** Review breaker failure protection applications of all transformer protection designs at stations using the Schweitzer Engineering Laboratories type SEL-501 relay. Modify the scheme if necessary. This review should be completed within one year and any necessary modifications should be completed in within two years. This recommendation would likely be well coordinated with Recommendation LT3 above.
- **Long Term No. 5:** Develop company specific guidelines as to the basic philosophies in the application and design of breaker failure protection systems. This recommendation should be completed before protection design work for Muskrat Falls interconnection project starts.

1 INTRODUCTION

This focus area report is part of an internal report on the Newfoundland and Labrador supply disruptions on 4th January 2014. The main report references this focus area with respect to findings and recommendations concerning protection system performance.

This focus area reviews the protection systems impact on the disturbances. This portion of the review is prepared by Henville Consulting Inc, a (British Columbia) corporation specializing in the application and setting of protection systems in large power systems. Recognizing that the vast majority of investigative work has been performed by Newfoundland and Labrador Hydro internal staff, this contribution to the investigation is termed "External Protection Review". It identifies protection issues from a high level.

In general terms, Newfoundland and Labrador Hydro transmission protection practices conform to typical North American best practices. Redundant protection systems are applied to minimize catastrophic results from protection failure, and breaker failure protection systems are provided for credible single contingencies. In the case of such extreme system stress as occurred on 4th January 2014, it is difficult for protection systems to determine whether conditions should be allowed to persist, or whether automatic operation is desirable to break up the system and allow restoration in an orderly manner. This element of the investigation identifies possible need for further investigation, and revision in protection practices and/or settings in general and specific cases.

The report includes the following main sections:

- The process used to perform the review, including the scope and the gathering and analysis of information received.
- Background as to how the reviewer became involved in this review.
- Sequence of events
- Findings of the review
- Recommendations.

2 REVIEW PROCESS

After identifying the most critical events with respect to protection, the External Protection Review focussed on three events to determine whether protection operations were expected or if not as expected, what may have gone wrong.

- The short circuit of T1 at Sunnyside at 9:05 am on 4th February.
- The initial attempt to restore power to Sunnyside 138 kV system at 12:58 on 4th January
- The second event to restore power to Sunnyside 138 kV system at 15:33 on 4th January

In addition other major events on 4th January were briefly reviewed.

The External Protection Review relied heavily on information and preliminary analysis received from internal staff, specifically, Art Bursey and Alex Lau. The investigation started on 30th January 2014 through telephone discussions and email exchanges between Charles Henville and Art Bursey and Alex Lau. The External Protection Review process began with a review of Draft 1 of the high level sequence of events report and (through discussion with internal staff) identification of the key protection issues that needed resolution. As the identification process focussed on the three areas mentioned above, the detailed sequence of events report, digital fault records, relays settings files, and relay event reports were exchanged by email and supplemented by telephone conversations to identify key protection issues. On Friday 8th February, Charles Henville started further investigation at Hydro Place using direct access to information stored in Newfoundland and Labrador Hydro files, drawings, and databases. Additional information was obtained from the internal review team meetings on 9th and 10th February, 2014. This report was drafted during 9-12 February 2014.

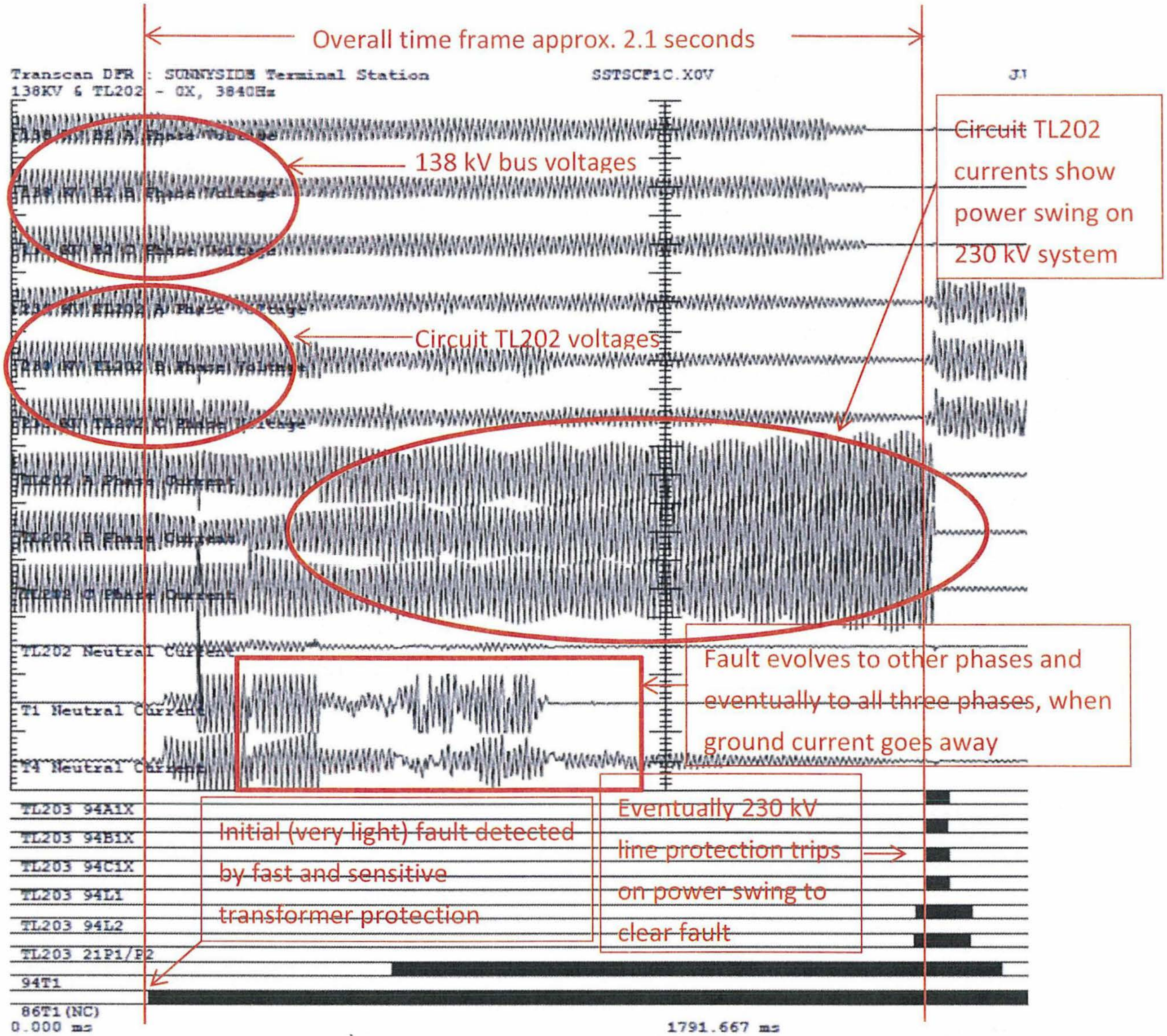
3 BACKGROUND

The Consultant Henville Consulting Inc. was retained to conduct this review by invitation from Newfoundland and Labrador Hydro. The scope and terms of the review are described in Henville Consulting Inc. quotation QNLH011 part of which is attached as Appendix 1

4 SEQUENCE OF EVENTS: RELEVANT TIME FRAME

The short circuit of T1 at Sunnyside at 9:05 am on 4th February.

A short circuit occurred at 09:05:34.600 inside transformer T1 at Sunnyside. The T1 transformer shares a tripping zone with similar transformer T4; so both transformers needed to be tripped off line by the same circuit breakers. The T1 protection correctly and promptly identified the fault and issued lockout trip signal by 86T1 as shown in Figure 1. Four of the five circuit breakers that needed to open did so promptly. However, 230 kV breaker B1L03 failed to open; so the fault was supplied for an additional extended time. See Figure A1-2 for location of the failed breaker.



<u>Figure A1-1 Initial (9:05) Sunnyside fault – Digital Fault Recorder Record of Currents, Voltages and Events at Sunnyside Terminal Station</u>

The fifth breaker, B1L03 failed to open. Since clearing was delayed, the T1 fault arc evolved to other phases and eventually created a sustained three phase short circuit that caused the transformer tank to expel oil that caught fire. The extended duration of the short circuit resulted in a power swing that caused TL203 and TL237 to trip in an expected fashion. Tripping of TL203 and TL237 isolated the Avalon Peninsula from the major source of power supply and resulted in a system collapse and blackout.

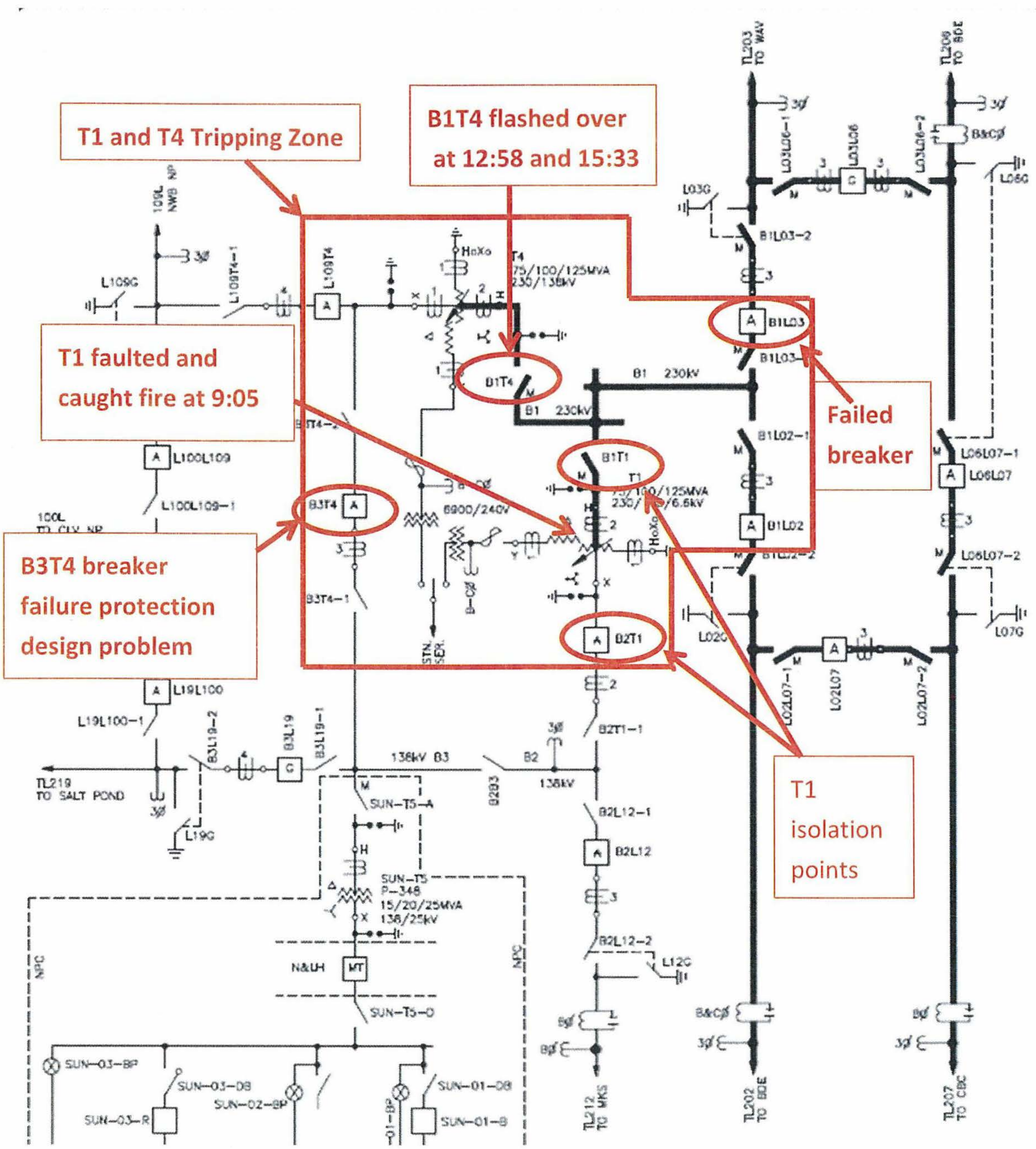


Figure A1-2 Single Line Diagram of Sunnyside Substation

The first attempt to load T4 at Sunnyside at 12:58 on 4th January 2014

At 12:58 after T1 had been electrically isolated, an attempt was made to re-energize the 138 kV side of the station. The 230 kV side was re-energized without incident at 12:56:55.000. Station service was successfully restored at that time. Immediately after 138 kV breaker B3T4 was closed at 12:58:23.928, T4 isolation switch B1T4 started to open, and within a few seconds, Sunnyside 230 kV Bus 1 was tripped by the bus differential protection. It was noticed that the CT secondary wiring on the T1 HV bushing would have been damaged by the fire; so it was disconnected by emergency field modifications. However, analysis during the later investigations showed that it was the opening of disconnect switch B1T4 (see Figure A1-2) under load that caused a fault. Since it is not designed to open under load, an arc was drawn that (approximately five seconds after the switch started to open), flashed over between B and C phases. Figure A1-3 shows the voltages and currents measured at the TL206 terminal at Bay D'Espoir during this event.

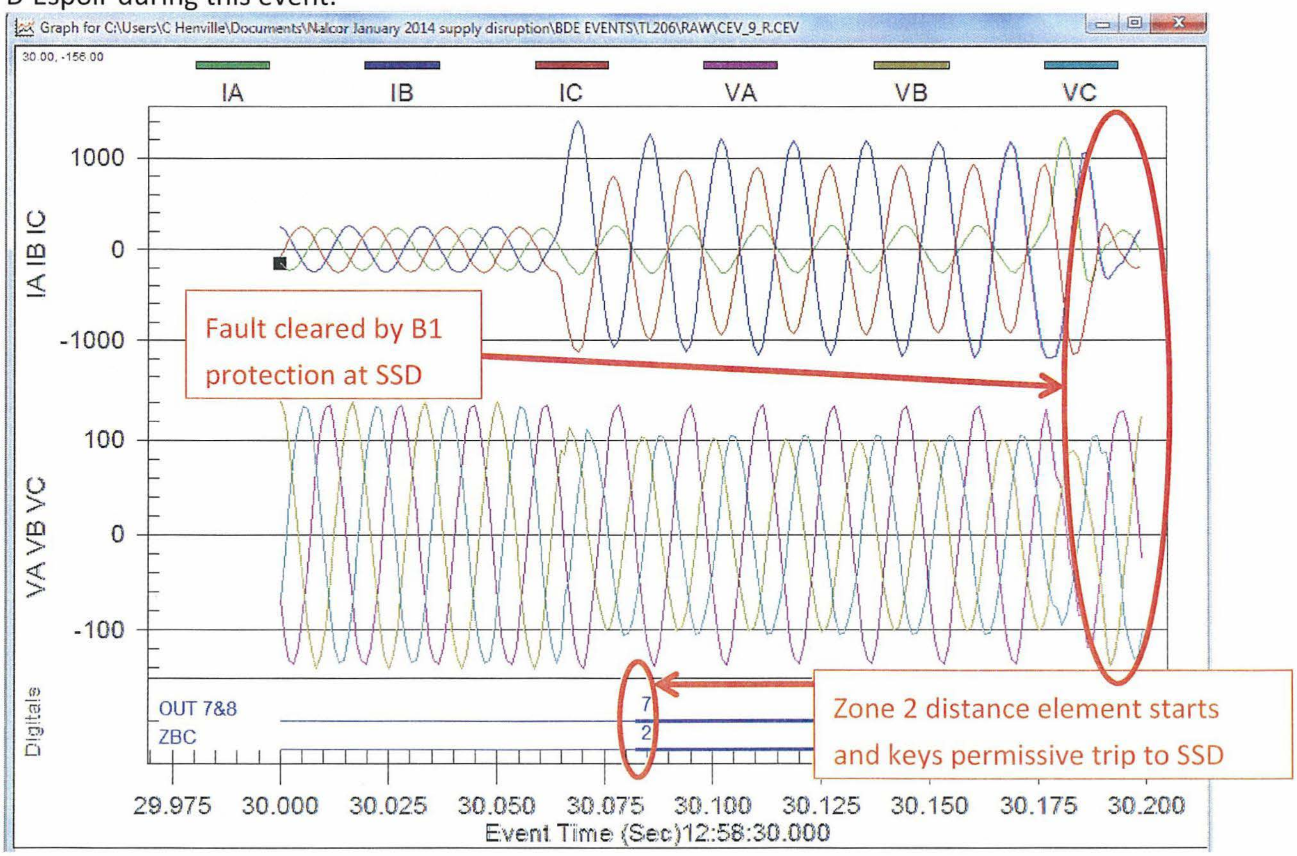


Figure A1-3 Voltages and currents at the BDE terminal of TL206 during the 12:58 event. This is the second fault at Sunnyside on 4th January

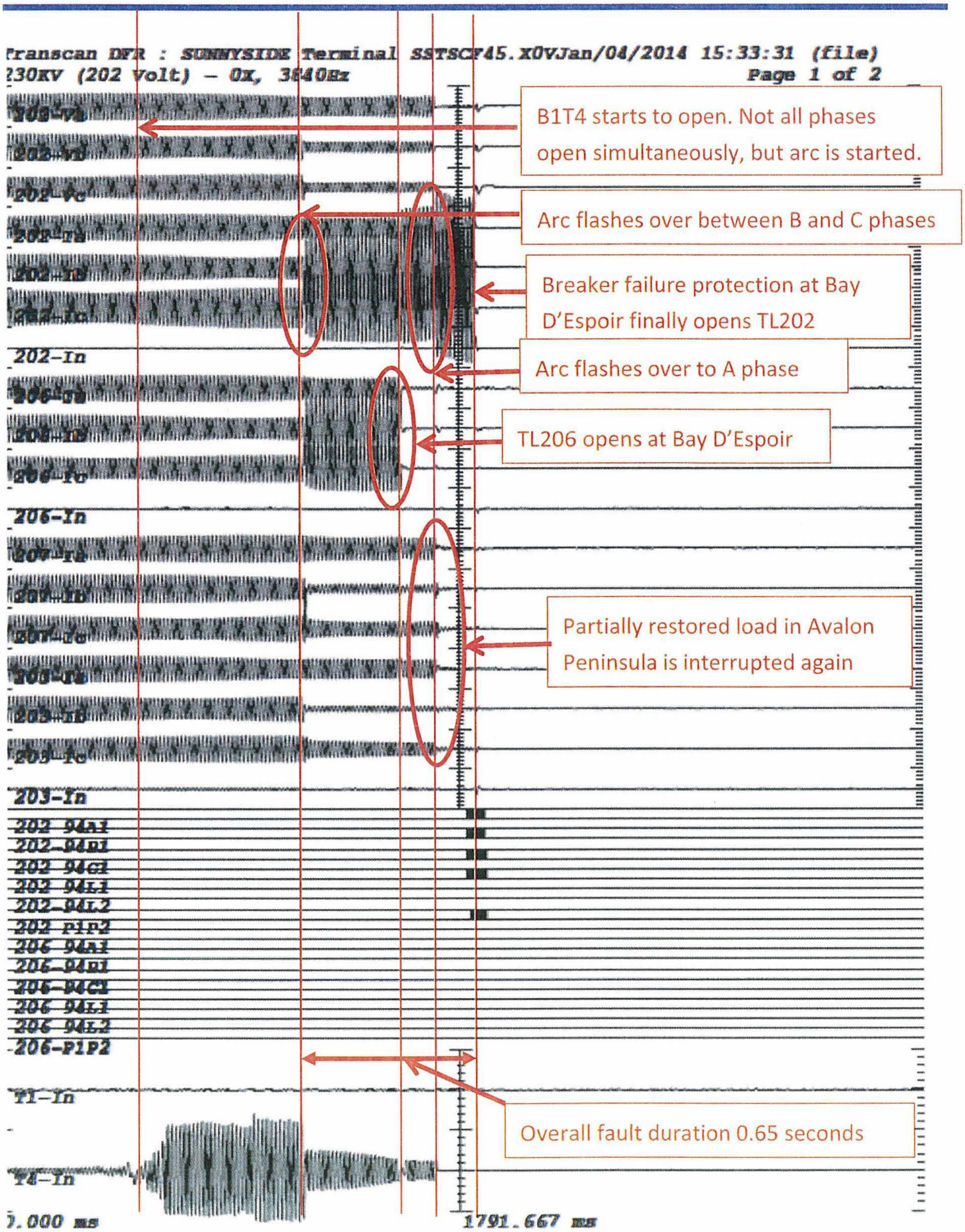
The increase in currents and depression in voltages on phases B and C can be seen. Also, the start of the phase BC zone 2 distance element can also be seen. These confirm the presence of a phase B to phase C short circuit at SSD B1 at this time.

The second attempt to load T4 at Sunnyside at 15:33 on 4th January 2014

At 15:33 on 4th January, a second attempt was made to re-energize the 138 kV bus at Sunnyside by closing breaker B3T4 to load T4. In this case the B1 bus protection did not operate, but similar to the 12:58 event, the T4 230 kV isolation disconnect switch B1T4 opened automatically under load. In this case the initial phase to phase fault evolved into a three phase fault. See Figure A1-4 for oscillographic capture of currents and voltages during this incident. The Sunnyside B1 bus protection which should have operated to clear this fault did not do so, and the fault was sustained for approximately 0.6 seconds. See Figure A1-5 for recorded currents and voltages at the Bay D'Espoir terminal of TL206 at the start of this fault.

Remote protection at the TL202 and TL206 terminals at Bay D'Espoir attempted to clear the fault by zone 2 delayed tripping after 0.3 seconds, but breakers at the TL202 terminal were slow to open and an additional delay was incurred until the breaker failure protection for both breakers timed out. The breaker failure protection eventually opened the two slow breakers plus additional breakers at Bay D'Espoir to shed additional generation and trip TL204. Tripping of TL202 and TL206 removed all remaining 230 kV supply to the Avalon Peninsula including St. John's load that had already been restored after the 9:05 incident and Come By Chance refinery.

TL206 tripped approximately 0.3 seconds after fault initiation (as expected for the zone 2 time delay). TL202 tripped approximately 0.35 seconds after TL206 due to the additional delay resulting from slow tripping, of both of its breakers, and waiting for breaker failure protection.



FigureA1-4 Third (15:33) Sunnyside fault – Digital Fault Recorder Record of Currents, Voltages and Events at Sunnyside Terminal Station

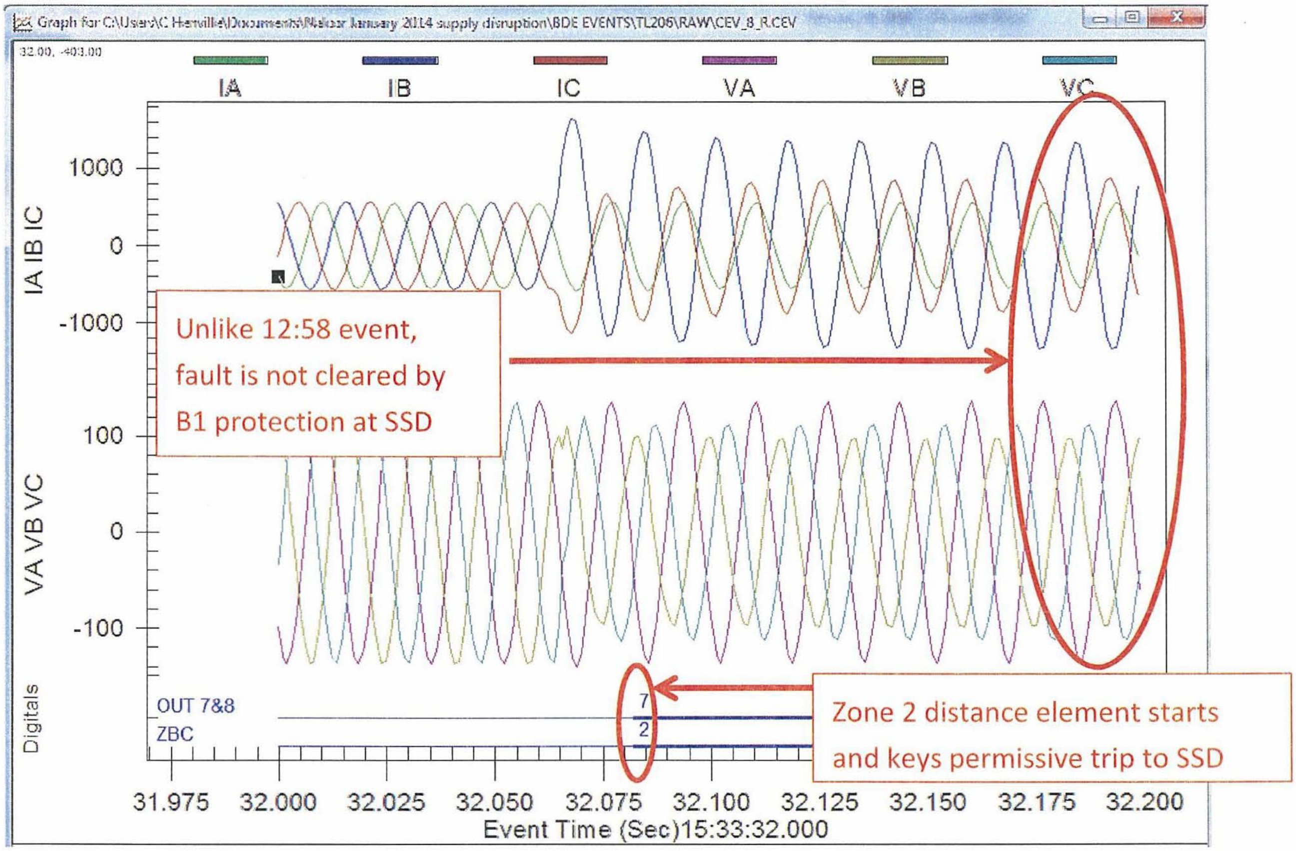
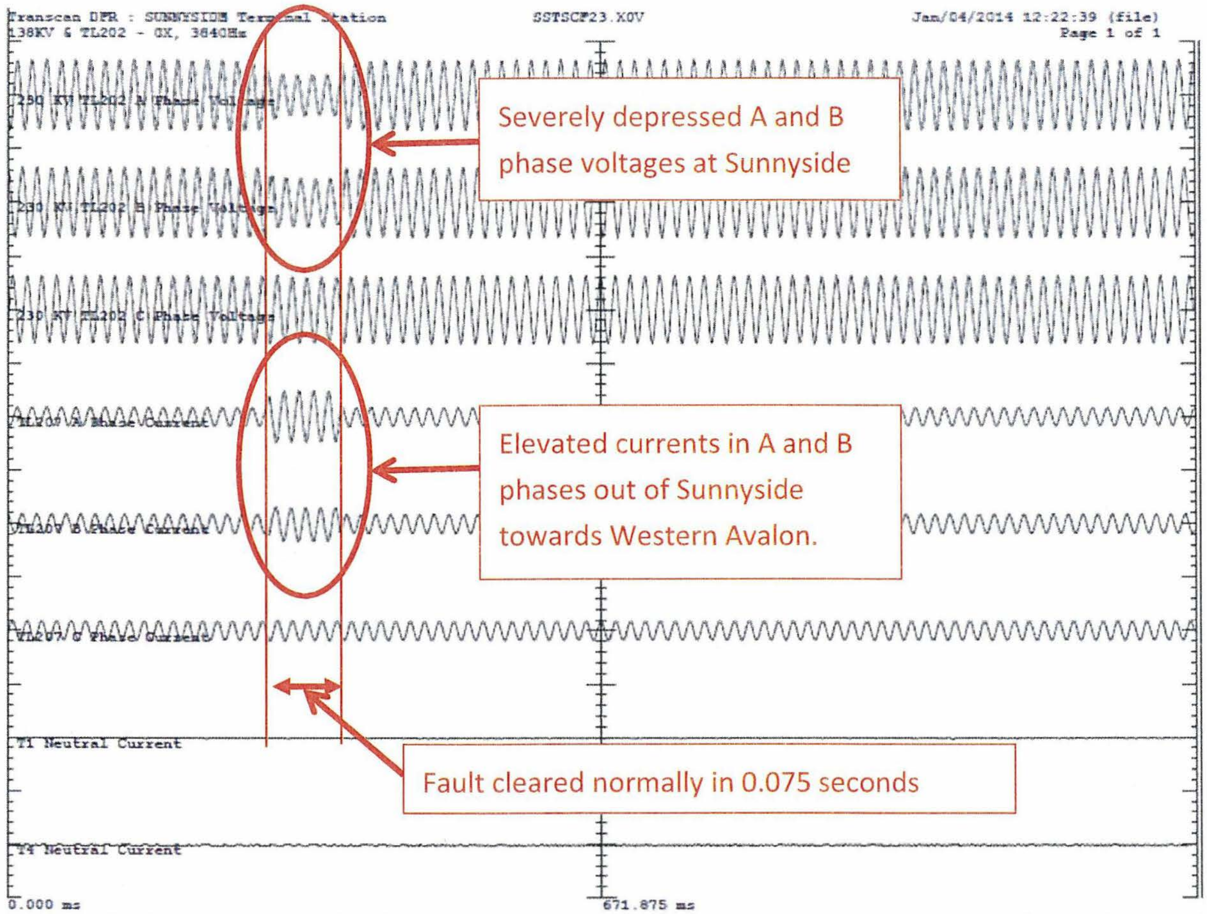


Figure A1-5 Third (15:33) Sunnyside fault – Digital Fault Recorder Record of Currents, and voltages at Bay D'Espoir Terminal of TL206

Western Avalon T5 Fault at 12:22 on 4th January 2014

The failure of Western Avalon T5 during the system restoration process had a negative impact on the restoration. Post mortem investigation of the T5 diverter switch showed evidence of arcing damage on two phases. No digital fault recorder (DFR) record of currents and voltages at Western Avalon was available for this event. The lack of a recording is attributed to a failed hard drive in the Western Avalon fault recorder. Although the recorder kept many records of events on 4th January, they were all stored in random access memory (RAM). The recorder is designed to transfer data from the RAM to a hard drive for storage and eventual retrieval. Records are retrieved by a master station at Hydro Place (once per day) and then archived on the Nalcor information systems network. In this case, with the hard drive failed, when multiple records were triggered on 4th January, the RAM filled up and stopped acquiring any more records until the data had been downloaded automatically to the master station at a much later time.

Records retrieved from DFRs at nearby stations (Sunnyside and Holyrood) show that the T5 fault was severe, between phase A and phase B, without ground being involved, and was cleared in less than 5 cycles, which is well within expectations for the protection system. See Figure A1-6 for currents and voltages at Sunnyside during the fault at Western Avalon.



<u>Figure A1-6 Western Avalon T5 fault (12:22) – Digital Fault Recorder Record of Currents, and voltages at Sunnyside</u>

5 KEY FINDINGS AND RECOMMENDATIONS

Transformer protection

For the two transformers that faulted, one at Sunnyside and one at Western Avalon, the transformer protection worked well. In the case of Sunnyside the initial fault was sensed in less than 30 milliseconds, and would have had very little impact on the system if all the breakers had opened within their rated clearing time to clear the fault. In the case of Western Avalon, the protection worked properly and the breakers worked properly so the fault was cleared in less than 80 milliseconds, which is well within the expected maximum time of 100 milliseconds.

It is noted that the existing transformer protection relays for the two transformers that failed are both electromechanical. Though they worked promptly for the two faults, they provided no more information about what happened than the targets (bright indicating flags) on their front. These targets simply indicate which device operated since the targets were last reset. They provide no information about the time when they operated. Modern computer based relays would have provided detailed sequence of events and recordings of currents and voltages during the fault to give a much richer set of information than was provided by the T1 and T4 neutral currents and lockout relay operating time as recorded by the station DFR and shown in Figure A1-1.

The key recommendation when observing the limited information available about these incidents is that the value of information obtained from modern computer based protection systems should be included in the cost benefits analysis undertaken when considering protection upgrading projects. For instance, in the case of Sunnyside T1 which will have to be replaced, it would seem an appropriate opportunity to also replace the existing transformer protection systems with modern relays at the same time to improve the information available for future events as well as to overcome the design limitations of the existing tripping and isolation logic.

Protection long term recommendation No. 1

Consider upgrading the T1 protection with modern digital protection when T1 is replaced.

Role of protection staff during emergencies

After the failed T1 had been isolated, the (still functional) circuit breakers B1L02 and B3T4 were able to be closed. At 12:58, B1L02 was closed and shortly after, B3T4 was closed. As soon as B3T4 was closed, B1T4 started to open, under load, and within a few seconds flashed over between phases B and C. B1L02 and B3T4 were immediately tripped by Bus B1 protection due to a short circuit on Bus B1 caused by the flashover at disconnect switch B1T4.

Since the T1 HV CT wires for the bus B1 protection had been damaged by the T1 fire, it was assumed that as soon as load current started to flow, the differential protection relay received incorrect information and operated the 86B1 lockout relay to de-energize B1 and T4. When this problem was assumed, emergency modifications to the wiring were made. A protection technologist who would have had experience with the process required to isolate CT wiring was not on site.

Subsequent post mortem analysis revealed that there actually had been a short circuit in the Bus B1 protection zone, and the B1 protection had in fact operated correctly for the 12:58 fault.

The fact that B1 protection failed to operate for a similar (to 12:58) fault at 15:33 confirms the probability that in addition to isolating the faulty CT wiring, the emergency modifications made the complete B1 bus protection inoperative. An inoperative B1 bus protection system contributed to the 15:33 event.

Protection long term recommendation No. 2

Consider including a protection technologist (with appropriate experience) where practical in the personnel who may respond to emergency events.

Transformer breaker failure protection and tripping and isolation logic at Sunnyside

The design of the transformer tripping and isolation scheme resulted in an arcing fault on disconnect switch B1T4 at Sunnyside during the first and second attempts to close B3T4 at that station. When B3T4 was closed at 12:58 and 15:44, the faulted transformer T1 had been isolated, but the lockout relay 86T1 had not been reset. This lockout relay is designed to provide a continuous trip signal to all circuit breakers to prevent them from closing until the transformer has been isolated. In the case of T1, the high voltage side was isolated by opening disconnect switch B1T1 shortly after the fire started. The low voltage side was isolated by circuit breaker B2T1 which had been opened automatically immediately during the T1 fault, and which had been kept open since. Failed circuit breaker B1L03 which also formed part of the tripping zone for T1 and T4 had been isolated by its disconnect switches shortly after the fire started.

T1 and T4 lockout relays are designed to trip all 5 breakers in the tripping zone shown in Figure A1-2, and maintain that tripping signal to the 230 kV breakers until after the faulted transformer has been isolated by its HV disconnect switch. Tripping of 138 kV breakers on the unfaulted transformer is also blocked if the faulted transformer has been isolated by its HV disconnect switch. However, the lockout relays initiate breaker failure protection **only** for 138 kV breakers in the tripping zone, not 230 kV breakers. The reason for not initiating breaker failure protections for the 230 kV breakers is not known, but is a key causal factor in the spread of the impact of the T1 fault beyond Sunnyside Terminal Station. The reason for initiating breaker failure protection through a different logic than initiating tripping is not clear. Newfoundland and Labrador Hydro do not have written guidelines as to the application or design of breaker failure protection systems.

By design of the tripping scheme, tripping of 230 kV breakers B1L02 and B1L03 is blocked by the B3T4 breaker failure protection through a non conventional application of the breaker failure protection relay retrip function. Non conventional application of the breaker failure protection relay retrip function (during design) was a key causal factor of the opening of disconnect switch B1T4 under load at 15:33 and its subsequent flashover.

Conventional use of the retrip function to trip the protected breaker without delay by the breaker failure protection would also have prevented this undesirable opening of the T4 disconnect switch under load.

Since the Bus B1 protection had been rendered inoperative by the previous emergency modifications, the bus protection was unable to initiate actions to clear the flashover resulting from undesirable automatic opening of the B1T4 switch under load. Disabling of the bus protection during emergency modifications was a key causal factor in persistence of the fault on B1T4.

The fact that two transformers were in the same tripping zone resulted in unusually complex tripping and isolation schemes. However, it is recognized that in substation design there has to be consideration given to the balance between the cost of primary equipment (such as breakers) and complexity of secondary equipment (such as protection).

Protection long term recommendation No. 3

Review breaker failure protection applications on all transformer protection designs at stations similar to Sunnyside to check whether all protection systems on both sides of the transformer initiate breaker failure protection systems for all breakers in the tripping zone. Modify where this does not happen. For instance it is clear that breaker failure protection for Sunnyside B1L02 and B1L03 should be modified. This is considered to be a long term recommendation due to the low probability of simultaneous multiple contingencies (i.e., transformer fault together with breaker failure)

Protection long term recommendation No. 4

Review breaker failure protection applications of all transformer protection designs at stations using the same breaker failure relay (Schweitzer Engineering Laboratories type SEL-501). This review is intended to check whether the breaker failure protection retrip function (if applied in the SEL-501) is being used in a similar non conventional application to that at Sunnyside. If it is, modify the scheme to prevent undesirable or unexpected response from the non conventional application.

Protection long term recommendation No. 5

Develop company specific guidelines as to the basic philosophies in the application and design of breaker failure protection systems for Newfoundland and Labrador Hydro.

Protection System Initiations of Breaker trip coils

Air blast breakers ABB type DCVF 245 MC6 have a second trip coil that is not intended to trip the breaker within its rated fault interruption time. This trip coil is remote from the operating mechanism of the breaker and causes a variable trip time that may in some cases even be longer than the breaker failure timer setting of approximately 0.3 seconds.

Consistent with common industry practice, where two trip coils are provided for breakers, Newfoundland and Labrador Hydro practice is to connect protection system No. 1 to trip coil No. 1 and protection system No. 2 to trip coil No. 2. The two tripping paths are normally kept separate and not cross connected between trip coils. Modern specifications of transmission class breakers require two independent trip coils, either of which will deliver rated breaker performance.

If the breaker is a type for which Trip coil No. 2 may not produce rated performance (such as ABB type DCVF), this seriously affects the redundancy of functionally equivalent redundant protection systems that are expected for HV transmission systems. Expected performance of functionally equivalent protection systems is to provide full backup if one of the protection systems fails. In the case of trip coil No.2 not providing rated performance of the breaker, both protection systems P1 and P2 must be connected to trip the same trip coil. One or the other may also trip the No. 2 trip coil if desired, but P2 must not trip **only** the low performing No. 2 trip coil.

The reason for the seriousness of this finding is that the transmission system is planned to have severe faults cleared in six cycles or less. Functionally equivalent protection systems are applied to ensure that if one protection system fails, the other will still ensure the transmission system meets planned performance in the case of a short circuit. If one of the protections is connected to a poorly performing trip coil, and the other protection fails to operate, one or both of the following undesirable consequence will result.

a) The fault clearing time will be slower than the maximum time for which the transmission system has been planned.
b) The breaker failure protection may operate and clear a larger zone than necessary.

Protection high priority recommendation No. H1

Check protection connections to all 230 kV breakers ABB type DCVF 245 MC6 in which trip coil No. 2 is not intended to produce the rated interrupting speed performance of the breaker. In cases where protection P2 is connected to a slow trip coil, add an additional P2 trip contact to the Trip Coil 1 initiation. If additional spare contacts are not available, re-direct the P2 tripping from trip coil No. 2 to trip coil No. 1. It is recommended that this survey be initiated immediately, and modifications completed where necessary within one year.

Protection system settings

The following comments are not related to the 4th January disturbance. However, they are important for continued reliable operation of the transmission system. It was found during the 15:33 slow fault clearing event that the TL202 and TL206 zone 2 protection systems operated in 0.3 seconds. An earlier study of these protection systems had revealed that a setting of 0.6 seconds was required to coordinate with the communications independent protection on the Sunnyside terminal of TL207. With a setting of 0.3 seconds there is a risk that if the teleprotection systems fail during or before a fault on TL207 the Bay D'Espoir TL202 and TL206 protections may operate simultaneously with the Sunnyside TL207 and cause a serious disruption of supply to the Avalon Peninsula. This adjustment of zone 2 delays at Bay D'Espoir terminals of TL202 and TL206 were included in a series of recommendations regarding settings changes and other modifications from earlier studies of 230kV protection systems East of Bay D'Espoir. It seems that not all of the recommendations from these earlier studies have been implemented. Some of the recommendations were awaiting protection system replacement projects, or other projects. However it is possible that some recommendations may be best implemented independently of other projects, and in view of their importance, should be implemented without undue delay.

Protection high priority recommendation No. H2

Adjust the time delay on the Bay D'Espoir TL202 and TL206 zone 2 elements from 0.3 seconds to 0.6 seconds. Note that previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances. This adjustment has been implemented.

Protection high priority recommendation No. H3

Review the recommendations in the previous two reviews of protection systems for transmission lines protecting the 230 kV lines in the Avalon Peninsula area, and determine if there are recommendations that can be implemented easily and independently of other projects. Note that previous implementation of this recommendation would not have affected the 4th January disturbances, but could be important to reduce the probability of future major disturbances. The review should be completed and an action plan developed by 31st December 2014.

6 RECOMMENDATIONS STATUS

High priority Recommendations

H 1. Check and if necessary, modify protection connections to all ABB type DCVF 245 MC6 breakers. It is recommended that this recommendation be completed by July 30th, 2014

H 2. Adjust the zone 2 time delays on Bay D'Espoir TL202 and 206 to 0.6 seconds. This recommendation has been completed.

H 3. Review status of implementation of recommendations in previous 230 kV transmission line protection studies and develop an action plan to implement as many of the recommendations as practical. It is recommended that the action plan be developed by December 31st, 2014

Longer term recommendations

LT 1. Consider replacing Sunnyside T1 protection at the same time as T1 is replaced. The decision should be made to allow sufficient time to be in service with the replacement T1.

LT 2. Consider including a protection technician in emergency response personnel. This recommendation should be implemented in coordination with other emergency response plans.

LT 3. Review applications of breaker failure protection to ensure all transformer protection systems initiate breaker failure protection for breakers tripped by the transformer protection. Modify where necessary. This review should be completed within one year and any necessary modifications should be completed within two years.

LT 4. Review breaker failure protection applications of all transformer protection designs at stations using the Schweitzer Engineering Laboratories type SEL-501 relay. Modify the scheme if necessary. This review should be completed within one year and any necessary modifications should be completed in within two years. This recommendation would likely be well coordinated with Recommendation LT3 above.

LT 5. Develop company specific guidelines as to the basic philosophies in the application and design of breaker failure protection systems. This recommendation should be completed before protection design work for the Muskrat Falls interconnection project starts.

APPENDIX 1

Proposal for Newfoundland and Labrador Hydro.

Review of Protection Operations on 4 and 5 January 2014

Scope of work:

Review and comment on the most critical or unexplained protection operations on 4 and 5 January 2014.

Background.

During the Newfoundland Island system disturbances on 4th and 5th January 2014, the transmission lines and system transformers were operating in many unusual conditions and with unusual system stress. There were some transformer faults and some slow or failed breakers. Under these conditions, there were many protection operations. Many of the operations were correct and easily explained, however in some cases there were protection operations that have not yet been resolved as of 24th January. It is proposed to assist Newfoundland and Labrador Hydro with analysis of the most critical or unexplained protection operations with a view to fully understanding the relationship of protection operations to the system conditions during the disturbances.

In the case of such extreme system stress, it is difficult for protection systems to determine whether conditions should be allowed to persist, or whether automatic operation is desirable to break up the system and allow restoration in an orderly manner. The proposed services will assist in identifying possible need (if any) for revision in protection practices and/or settings in general or specific cases.

The deliverables are:

1. Assistance with understanding the impact of protection operations on the system performance during the disturbances. This understanding will help determine whether the operations were correct under the circumstances and if correct, whether they were desirable or not under the circumstances.
2. If necessary, recommendations for immediate or longer term modifications to existing protection applications, systems or settings.
3. A verbal report and contribution to the TapRoot analysis meeting on 10th and 11th February 2014.
4. An optional written report to be delivered at a mutually agreeable date in March.

Proposed Approach (work items).

1. Engage in telephone discussions with appropriate NL Hydro engineers during the weeks of 27 January and 3 February.
2. Review preliminary TapRoot Analysis report when available.
3. Identify most critical and/or unexplained protection operations for analysis.
4. Obtain detailed (high resolution) sequence of fault recorder records and protection relay records for operations of highest importance. Obtain drawings and other relevant information by telephone and/or email.
5. Determine preliminary findings.
6. Travel to St. Johns on 6th February for face to face discussion with protection engineers and other staff on 7th February (possibly also 8th or 9th February) before the TapRooT meetings on 10th and 11th February.
7. Participate in TapRooT meeting in St. John's on 10th and 11th February. Provide verbal input.
8. **Optional** – prepare written report of findings if necessary.