Protection of EHV Transmission Lines With Series Compensation: BC Hydro's Lessons Learned

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***Abstract*—The BC Hydro transmission network includes 33 wholly owned 500 kV circuits and three 500 kV interconnections with other utilities. Eleven of these lines include series compensation, and many were upgraded to provide single-pole tripping (SPT) capability to improve power transfer capability and stability margins. To reduce construction costs, the majority of these lines are not shielded, which increases the probability of low-grade, single-line-to-ground faults due to high tower grounding resistance. Over the years, BC Hydro has developed strict performance specifications for both sensitivity and speed of protection systems based upon fault location and fault type. We also have a well-developed process for model power system testing of protection systems to verify conformance to these performance specifications.**

In this paper, we discuss the lessons learned in applying protection systems and optimizing protection sensitivity and speed for these challenging applications. We also discuss a number of problems and challenges discovered in real-world experiences and during simulation, many of which are associated with discerning the difference between normal system unbalances and/or unbalances caused by operation of series capacitor protection and resistive ground faults up to 300 Ω. The paper includes a discussion of the impact of reclosing control and automatic reinsertion control of series capacitors on protection systems. The paper also includes a number of digital fault recorder (DFR) records for actual power system faults on series-compensated lines.

I. Introduction

BC Hydro's 500 kV transmission system of 33 wholly owned lines and three lines interconnecting with other utilities presents some unique protection challenges. These lines typically traverse mountainous terrain with high soil resistivity in the hundreds of ohms. This, coupled with the prohibitive expense of transmission tower counterpoise and shield wires, requires that the applied protection systems detect ground faults with a minimum targeted resistive coverage of 300 Ω over the entire circuit.

The requirement for such sensitive protection is challenged by steady-state unbalances on the network. These unbalances can manifest in a number of ways that may occur singly or in combination due to:

- Unequal transmission line transpositions (both in the protected line and adjacent lines)
- Unequal extra-high-voltage (EHV) transmission cable lengths per phase
- Transmission line single-pole open (SPO) conditions
- Series capacitor single-pole bypass/insertion (legitimate and spurious)

Series capacitors are applied on many of BC Hydro's 500 kV transmission lines and create challenging line protection issues, such as:

- Zone 1 overreach
- Voltage inversion
- Current inversion

These issues and others are covered elsewhere in literature [1][2][3]. This paper focuses on capacitor switching issues during line faults and routine line energization/de-energization. In the paper, we briefly review BC Hydro 500 kV line protection requirements and protection systems. Then it discusses a number of problems and challenges discovered on the series-compensated 500 kV lines. These include undesired operation of fault direction and detection elements, influences of unbalance currents caused by single-pole switching of the series capacitor and/or line tripping and autoreclosing, subsynchronous resonance problems, and series capacitor switching. Finally, we introduce the transient model power system testing procedures used in validating these line protection systems.

II. 500 kV Line Characteristics

A previous paper presents the protection characteristics of BC Hydro 500 kV lines and describes the protection functions, some of which are commonly applied to almost all 500 kV lines [3]. These common protection requirements define the trip and reclose operation modes, the protection system operation speed, and the sensitivity for various kinds of faults on the 500 kV lines.

For all BC Hydro 500 kV transmission lines, the line protection consists of identical primary and standby systems (except for minor settings differences between systems). This protection architecture is also commonly called Main 1 and Main 2, or dual primary systems, in literature. Use of identical primary and standby protection systems results in increased security and lower costs. Dependability concerns due to common-mode principle failure are addressed by extensive model power system tests for each unique application [4].

Some common protection requirements are summarized in the following paragraphs.

A. Trip/Reclose Modes

Many of the applications require single-pole tripping (SPT) and reclosing (SPR) for single-line-to-ground (SLG) faults and three-pole tripping (3PT) and reclose (3PR) for multiphase faults. The application of SPT provides the five trip/reclose modes listed in Table I.

TABLE I
SPT RECLOSE MODES

Mode	Fault Type	Trip Mode	Reclose Mode
1	Any Fault	3PT	No Reclose
2	SLG Fault	3PT	3PR
	Multiphase Faults	3PT	No Reclose
3	Any Fault	3PT	3PR
4	SLG Fault	SPT	SPR
	Multiphase Faults	3PT	No Reclose
5	SLG Fault	SPT	SPR
	Multiphase Faults	3PT	3PR

The protection systems are normally operated in Mode 5, but the other modes may be applicable in certain circumstances. Furthermore, 3PT is initiated and automatic reclose is blocked if the trip or transfer trip is initiated from the following protection functions:

- Breaker failure protection
- Pole disagreement protection
- System overvoltage protection
- Time-delayed channel independent ground overcurrent protection or phase distance protection
- Switch on to fault (SOTF)
- Line open-end keying
- Other special protection functions for some lines

B. Speed/Sensitivity

The mandatory requirements for the relay scheme's maximum operating times, including communications time (if applicable), are given in Table II.

TABLE II
SPEED AND SENSITIVITY SPECIFICATIONS

Fault Type	Ground Resistance	Speed	Fault Location
Multiphase	N/A	1 Cycle	< 24% From Line Terminal
Multiphase	N/A	2 Cycles	> 25% From Line Terminal
SLG	0–50 Ω	2 Cycles	0–100% Line
SLG	50–100 Ω	4–5 Cycles	0–100% Line
SLG	100–200 Ω	7 Cycles	0–100% Line
SLG	200–300 Ω	20 Cycles	0–100% Line

The speed and sensitivity requirements are also applicable when the system is weak or open at one terminal.

Note that BC Hydro has unusually stringent requirements for sensitivity due to the lack of shield wires on the transmission circuits and high tower footing resistances. When SPT is applied, the requirement for correct phase selection and tripping applies to SLG faults with at least 300 Ω and desirably more.

The permissive overreaching transfer trip (POTT) scheme with echo logic is used on all 500 kV lines. To detect high-impedance SLG faults, residual and negative-sequence directional overcurrent elements are used to initiate the communications-assisted trip. Phase-segregated direct transfer trip (DTT) is also applied to improve sensitivity and minimize the operating time for some SLG faults. See Appendix B, Section C for more details on the advantages of using DTT to supplement the pilot logic.

III. LINE CHARACTERISTIC-RELATED CHALLENGES

A. Importance Correct Directional Settings

1) Directional Element Operating Principle

The directional elements applied on the BC Hydro system are based on negative-sequence impedance and offer the advantage of immunity to zero-sequence mutual effects. The directional elements also offer settings latitude in the presence of strong positive-sequence voltage sources where the expected fault negative-sequence voltage (V2) can be quite low, and steady errors may contribute to an incorrect directional decision [5]. Fault direction is determined by the magnitude and sign of the calculated negative-sequence impedance [5][6]. Fig. 1 illustrates the typical settings for the forward (Z2F) and reverse (Z2R) negative-sequence directional settings for a line terminal in the negative-sequence impedance plane.

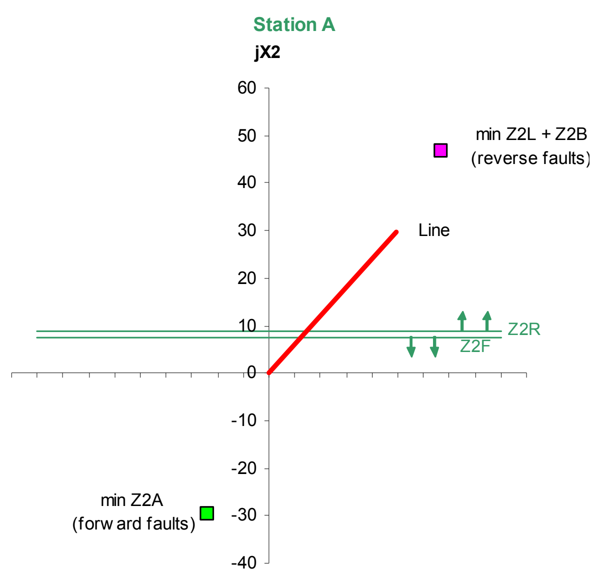

Fig. 1. Typical directional element settings

There are two approaches to setting the element:

- Set on the basis of half the line Z2 impedance.
- Set considering the minimum Z2 source for a forward and reverse fault, as well as the line Z2 and setting the elements to half of this total impedance.

Refer to Appendix A for a discussion of the pros and cons of the two methods.

As shown in Fig. 1, BC Hydro chooses the latter approach, which offers the advantage of reducing V2 errors while maintaining maximum sensitivity. The former approach, recommended by the manufacturer and based only on the transmission line data, has the major advantage of being independent of system changes (i.e., magnitude of the Z2 source impedance at each bus).

2) *Misapplied Z2F and Z2R Settings*

The manufacturer's recommendation is to set these elements on the basis of the compensated line impedance [7]. The following example shows the consequences of misapplication where these elements were set based on the uncompensated line impedance.

Fig. 2 shows a simplified representation of the power system with the line of interest identified by Terminals A and B. Note that the representation from DMR to LDR is greatly simplified, as it involves many transmission lines and several sets of voltage transformations.

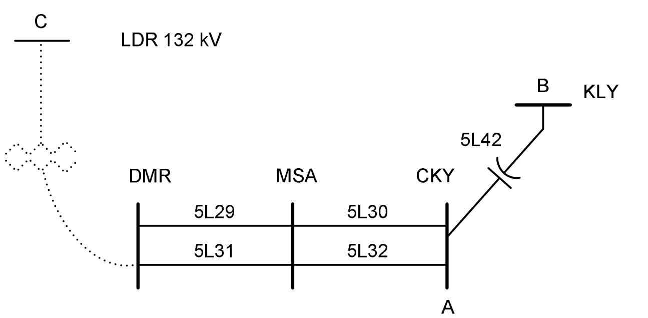

Fig. 2. Simplified system diagram

Fig. 3 shows the originally applied Z2F and Z2R settings in the Z2 plane for Terminal A. Event records indicate the external fault is at location C.

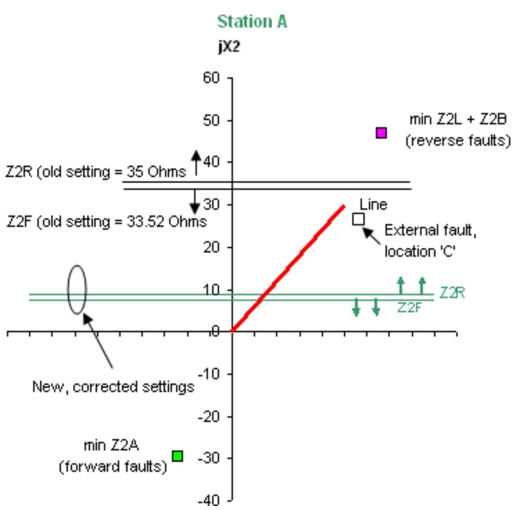

Fig. 3. Terminal A sees forward for external fault

Notice with the incorrectly applied Z2F setting that the fault impedance plots as positive, indicating that the fault is reverse, but it is not positive enough to cross the threshold, which results in a forward direction decision. Terminal A keys "permissive," thinking the fault is in the forward direction. Terminal B correctly sees the fault as forward. Both terminals trip, because they see the fault as forward and receive permissive.

The circled settings identify the revised settings, showing that the scheme would have been secure with the correct settings.

B. *Natural System Unbalances*

A further examination of the misapplication in the previous section yields some surprisingly different results when a fault study program is used to calculate the fault location C for the fault at LDR under the given system conditions. Notice that the negative-sequence impedance calculated by the fault study program is significantly beyond even the erroneous reverse threshold. If the relay had measured this impedance, it would have properly identified the fault as reverse, and no tripping of the line would have occurred. Fig. 4 shows the fault location calculated by the fault study program in the Z2 plane for the fault at location C.

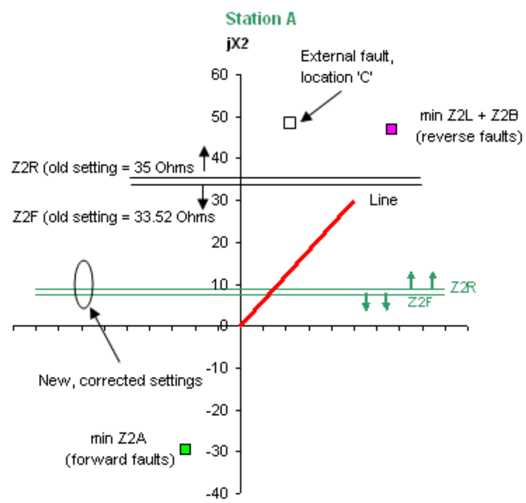

Fig. 4. External fault based on fault study

One major simplification when using symmetrical components is that the power system under normal conditions is perfectly balanced. Because the fault study program models the system using symmetrical component quantities, the results cannot predict the effect of normal unbalances in the power system.

Examination of the prefault data from the relay event record indicates a standing negative-sequence unbalance current is flowing on the line. Furthermore, this prefault 3I2 current flow is nearly in phase with the 3I2 current caused by the remote fault. The steady-state unbalance and the fault unbalance currents are additive such that the negative-sequence impedance measured by the relay during the fault is lower than expected and below the erroneous threshold.

Most of the BC Hydro EHV transmission system is well transposed, so steady-state unbalances on the system are minimal and can be ignored in setting these sensitive directional elements. This particular line has two characteristics contributing to greater than normal unbalance. Firstly, the line was approximately 176 miles long with three transposed sections of around 59 miles each. The line was shortened by 54 miles when a new switching station was installed about five miles into the third transposition section. Secondly, the new switching station terminates a branch of the EHV grid that includes two submarine cable lines connecting the mainland to Vancouver Island. Due to physical separation requirements of the phase conductors on the ocean floor, the outer phases are longer than the inner phases, resulting in significantly different charging currents between the phases.

Unbalance quantities are useful in protective relaying, because they represent fault quantities and are not adulterated by balanced load quantities. To discern fault unbalance quantities from normal unbalance quantities inherent in real power systems, ratios a2 = I2/I1 and a0 = I0/I1 are used [8]. If the ratio of unbalanced to balanced current is above these ratios, we can safely use the unbalance quantities to make a directional decision. Of course, setting these ratio thresholds too high can reduce sensitivity to high-impedance ground faults during high load flow conditions, so a compromise must be made. In this case, increasing the a2 ratio threshold and correcting the Z2F and Z2R settings should improve the security of the protection systems.

IV. Autoreclosing-Related Challenges

A. Single-Pole Line Switching

1) Disabling Sensitive Ground Elements

It is well-known that a series unbalance on a transmission circuit, such as a single-pole open, will appear as an internal fault to permissive-based line protection [9]. With the requirement of having sensitive tripping for high resistive ground faults, it is necessary to temporarily disable certain elements during the open-pole period of the SPT and reclose cycle. Fig. 5 shows a simplified logic diagram illustrating how sensitive ground elements 67Q2T and 67G2T are disabled during the open-pole period.

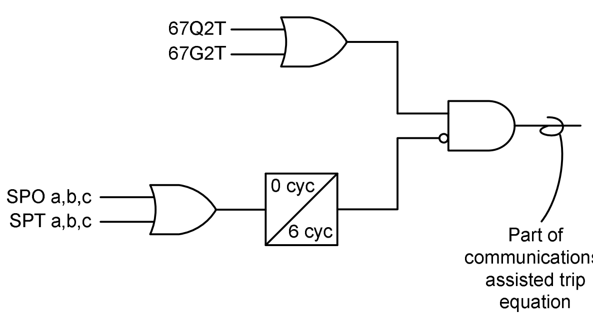

Fig. 5. Disable elements during open pole

In Fig. 5, the SPO label refers to a single-pole-open condition on any phase. Similarly, SPT refers to a single-pole trip on any phase. Note also that the time delay of 6 cycles, which extends the SPO condition for 6 cycles, makes the ground fault protection quite secure for an uncompensated transmission line.

Disabling sensitive elements in the permissive keying equation is implemented differently than in Fig. 5. Fig. 6 shows that sensitive keying variables 67Q2 and 67G2 are torque-controlled by SPO or SPT conditions to avoid spurious keying during a line SPO condition.

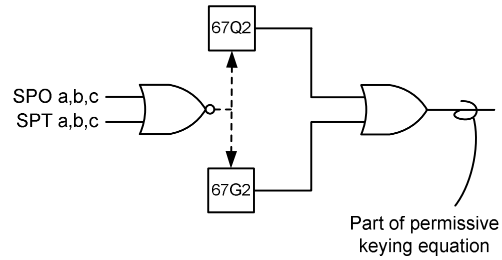

Fig. 6. Disable sensitive permissive elements

2) Disabling Ground Time-Overcurrent Elements

A ground time-overcurrent element (51T1) is applied to provide sensitive backup ground fault protection in the event of a communications failure. This protection can also provide ground fault protection for the open-pole period during evolving ground faults.

During the BC Hydro 500 kV protection replacement program, ground time-overcurrent settings were kept the same throughout the 500 kV network to avoid a system-wide ground overcurrent coordination study. This had negative consequences on some circuits.

During an SPO condition on some circuits, the 51T1 element would operate on the load-induced ground current during the SPO period. Raising the pickup setting or increasing the time dial meant a possible recoordination study. The solution was to torque-control the offending element by an SPO or SPT condition. To replace any functionality lost for the 51T1 element during the open-pole period, a second, higher set element without torque control was applied. This is depicted in the logic diagram in Fig. 7, with example settings as illustrated.

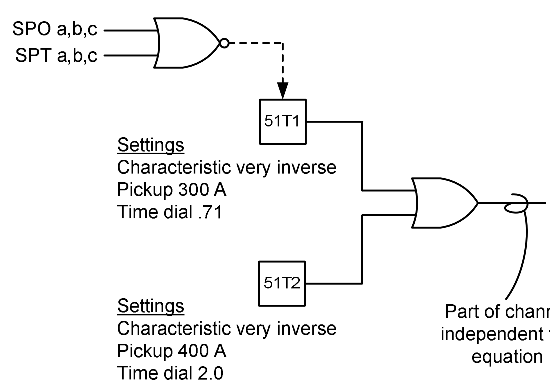

Fig. 7. Open-pole 51T1 and 51T2 application

Notice that the logic in Fig. 7 is similar to the logic shown in Fig. 6 for disabling sensitive keying elements during the open-pole period.

B. Lead/Follow Single-Pole Reclosing

Historically, the BC Hydro system has not had a lead/follow terminal relationship for automatic single-pole reclosing. For system planning reasons, BC Hydro has recently been implementing lead/follow SPR. For severe SLG faults, the planners felt it was better to test the line at only one terminal, with the follow terminal reclosing on restoration of line-side voltage on the open pole to indicate that the line was no longer faulted.

With lead/follow terminal logic, the lead terminal will reclose first and possibly reenable its sensitive unbalance elements while the line is still SPO, because the follow terminal has not yet reclosed. These sensitive unbalance elements may then misoperate before the follow terminal recloses. Recall Fig. 5, which shows the logic at the local terminal to block sensitive ground elements. Solutions to this problem include:

- Blocking sensitive ground elements by remote SPO indication (in addition to local SPO indication).
- Adjusting single-pole reclose open interval times.
- Increasing the SPO dropout timer that reenables sensitive unbalance elements after SPO (see Fig. 5).
- Optimizing the follow reclose supervision logic by using "fast" elements. Note that programmable logic elements with a longer processing interval than the protection logic were originally used to make up this logic.

The last alternative was chosen and found to be satisfactory.

V. Series Capacitor Switching

A. Series Capacitor Switching Specification

BC Hydro's switching specification for series capacitors is somewhat unique compared to other applications in the world and has evolved since the first series capacitor station was installed on the BC Hydro system in the 1960s.

Unlike other applications where series capacitors are viewed as part of the line and not switched unless there has been a capacitor bank fault (or applied metal oxide varistor [MOV] protection has operated), BC Hydro capacitors are switched (inserted when the transmission line is reclosed) and bypassed when the transmission line is tripped. The rationale for such operation is described elsewhere in literature [2].

Further, for SPT and reclosing applications, only the affected phase of the capacitor bank is bypassed and inserted. This assures maximum power transfer is maintained on the remaining two phases that have those phases of the capacitor bank in service. This can result in the condition that, immediately following an SPT/SPR cycle, the line is unbalanced until the series capacitor on the affected phase is reinserted.

The basic capacitor bank duty cycle requirements for switching include:

- When the line (or individual phase) is de-energized, the bank will automatically bypass all three phases (or an individual phase) within 6 cycles of the last line terminal opening.
- The bank will remain bypassed until the line (or affected phase) is closed in at both ends as indicated by the restoration of load current and the presence of phase-to-neutral voltage at the capacitor bank. The bank will automatically insert within 10 cycles after the last line terminal is closed.

Besides designing the protection system to accommodate the above two switching requirements, there is an additional requirement related to an event some years ago when a spurious single-phase bypass and insertion of the capacitor bank occurred. There were no system faults at the time of the disturbance. In the presence of relatively high load flow, the series unbalance appeared as an internal fault to the line protection and caused an undesirable trip of the line. Digital fault recorder (DFR) records for the event indicate that the single-phase-bypass period was around 15 cycles.

Such operating conditions can impose onerous requirements on the line ground fault protection. This is particularly the case where there is a requirement to detect ground faults in the hundreds of ohms and where it is necessary to selectively trip only the faulted phase and reclose the circuit.

B. Setting Sensitive Ground Elements

Section IV describes the applicable remedies for a transmission line switched single pole without a series capacitor.

For a transmission line with series capacitors, longer time delays are required to accommodate single-pole capacitor bank switching. For Fig. 5, the blocking time delay of 6 cycles has to be extended to 12 cycles. This timing was confirmed by actual simulations of the transmission line and the associated series capacitor at the manufacturer's test facility.

With modern series capacitor installations and the availability of digital communications, it is possible to provide an indication of series capacitor single-phase switching conditions and communicate this back to the line terminals. The appropriate received signals can directly block sensitive elements in the line protection, as shown in Fig. 8.

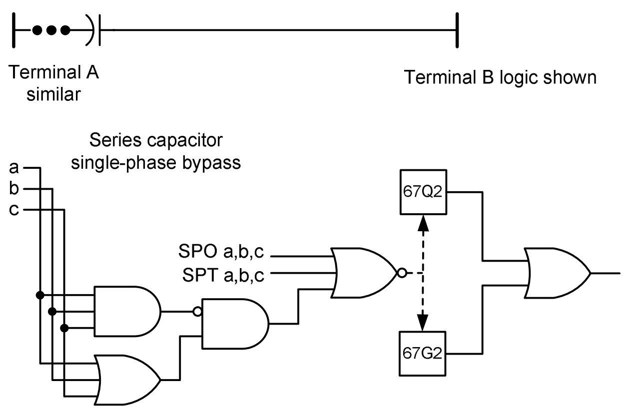

Fig. 8. Series capacitor bypass logic

C. Spurious/Undesired Capacitor Bank Switching

As described in Section V, Subsection A, it is desirable for the line protection to be secure during a spurious single-phase bypass and insertion operation of the series capacitor bank. Fig. 9 shows the protection logic that has a time delay of 17 cycles for some of the sensitive protection logic. Notice that the 17-cycle delay provides some margin over the 15-cycle spurious bypass condition that was observed from field records, yet this time delay is less than the 20-cycle resistive ground fault specification for ground faults in the region of 200 to 300 Ω referred to in Table II.

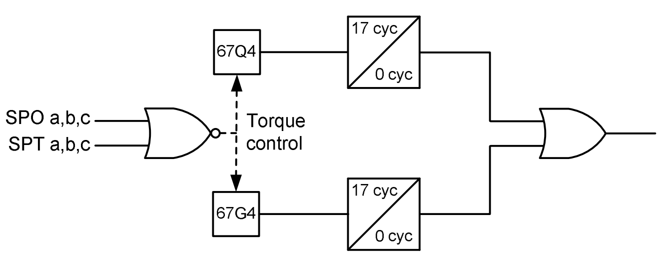

Fig. 9. Sensitive logic with long time delay

VI. Subsynchronous Resonance-Related Challenges

Fig. 10 shows two major transmission switching stations within the BC Hydro system, WSN and KLY. The three 500 kV lines connecting these stations are about 50 percent series compensated at roughly the midpoint. Power flows from the northern station (WSN) to the southern station (KLY) on these lines. This section describes a major disruption in this part of the system, where line protection misoperation due to subsynchronous resonance-induced transients was one of the significant contributing factors.

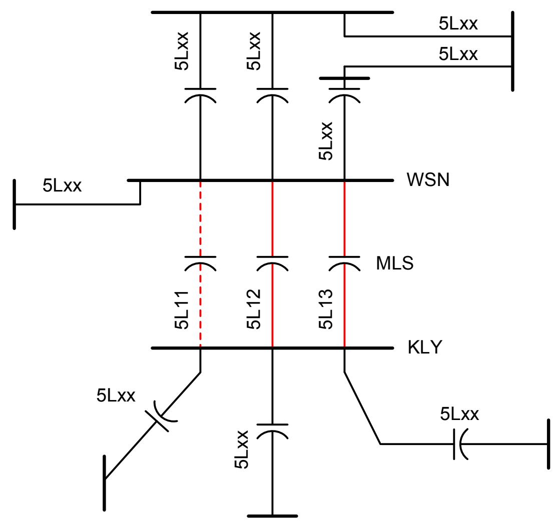

Fig. 10. 500 kV interconnection between WSN and KLY

All three lines are equipped with POTT. Besides overreaching phase distance elements, negative-sequence fault detectors are used in the permissive scheme to meet the ground fault sensitivity criterion, as discussed in Section II. Before this disruption, one 500 kV circuit (5L11) was out of service, which is shown as a dotted line.

The disturbance was initiated by an operator error, opening the 5L12 line disconnect switch under load at WSN, which led to a B-C fault close to that station. The 5L12 protection correctly tripped and isolated the fault. Before the reclose attempt, 5L13 tripped undesirably about 8 cycles after 5L12 tripped and separated the northern and southern systems, causing major disruption. Fig. 11 shows waveforms of three-phase currents from the two lines, 5L12 and 5L13, and the 500 kV bus voltage at WSN recorded by a disturbance recorder. The subharmonic oscillations in the B- and C-phase current waveforms after the parallel line opens are significant. The A-phase current is relatively undisturbed.

Fig. 12 shows disturbance records from the 5L13 relay at WSN. Unfortunately, no relay record or DFR record was recorded at the KLY terminal, so analysis had to be performed on information from only one terminal. Initially, the reverse trip block (Z3RB) was asserted for the fault on the adjacent line. After the fault on the adjacent line cleared, forward-looking negative-sequence fault detectors picked up at both terminals. Pickup of the remote forward fault detector is illustrated by the permissive trip received on IN4 and locally by 67Q2 and 67Q2T. The forward fault detectors remained asserted until shortly after the current reversal guard logic, Z3RB timer, dropped out, 5.5 cycles after the fault was cleared on the adjacent line. At that point, the forward pilot tripping element, coupled with permissive from the remote terminal, allowed a POTT trip.

Analysis of the recordings indicates that a significant resonant current flow with a frequency of around 38 Hz was excited between the B- and C-phase elements of the power system by the initial fault. When the faulted line opened, all of this resonant current flowed through the remaining line.

The digital filters attenuate but do not reject these nonharmonic frequency components. It is interesting to observe that the sequence components in this nonharmonic current flow consist of only positive- and negative-sequence components, consistent with a phase-to-phase unbalance.

One way to look at this is to consider that the 60 Hz system was in a relatively balanced state, and the Z2 measurement approaches infinity. However, the superimposed 38 Hz system looked like it was in an SPO condition on A-phase, since no 38 Hz current was flowing on A-phase. Further, as stated earlier, the negative-sequence impedance-based directional elements at both ends of the line will assert forward for an SPO condition. Even though the 38 Hz negative-sequence current flow was attenuated by the filters, its magnitude was great enough to assert the fault detectors and allow a trip.

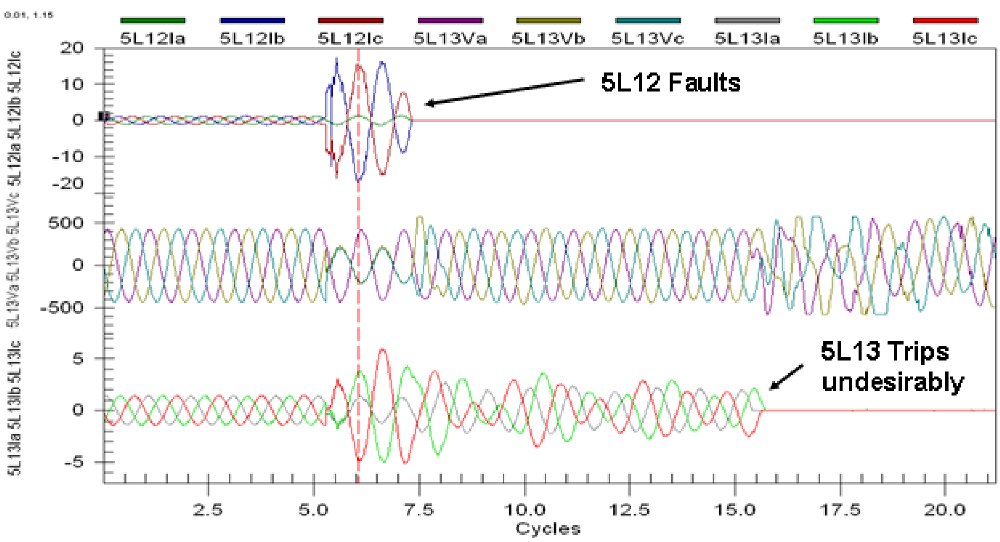

Fig. 11. Disturbance records of line current and bus voltage during fault

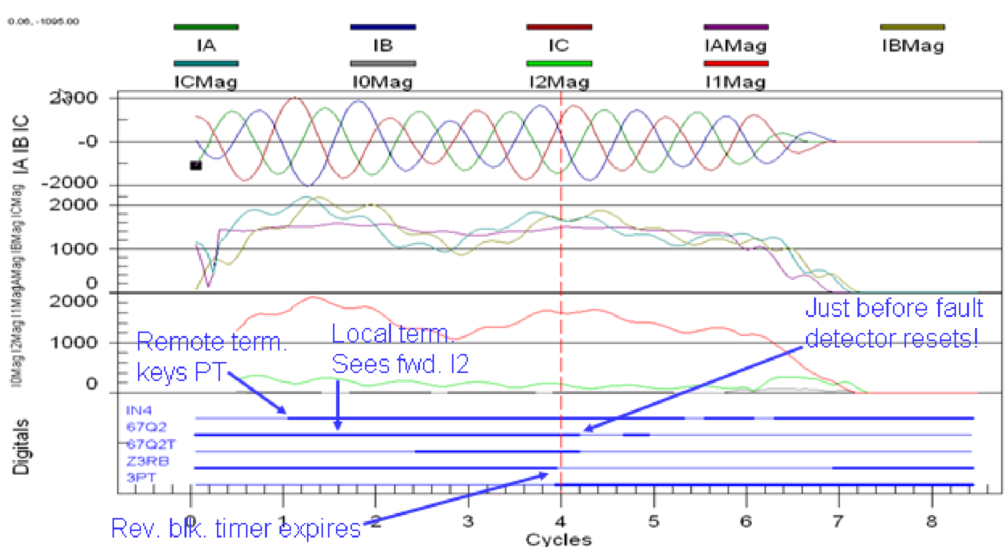

Fig. 12. 5L13 relay at WSN during misoperation

Fig. 13 shows a plot of the negative-sequence impedance measured by the relay at WSN during the time between the 5L12 and 5L13 openings. The X axis of the plot is in cycles. This is a plot of the same type of information contained in Figs. 1, 3, and 4. However, the plots in Figs. 1, 3, and 4 are static plots on an RX diagram, and the Fig. 13 plot contains the magnitude of the Z2 impedance along with the Z2F and Z2R thresholds, with respect to time. As previously discussed, the measured impedance will be positive for a reverse unbalance and negative for a forward unbalance.

Notice that the impedance measurement oscillates at twice the subharmonic frequency. This error is because the filter is optimized to measure 60 Hz.

On one hand, the negative-sequence fault detector is well-suited for sensitive ground fault protection of parallel lines due to its immunity to zero-sequence mutual coupling. On the other hand, this incident demonstrates its vulnerability to subsynchronous resonance transients. At the time of this writing, an effective mitigation to this problem is still being studied.

VII. Transient Testing

Transient model power system testing is an integral part of BC Hydro's EHV application philosophy, which specifies the use of identical Main 1 and Main 2 relaying systems [4]. Each time a line protection system is installed or upgraded on the EHV network, the system is tested with its actual application settings on a transient model power system. Transient testing is used to validate the relay algorithms, hard-coded and custom logic programming, the coordination of the protection element set points, etc. This is one way to mitigate the chances of a common-mode settings error or relay algorithm issue affecting identical Main 1 and Main 2 relaying systems.

Once in service, all trips on the EHV system are analyzed for proper operation. When an undesired operation occurs, investigation follows through until the root cause is identified. The results of these investigations drive continuous improvement in all areas of engineering, maintenance, and operations to lessen the possibility of future undesired operations of the protection systems. In many cases, investigations result in changes in relay scheme design, settings calculation philosophy, and often, changes to testing procedures. For example, failure to detect a settings error that should have been caught during transient testing indicates that the test procedures require improvement. For this reason, testing procedures have evolved over time.

While transient testing has long been an integral part of BC Hydro's EHV protection application philosophy, it is continuously evolving. Early on, transient model power system testing used analog simulator technology [10]. This evolved to computer-based simulation using the Electromagnetic Transients Program (EMTP) and waveform playback. Computer simulation makes model development easier and also makes it easier to change the power system configurations to test more scenarios. However, the biggest limitation of computer simulation is that this method is no longer a closed-loop environment where action of the protection and control system under test directly affects the power system. The difficulties of using these earlier transient simulation methods limited the thoroughness of the testing.

Today, real-time digital simulator technology allows us to combine the ease of use of computer-based simulation with the closed-loop testing environment of an analog model power system simulator [11][12]. Easy-to-use scripting tools allow us to run thousands of test cases in batch runs and bring the huge amount of test data generated into analysis tools, such as Microsoft® Excel®, for easy analysis.

With the advent of microprocessor-based protection systems, we also now have the benefit of accurate computer-based models of the protection algorithms that run in easy-to-use analysis tools, such as Mathcad® [13]. Early on, these tools were used extensively to visualize and understand the response of the relay to the limited number of test cases that could be generated in a timely manner. Simply looking at the output of the relay only gives binary information, either the relay tripped or it did not. It is not possible to tell how close the relay is to a boundary or threshold. Using these computer models, it is possible to gain greater understanding of the relay response and adjust margins to gain greater confidence that the relay would perform acceptably in service.

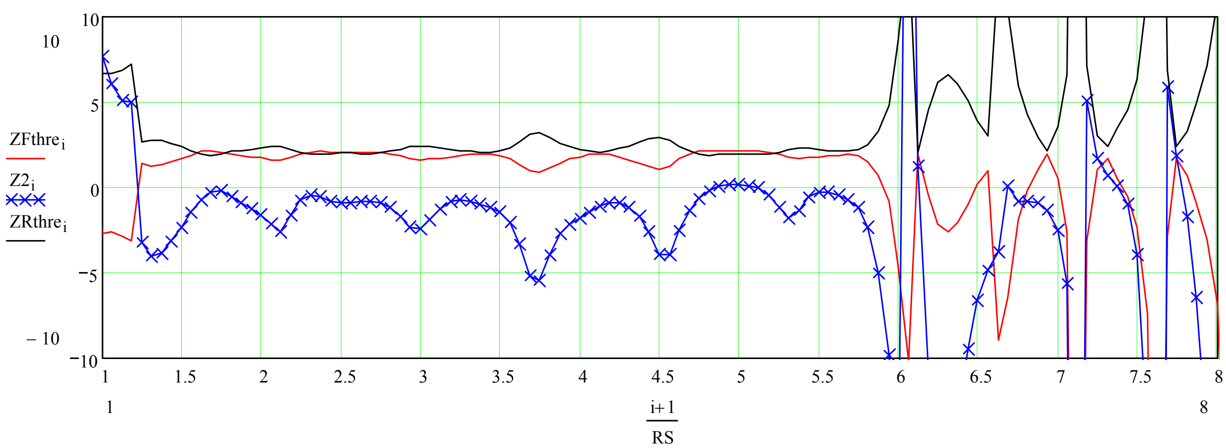

Fig. 13. Negative-sequence impedance element during subharmonic current flow on B- and C-phases

Although these computer-based relay models are still a valuable tool used during our testing and analysis activities, testing leans more toward using the efficiency of the Real Time Digital Simulator (RTDS®) test environment to subject the relays to a large number of test cases. Running large numbers of tests under realistic, yet extreme power system conditions gives greater confidence that some challenging condition was not missed.

Microprocessor-based relay technology also gives us the advantage of relay event records that can be downloaded from the relays and analyzed. It is now very easy to get to the root cause of any undesired operation that occurs during testing or in the field. Analyzing the logic diagrams for a particular protection element that is behaving unexpectedly allows us to track the status of variables that lead up to the output of the protection element. Sometimes supervisory elements, such as load encroachment or directional supervision, may be the cause of an element not asserting. Timing often plays a critical role in the proper operation of protection systems. For example, a transient assertion of an element at just the wrong time may lead to an unexpected output. This detailed view of the inner workings of the relay nearly eliminates the “unexplained” entries in the log book. The data from event reports can also be read into the computer-based relay element models to understand what the relay saw and why it did what it did.

These event reports are also valuable in figuring out what happened on the power system and why. The subsynchronous resonance case described earlier is one such example. This information is invaluable in assessing the accuracy of our transient modeling. It is also used to refine what power system conditions need to be modeled to challenge the protection systems and ensure that any possible flaws are uncovered in the settings.

A. Transient Test System Modeling

For each EHV line protection upgrade project, the protection and control planning engineer assigned to the project creates a protection replacement application note. This document identifies the major items that must be taken into consideration for the project. Major application considerations, such as available pilot channels, special requirements, and special system operating conditions that affect the protection system are identified.

This application note is an important first document to the transient testing engineer. The main items of interest for development of a transient system model are the system operating conditions. Typically, five to seven load flow and contingency cases are identified. These may represent:

- System normal (strong with high load flows).
- System load flow direction through the protected line (when appropriate).
- Parallel transmission paths out of service.
- System weak behind each terminal, considering contingencies that will affect either positive- or zero-sequence source impedances or both.

The protection and control planning engineer consults with a system planning engineer to determine realistic, yet extreme system conditions that will challenge the protection systems.

Once these load flow cases are identified, the transient testing engineer creates a reduced model of the power system that can run in real time on the digital simulator. The model must be designed with a high level of detail for the protected line and directly adjacent network elements. Transmission network elements at both the EHV and lower voltage levels that are mutually coupled to the line of interest must also be considered. Detail is reduced, and system boundary equivalents and transfer impedance branches are used farther from the protected line. The number of nodes that can be modeled and solved in real time are a function of the amount of parallel processing capacity of the simulator.

A reduced network is proposed to the protection and control planning engineer by the transient testing engineer. In addition to being designed to accommodate the various load flow conditions previously identified, the model must consider locations of nodes for sliding and fixed fault locations. Locations for internal faults must cover the locations that are checked to meet the performance criteria listed in Table II. Sliding internal faults are desirable to be able to cover the limiting locations for fault resistance sensitivity (see Appendix B, Section C for more discussion on this topic). Locations of external faults must include challenging locations where overreach is a concern, especially on lines near series capacitors. Parallel loop flow paths must be identified, and external fault locations should be included to cover SPO and current reversal conditions in parallel transmission paths.

Once general agreement is reached on the configuration of the reduced system model, building it within the RTDS environment can begin. Often there will be several iterations before the requirements of the protection and control engineer, the system planning engineer, and the transient testing engineer are satisfied.

Once the transient model is completed, the system planning engineer goes through the network reduction process with the system planning model until it is equivalent to the transient system model. The system planning engineer then creates solved load flows for each case that detail the P, Q, V and angle at each major bus and machine. Machine dynamics are also often included [11].

The transient testing engineer enters these data into the model. This allows the RTDS model to match the system load flow conditions identified for the test very closely. The model is then validated for both power flow and fault current levels. The high level of cooperation that has been developed between the protection and control planning engineer, the system planning engineer, and the transient testing engineer is important for obtaining a high degree of confidence that the testing of the protection systems is as realistic and thorough as possible.

Finally, it is necessary to understand and properly model power system equipment control circuits. The following are several controls that are important to model correctly:

- Reclosing controls on adjacent and parallel lines.
- Automatic shunt reactor switching controls.
- Circuit breaker closing controls, such as timing of pre-insertion resistors, point-on-wave closing, or staggered pole closing.
- Series capacitor bypass and automatic reinsertion controls.
- Series capacitor protection elements.

B. Test Procedure

Table III shows a typical test regimen for a 500 kV line protection system. Appendix B at the end of this paper describes some of these tests in more detail. Typically, one week is required to completely test a line. The first day is usually taken up with reviewing the test plan, the relay settings, and model validation.

TABLE III
TYPICAL TEST PLAN

Test Number	Test Procedures
1	Basic Internal/External Faults
2	Zone 1 Margin Tests
3	Sensitivity Test: Z0 Centers and Z2 Centers
4a	SOTF (Line Pickup/Load Pickup for Heavy Load Flow)
4b	SOTF (Line End/Close In for Normal/Weak Load Flow at Each End)
5a	Evolving Faults: SLG→DLG (Double Line to Ground) With 1-Cycle Delay
5b	Cross Country Faults: External→Internal With 1-Cycle Delay
5c	Cross Country Faults: Internal→External With 1-Cycle Delay
6a	Fault During Open-Pole SLG→DLG With 15-Cycle Delay
6b	Permanent Fault (Fault Stays On)
6c	Fault During Reset and Fault After Reset
7	51G Time Out During SPO With Heavy Flow
8	Pole Scatter
9	Z3RB Margin for External High-Impedance Ground Faults (HIF) Behind Each Terminal
10	Uncleared External Fault
11	Power Swing Tests
12	HIF Batch Test Internal Fault Locations (50, 100, 200, 300 Ω) All Load Flows
13	Batch Tests 0 Ω Faults All Load Flow Cases/All Fault Locations

Test Procedures 1, 2, and 3 are meant to fine-tune the normal fault protection elements and verify that they are properly set to meet BC Hydro's speed and sensitivity requirements. These tests are generally run first to improve the chances of successfully meeting the performance criteria during a full batch run (Tests 12 and 13).

Tests 4 through 11 are meant to verify settings and logic associated with specific special protection functions. The results are often reported for informational purposes only, because they do not have specific performance requirements that must be met.

Tests 12 and 13 are run to gather a complete picture of protection system performance over the complete range of load flow and contingency cases. These cases are often run in overnight batch tests so the results can be reviewed at the start of the next day. A typical Test 13 batch test consists of:

- Five to seven load flow cases.
- Ten to twelve fault locations (including both internal and external).
- Ten fault types (AG, BG, CG, ABG, etc.).
- Three points-on-wave (to stimulate different transients).

This results in between 1,500 and 2,520 individual fault shots. The RTDS saves oscillographic records for each shot that is stored in Common Format for Transient Data Exchange (COMTRADE). The RTDS also saves space delimited text files that contain the elapsed time between fault initiation and element assertion for typically 32 digital signals from the relays.

BC Hydro has developed analysis spreadsheets in Microsoft Excel to easily process this high volume of test data. The text files are brought into Microsoft Excel spreadsheets that are programmed to highlight undesired operations (fail to properly SPT, 3PT on internal faults, or overtrips on external faults). The minimum, maximum, and average trip times versus the performance criteria are presented in graphs so failures to meet performance criteria are easily discerned.

Typically, it is necessary to run the batch tests multiple times during the week. Each time, the testing team thoroughly investigates undesired operations and poor performance cases identified by the data. Analysis usually begins with examining the COMTRADE record from the shots of interest. If necessary, shots are repeated, and detailed event records are downloaded from the relays. Once root cause is found and a solution is proposed and validated, the batch tests are repeated with new settings to verify desired performance.

VIII. Conclusions and Summary

This paper has presented several examples of protection challenges and problems on series-compensated 500 kV lines.

Care must be taken in applying negative-sequence directional settings for line protection. We must be certain to consider the compensated line impedance when a series capacitor exists on the transmission line. Further, depending upon system aspects, one of two methods may be applicable for setting these elements:

- Method 1: setting Z2F and Z2R based only on the negative-sequence impedance of the transmission line. This method is valid where the system impedance at each line terminal is similar.
- Method 2: setting Z2F and Z2R based on the negative-sequence impedance of the line plus the system impedances at each line terminal. This method has merit where the system impedances are disparate (different) at each line terminal.

Nontransposed circuits impact the security of negative-sequence directional element settings. Solutions include appropriately setting unbalance-to-balanced current ratio factors a2 and a0 and adjusting the Z2F and Z2R settings.

Automatic reclosing challenges, particularly SPT and reclosing applications, are addressed by applying appropriate time delays to sensitive ground fault detecting elements. Attention must be paid to situations where both terminals do not reclose at the same time, such as the case where a lead/follow relationship exists between the terminals.

Series capacitor switching presents some challenges. Solutions include:

- Setting longer time delays for sensitive ground fault detecting elements.
- Utilizing communications between the capacitor bank and the line terminal(s) to appropriately condition the protection logic.

Subsychronous resonance issues present some interesting challenges, and further work needs to be done to determine the most effective mitigation to these problems.

Section VII provides information on the importance of transient testing in protective relaying applications on EHV systems. Details on modeling and information on a generalized test plan are provided.

Appendix A provides detailed examples on setting negative-sequence directional elements to aid in the understanding of Section III.

Appendix B provides an expansion of the generalized test plan described in Table III, explaining the rationale and benefits of each test.

IX. Appendix A: Negative-Sequence Directional Element Settings Examples

A. Introduction

This appendix describes the application of two settings methods for negative-sequence directional elements, as described in Section III.

- Set on the basis of half the line Z2 impedance (Method 1).
- Set considering the minimum Z2 source for a forward and a reverse fault, as well as the line Z2 and settings elements to half of this total impedance (Method 2).

To aid in understanding how and why a particular method is applied, consider the two fictitious system diagrams in Fig. 14.

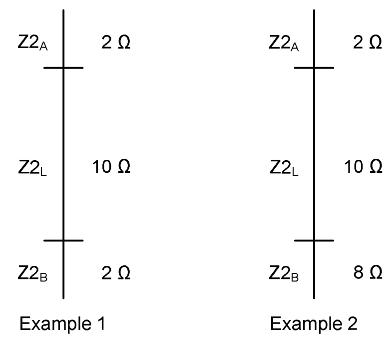

Fig. 14. Z2F setting applications

The impedances shown are in the Z2 plane, considering only the reactive component of the negative-sequence impedances.

Using the first method in Example 1, it is clear the Z2 elements will be set at the 5 ohm point of the transmission line. The second method will yield the same results, because the Z2 sources at both ends of the line are identical to each other. Whereas in Example 2, using the second method, the Z2 elements are set off center to the line and calculated as follows:

$$\frac{(8+10+2)}{2} = 10\ \Omega$$

Starting from Terminal B, the settings point of the line is 2 Ω out on the line.

B. Practical Examples

Using actual transmission line and system data, the two practical examples that follow illustrate where one method may be favored over the other. Note that in the following figures, the heavy diagonal line represents the Z2 impedance of the transmission line. The square data points in the first and third quadrants represent the Z2 sources.

1) Practical Example 1

In the first practical example, the source impedances behind each line are relatively equal.

Fig. 15 shows the results of using Method 2. Fig. 16 shows the results of using Method 1, which considers only the negative-sequence impedance of the transmission line.

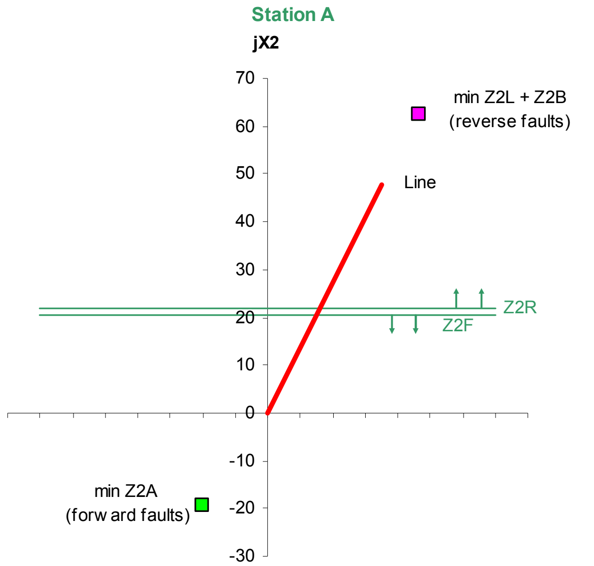

Fig. 15. Practical Example 1: using Method 2

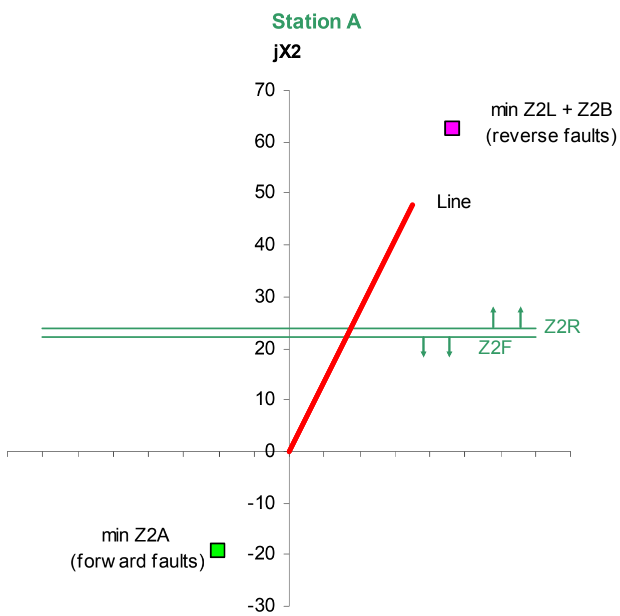

Fig. 16. Practical Example 1: using Method 1

From visual inspection, the results appear similar for the two methods. The mathematical calculations that follow illustrate the subtle differences.

2) Magnitude of V2 Polarizing Voltage

When setting the Z2F and Z2R elements, we should consider the calculated negative-sequence voltage that results from the applied negative-sequence level detectors. The following formula is applicable for the forward-looking (67Q2) level detector:

$$V2 = \frac{67Q2}{3} \bullet \left(Z2F - Z2A \bullet \sin \angle Z2A \right)$$

where:

67Q3/3 is the level detector setting in I2 secondary amperes.

Z2F is the forward directional setting in secondary ohms.

Z2A terms are the reactance portion of the negative-sequence impedance behind the relay terminal.

Note that a similar formula can be developed for the reverse-looking 67Q3 detector.

The calculation is important, because depending upon the settings of 67Q2 and Z2F, a low-calculated V2 may result. A low-calculated V2 is a concern, particularly if there are issues with unbalances in the network. Standing prefault V2 can impact the negative-sequence directional element and cause an improper directional decision to be made. Using the above formula, if the absolute value of the $\left(Z2F - Z2A \bullet \sin \angle Z2A \right)$ term is large, this will contribute to a larger calculated fault V2, providing greater tolerance to prefault V2 unbalances.

Table IV shows the calculated V2 (expressed in percentages) for Method 1 and Method 2 in Practical Example 1. For clarity, only the forward directional elements are considered. Further, the same 67Q2 settings are assumed to be applicable at both relay terminals. The results are similar, regardless of the settings method used.

TABLE IV
PRACTICAL EXAMPLE 1, CALCULATED V2 AT 67Q2 SETTING CURRENT

Method	Station A	Station B
1	2.67%	2.43%
2	2.54%	2.54%

3) Practical Example 2

In the second practical example, the source impedance behind the local terminal is much higher than the source impedance behind the remote terminal. Fig. 17 and Fig. 18 show the results of using settings Method 1 and Method 2, respectively.

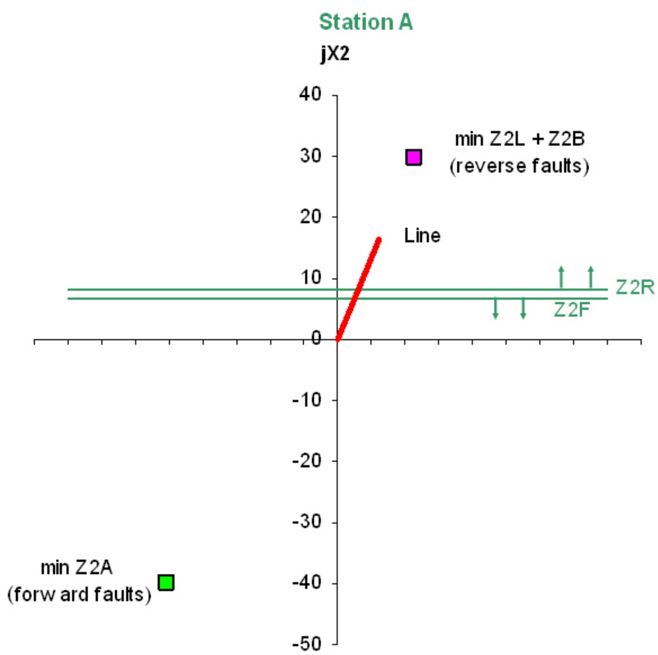

Fig. 17. Practical Example 2: using Method 1

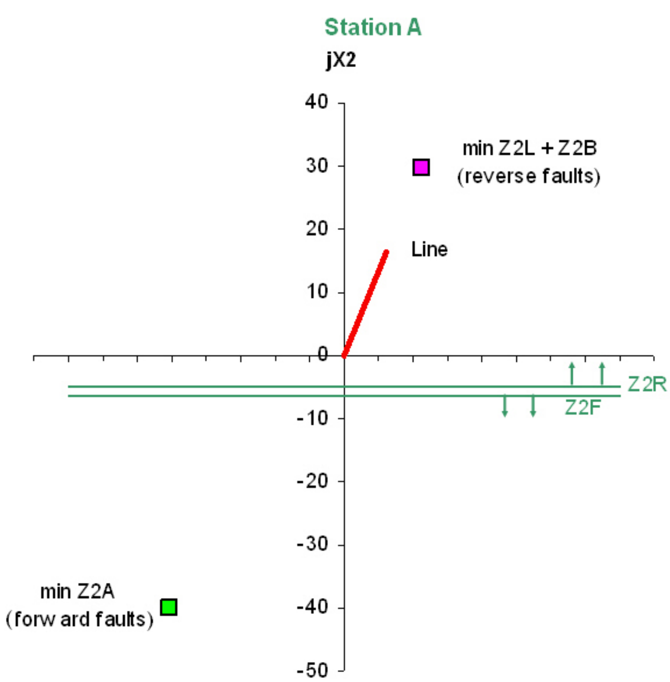

Fig. 18. Practical Example 2: using Method 2

The Z2F and Z2R settings are quite different for the two methods. Table V shows the calculated V2 (expressed in percentages) for Method 1 and Method 2 in the Example 2 power system. Using Method 2, the polarizing V2 at the limit of sensitivity of the directional elements is equal (and maximum) at the two terminals of the line. Using Method 1, the polarizing V2 at the strong terminal is very low, while it is larger at the weak terminal.

TABLE V
PRACTICAL EXAMPLE 2, CALCULATED V2 AT 67Q2 SETTING CURRENT

Method	Station A	Station B
1	2.99%	1.3%
2	2.14%	2.14%

4) Conclusions

We can draw some conclusions from the analysis of the two settings methods for the two example transmission lines.

Method 1 results in an extremely low value of V2 at the limits of sensitivity of the directional elements that could be overwhelmed by normal system unbalances. For a transmission line with disparate Z2 source impedances, there is an advantage in using Method 2, as a higher standing V2 error can be accommodated.

A simple way to determine whether the exercise is worthwhile is to view the results from Table V for the simpler method, Method 1. Calculate the average of the percentage V2 error that can be accommodated for the two terminals. Table VI shows this approach for the two example transmission lines.

TABLE VI
AVERAGE OF V2 POLARIZING SIGNAL AT EACH TERMINAL

Circuit Example	Station A	Station B	Average
1	2.67%	2.43%	2.55%
2	2.99%	1.3%	2.14%

In Example 1, there is little difference between the results at each terminal. For Example 2, there is a large difference. This simple assessment shows that Method 2 would be worthwhile for the second circuit example but not worthwhile for the first circuit example.

X. APPENDIX B: TEST PROCEDURES

This appendix describes in more detail some of the test procedures mentioned in Table III.

A. General Considerations

1) Fault Type

The four basic fault types include:

- Single line to ground (SLG)
- Double line to ground (DLG)
- Phase to phase (PP)
- Three phase (3PH)

During preliminary tests, we typically try one of each fault type at each fault location. The reason for this is that the relay uses different elements and logic supervision paths, depending upon the fault type. The following are some examples:

- The faulted phase identification selection (FIDS) logic enables only one ground distance loop and one phase distance loop for faults involving ground [6]. For faults not involving ground, all three phase loops are active.
- Phase distance elements are supervised by different elements, depending upon whether the fault is balanced (3PH) or unbalanced (PP or DLG).
- 67G elements respond to SLG and DLG faults, but this element is supervised by the 32Q (negative-sequence) directional element.
- 67Q elements respond to all fault types except 3PH.

2) Load Flow and Contingency Conditions

Load flow and source impedance conditions can have a major effect on the performance of the protection systems.

Load flow conditions are especially problematic for SPT systems due to the unbalance currents that flow in the protected line when it or adjacent lines are SPO. Therefore, tests of elements that respond to unbalanced load flow currents are made during high-flow cases.

3) Source Impedance Conditions

Source impedance conditions can affect the protection systems in many ways:

- Series capacitor protection responds to the instantaneous current level through the capacitors. Strong system conditions tend to reduce the problems introduced by the series capacitors, because they bypass the capacitors much more quickly.
- High source impedance ratios (SIRs) result in extremely low voltage at the terminals for external faults. This typically makes transient overreach more of a problem for system weak conditions.

For this reason, transient overreach tests typically include system weak conditions behind each terminal.

B. Test 2, Zone 1 Margin Test

Zone 1 elements must never overreach the protected line. Transient overreach can be affected by several power system conditions:

- DC offset in the fault current.
- Mutual coupling in lines that share right of way.
- Imperfect transposition of the line, resulting in different impedances for different fault loops.
- Subsynchronous oscillations caused by resonance of the system impedances with series compensation elements.
- High SIR-causing voltage measurement errors due to both capacitance voltage transformer (CVT) transients and the extremely low level of voltage present at an end-of-line fault.

Two methods have been used to verify Zone 1 margins. One method is to do trial shots for phase and ground loops, use a computer-based model of the distance elements to measure the lowest observed transient impedance value seen by the relay, and then take a margin of 90 percent of that value as the setting. The problem with this method is that it is very time-consuming to do this measurement for more than a few shots, and it is likely that the few shots would not necessarily cover the worst-case conditions listed above.

The second method results in a high degree of confidence that the worst-case conditions will be covered. A special script is prepared to run a batch of remote bus faults for each terminal. Every fault type is run with point-on-wave from 0 degrees to 110 degrees in 10-degree increments for system normal and the weakest case behind each terminal. This provides 2 • 120 = 240 shots for each terminal. If the relay passes this test with no overreaches, the normal batch tests are run. The normal batch tests cover remote bus faults for all load flow cases, but with only 30 shots instead of 120 shots.

C. Test 3, Sensitivity Test

Whenever channel availability allows, BC Hydro uses phase-selective DTT in SPT applications. This, coupled with the use of both 67G and 67Q elements, is an important tool for obtaining fault resistance sensitivity levels usually associated with line current differential systems out of a directional overcurrent-based POTT scheme. To get proper SPT, only one terminal needs to detect that there is an internal fault and properly phase select. The stronger terminal, once it makes an SPT decision, trips the weaker terminal through a phase-selective DTT.

As the fault location is moved closer to one terminal, that terminal’s ability to see the fault becomes greater, and at some point, it becomes the decision-making terminal. The relative source impedances affect the balance point. At the electrical center of the system, the contribution from each terminal becomes equal, and either terminal has an equal chance of seeing the fault. When moving off the electrical center, one terminal becomes stronger, and the other terminal becomes weaker. The stronger terminal then becomes the decision-making terminal at the limits of sensitivity and DTT trips the weaker terminal.

By using both 67G and 67Q elements, coverage is further improved, because there are at least two electrical centers of the system: one in the negative sequence and one in the zero sequence. At the negative-sequence electrical center, one terminal will typically be stronger in the zero sequence, which will make it able to trip via 67G, even if the fault resistance is too great for the 67Q element to operate. Similar logic applies to faults at the zero-sequence center of the system. In lines with series compensation, there are often two zero-sequence electrical centers and two negative-sequence electrical centers in the line.

The sensitivity limits of the line protection schemes are tested using the following procedure:

1. Use the fault study program to identify the location of the electrical centers of the system in both the negative-sequence and zero-sequence networks under system normal conditions.
2. Move the sliding fault within the RTDS model to those locations, and trigger an SLG fault.
3. Compare the fault contributions from each terminal to verify that the RTDS sliding fault location is in relative agreement with the fault location obtained from the fault study.
4. Increase ground fault resistance in 50-ohm steps, and note the response of the protection systems.

Table VII gives an example of the test data recorded for this test at one of the zero-sequence electrical centers of the system for line 5L11. For fault resistance starting at 300 Ω and ending at 400 Ω, KLY was likely stronger in the negative sequence, so it was able to sense the high-resistance faults and keyed permissive. Since the WSN terminal was too weak to see the fault, it echoed. KLY was able to trip via pilot echo logic and then direct transfer tripped the WSN terminal to complete the fault-clearing sequence.

TABLE VII
FAULT RESISTANCE SENSITIVITY TEST, KLY TO WSN

Fault Ω	KLY Terminal	WSN Terminal
300 Ω	Tripped on Rx Echo	Tripped on Rx DTT
350 Ω	Tripped on Rx Echo	Tripped on Rx DTT
400 Ω	Tripped on Rx Echo	Tripped on Rx DTT
500 Ω	No Trip	No Trip

If the relays successfully trip for over 300-ohm fault resistance for all electrical center tests under system normal conditions, the performance of the system is verified for all load flow cases at all critical internal fault locations in a batch test (see Test 12 in Table III).

D. Test 4, Switch-on-to-Fault Tests

Switch-on-to-fault logic serves two purposes:

- Ensure tripping for a zero-voltage fault when the polarizing memory of the normal protection elements is invalid due to the line being de-energized with line-side potential.
- Trip high-speed unconditionally via overreaching elements when the remote end of the line is open and it is impossible to overreach the open terminal.

To verify operation for these two scenarios, a series of eight shots is initiated for each terminal with the remote terminal open for a total of 16 tests.

1. SLG at 0 percent of the line, system normal.
2. 3PH at 0 percent of the line, system normal.
3. SLG at 100 percent of the line, system normal.
4. 3PH at 100 percent of the line, system normal.
5. SLG at 0 percent of the line, system weak.
6. 3PH at 0 percent of the line, system weak.
7. SLG at 100 percent of the line, system weak.
8. 3PH at 100 percent of the line, system weak.

E. Test 6, SPT and Reclosing Tests

1) Fault During Open-Pole Test

This test is used to determine the limits of sensitivity for a fault that occurs during the SPO condition. As mentioned in Section IV, the sensitive 67G and 67Q elements are disabled during SPO. Thus, the only elements that are available to trip for this fault are the ground distance elements. To set up this test, an evolving fault is arranged that evolves from an AG to ABG fault at 15 cycles. The fault location is typically midline or at the zero-sequence electrical center of the system. Fault resistance is added, and the results are recorded for each test.

The SPT mode switch is put in Position 5, as described in Table I, (SPT and SPR for SLG faults, 3PT and 3PR for multiphase faults). If the second fault occurs during SPO, the relay is expected to 3PT and start the 3PO interval timer and reclose. If the second fault is not detected, it evolves to a DLG fault upon expiration of the SPO interval timer and closure of the open pole, and the relay issues a 3PT. At this point, the recloser detects this as a permanent fault and goes to lockout. Table VIII shows an example of the results for one such test.

TABLE VIII
FAULT DURING OPEN-POLE TEST, KLY TO WSN

Fault Ω	Results
0 Ω	KLY Tripped Zone 1, WSN Tripped Pilot, Three-Pole Reclose
50 Ω	Pilot Trip, Both Terminals, Three-Pole Reclose
100 Ω	Pilot Trip, Both Terminals, Three-Pole Reclose
150 Ω	No Trip Until SPT Reclose, Lockout

2) Reclosing Sequence Tests

This is a logic programming test. The SPT mode switch is placed in its various positions. Fault timing sequences are initiated, and proper operation is checked. Cases are checked for:

- Permanent fault
- Fault after reclose but before reset
- Fault after reset

F. Test 9, Z3RB Margin for External Faults

This test is designed to verify proper coordination of the pilot tripping elements with the pilot blocking elements. With the highly sensitive settings used with the 67G and 67Q pilot tripping elements, they easily see faults at extreme distances away from the protected line. It is important that the reverse blocking elements in the pilot scheme correctly block echo of the forward tripping elements of the remote relays.

This test involves placing a fault one bus away from the protected line in each direction and increasing fault resistance until the overreaching pilot elements fail to pick up. If the reverse pilot blocking element is still picking up solidly for this condition, coordination is verified.

G. Test 10, Uncleared External Faults

During normal tests, external faults are cleared with simulated relay times of 1 to 2 cycles and simulated breaker mechanism times of 2 cycles. Breaker opening transients when an external fault is cleared often challenge the stability of the protection systems, but when the external faults are cleared quickly, the stability of very sensitive time-delayed protection schemes may not be challenged. Therefore, a limited number of slow clearing external faults are run to verify that these elements will not falsely operate.

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XII. Biographies

Frank Plumptre graduated from the University of Calgary with a B.Sc. in Electrical Engineering in 1975. He has over 30 years experience in the field of protective relaying and is presently a specialist engineer with BC Hydro. He is a member of the IEEE Power System Relay Committee (PSRC), a past Awards and Recognition Chair of the PSRC, and the current chair of the Substations Subcommittee. He is also active in several working groups. Most recently chair of K13 Series Capacitor Protection and the successful publication of the IEEE guide on "Protection of Transmission Line Series Capacitors," he is also involved as a corresponding member in several CIGRE work groups.

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