Validation of Out-of-Step Protection With a Real Time Digital Simulator

Frank Plumptre, *BC Hydro*, Stephan Brettschneider, *Cegertec*, Allen Hiebert, *BC Transmission Corporation*
Michael Thompson and Mangapathirao "Venkat" Mynam, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—This paper describes the use of a real time digital simulator with dynamic machine models to validate out-of-step tripping and blocking elements in a new protective relaying system being installed on the BC Hydro 500 kV power system. The technique has also been used to study and validate a generation shedding remedial action scheme. This unique approach has many advantages over traditional methods of studying the effect of power swings on protection systems. Traditional methods for studying power swings are limited in their ability to predict the response of protective elements due to the fact that they model the power system in the positive-sequence network only. A real time digital simulator can represent the power system under more realistic conditions so that the response of the protective system can be tested under conditions that nearly match actual field conditions. Case studies are discussed in the paper showing the importance of this new approach.**

I. Introduction

Protective relays, especially distance elements used for detecting and isolating faulted sections of the power system, can respond to power system swings and out-of-step conditions. BC Hydro uses the principle that distance elements will trip and generally accepts natural tripping of transmission lines for out-of-step conditions. It is recognized that such tripping may be at a nonoptimal angle across the tripped breakers; however, transmission line breakers can be specified for such a switching duty. In situations where protective relaying will not respond to power swings, dedicated out-of-step tripping protection may be applied. For example, where the expected swing is within a transmission line that is protected by only current-based protection (i.e., line current differential or phase comparison) or within power transformers.

There are situations however, where the natural response of distance elements to out-of-step tripping on power system swings and out-of-step conditions is undesirable. Tripping may open critical paths of the transmission system grid while the system is under a stressed condition, which could potentially make the situation worse and could lead to complete collapse of the power system. Most multifunction distance relays today include some form of power swing blocking and out-of-step tripping elements. Power swing blocking elements prevent the undesired tripping of critical transmission paths during a power swing, and out-of-step tripping elements allow intentional opening of transmission paths to aid in creating grid islands.

Traditional methods of studying dynamic power system stability do a good job of predicting what conditions of load flow and system contingencies can cause a system to go out of step. These methods can also identify specific line terminals that are susceptible to tripping during power swings. They are also used to design remedial action schemes to shed load or generation under certain conditions and to keep the system from going unstable. The information provided by dynamic stability studies is also invaluable to the protection engineer who is charged with implementing blocking and/or tripping elements in the protective relays to improve the robustness of the protection system during these power swing disturbances.

However, most dynamic-stability programs assume balanced conditions and model the system in the positive-sequence only. Distance elements are complex devices that do not simply measure the V/I = Z [1]. Modern numerical distance elements also often include many supervisory checks that must be satisfied before they issue a trip. Simply plotting the apparent positive-sequence trajectory on an RX diagram versus the distance element's characteristic will not fully predict the response of the element during a real power swing disturbance.

Modern real time digital simulators (RTDS) can model the power system under both balanced and unbalanced conditions. The dynamic machine data models (generator, excitation controls, governor controls, stabilizer controls, etc.) from popular dynamic stability programs can be used to build dynamic machine models that can run in real time on the simulator. The actual protective relays on the system can be connected to the simulator and their response during power swings can be examined and adjusted to ensure that the desired operation is achieved.

In this paper, we will provide two examples of using this new tool. The first example describes validating the design and settings for an out-of-step blocking and tripping scheme. The second example describes validating a generation shedding remedial action scheme. But first, we will provide some background on the subject of out-of-step relaying.

II. Background

A. Traditional Analysis

A system planner uses a dynamic-stability program to simulate the power system's response following possible disturbance events, especially those that could stress the system to, or beyond, its dynamic stability limit. The power system disturbance events of special interest to the system planner and also the protection engineer are those that show a marginally stable or even unstable result. These simulations, with variations on the severity of the system loading and the disturbance, can be used by the system planner to provide stability study results for a variety of out-of-step events.

When assisting the protection engineer with out-of-step protection settings on a particular transmission line, the system planner uses the same power flow and stability model that is already available from the planner's dynamic stability studies of the same region. To show the out-of-step condition, it is usually necessary to assume the disturbance has a longer than normal fault duration or assume that the system is loaded beyond its operating limits. A range of out-of-step simulation cases can be provided—from one that almost slips, to one that is just marginally unstable (a slow-developing slip), to one that shows a fast slip such as a line reclose when the generating station is already isolated and has a frequency difference of several hertz.

The protection engineer typically requests the transmission line's apparent impedance during the power swing and possibly also the voltages and power flows at the line terminals. The apparent impedance trajectory can be shown along with the line protection's distance element characteristic. Because the system planner's usual stability model uses only the positive-sequence network, these simulation results are for a balanced system only. Attachments 1 and 2 show the impedance trajectories overlaid on a mho characteristic for stable and unstable power swings respectively. Attachment 1 shows the impedance trajectory (stable swing) entering the Zone 2 mho characteristic for the fault and then swings out as the fault is cleared. The impedance re-enters the Zone 3 characteristic during the swing and then swings out as the swing dampens out.

B. Power Swing Detection

Power swing detection methods are based on the fact that the change in apparent impedance, seen by the relay due to a power swing, is gradual compared to a step change that occurs when the system is faulted. Traditional techniques used double blinders, concentric polygons, or concentric circles to detect power swings [2] [3]. Fig. 1 shows an example of an out-of-step element that uses concentric polygons.

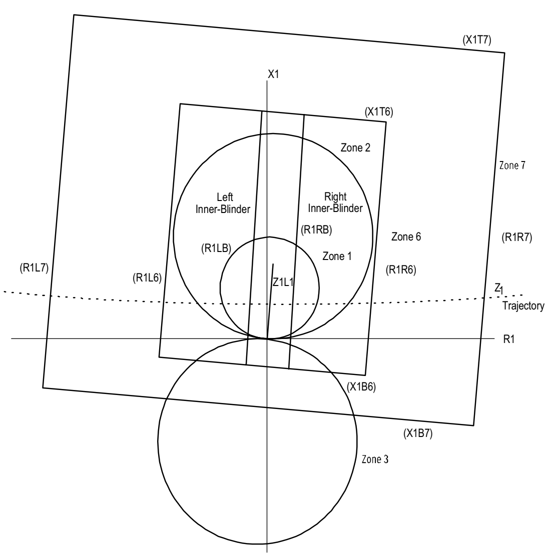

Fig. 1. OOS Characteristic Using Concentric Polygons

The detection and decision of the nature of the power swing is derived from the travel time of the positive-sequence impedance, which is measured between the moment that it enters the outer characteristic and the moment that it enters the inner characteristic. If the measured impedance stays between the characteristics for a predetermined time, an out-of-step condition is declared and the distance elements are blocked. The out-of-step blocking (OSB) element is typically given ANSI device number 68.

Out-of-step tripping (OST) schemes are designed to protect the power system during unstable power swing conditions by forcing separation at predetermined optimal locations. The OST element is typically given ANSI device number 78. Typical logic for the OST detection uses a trip duration timer, which needs to be expired before the block duration timer at the moment when the impedance reaches the inner characteristic.

An additional desirable characteristic of OST elements is that they should initiate the trip after the first pole slip and as the two systems are coming back into phase. It is not as desirable for the breaker to be trying to interrupt while the two systems are near 180 degrees out of phase, as would be the case if the relays initiate the trip when the swing enters their distance characteristic.

Out-of-step relaying systems, made up of separate impedance elements and timers, typically block the distance elements for all faults for a minimum time after the swing is detected. This led to concerns about reducing the dependability of the protection system to trip for in-zone faults during or after a power swing. With modern multifunction relays, advanced logic is integrated to ensure that the occurrence of an unbalanced or balanced fault is detected during a swing condition. Negative-sequence current detectors are typically used to distinguish between a balanced swing condition and a faulted condition. This approach performs satisfactorily for unbalanced faults; however, it is not adequate for detection of balanced three-phase faults, which do not produce any negative-sequence current. One method to unblock for three-phase faults is to use an inner blinder. During a fault, the apparent impedance will enter this inner blinder and not come out. After an adaptable time delay that is greater than the time calculated to cross the inner blinder at the measured swing rate, the phase elements are unblocked to allow tripping.

C. Setting Out-of-Step Elements

Reference [4] provides a detailed description of how to set out-of-step (OOS) elements. But, in general, the settings are implemented in two basic steps. First, the two concentric characteristics have to be set, and second, the values for the two timers have to be determined. Typically, the outer polygon has to be set so that it excludes the maximum load impedance point. This condition has to be observed for either OSB or OST elements. In addition, a certain security margin should be added. The inner blinder has to be set in a manner so that it encloses all zones of the phase distance protection for which out-of-step blocking should be applied. Again, a certain security margin should be applied. The timers associated with out-of-step blocking and tripping logic should be set based on the swing rate for stable and unstable power swings.

However, the settings of the characteristics are subject to certain limitations resulting in a minimum and maximum swing rate for which OST or OSB can be applied. A lower limit for the timers is determined by the processing speed of the numerical protection device. Further, a certain security margin has to be observed between the two timers. Thus, depending on the distance between the two polygons and the minimum setting for the OST timer, a maximum swing rate may be observed for the OST element. On the other hand, the minimum swing rate for tripping (and the maximum swing rate that will be blocked if OSB is activated) is determined by the setting of the OSB timer, which has to be greater than the OST timer setting. A greater OSB timer value corresponds to a smaller minimum rate of the power swing that can be detected as an unstable swing condition.

There are additional considerations for these settings. As the distance between the two concentric polygons becomes greater, the travel time of the measured positive-sequence impedance becomes longer, and the freedom of choice for the set-point values becomes greater. However, settings of the characteristics are subject to certain limitations. Thus, depending on the distance between the two characteristics and the minimum setting for the trip duration timer, a maximum swing rate may be observed for the OST element. The minimum setting of the OSB block duration timer is determined by the minimum setting of the trip duration timer plus an adequate security margin. The setting value of the OSB timer corresponds to the maximum swing rate for which OSB can be applied.

D. *Limitation of the Traditional Analysis Techniques*

It is possible to use the positive-sequence dynamic stability program to simulate unbalanced faults and pole-open conditions by using equivalent positive-sequence impedances. References [2] and [5] show methods for determining and applying equivalent impedances for these unbalanced conditions. For a single line-to-ground fault on a transmission line, the stability study objective would be to determine whether the successful auto-reclose of the faulted phase would provide a stable outcome. In the simulation of a single-pole-open condition, the transmission line's impedance is increased to the equivalent impedance value, and then, at the time of the successful reclose, the line impedance is returned to normal.

The power system's voltages and currents shown by this approach during the resulting simulation are valid only as the positive-sequence values and the individual phase voltages and currents are not available. The simulation does show a valid result for the generators' rotor swings, for the power transfer on the unbalanced line and for the positive-sequence voltages. During the period of unbalanced operation, this simulation indicates the line's apparent impedance trajectory, but this cannot be used by the protection engineer as an indicator of what the individual phase and ground distance element measuring loops will see.

The system planner also needs to be cautious in the judgment of whether the single-pole-open disturbance event with a large power swing has a stable outcome or possibly leads to a trip of the two remaining phases. To be sure the line's remaining phases do not trip, it is necessary to review with the protection engineer the expected voltages and currents during the disturbance. This evaluation requires more modeling capability than the system planner's usual dynamic-stability program can provide.

III. RTDS-Based Testing

Steady-state signals, dynamic signals, and transient signals are the typical test signals used to test protective-relay systems. Transient signals reproduce all components of the test signal that are critical to test the performance of a protection system. EMTP-based programs like ATP, EMTP, EMTDC, and PSCAD are generally used to test the protection systems using the transient signal approach. The power system network will be modeled in software and voltage and current signals generated for faulted conditions. Later, these signals will be played back to the protection systems for testing.

The real time digital simulator, which was used in the tests that are the subject of this paper, is made by RTDS Technologies, Inc. The simulator performs fully digital electromagnetic transient power system simulation in real time; it utilizes, the Dommel Algorithm [6] similar to non-real time EMTP-type programs. Unlike analog simulators, which output continuous signals, digital simulators compute the power system at discrete instants of time. The time between the discrete instants is referred to as the time step. Typical time steps are in the order of 50–80 μsec.

The simulator with parallel processing architecture is specifically designed for power system simulations and ensures continuous real-time operation. This type of simulator is an ideal tool for designing, studying, and testing protection schemes. With features like closed-loop testing and batch processing, the simulator provides more flexibility for applications like single-pole tripping and reclosing, out-of-step conditions, remedial action schemes, etc. Using a real time digital simulator, the protective systems are continuously fed with the voltage and current signals resembling a realistic environment. Feedback signals, such as breaker status and relay trip and close, are interfaced between the software model and the protection system through a digital interface. Fig. 2 shows the major components of a typical test setup.

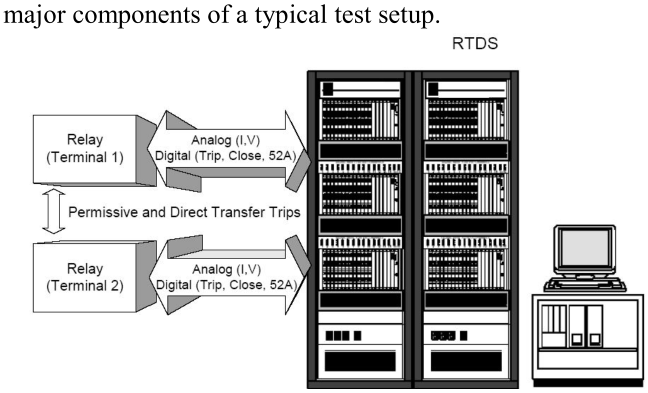

Fig. 2. Real Time Digital Simulator Test Setup

A. Machine Dynamics

Including machine dynamics (generator inertia, exciter controls, governor controls) in the transient system is critical to study the protection system performance under out-of-step conditions, pole open conditions, trigger of remedial action schemes, and other stressed conditions [7]. The case studies emphasize the importance of using machine dynamics to study the systems under stressed conditions. Fig. 3 shows the response of each of the three phase distance elements with respect to time for a power swing condition. The plots represent the apparent impedance as a function of equivalent reach seen by the relay's distance elements during and after an external three-phase fault that caused a power swing. The X axis of the plot is in cycles—i (sample number) divided by RS (samples per cycle). The Y axis is in secondary ohms. This plot was generated by feeding a recording of the swing data into a model of the relay's measuring elements. A response such as this could not be observed using static source models in the simulation.

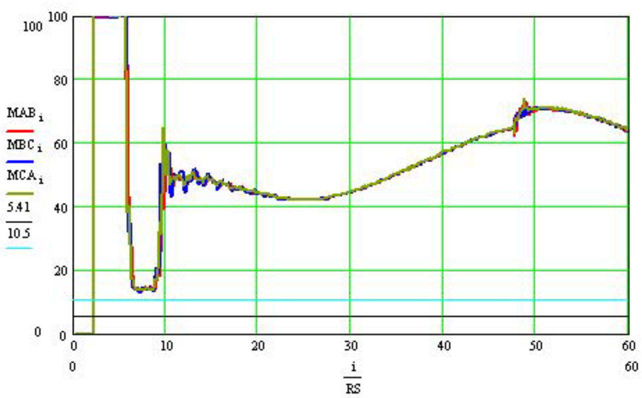

Fig. 3. Apparent Impedance as a Function of Reach Seen by a Distance Element for a Power Swing Event

IV. Modeling and Validation

Every simulation tool has its own limitations. The simulator at the test facility is limited to modeling 216 single-phase nodes and approximately 100 power system components. The typical approach for modeling a test system is to build an equivalent of the original system and judge the importance of the neighboring system relative to the line/system under test.

A. Modeling the Test System

For relay testing purposes, the model power system requires at least the test line's adjacent stations and lines to be retained explicitly, but more distant parts of the system can be replaced by equivalents. To provide an acceptable dynamic model, it is necessary to retain additional power system data in explicit form—especially the connections to the largest generating stations that are electrically near the test line. The system planner's first step is to reduce the full-size dynamic stability model to a small version that will have the same power system configuration as the protection planner's relay testing transient model, with the test line kept in detail and with distant generators replaced by static voltage sources. In this case, the software used for the dynamic-stability study work is PSS/E, made by Siemens PTI.

Reduction of the full PSS/E dynamic model to a small dynamic model requires testing the full dynamic model to determine which portions of the power system are electrically remote from the line being tested. These remote portions can be replaced in the power flow data by a static voltage source behind an impedance and in the dynamic data by a generator rotor with infinite inertia (a "fixed" rotor). For the retained generators near the test transmission line(s), it is desirable to retain the generators' dynamic-model details (including exciters and governors, along with the interconnecting lines and transformers). Model size constraints usually make it necessary to combine several generators or even several generating stations into a single equivalent generator connected by an equivalent transmission system impedance.

Where generators and their exciters and governors are combined into a single equivalent generator, it may be necessary to simplify the exciter and governor data for the small PSS/E model. Comparisons of the full and small PSS/E dynamic-stability models' responses to the planned test disturbances determine whether the small dynamic model is suitable for relay testing purposes. It is not necessary to have identical dynamic results from the small PSS/E model but the results should be at least similar and show reasonable damping. The comparison test cases can include line trips with normal fault-clearing times for a stable outcome and also some cases with more extreme predisturbance loading or with extremely slow fault-clearing, so that the small and full-size PSS/E models can both demonstrate a power swing severe enough to cause a near-slip and even a loss of synchronism.

A conversion utility in the RTDS software uses PSS/E-generated files to extract the dynamic generator model information from the small PSS/E model. PSS/E software generates a *.dyr file and a *.raw file, which contain information on the dynamics of the generator (governor, exciter, stabilizer) and system network, respectively. The conversion program uses the files to generate RTDS dynamic models corresponding to the ones used in the PSS/E model. The static models in the RTDS test system are then replaced with dynamic machine models.

B. Validation

The dynamic model built in the RTDS is validated by comparisons with the small PSS/E model in two steps. Step one ensures that the system impedances (network and generators) are correct. This is done by initiating three-phase and single line-to-ground faults on different locations of the test system and comparing the fault contributions with the original full-sized model.

Step two is called a bump test. It ensures the dynamic data have been correctly transferred into the transient simulator model. The generator dynamic data can be checked for "base MVA" and inertia values by initiating a three-phase fault on the high side of the generator's unit transformer for several cycles. The increase in rotor speed confirms that the generator's rotor acceleration matches closely between the small

PSS/E model and the RTDS model. After the fault is cleared (with no line or transformer tripped), the generator speed should return to normal with good damping.

The exciter and stabilizer data can also be checked in this bump test. The exciter's response to the very low generator terminal voltage during the fault-on time and the stabilizer's output signal can be compared to check that the exciter, stabilizer, and data are similar in the two models. Fig. 4 shows the speed response (δω) comparison between PSS/E and the RTDS models for a three-phase fault at the terminals of the generator step up (GSU) transformer. For the same event, Fig. 5 shows the comparison for generator terminal voltages.

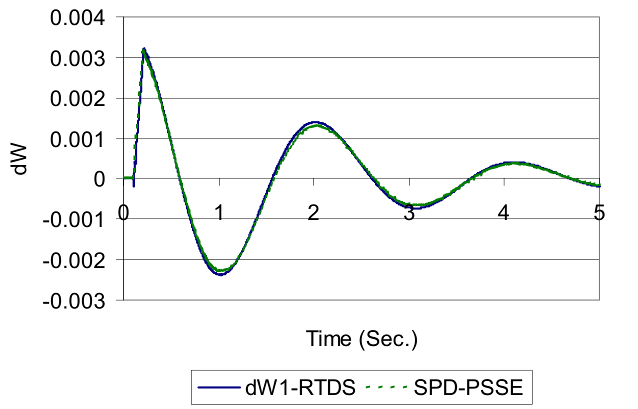

Fig. 4. Generator Speed Response Comparison Between PSS/E and RTDS

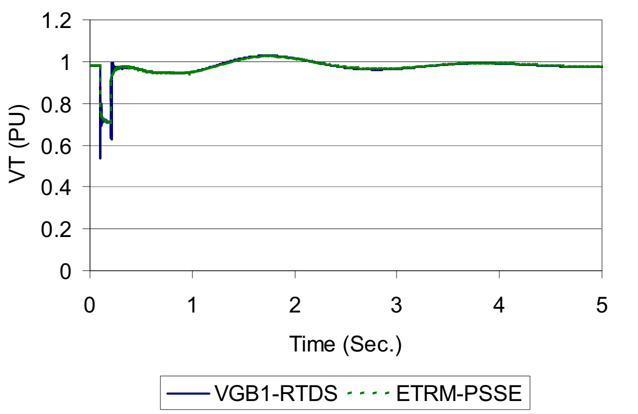

Fig. 5. Generator Terminal Voltage Comparison Between PSS/E and RTDS

When the two models compare well in the bump test, another test can be run—a system fault event with a balanced fault and a line trip out. The quantities such as rotor speed, generator real and reactive output, and line flow (current, real power, reactive power, and voltages at the buses) are compared to see that the characteristics of the power swing results are similar. An exact match is not necessary. The objective is a dynamic model in both the system planner's stability program and in the protection engineer's transient model so that both models can demonstrate the severe power swings. During the relay testing process, some variations on power system disturbances can be evaluated to show larger or lesser power swings by adjusting the fault duration, or perhaps adjusting the predisturbance loading so that the postdisturbance system is more stressed.

V. Case Study One

BC Hydro is upgrading protection on 500 kV line, 5L63, that ties the coastal area near Prince Rupert (Skeena, SKA and Kemano, KMO) to the main BC Hydro 500 kV grid. The line protection systems require power swing blocking to prevent separation of the coastal load centers served from SKA, from the main grid for power swings, and out-of-step tripping of an external line that separates the KMO generation for an unstable swing. A simplified single-line diagram of the system is shown in Fig. 6. It shows the locations where out-of-step tripping (OST) and blocking (OSB) are applied. The theoretical swing center, as shown in the diagram, is predicted to swing through the SKA 500/287 kV transformer. Attachment 3 shows the complete reduced test system used for case study one. The source models with "I" are inertia models (governor, exciter and stabilizer controls). The models with "S" are static models.

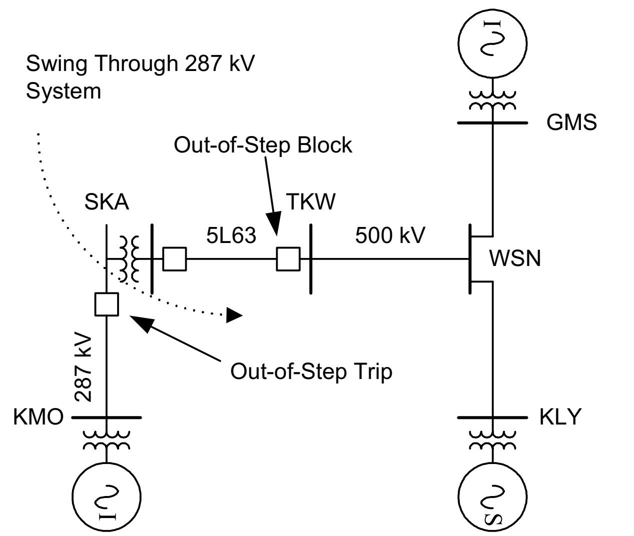

Fig. 6. Simplified Single-Line for Case Study One

Initially, the design called for only applying the OST (78) element in the SKA terminal relay of 5L63. The swing center would be through the transformer behind the relay and easily sensed by that relay. A trip would be issued to the 287 kV breakers to separate the generation at KMO and keep the SKA loads connected to the main 500 kV grid.

The application of an OSB element was not originally contemplated by BC Hydro. Traditional analysis said that, with the predicted swing center behind SKA, the reverse-blocking protection element at SKA would assert before the forward-overreaching tripping elements at TKW—guaranteeing stable relaying for a power swing. Because it was not expected to be needed, there was no need to reduce dependability for a fault in the protected line during a power swing, which was the case with the existing out-of-step protection system.

A. Preliminary Out-of-Step Settings

The new protection system for this application uses two concentric polygons inclined to the line angle as shown in Fig. 1 for out-of-step protection [8]. First, the settings for the two concentric polygons were calculated under consideration of the maximum load point (2915 amperes at an angle of 25 degrees) and the maximum mho reach (7.98 ohms). The line impedance angle was 86°. The following security margins were applied: 5% between the resistive setting of the outer polygon and the maximum load, 10% between the resistive setting of the inner polygon and the maximum protection zone setting, and 20% between the reactance setting of the inner polygon and the maximum zone setting.

For the line terminal with OSB (TKW–5L63), the settings of the outer polygon were 10.89 ohms resistive and 20 ohms reactive under the above-stated conditions. The values for the inner polygon were calculated as 7.75 ohms resistive and 16.85 ohms reactive. Thus, both polygons were quite close together and the minimum block duration timer setting of 0.5 cycles corresponded to a maximum swing rate of 4.3 hertz, for which a blocking decision could be issued. These settings proved to be convenient for the present application in the model power system tests.

For the line terminal with OST (SKA–5L63), the relative proximity of the two polygons did not give good conditions for the setting of the timers. In order to start the testing, both timers were first adjusted to the minimum values for preliminary setting—0.5 cycles for the trip duration timer and 1.125 cycles for the block duration timer. The reactance setting was increased to the maximum values, 96 ohms and 95 ohms for the outer and inner polygons, respectively.

B. Preliminary Testing

During the testing for a slow clearing three-phase fault at the SKA287 bus that developed into a power swing, line 5L63 tripped. Fig. 7 shows the protection system's response at either end of the line. Prefix 1 on Fig. 7 corresponds to the SKA terminal and Prefix 2 corresponds to the TKW terminal. The first analog axis corresponds to the voltages at the SKA and TKW 500 kV buses. The second axis corresponds to currents seen by the TKW terminal, and the third axis corresponds to the currents seen by the SKA terminal.

The protection scheme consisted of a hybrid permissive overreaching transfer trip (POTT) scheme that includes both forward-permissive elements and reverse-blocking elements. Echo keying is used in the POTT scheme to enhance sensitivity and cover weak feed conditions. This scheme is supplemented by a phase-segregated direct underreaching transfer trip scheme (DTT). The pilot channel uses relay-to-relay logic communications that sends eight bits of pilot tripping signals between the two line terminals.

As previously stated, one would theoretically expect that the impedance would enter the reverse element closest to the swing center before the forward element away from the swing center. This would provide coordination between the elements and result in correct blocking. A plot of impedance trajectories, similar to that shown in Fig. 3, verified that the apparent impedance did behave as expected. But, the relay at SKA was late in asserting its reverse elements. This resulted in a line trip on echo. Fig. 7 shows SKA reverse-block element, 1_Z3RB, was 40 msec behind TKW forward element, 2_KEY.

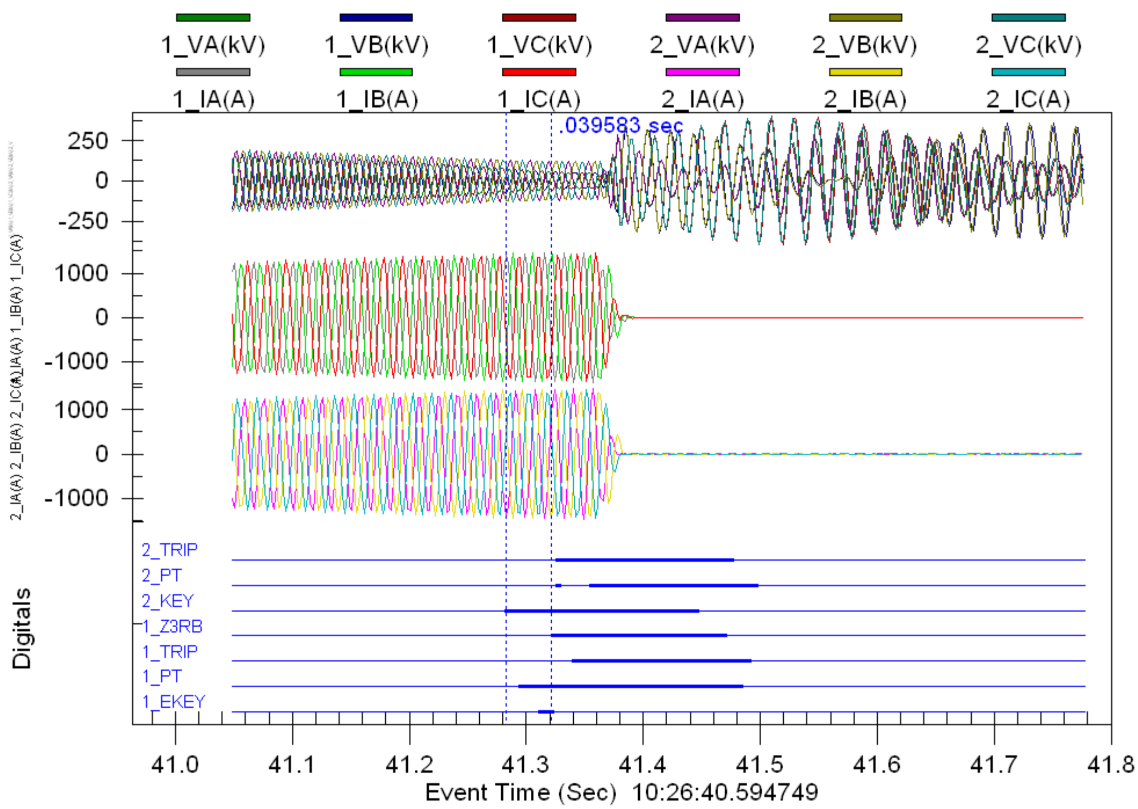

Fig. 7. SKA and TKW Relay Response for a Three-Phase Fault at SKA287

The reason for the problem relates to an additional security check built into the phase distance elements for balanced faults. The protective relay does an angle check for balanced faults with a characteristic of +120° and –60°. This check is intended to prevent misoperation on load flow. Coupled with the directional element characteristic of the line angle +/– 90°, the relay characteristic has a dead zone in the impedance plane when the apparent impedance is between –60° and, in this case, –4° (86°–90°).

For a power swing condition, the impedance characteristic could easily fall in the dead zone. The slight difference in VAR load between the two terminals due to line charging, can result in the two ends crossing these thresholds at different times. Based on these real time digital simulator tests, it was determined that OSB should be applied at TKW. Fig. 8 and Fig. 9 show the impedance trajectory for a three-phase fault at SKA287 bus. MHO and OSB characteristics are overlaid on the trajectory to provide a better understanding of the applied OST/OSB system. In these two figures, the X axis is in secondary ohms resistance and the Y axis is in secondary ohms reactance.

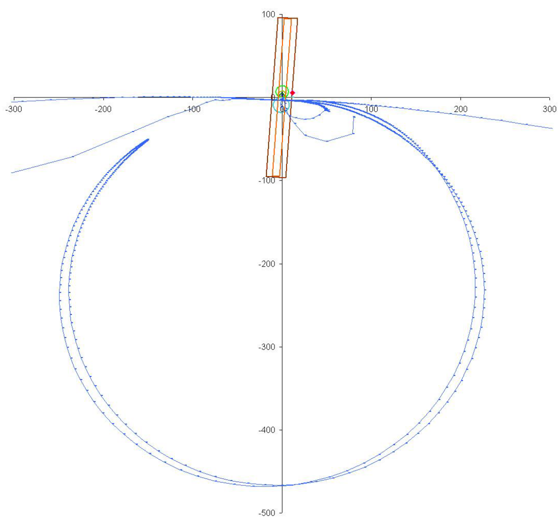

Fig. 8. SKA Impedance Trajectory for a Three-Phase Fault at SKA287

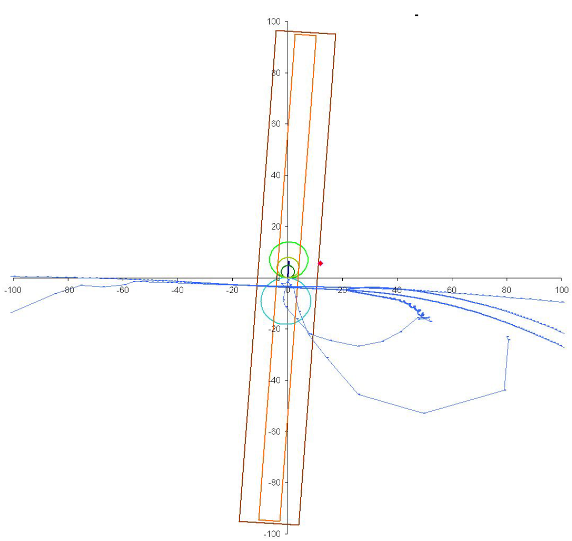

Fig. 9. SKA Impedance Trajectory for a Three-Phase Fault at SKA287, Magnified

C. *Tuning Out-of-Step Setting at SKA*

At the SKA terminal of 5L63, because OSB is not in use, the inner blinder can be set without regard to coordination with the mho elements. The outer blinder must still be set to coordinate with load. The blinders were set to obtain tripping for slip rates between 5 and 10 hertz. The problem is that this reduced the loadability of the line to 2000 amperes at 30 degrees. Because blocking is not in use, the blinders could be moved in while keeping the distance between them the same. Sometimes, OST would not assert on the first pole slip with these settings. By reducing the OSB delay, the valid tripping range was widened to 2–10 hertz slip rate. Based on the results, the out-of-step elements were set as follows:

- Block duration timer = 2.5 cycle
- Trip duration timer = 0.5 cycle
- Outer resistive blinder setting = 10.89 ohms
- Inner resistive blinder setting = 3.88 ohms

With these settings, OST asserted reliably on the first pole slip. With the reduced blinder settings, we are less likely to false trip on a stable swing.

However, because the relay issues OST when the impedance characteristic leaves the inner polygon, the trip occurs at a fairly wide system angle (just past 180°). To address this, positive-sequence voltage magnitude supervision was added to the OST logic. When the two systems are 180° out of phase, the voltage near the swing center is at its lowest value. As the swing progresses back towards 0°, the voltage near the swing center recovers. The modified OST logic has a timer that provides the relay with a 60-cycle opportunity window. If the positive-sequence voltage recovers to 0.8 per unit within that window of opportunity after the system has determined that a pole slip has occurred, a trip to the protection system on the SKA-KMO 287 kV line is issued to separate the KMO generation.

Fig. 10 shows the relay response for a three-phase fault (8.1-cycle duration) at SKA287 bus. The first analog axis corresponds to the voltages at the SKA and TKW 500 kV buses. The second axis corresponds to currents seen by the TKW terminal, and the third axis corresponds to the currents seen by the SKA terminal. A fault duration of around 8.0 cycles was the boundary for the system to lose synchronism. The system tried to remain stable after the three-phase fault but three seconds later it started slipping poles. The TKW terminal successfully asserted OSB (TOSB) for the event. The SKA terminal asserted OST (SOSTO). The SOST signal in Fig. 10 is the output of the out-of-step trip with the voltage supervision logic. Examination of the figure shows that the trip was delayed by the voltage supervision logic for 5 cycles to facilitate a favorable angle.

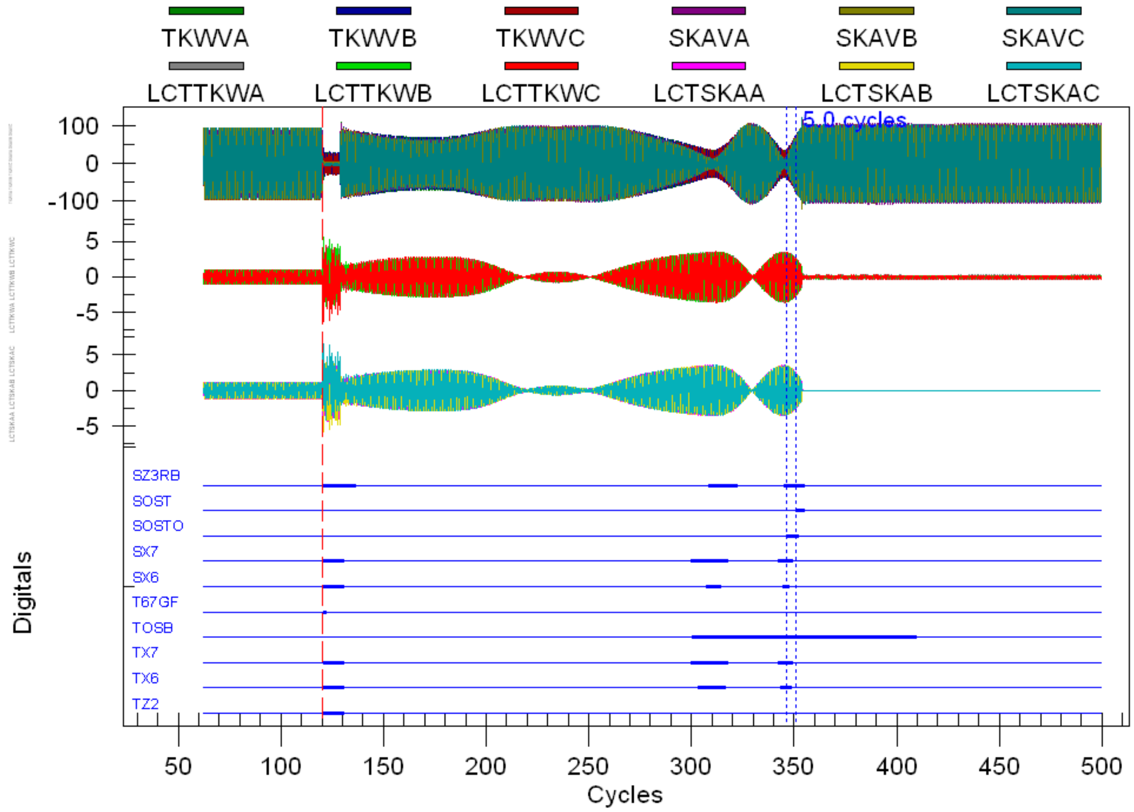

Fig. 10. Relay Response for an 8.1-Cycle Three-Phase Fault Behind SKA.

D. Tuning Out-of-Step Settings at TKW

At TKW, OSB is in use but not OST. For this protection system, the blinder settings must be outside of the mho elements but inside the loadability criteria. The distance between blinders is therefore constricted. For this element, the block duration timer was set to its minimum value in order to accommodate blocking. The protection system was set with the following set points:

- Block duration timer = 0.5-cycle
- Outer resistive blinder setting = 10.89 ohms
- Inner resistive blinder setting = 7.75 ohms

With the listed settings, the relay will block for slip frequency up to 4.3 hertz. For slip rates faster than 4.3 hertz, the relay will not block.

E. Faults During the Power Swing

To test for the dependability of the protection system for faults during a power swing, a series of additional simulations were initiated on the system. In these simulations, the swing was initiated by a three-phase fault on the SKA 287 kV bus. Then a single line-to-ground fault was applied internal to line 5L63. Timing on the internal fault was changed to verify the protection system response at different points in the swing. For a midline AG fault with OSB asserted at TKW, the SKA end asserted OST, but the voltage supervision did not allow the relay to trip because the SLG fault depressed the positive-sequence voltage.

Fig. 11 shows the SKA protection system response for the event. Signal PSV43, shown in Fig. 11, is the voltage-supervised OST output. SKA saw the fault in Zone 1 and issued a single-pole trip. SKA then transfer tripped TKW to clear the single line-to-ground fault. The event record for the TKW terminal relay is not shown. But, the TKW Zone 2 element also asserted to initiate pilot tripping after it was unblocked by its negative-sequence OSB unblocking logic.

During the single-pole-open condition, the swing center moved towards TKW because of the higher transfer impedance of the SPO line. Fig. 12 shows the impedance trajectory as measured by the RTDS. The first pole slip goes through the transformer behind the line terminal as expected. The second pole slip (after the single line-to-ground fault) goes through the protected line. Note that the curly characteristic of the impedance plot is caused by the fact that the RTDS apparent impedance measurement does not include frequency tracking. So, the measurement oscillates when operating at off-nominal frequency after the system starts slipping poles. SKA then operated its Z1G element on the next swing through center. Because this trip occurred during the pole-open period before the reclose, the relay converted to 3PT and opened the line.

Out-of-step blocking is not enabled at SKA; therefore, SKA tripped and transfer tripped TKW during the pole open. Ideally, we would want the relaying to selectively trip and reclose for a single line-to-ground fault during the swing. Applying OSB at SKA could help; however, this will constrain coordinating the blinders with the tripping elements and the loadability of the transmission line. BC Hydro decided to accept this operation, because this scenario is extremely unlikely to occur in operation.

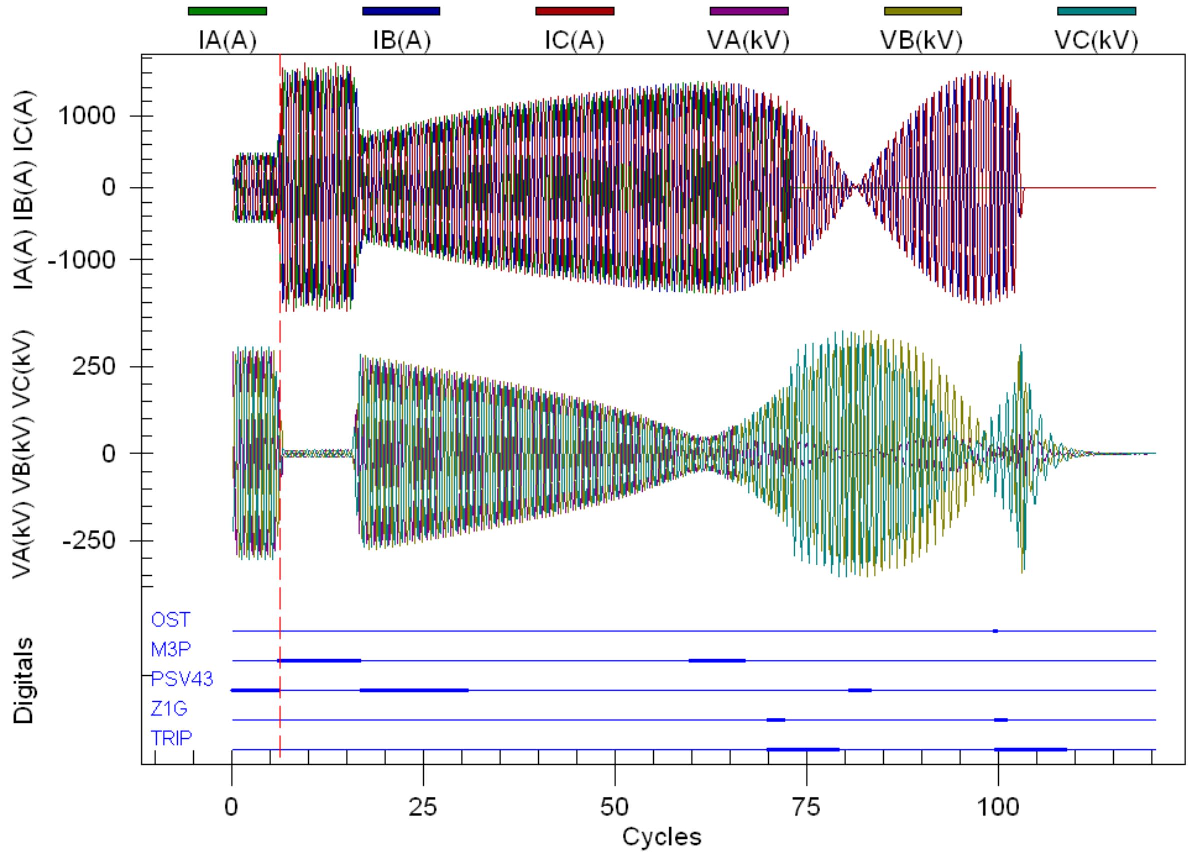

Fig. 11. SKA Protection System Response for an AG Fault During the Swing

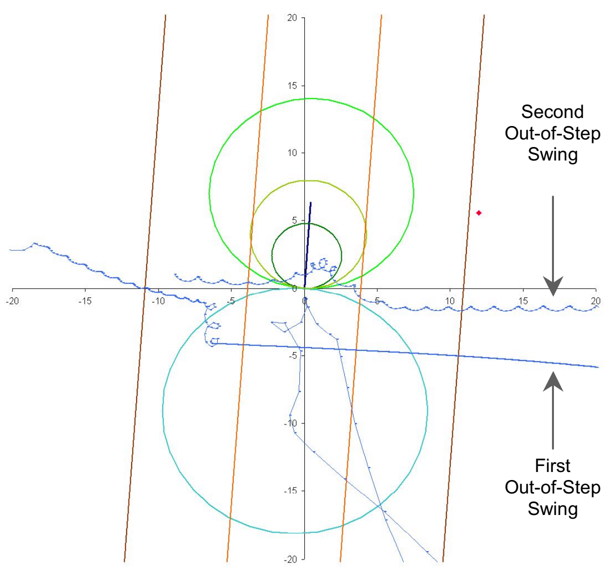

Fig. 12. SKA Impedance Trajectory for an AG Fault During the Swing

F. Final Testing

With final settings on the protective systems at either ends, a series of swing tests were initiated with a three-phase fault of duration varying 7 cycles to 20 cycles. This series of tests were intended to make sure that the blocking and tripping logic would assert for various swing rates. The relays successfully blocked at TKW and issued out-of-step trips at SKA for swings initiated by faults of 7–15 cycles.

Fig. 13 shows the impedance trajectories seen by SKA for a 10- and 15-cycle three-phase fault behind SKA. It is interesting to see the impedance trajectories start at the loading point (not shown), enter the mho characteristic during the fault, and then come out of the characteristic after the fault is cleared. The impedance trajectories try to stay outside the characteristic for a while, but eventually go for a full swing when the system collapses.

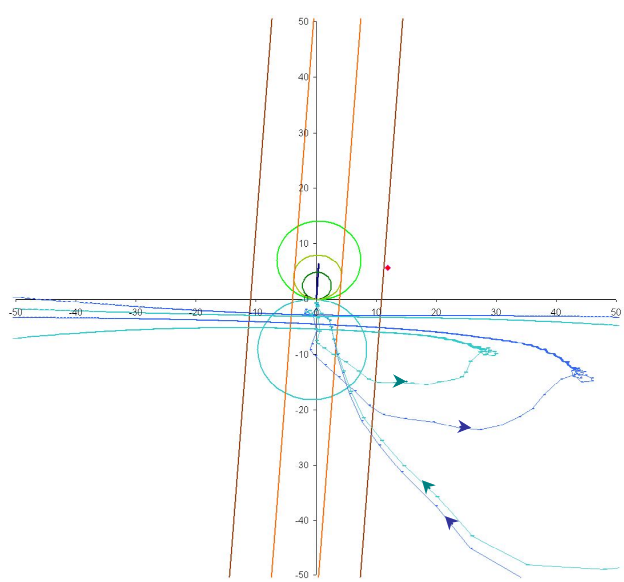

Fig. 13. SKA Impedance Trajectories for 10- and 15-Cycle Three-Phase Faults

The real time digital simulator, complemented with modeling machine dynamics, enabled us to refine the settings on the protection system. This would not have been achieved using conventional techniques.

VI. Case Study Two

To support high-power transfers westward on two long 500 kV lines, Selkirk (SEL) to Ashton Creek (ACK) and SEL to Vaseux (VAS) to Nicola (NIC), a remedial-action scheme is installed to shed generation near SEL during system contingencies to maintain stability across the East to West tie. Fig. 14 shows a simplified one-line diagram of the system. To be able to maintain the high flows during a permanent outage of one of these critical tie lines, single-pole trip protection systems are being added to these lines.

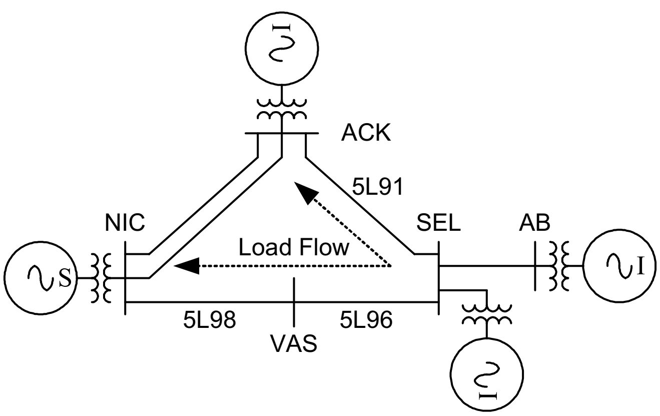

Fig. 14. Simplified One-Line Diagram for Case Study Two

The generation is from several 230 kV-connected generating stations near the SEL 500/230 kV station. An additional source of East to West power flow is delivered to SEL by the 500 kV intertie from Alberta. Attachment 4 shows the test system used for Case Study Two. The source models with "I" are inertia models (governor, exciter and stabilizer controls). The models with "S" are static models. A series of tests were performed using a real time digital simulator to test the protection on lines from SEL to VAS and from VAS to NIC. This discussion is limited to the tuning of the remedial action schemes (RAS) under single-pole-open conditions and once again emphasizes the use of new technology to study and analyze systems.

A. *RAS Associated With 5L96 and 5L98*

With one SEL 500 kV line, 5L91, open, 5L96 at SEL may be loaded to about 1700 MW. Stability studies of this operating condition and a single-pole trip on the line indicated that the rotor swing would be stable without using any generation-shedding RAS. Fig. 15 shows the results of the dynamic stability program predicting stable relaying for a 5L96 pole-open condition with 5L91 out of service. The plot shows the impedance trajectory staying outside Zone 3 while the faulted pole is open, then moving into Zone 3 due to the successful reclose, and finally exiting Zone 3 as the swing damps out. Refer to Attachment 5 for the complete impedance plot from the stability program.

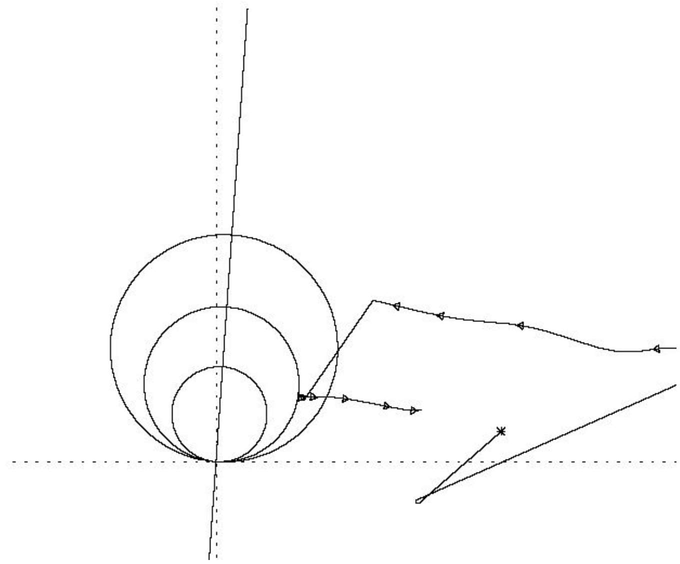

Fig. 15. Impedance Seen by 5L96 Relay at SEL for a Single Line-to-Ground Fault With 5L91 Out of Service

B. *Preliminary Testing*

The tests were performed on the system with 5L91 out of service. The relaying on test line 5L96 is of similar configuration to that described in Case Study One for line 5L63. For an AG fault close in to the SEL terminal of line 5L96, SEL issued a trip on pole A (STPA1) and transfer tripped the A-phase VAS terminal. During the pole-open period, the SEL terminal unfortunately issued a three-pole trip and sent a three-phase direct transfer trip to the VAS terminal. Fig. 16 shows the relay response for the event. The first analog axis in the figure corresponds to the secondary bus voltages seen by the SEL and VAS terminals. The second- and third-analog axis correspond to the secondary currents seen by the SEL and VAS terminals respectively. The digital traces labeled "nTPp1" represent the individual phase trip signals, where "n" is the terminal and "p" is the phase. "SPTR" represents SEL Permissive Trip Received and "VRDTT" represents VAS Direct-Transfer Trip Received.

Traditional dynamic-stability analysis indicated that the system would remain stable for this load flow during a single line-to-ground fault and a subsequent single-pole trip. What the traditional analysis could not predict was what the relay's measuring elements would see during this single-pole-open condition.

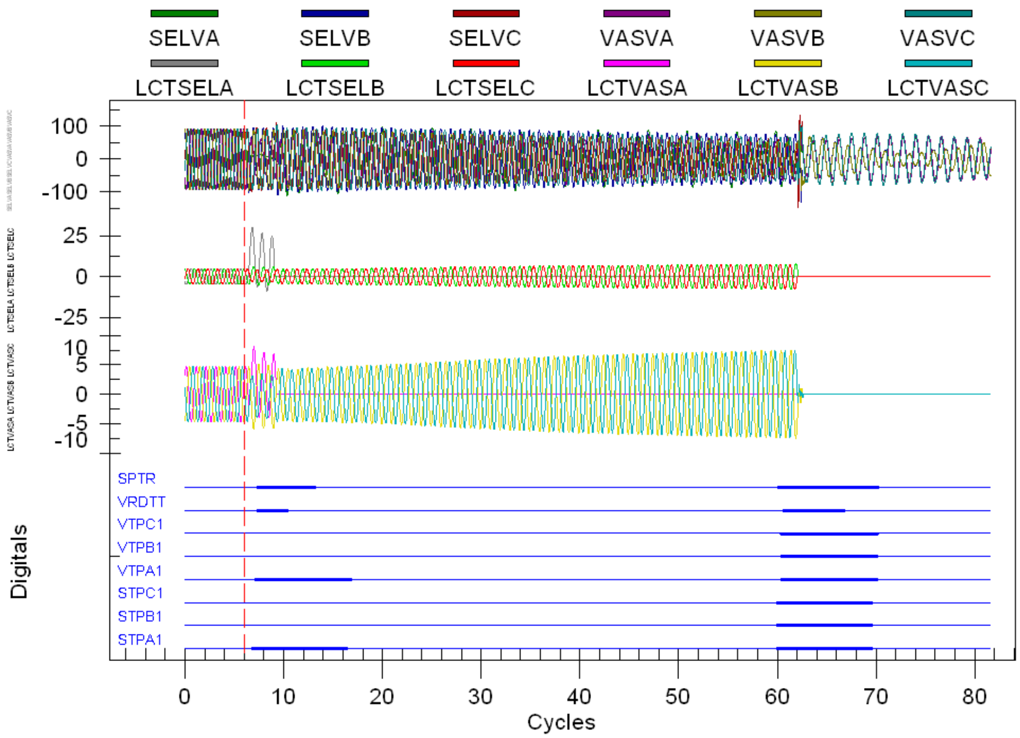

Fig. 16. Protection System Response at Either Terminal for a Close-In AG Fault at SEL End on 5L96

Fig. 17 shows the apparent impedance as a function of line reach with respect to time for the three ground-distance measurement elements as seen by the SEL terminal. During the fault, the phase A ground distance (MAG) element goes immediately below the Zone 1 ground threshold causing a trip on phase A. The other two measurement loops are disabled by the faulted loop identification logic (FIDS) so their measurement is not valid during this time. During the pole-open period the B- and C-phase ground loops are then re-enabled. The ground impedance trajectory on the healthy phases (MBG, MCG) swings below the Zone 2 threshold during the resulting power swing. When a second trip occurs during the single-pole-open period, the relay converts to three-pole trip.

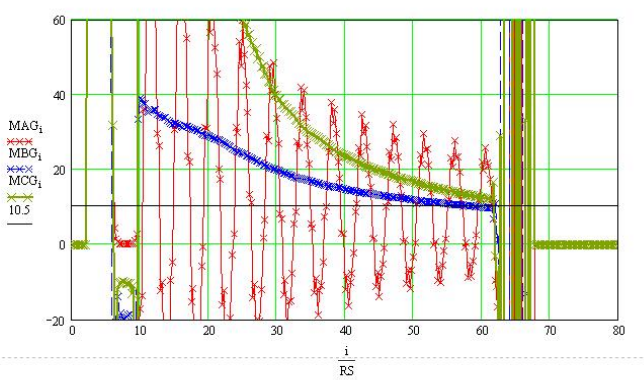

Fig. 17. SEL Ground Elements for an AG Fault on 5L96, no RAS

To stabilize the relaying under single-pole-open conditions, the planning engineer suggested including 200 MW of generation shedding in the RAS scheme for single-pole trips for that system contingency. Previous to the test, it had been expected that no RAS would be required for single-pole trips for this system contingency.

Tests were repeated with the proposed modifications to the RAS system. Fig. 18 shows the response of the mho ground elements for an identical event described earlier in the section but this time with generation shedding. This time, the system is able to ride through the single-pole-open condition until the reclose and remain stable. The modified use of the generation-shedding RAS ensures that the 500 kV line protection system does not trip the single in-service 500 kV East to West line and prevents the system from going out of step.

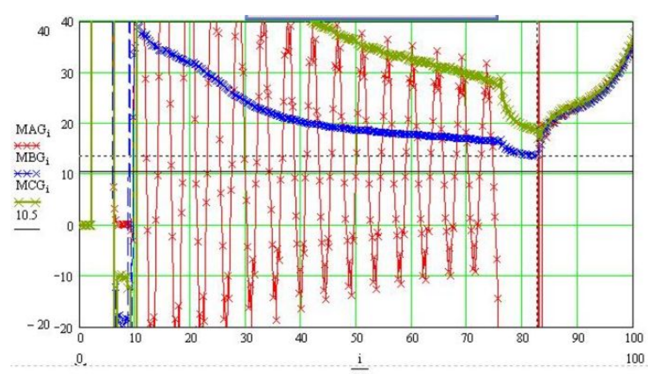

Fig. 18. SEL Ground Elements for an AG Fault on 5L96, With RAS

During this exercise some tests with three-pole trips were done to confirm the generation shedding amount necessary to provide a stable result. For a three-phase fault on line 5L91 with an unsuccessful reclose, a generation shed of 400 MW was just enough to prevent instability in the absence of 5L96 relay action. However, with the relays active during the test, the relays on line 5L96 issued a three-pole trip on the resulting power swing. The testing indicated that shedding an additional

200 MW of generation kept the protection system stable under these conditions.

VII. Conclusions

1. Traditional methods for doing dynamic stability studies do a good job of determining how stable the power system is under various operating contingencies. However, the simplistic plot of positive-sequence impedance on the RX plane cannot fully predict the response of relay elements during the disturbance.
2. When protection experts and dynamic-stability experts work together in a team approach using a real time digital simulator, the reality of transient and dynamic simulations is greatly improved.
3. This technique can be used to validate the response of out-of-step blocking and out-of-step tripping elements.
4. This technique can be used to validate the response of remedial action schemes for both three-pole-trip and single-pole-trip contingencies.
5. Better understanding is gained and the response of relay elements to power swings during unbalanced conditions can be thoroughly studied by using this technique.
6. Testing has greatly improved the quality of protection system design and settings on the BC Hydro system.

VIII. References

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[2] D. Tziouvaras and D. Hou, "Out-of-Step Protection Fundamentals and Advancements," Proceedings of the 30th Western Protective Relay Conference, Spokane, WA, October 2003.

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[4] Joe Mooney and Normann Fischer, "Application Guidelines for Power Swing Detection on Power Systems," Proceedings of the 32nd Western Protective Relay Conference, Spokane, WA, October 2005.

[5] Prabha Kundur, *Power System Stability and Control*, McGraw-Hill, 1994, pp. 885–902.

[6] Hermann W. Dommel, "Digital Computer Simulation of Electromagnetic Transients in Single and Multi-Phase Networks," Paper 68 TP 657-PWR presented at IEEE Summer Power Meeting, Chicago, IL, June 1968.

[7] Charlie Henville, Ralph Folkers, Allen Hiebert and Rudi Wierckx, "Dynamic Simulations Challenge Protection Performance," Proceedings of the 30th Western Protective Relay Conference, Spokane, WA, October 2003.

[8] SEL-421 Relay Instruction Manual, January 2005.

IX. Biographies

Frank Plumptre received his BSc degree from the University of Calgary, Alberta in 1975. Since 1976 he has been with the Protection Planning Section of BC Hydro and is presently working as a specialist engineer within that group. Frank is a member of the IEEE, and is an appointed member of the IEEE Power System Relay Main Committee (PSRC). He is also vice chair of the Substations Protection Subcommittee, and Awards and Recognition Chair of the PSRC. He is a registered Professional Engineer in the province of British Columbia.

Stephan Brettschneider received his electrical engineering degree from the University of Karlsruhe in Germany in 1996. Afterwards, he joined the University of Quebec in Chicoutimi, Canada, where he obtained his Ph.D degree in high voltage engineering in 2000. In 2001, he moved to HV Technologies Inc., USA, as a technical specialist. Since 2003, he has been with Cegertec Inc., Canada, as a consultant in the fields of power system engineering, protection design, and electrical maintenance services. He is a registered Professional Engineer in the provinces of Quebec and British Columbia and a member of the IEEE.

Allen J. Hiebert received his BASc degree from the University of British Columbia in 1972. He has 30 years of experience in transmission planning. He is presently a senior engineer in Transmission System Planning at British Columbia Transmission Corporation (the operator and manager of BC Hydro's transmission system). He is a registered Professional Engineer in the province of British Columbia.

Michael J. Thompson received his BS, Magna Cum Laude from Bradley University in 1981 and an MBA from Eastern Illinois University in 1991. He has broad experience in the field of power system operations and protection. Upon graduating, he served nearly 15 years at Central Illinois Public Service (now AMEREN) where he worked in distribution and substation field engineering before taking over responsibility for system protection engineering. Prior to joining Schweitzer Engineering Laboratories in 2001, he was involved in the development of a number of numerical protective relays. He is a Senior Member of the IEEE and a member of the Substation And Rotating Machinery Subcommittees of the IEEE, PES, Power System Relaying Committee. Michael is a registered Professional Engineer in the State of Washington and holds a patent for integrated protection and control system architecture.

Mangapathirao "Venkat" Mynam received his MS in Electrical Engineering from the University of Idaho in 2003 and a Bachelors in Electrical and Electronics Engineering from Andhra University College of Engineering, India, in 2000. He is presently working as a protection engineer with Schweitzer Engineering Laboratories. He is a member of IEEE. His interests include power system protection, system modeling, and power electronics.

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Attachment 1

PF-3500MW-FOR-DEMO-SWINGS

SHAW POWER TECHNOLOGIES INC.

FILE: ...\pf-eq4\ou-att-pf14-eq4-a-3500-demo-slip-5L3and2WSN2p0cy.out

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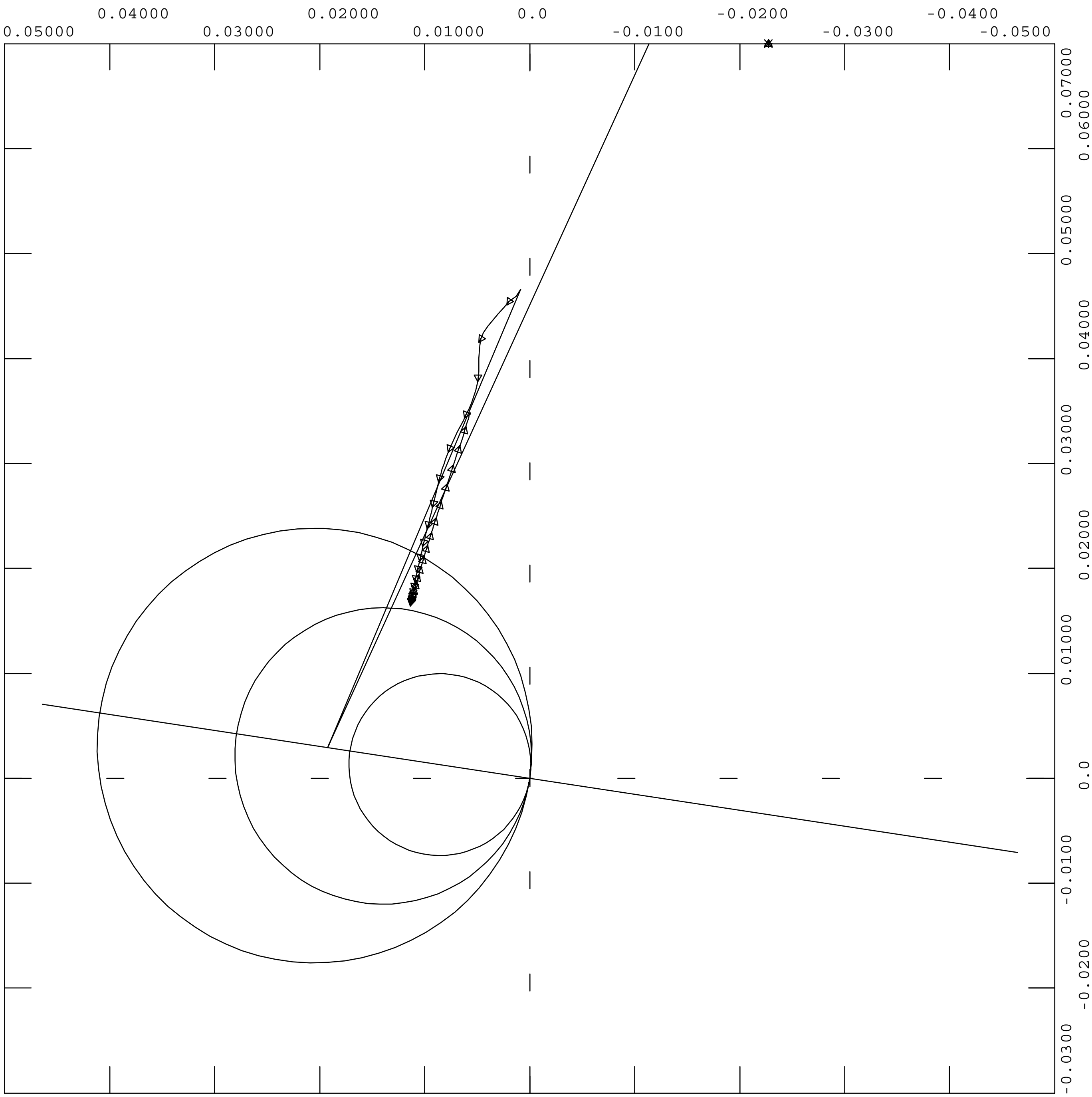

Attachment 2

SHAW POWER TECHNOLOGIES INC.©

PF-3500MW-FOR-DEMO-SWINGS

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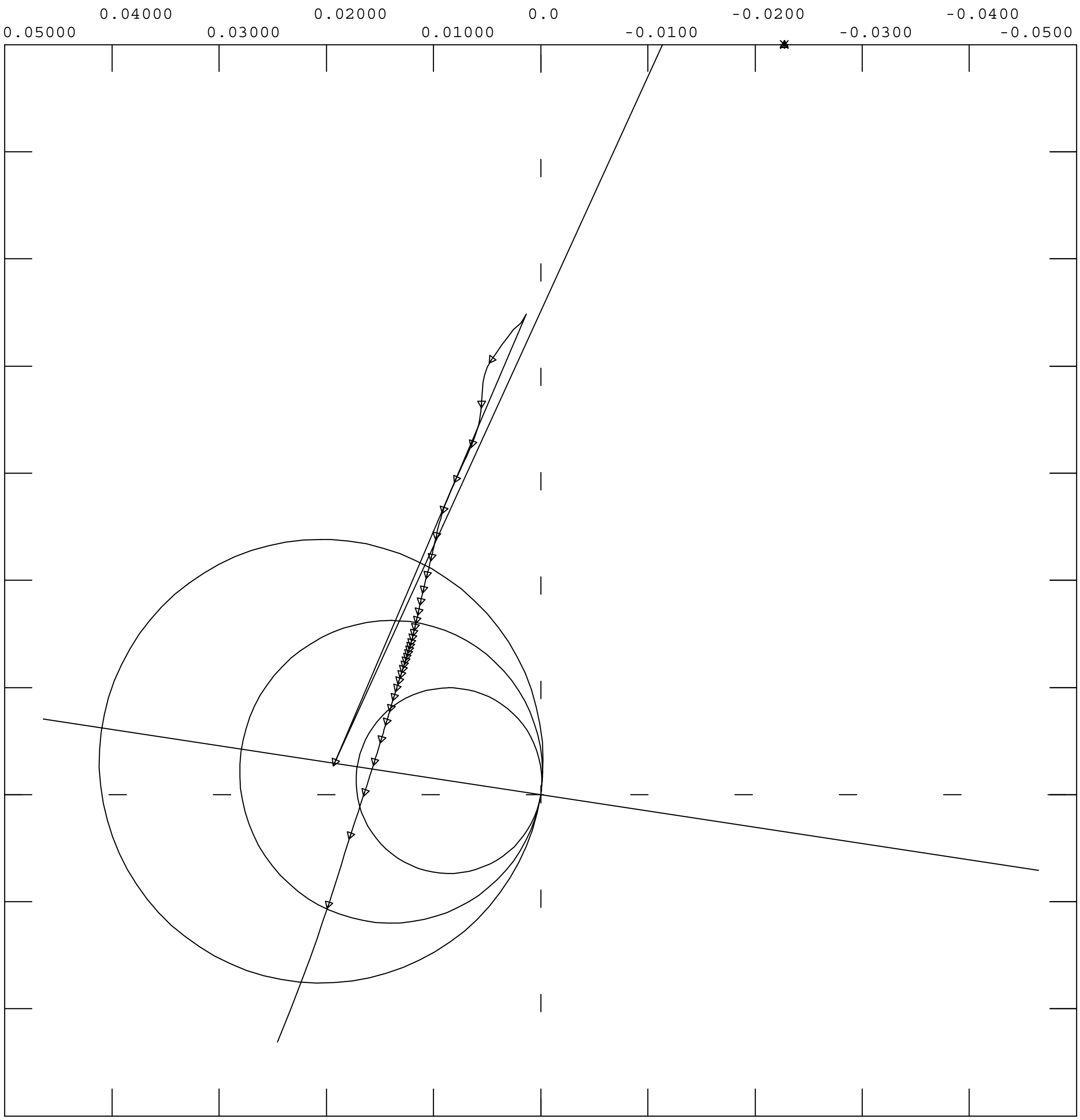
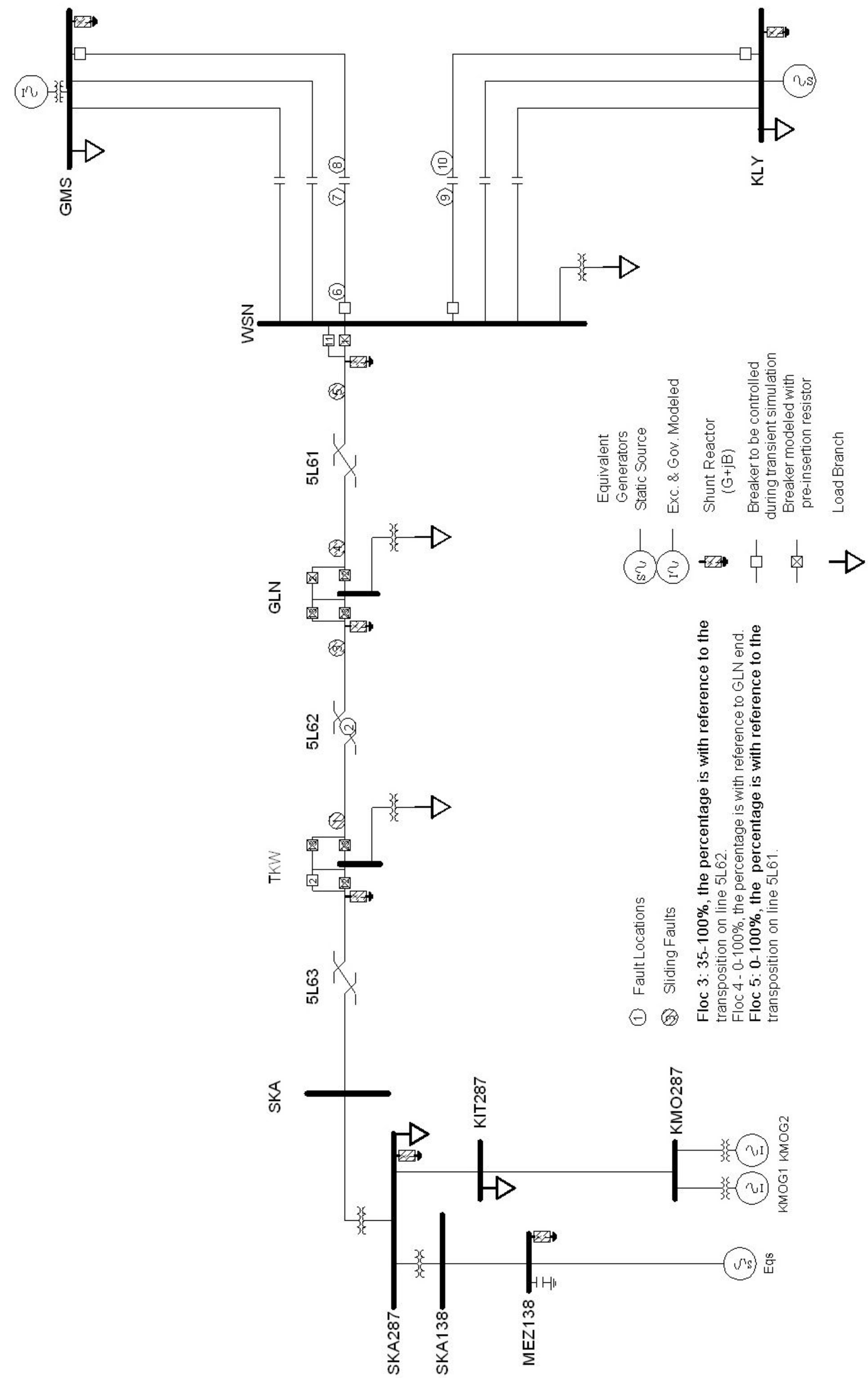


THU, MAR 09 2006 11:09

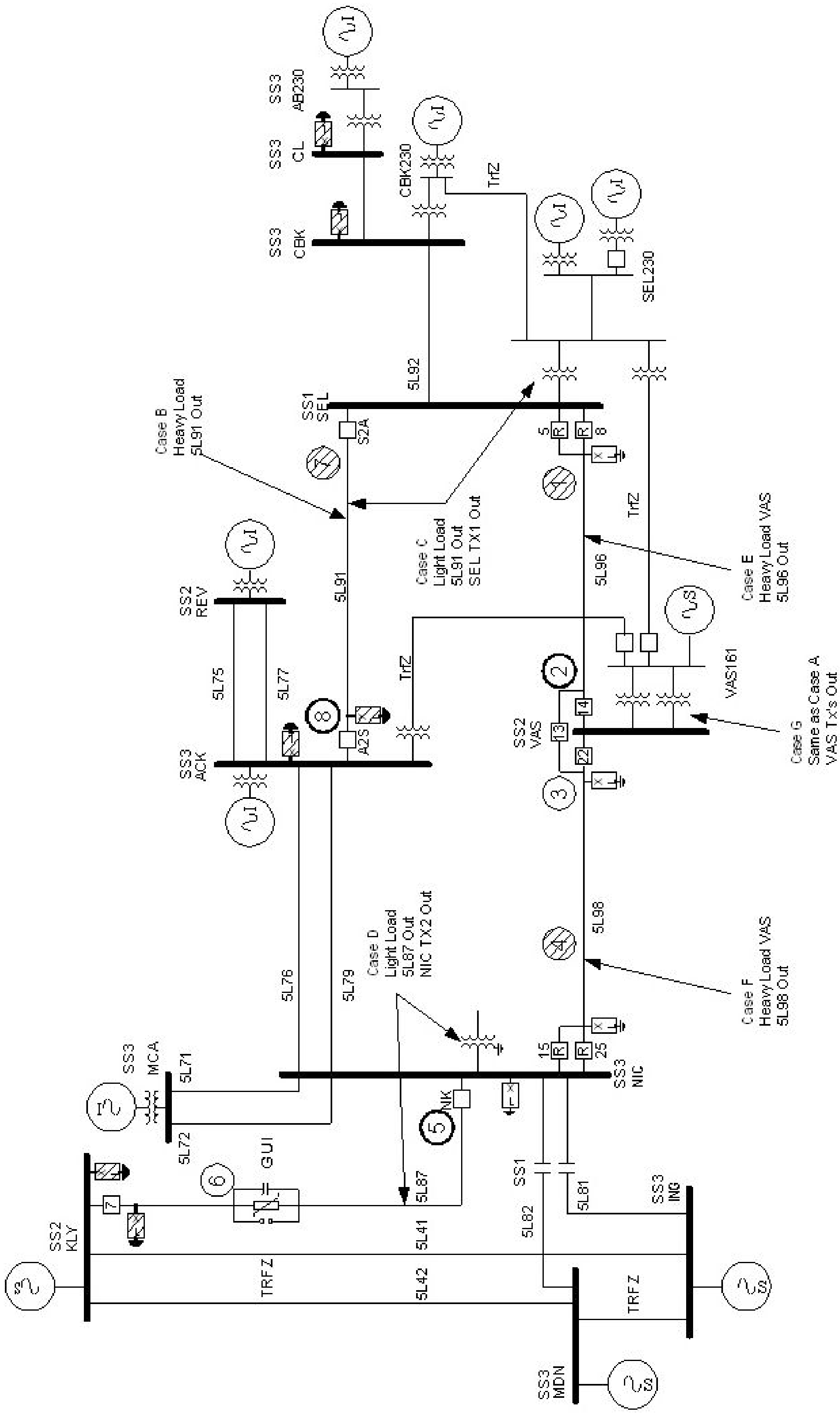
APPARENT R,X PU GMS-WSN

Attachment 3



Test System for Case One

Attachment 4



Test System for Case Two

Attachment 5

SHAW POWER TECHNOLOGIES INC.

PF-SVN-B - 5L91 SEL-ACK OPEN, 5L96 SEL-VAS AT 1700 MW
- FOR 5L96 SLG FAULT AND SUCCESSFUL RECLOSE.

THU, MAR 09 2006 11:11

APPARENT R,X PU SEL-VAS

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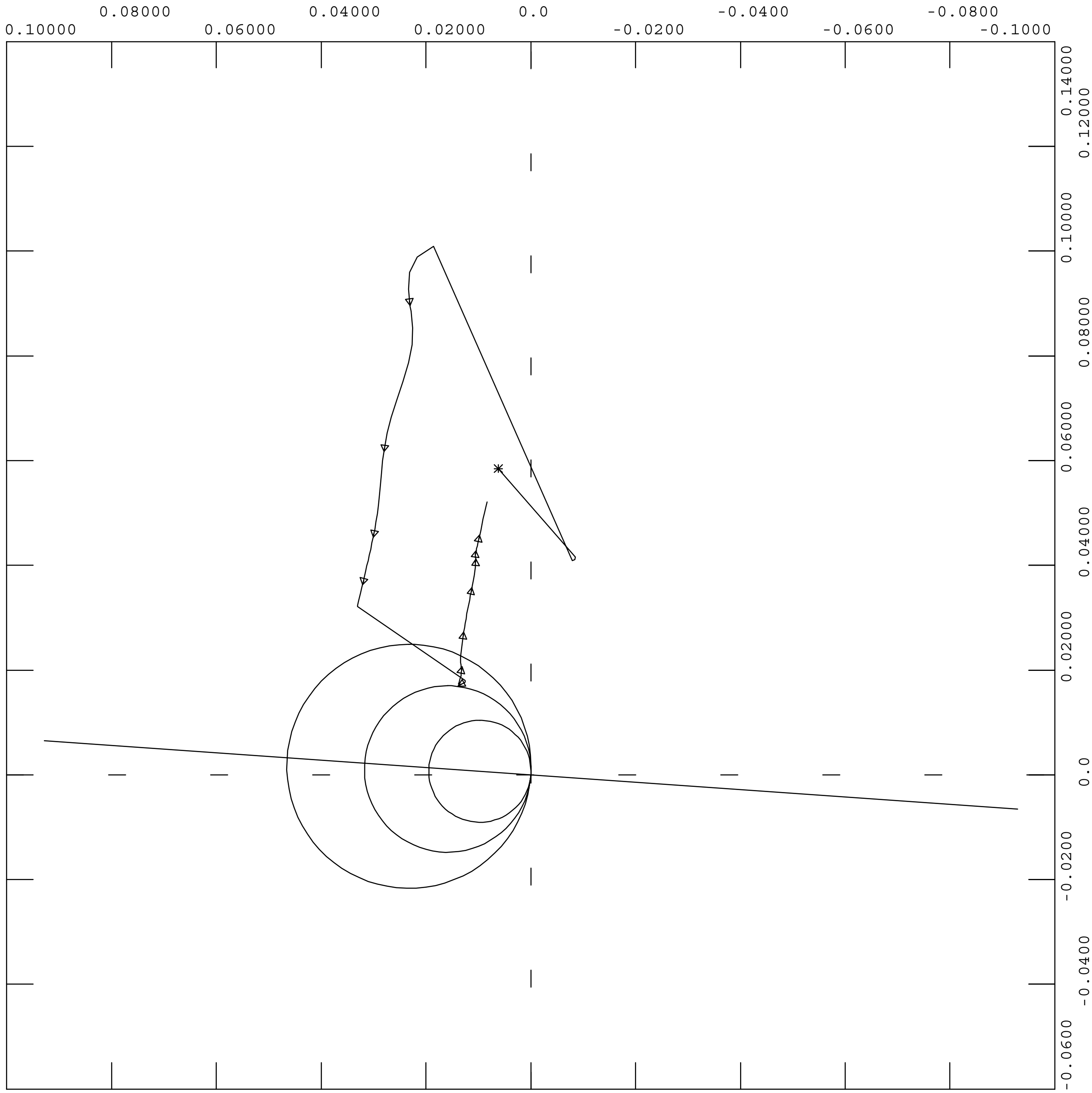

CHNL# 157: [APPARENT R PER UNIT SEL-TO-VAS]