Extreme Line Distance Protection Testing

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Extreme Line Distance Protection

Abstract: Modern line distance protection relays are manufactured with complex algorithms, sophisticated schemes, and programmable logic and are designed to operate quickly, reliably, and securely for all types of faults that can occur during varying power system conditions. In 2008 the Bonneville Power Administration (BPA) began testing the most recent line protection relays from multiple vendors for the purpose of qualifying a new design package for its 500kV line protection.

Awareness of BPA protection standards as well as existing equipment guided the engineers creating the test procedure. The BPA 500kV line protection standard requires that relays provide secure, high-speed, single-phase tripping on long and short lines with weak and strong sources. The relays must be secure from false operation for heavy loading, system swings, mutual coupling from parallel lines, faults on parallel lines, resistive faults, very weak sources, very strong sources, and when series capacitors are in the vicinity of the relay location. The relays must be capable of operating with two-tone and four-tone FSK audio analog microwave radios as well as with newer digital communications via optical fiber and digital radio.

BPA engineers also had to understand the configuration of their transmission system and the extreme conditions it operates under. Two identical line distance relays were used to simulate protection for each end of a modeled transmission line using a digital power system simulator that replays COMTRADE files created from EMTP simulations. A specific 500kV transmission line within BPA's control area was selected to be protected component of the modeled power system for the purpose of testing the relays because it offered an extremely challenging line configuration with demanding operating conditions where false trip operations could cause the greatest problems for the BPA system. The primary component of the modeled power system consists of a long line with series capacitors at both ends that is in parallel to another line with series capacitors at both ends. One of the important decisions BPA engineers had to make was to what extent the surrounding system should be modeled.

The theory behind distance elements from different relay manufactures must be understood in order to apply the optimal settings for the best results. Some of the operating conditions that the relays were subjected to included; faults on heavily loaded lines, resistance in the ground fault path, mutual coupling, faults on parallel lines, series capacitors internal and external to the zone of protection, sub-harmonic oscillations during fault events (varying measured fault impedance), unbalanced load transfer from an adjacent faulted line to an unfaulted line, detecting a ground fault with fault resistance on a heavily loaded line, and properly detecting faults when the series capacitors do not bypass.

This paper describes the process BPA engineers used in creating a comprehensive test platform necessary to test the full capabilities of modern line relays as well as the challenges of applying different line protection relays and evaluating the performance for extreme but realistic fault cases.

Introduction: The BPA operates and maintains approximately 75% of the high-voltage transmission in the North West United States. This includes the BPA's EHV main grid transmission, which is a 500kV system that as of 2008, spanned 4734 circuit miles with lines in Washington, Oregon, Northern Idaho and Western Montana and interconnections with British Columbia and California. Because the North West system is primarily built on remote generation sources, many of the lines are 100 miles or longer. BPA uses series capacitors on parallel paths to improve the stability margins of the system and increase load capacity levels of these long lines. Also to increase the stability and reliability to the system, BPA requires high speed protection in single-phase tripping schemes for most of the lines. BPA's existing EHV line protection schemes consist of high spend, hybrid combination of single-phase static directional wave relays and solid-state distance relays and early to late obsolete micro-processor distance relays. Some of the protection packages have been operating on the BPA EHV system for 30 or more years. As the protection equipment begins to fail or transmission requirements in the form of tighter operating margins and stricter regulatory standards exceed the existing equipments capabilities, BPA is forced to constantly replace it one line position at a time. In 2008, system protection engineers at BPA began testing the most recent line distance protection relays from multiple vendors for the purpose of qualifying a new design package for its 500kV line protection.

Distance elements embedded in a transfer trip type scheme were chosen to be the next protection system for BPA's EHV lines for several reasons. BPA requires two redundant sets of relays with two sets of redundant communications. Because not all of BPA's communication systems have been upgraded from analog microwave to digital communications via optical fiber or digital radio, any protection scheme must be capable of communicating between relays over audio channels.[1] The well known advantages of distance relays provide a reliable protection option that work well with some of BPA's limited communication equipment available. These advantages include: a fixed reach function of the line impedance that make them independent of system load and the capability of detecting wide range of fault levels.[2] The transfer trip scheme is a phase segregated permissive over–reaching scheme with echo back logic. Setting the distance relays in a heavily loaded series compensated system can get quite detailed, and involves compromises. It is for this reason that BPA also included a line differential relay in the new protection scheme for the 500kv system. Where digital channels are available, line differential schemes will be used and distance relay protection will be included as back up.

Once the type of protection was selected, BPA engineers began taking the necessary steps of creating a comprehensive evaluation procedure. The first step taken was creating a wide-ranging list of system operating states, line configurations and past recorded faults of BPA's EHV system. From this list, some of the most challenging conditions that were identified included: heavy loading, single-phase tripping requirement, series-compensated lines, parallel line configurations, and high resistant faults recorded. BPA engineers then defined the minimum hardware and performance requirements that a modern distance relay platform must meet to be applied to BPA's 500kV system. Based on these conditions and requirements, a specific 500kV transmission line within BPA's control area was selected to be the protected component of the modeled power system because its characteristics encompassed many of the protective challenges indentified and could provide a good model to measure the reliability of a modern relay system. The line model was also chosen because it required a high degree of security for which it offered multiple disturbances that the relay should not trip.[3] False trip operations on this line could cause severe instability problems for the BPA system. Relays that operate correctly for this line model can operate properly on any line in the 500kV system. EMTP studies based on the list of challenging conditions and actual system faults were performed to generate test cases using this line model. The overall goal in developing the test was to measure the dependability of the protective relay to correctly operate for internal fault conditions and the security of the protective relay to correctly not operate for external fault conditions.[4]

With the protection scheme and line model chosen, BPA engineers built the test bed for evaluation. A digital model power system was used to playback the EMTP test cases and record the trip times and operations of the relays. The engineers then solicited multiple vendors to submit two of their most advanced line distance protection relays for local and remote protection of the line. The breaker simulator was programmed using an actual 500kV breaker failure relay.

Distance Protection Challenges:

BPA's 500kV system includes many of the challenging conditions presented to line distance relays that are commonly found on other EHV systems. Six of the most common challenges found on BPA's EHV system include the requirement for single-phase tripping, series-compensated lines, parallel lines, high resistance faults, power system swing conditions, and heavy line loading. This paper gives only a brief explanation of these challenges. Please see the list of references for complete and comprehensive report of these conditions.

Single-phase Tripping

Single-phase tripping (SPT) is used to open the faulted phase during a single-line to ground fault.[2] Its well known that single line to ground faults are the most common types of faults accounting for 70% of all instances and in the case of 500kV transmission lines they account for 93% of all instances due to the increased spacing of the EHV conductors.[5] With SPT the system stability is improved and the power transfer capacity is increased during one-line-to-ground fault conditions, because the system remains interconnected on two phases. This allows for the system to remain synchronized and for power to be transferred during a single-line-to-ground fault condition.[2,6] For the benefits of SPT to remain the fault must be cleared, any remaining secondary arc must also be cleared, and the line must be reclosed.

The measuring elements from distance relays that are used in SPT logic include: fault zone detection, directional discrimination, load discrimination, and phase selection.[5] Thoughtful application of these elements are required to overcome the challenges from utilizing a SPT scheme. The two most difficult challenges with a single-phase scheme are proper selection of the faulted phase and the open phase condition that occurs after the faulted phase is tripped. Phase selection is troublesome for distance relays because unfaulted phase elements and ground elements that are based on zero sequence current and a compensating factor, tend to pickup for faulted phases.[5,6,7] This may occur when the zero sequence impedance is less than the positive sequence impedance as seen from the point of the fault. If a relay overcomes the problem of selecting the correct phase it is then faced with the issues surrounding an open-phase condition. Depending on how a relay is designed, distance and directional elements could be adversely affected by open-phase conditions. Distance elements that use positive sequence voltage measured from line side PTs to calculate frequency are subjected to magnitude and frequency excursions during an open phase conditions.[8] The frequency excursion is the result of energy stored in the line reactance and capacitance, and any shunt reactance, which results in a resonant circuit that produces a natural frequency that may be close to the fundamental.[7] If the distance elements do not have mechanisms to track to the correct frequency, they could overreach because the apparent impedance may cross their zone of protection. Directional elements that depend on negative and zero sequence quantities are subject to false indications at both ends of line, due to the negative and zero sequence currents that flow in the protected circuit during an open-phase condition.[6]

Series Compensation

Series capacitors are inserted into transmission lines to reduce their total impedance which reduces the overall transmission loss. This benefit results in a higher power transmission capacity, higher system stability limits, better load division on parallel paths, ability to adjust line load loses, and reduced voltage drop during severe system disturbances.[2, 9]

There are three primary attributes of series compensated lines that adversely affect distance relaying. The first attribute is the amount of added capacitance to the line. The added capacitance is detrimental to the fixed reach benefit of distance protection. Lines with series capacitors are normally compensated between 25% - 75% of the line impedance.[9] A typical zone 1 setting must be shortened to less than the overall impedance of the compensated line. For example, a zone 1 set for instantaneous tripping with a setting of 85% of the line impedance must now be set at around 85% of the compensated line impedance to prevent false trips on through faults. In some extreme cases the zone 1 setting must be lowered even more. Under reaching distance elements of non-compensated lines are susceptible to false trips for external faults on adjacent series compensated lines and therefore should be set no more than 50% of the line. The added capacitance affects the transmission circuit by contributing to the series resonance when it is combined with impedance of the line. System disturbances will excite the system and a subharmonic frequency will produce a transient current.[9] The second attribute of series compensated line that affects distance relaying is the location of the series capacitors. Series capacitors can be located at either end of the line or in the middle of the line. Typically they are located at the ends of the line to eliminate installation cost of building a new site that would be required if they were to be located in the middle of the line. Capacitors located at the end of the lines are subject to more complex proyection challenges. When series capacitors are located at the line ends, the PTs may be placed either on the bus side or the line side of the series capacitors. Two common problems associated with series compensated lines are voltage inversions and current inversions.[9,10,11] Voltage inversion is a 180 degree shift of the voltage angle that occurs for a fault near a series capacitor and the resulting impedance seen from the location of the PTs to fault is a negative or capacitive value. While this may occur if the series caps are placed the center of the line, it's much more likely to occur for a close end fault where PTs can be located either on the bus side of the series caps or located on the line side of the series capacitors. Figure 2 depicts how the location of the measuring PTs affects the polarity of voltage seen by the protective relay for an internal fault and an external fault.

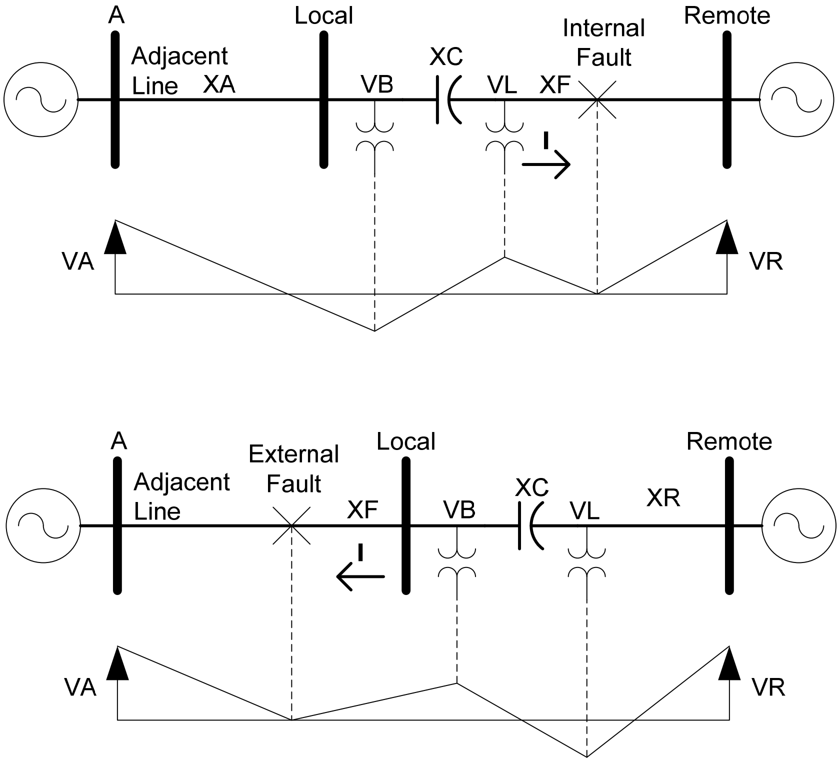

Figure 2 Voltage Summary for Internal and External Faults

For a voltage inversion to occur the series capacitance must be greater than the faulted line impedance XF, but less than combined source impedance of XA or XR and the faulted line impedance XF. Directional elements that measure voltage from the fault side of the series capacitor will correctly identify the fault direction. Directional elements that measure voltage from the unfaulted side of the capacitor may not identify the correct fault direction.[9,10] Directional elements that rely on negative sequence and zero sequence networks are vulnerable to voltage inversion, if the total impedance measured behind the relay is less than the capacitance. For internal and external faults, the sequence directional element using voltage measured from the faulted side of the capacitor will incorrectly indentify it in the reverse direction while the sequence directional element using the voltages measured form the unfaulted side will correctly indentify it in the forward direction.[9,10] A current inversion occurs for an internal fault when the current at the local end of the line is seen going into the line because the line impedance at that end appears inductive, while at the remote end of the line the current is seen coming out of the line because the line impedance at that end appears capacitive. For a current inversion to occur the total system impedance must be less than the capacitance. The event of a current inversion is independent of the location of the PTs but is more likely to occur with the series capacitors are located at the end of the lines. Current inversion affects the directional and distance elements line distance protection relays. In general capacitors placed in the middle of the line, primarily affect the distance elements but not the directional elements. The exception is when the quantity of series compensation is very high.[10] The third attribute of series compensation that adversely affects distance relaying is overvoltage protection of the series capacitor. Most of the series capacitors on the BPA system use metal oxide resistors with bypass breakers to provide over voltage protection. Some of the series capacitors on the BPA system also include a triggered gap as shown in Figure 3.[1]

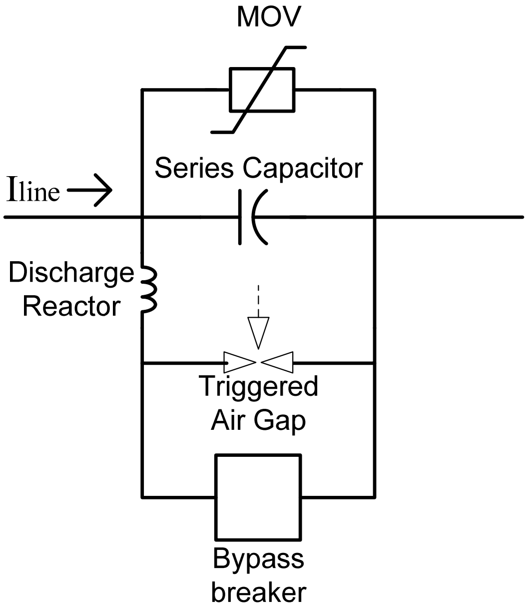

Figure 3 Basic Circuit of an MOV-Protected Series Capacitor

When a fault current or heavy loading causes voltage across the capacitors to increase, the MOV limits the voltage increase to a preset level of 2 to 2.5 per unit by absorbing the energy. The MOV begins to conduct when the overvoltage threshold is reached which will change the value of the impedance of the line compensation. For some internal faults the MOV is not capable of dissipating all of the energy and must be bypassed with a breaker. This may take as long as two cycles. If a trigger gap is included in the capacitor protection then it may be bypassed much faster for an especially high fault current. MOVs, generally will not need to be bypassed for external faults. Because the MOVs are absorbing energy they do not remove the series capacitance in a linear fashion. MOV protected series capacitors are challenging for the distance elements of line relays because they could be in service, bypassed by the non-linear resistance of a MOV, or bypassed by a breaker or gap. Over reaching distance elements are susceptible to a fault appearing more resistive and their pickup may be delayed due to conduction of an MOV. Therefore this element should be set higher than normal on series compensated lines that have MOV protection.[10] The non-linear resistance characteristic of the MOV protection can influence a voltage reversal condition by reducing the faulted phase angle shift to well below 180 degrees.

Parallel Lines

Benefits of parallel lines are similar to those of series compensated lines. They result in a higher power transmission capacity, higher system stability limits, and better load division on parallel paths.

The three main challenges associated with parallel transmission lines that adversely affect the security of distance protection schemes are mutual impedance, current reversals, and cross country faults.[12] Mutual impedance is the inductive coupling that exists between two lines that are parallel for part or all their lengths and can be as high as 50-70% of the zero sequence self-impedance. The detrimental effects of mutual impedance result when a ground fault occurs. Specifically ground distance elements are affected because an induced voltage that is proportional to the zero sequence current of unfaulted parallel circuit is added to the voltage of the faulted circuit. The fault current itself, is not affected by the mutual impedance. Depending on the direction of the current flow in the healthy circuit, the ground distance element could either underreach or overreach its measured impedance. The second challenge when using a distance protection scheme to protect parallel lines is current reversal. Current reversal is not the same as the current inversion that occurs with series compensated lines. As shown in Figure 4, if a fault occurs close to breaker B, a current reversal results on the unfaulted line (CD) immediately after breaker B trips open and lasts until the breaker A is tripped open.

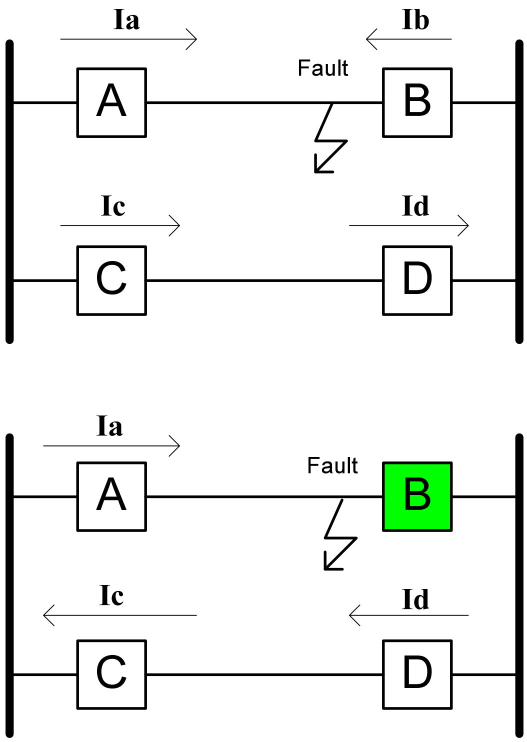

Figure 4 Current Reversal Condition

In this case, the operation of the distance and directional elements in a permissive overreaching transfer trip scheme will affect the security of the unfaulted line if appropriate blocking logic and delay timers are not used. The third challenge when using a distance protection scheme to protect parallel lines is the possibility of "cross country faults". One type of cross country fault occurs when two parallel lines are built too close together and one phase from one line faults to one phase from the parallel line. Because cross country faults can appear to be multi-phase faults, distance protection schemes will tend to trip three phases, which would be harmful to the overall system integrity for single phase schemes. Especially if the distance relays were to trip three-phase for both parallel lines.

Fault Resistance

Fault resistance can appear from a number of sources including vegetation, arcs, and tower footings. Fault resistance causes a shift in the apparent impedance that is measured by distance relays and is dependent on the angular difference between the voltages of the local and remote bus. When a fault occurs during the transfer of load the local and remote currents are out of phase with each other. In Figure 5, the relays at the local end will not account for the voltage drop $I_R Z_F$, that results from the remote current and the apparent fault impedance that includes the fault resistance.

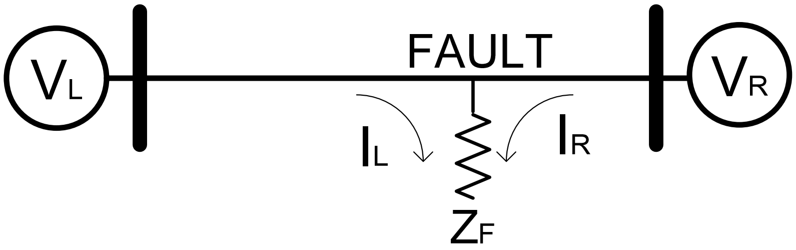

Figure 5 Fault Resistance Condition

The fault resistance will appear higher when the voltage at the local bus leads the voltage at the remote bus and lower when the voltage at the local bus V_L lags the voltage at the remote bus V_R.[2] As shown in Figure 6, ground distance protection that uses quadrilateral elements with large resistive reaches will be vulnerable to overreaching if V_L leads V_R.

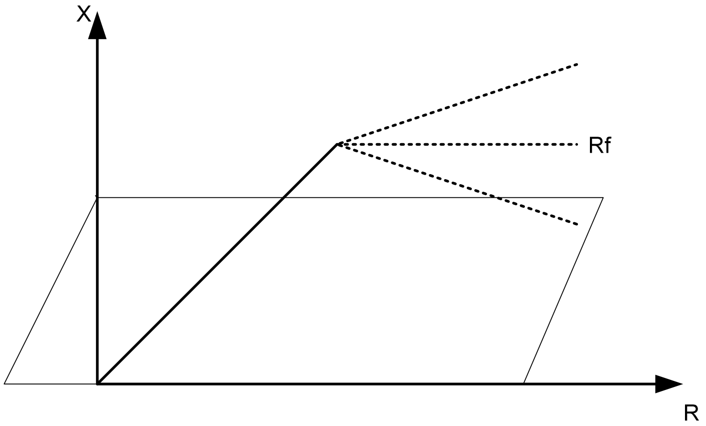

Figure 6 Fault Resistance on Quadrilateral Ground Distance Element

Shown in Figure 7, Ground distance protection that uses mho elements will be vulnerable to underreaching for resistive ground faults.

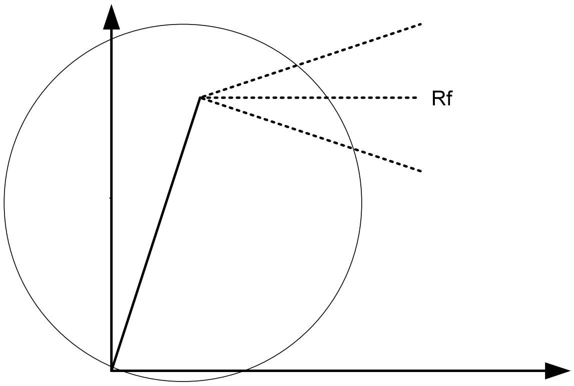

Figure 7 Fault Resistance on MHO Ground Distance Element

The effect on whether V_L leads or lags V_R will be minimal for ground mho elements.

Power Swings

Power Swing conditions are the consequence of electrical-mechanical oscillations that result from major system disturbances such as power system faults, line switching, generator disconnection, and the loss of large blocks of load.[15] These electrical-mechanical oscillations cause changes in the angles of the line terminal voltages which produces power flow swings on the lines.[17] Distance relays that protect long transmission lines that are heavily loaded and are near the center of power swings are vulnerable to tripping if the apparent impedance enter the relay characteristic and remains there longer than the time delay of the setting of the zone. Figure 8 shows the possible path of the apparent impedance of a power swing.

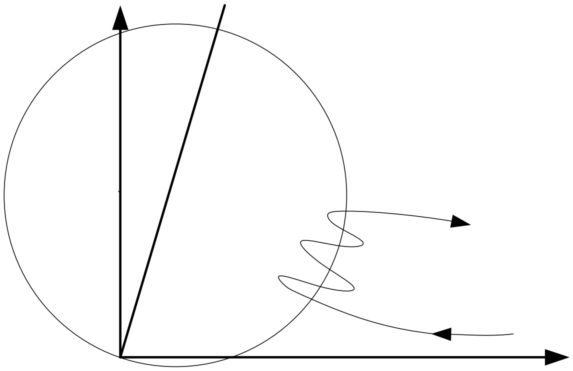

Figure 8 Power Swing Apparent Impedance

Out of step detection or the monitoring of the rate of impedance change seen by distance relays, is used to prevent unwanted tripping from a power swing.[2] Two distance elements, one larger then the other, are required to monitor the rate of change of impedance. Out of step detection occurs if the time it takes the swing impedance to cross from the outside of larger element into the smaller element larger than a preset time. Generally the impedance of a fault will cross the characteristics of both distance elements much faster than the apparent impedance of a power swing.

Heavy line loading tends to reduce the security of distance protections schemes. Phase distance elements without load encroachment characteristics and long reaches are vulnerable to tripping for heavy load conditions because the apparent impedance could cross over into distance characteristic. Heavy line loading tends to exacerbate each of the challenges already mentioned. Regarding SPT, heaver load flow results in larger open phase voltages, which produce larger values of negative sequence and zero sequence current.[7] The security of the negative sequence and zero sequence current directional elements are more adversely affected by the heavier load flow. With series compensation, the effects of extreme line loading depend on whether the power is being imported or exported.[12] If the load is being exported the forward element of distance protective relay has difficulty detecting a fault. If the load is being imported a reverse element of distance protective relay could mis-operate. Bus side potential intensifies these problems associated with the importing and exporting of load flow. For parallel lines, the direction of load flow will contribute to the effect of mutual impedance. A high fault resistance or impedance combined with heavy load flow will alter the apparent impedance and may cause the distance relay shift.[21]

Defining the Requirements for Modern Distance Relays:

The BPA's 500kV substation configuration includes breaker and half schemes and ring bus schemes. The relay hardware requirements are centered on the tripping and reclosing of two breakers. For two breaker control schemes BPA requires the following hardware configuration for EHV line protection relay:

1) Currents for two breakers are applied to separate inputs in the relay, and are internally summed to form the line current. This more easily allows for one breaker to be taken out of service for maintenance.

2) Three Line voltages inputs for normal line protection and two auxiliary voltage inputs for synch, hot line, and dead line checking.
3) Minimum of 16 high speed trip current rated output contacts for single-phase tripping, three phase tripping, reclosing of two power circuit breakers and for use with external transfer trip equipment where digital communication is not available.
4) BPA currently uses one of two options for transfer tripping; relay to relay communication and external transfer trip equipment. Relay to relay communications where the relays communicate directly with each other is the preferred method of sending and receiving transfer tripping signals. External transfer trip equipment is also an option. In both cases a minimum of four bits must be available for transfer tripping.

Figure 1 describes the hardware connections required for transmission line protection relay.

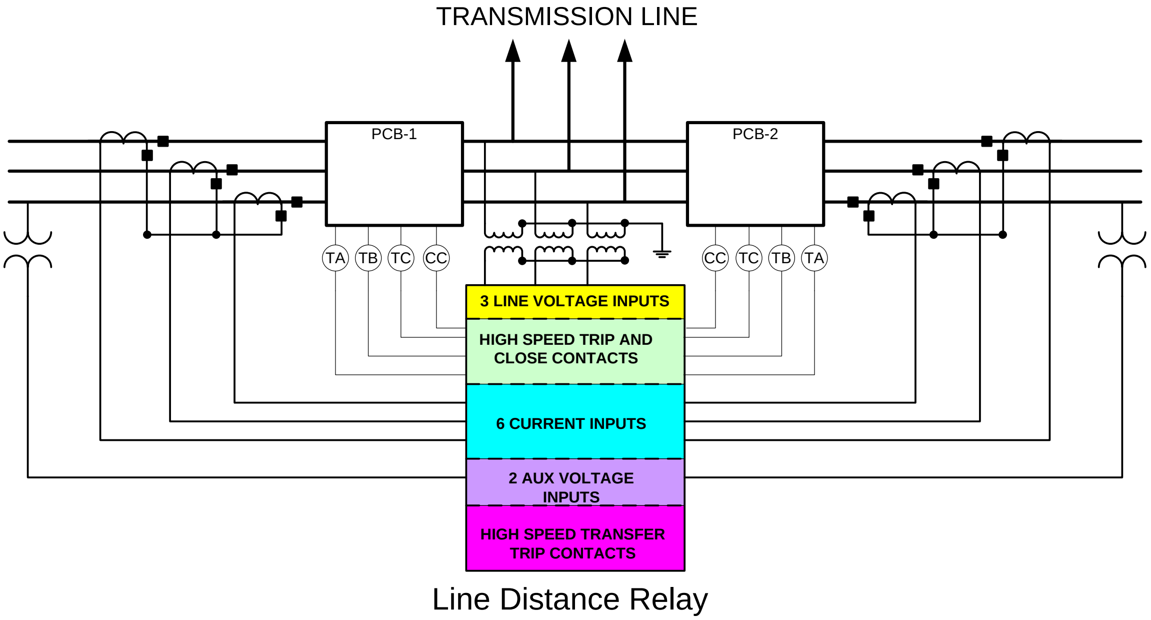

Figure 1 Relay Hardware Requirements

The BPA reliability criterion requires the following performance requirements for relays that are applied to the 500kV system: [1]

1) High speed three phase tripping and accurate high speed single-phase tripping in 1 cycle or less for close-in high magnitude faults with an additional cycle for communications aided tripping.
2) The relays must operate correctly, and they must be secure from incorrect operations for the following conditions:
    a) Heavy loads including emergency loading:
        i) The settings must meet the NERC load encroachment criteria.[20]
        ii) The relays must not operate under emergency loading conditions, or for recoverable system swings.
        iii) The relays must not operate if an adjacent, heavily loaded line trips all three phases, and its load is suddenly transferred to an un-faulted line.

b) Open phase on a loaded line:
    i) When one phase in a heavily loaded line is open during a single line to ground fault operation, the relay measuring the un-faulted phases must not operate during the dead time of the reclosing relays when these conditions exist.

c) Single phase load transfer from a faulted line to an adjacent un-faulted line:
    i) When load is transferred to one phase of an un-faulted line during a single phase fault operation on an adjacent line, the relays on the un-faulted line are subjected to zero sequence and negative sequence currents. Relays on the un-faulted line must be secure from false operations during the dead time of the reclosing relays on the faulted line.

d) Current reversal during fault clearing on an adjacent parallel line:
    i) Faults near the end of the line will normally be cleared by zone 1 at the near terminal and by permissive zone 2 at the distant terminal. The approximately 1 cycle difference in clearing times between the terminals can create a fault current reversal in a parallel line. The current reversal logic must momentarily block the permissive logic during the time when a current reversal can occur preventing a false permissive trip on the un-faulted line.

e) Severe sub-harmonic oscillations in a series compensated system during a fault operation:
    i) Faults in a series compensated system create sub-harmonic oscillations in all phases in the power system. These oscillations are measured by the relays as dynamically changing impedances. The relays must trip only the faulted phase in the faulted line. The relay elements for the un-faulted phases, and the relays on the adjacent lines must not trip, even if the measured apparent impedance momentarily crosses into the operate region of a permissive element. The coordination between the zone 2 and zone 3 elements is crucial in preventing false tripping under this condition. Phase segregated permissive tripping logic is required to increase security for this case.

f) Series capacitors in front of and/or behind the line relays.
    i) The line relays on terminals with series capacitors either in the forward direction or in the reverse direction must not fail to trip, over-trip, or trip for close in reverse faults when the series capacitors do not bypass.
    ii) The relays must not over trip for faults on the bus side of series capacitors at the remote terminal.
    iii) The relays must not over-trip for faults on the line side of series capacitors on other lines at the remote terminal, particularly when they do not bypass during the fault operation.
    iv) On series compensated parallel lines, the relays must not over trip for faults near the remote terminal of a parallel line, but far enough out on the line such that the series capacitors on that line do not bypass.

g) Reclosing into a fault:
    i) The line relays must output an instantaneous three phase trip when a line terminal recloses into a fault.
    ii) A backup three phase direct trip signal must be sent to the remote terminal to trip the remote breakers three phase and block the remote reclosing relays.

h) Reclosing at the second terminal:

  i) This reclose picks up load on the line. The series capacitors on the faulted phase may be bypassed as a result of a close in fault. The series capacitors on the two un-faulted phases will remain in service. The new series capacitors bypass only the faulted phase. When load is picked up during the reclose operation, there is a phase current unbalance for a short period of time until the series capacitors on the faulted phase are re-inserted. The relays must not operate during this short period of load unbalance.

i) High ground fault resistance:
  i) BPA has experienced a number of ground faults where the ground fault resistance either was close to, or greater than the resistive reach setting of the line relays. This is usually due to high tower footing resistance, but on a couple of occasions, high resistance mid-span faults occurred when forest fires passed under the lines. Additionally some of the faults from fires were multi-phase faults.
  ii) Previous testing indicated that the resistance setting of ground distance relays can be set up to about 100 ohms without false tripping due to sub-harmonic oscillations, or due to single phase load transfer. Even though load encroachment is a three phase event, heavy load can operate the ground distance elements during conditions of severe load unbalance. A minimum resistive reach of 100 ohms was the setting goal for the ground distance relays. The relays must operate properly for high ground fault resistance conditions.

j) Bus faults:
  i) Bus faults may have high fault currents, but the contribution from the individual lines is, in general, is not very high. Typically series capacitors on the lines and line terminals will not bypass and all series capacitors will be fully in service during the fault.

k) Multi-phase faults:
  i) For multi-phase faults, relays must trip all three phases, and reclosing is blocked.
  ii) A backup three phase direct trip is sent to the remote terminal.

l) Three phase faults:
  i) Three phase faults are positive sequence events. Distance elements must operate only on positive sequence quantities.
  ii) Distant three phase faults can look very similar to heavy load. Unless the relay has pre-fault load subtraction, the load current will sum with the fault current. If the load is in one direction and the fault is in the other direction, the calculated apparent impedance can approach zero. This happened on two occasions with static distance relays on the BPA system. The remote three phase faults were in the reverse direction and the load was in the forward direction. The measured apparent impedance approached zero and entered the tripping zone of the relays.

Designing the Test:

Selecting and Modeling the Line Configuration

The transmission line within BPA's control area that was selected to be the protected component of the modeled power system was the Malin–Round Mountain (MALN-RDMT) #1 500kV line. BPA maintains the protection at Malin and coordinates with the owners of the equipment at Round Mountain. Shown in Figure 8, the MALN-RDMT #1 line encompasses many of the protective challenges indentified.

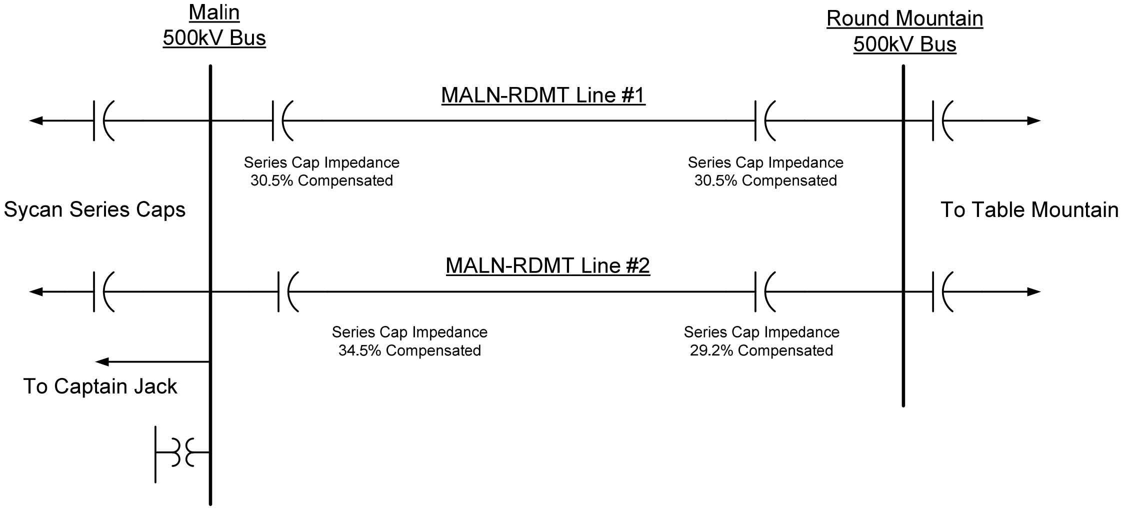

Figure 8 Modeled Protected Line

The portion of the system that was selected for modeling has parallel lines, long intertie lines, series compensation, and load flow in both directions depending on the time of the year. The line is approximately 95 miles long, requires single phase tripping, is 61% series compensated with capacitors located at both ends and is parallel to the MALN-RDMT #2 line, which has attributes that are almost identical to line the #1. Adjacent lines on both buses are series compensated. Being on the pacific AC intertie, the line is used to transfer heavy loads and requires a high degree of security from the relays performance. False trip operations on this line could cause severe instability problems for the overall system.

With the line chosen, an EMTP line model needed to be created. BPA engineers maintain an EMTP model shown in Figure 9, of the two 500 kV AC lines of the Pacific AC Intertie, plus a third 500 kV AC line of the California-Oregon Transmission Project (COTP) that was created in the Alternate Transients Program.[19] The intertie model consists of 22 500kV buses, 15 lower kV load buses, 7 generation sources, and 17 series compensated lines. A few years prior to the relay testing, new series capacitors were installed on these lines and staged fault testing was performed at both terminals.[1] The purpose was to verify the operation of the series capacitor protection and bypassing schemes. Data from this testing was used to check the accuracy of the EMTP models.

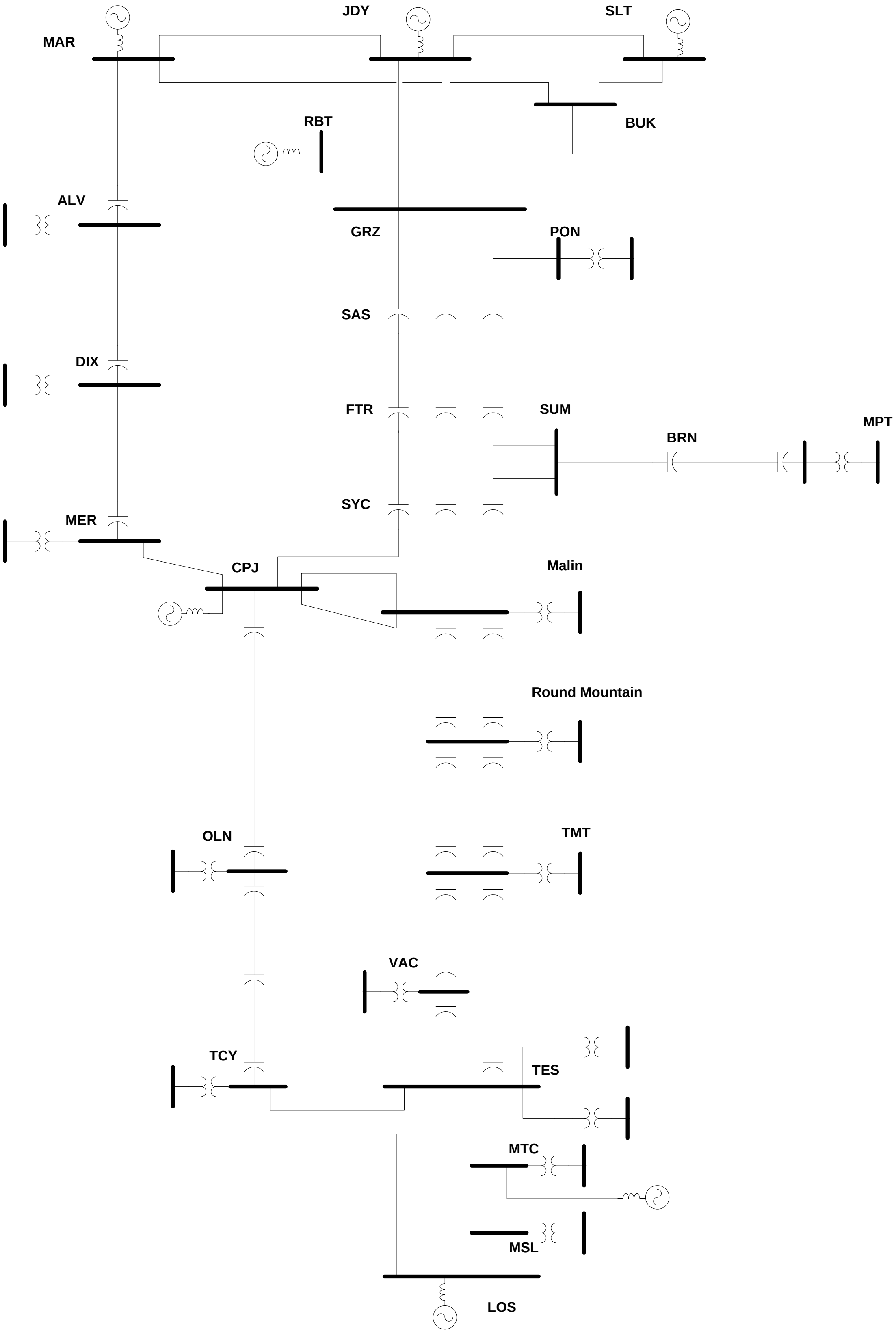

Figure 9 EMTP Model of AC Intertie

With the overall system modeled, BPA engineers focused on detailing system around the MALN-RDMT lines 1 and 2, for the purpose performing EMTP studies that would capture most of the challenging conditions listed before and to generate test cases. EMTP studies were performed at selected locations on line #1, and at locations of known faults where the models were compared to DFR data as a check of the accuracy of the EMTP models. Figure 10 is a detailed picture of the EMTP Malin – Round Mountain System that describes where the measured currents and voltages were taken.

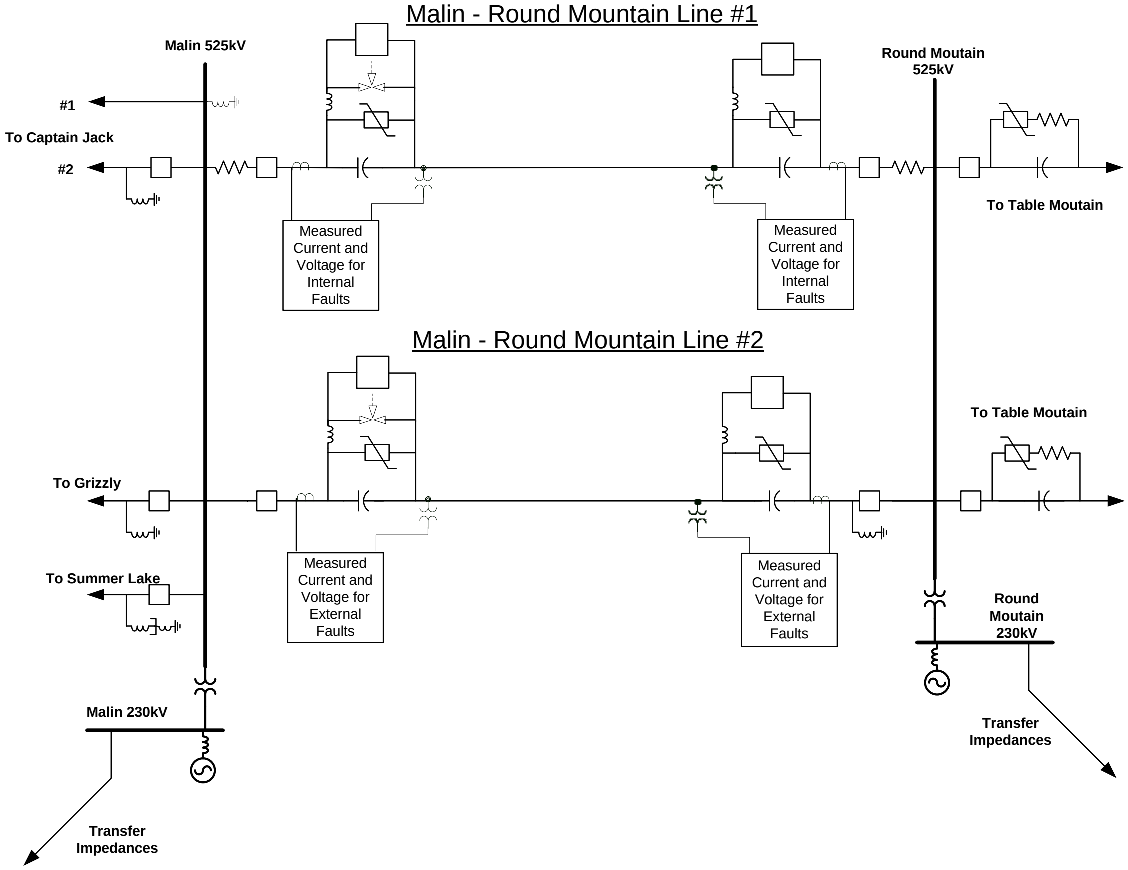

Figure 10 Detailed EMTP Line Model

The EMTP line model describes the series capacitor protection components on the protected lines and the parallel line as well as the local phase inductors. Because the attributes of both lines are very similar and a number of internal fault cases were to be generated on Line #1, the engineers decided to capture the voltage and current quantities from Line #1 and Line #2 in order to generate external fault cases at the same time. As shown the measured quantities were taken from the location of the CTs and PTs that were to be used by the protection relays of both locations. The primary fault studies were performed on line #1. Relay fault data for both terminals of both lines was created and saved. Line #1 data was played into the relays to test the relay operation for internal faults. Line #2 data was played into the relays to test the relay operation on the un-faulted, parallel line. Note: The current Series Caps on line #2 at Malin are protected by sparks gaps and not MOVs. These series caps are slated to be replaced in the near future with MOV, trigger gap, and bypass breaker protection. Therefore the engineers decided to model the future configuration for these purposes.

Fault Selection criteria for EMTP generated test faults

The types of faults that were selected for the relay testing were mainly based on performance requirements of the 500kv system and on problems that have been encountered during past fault operations. These requirements and conditions are the basis for the selection of the EMTP generated test fault cases The two lines that were selected for the testing represent the greatest challenges to the transmission line relays. The results of these tests will also be used to test settings, develop setting criteria, test the operational logic, and test the communications aided tripping schemes.

Single line to ground faults and multi-phase faults were simulated at various points on the line. These lines are not double circuit lines so cross country faults were not simulated. For the internal fault cases the following fault simulations were made:

1. Faults were simulated on the line side of the series capacitors at both ends of the line. For these cases the series capacitors will bypass during the fault operation.
2. Faults were simulated on the line near each terminal, but far enough out on the line such that the series capacitors are fully in service.
3. An actual resistive line to ground fault that occurred in 2006 was also included for testing.
4. The faults were rotated between phases to provide a more thorough test of the internal logic in the relays.
5. The faults were run with an average line load of 700 megawatts and also with an emergency line load of 2300 megawatts.
6. The ground faults were run with varying values of ground resistance up to 100 ohms.

Faults external to the Malin – Round Mountain lines typically will not have enough current to bypass the series capacitors when both lines are in service. For a close in fault the relay at the near terminal will measure a reverse capacitive reactance while the relays at the remote terminal will measure an inductive reactance.

The following external faults were simulated:

1. Single phase faults and multi-phase faults on the buses at Malin and Round Mountain were simulated. Even though these faults are quite severe, the series capacitors on the lines typically will not bypass.
2. A single phase fault, a phase to phase fault, a phase to phase to ground fault, and a three phase fault were simulated at Round Mountain on the line side of the series capacitors on the Table Mountain #1 line. The Malin Round Mountain line #1 had a heavy load of 2300 megawatts.

Faults at the staged fault test locations were included as part of the testing. Faults external to the parallel lines were also included. Testing the operation of the relays for external faults was given a high priority.

Table 1 describes the 50 fault cases, by the fault type, location, resistance in the fault, the load level per parallel line, whether the series Caps were in service, bypassed, or MOV protected, and where the currents and voltages were measured. Not mentioned in the table is the reclosing sequence of each case. For the single-phase faults, the cases were run for either a successful reclose or an unsuccessful reclose in which the line was reclosed into a permanent fault. The first 19 faults are internal faults located on the line 1. Cases 20-38 are the same faults as the first 19 cases except the voltage and currents were measured from PT and CT locations on line 2. Because the attributes and protection requirements of lines 1 and 2 were virtually identical, the relays settings remained unchanged for the external faults on lines 2. Cases 39-50 were external faults that were located at the buses and beyond the parallel line sections. The voltages and currents for these cases were measured from the line 1 location. Figure 12 shows the fault locations of the internal and external faults.

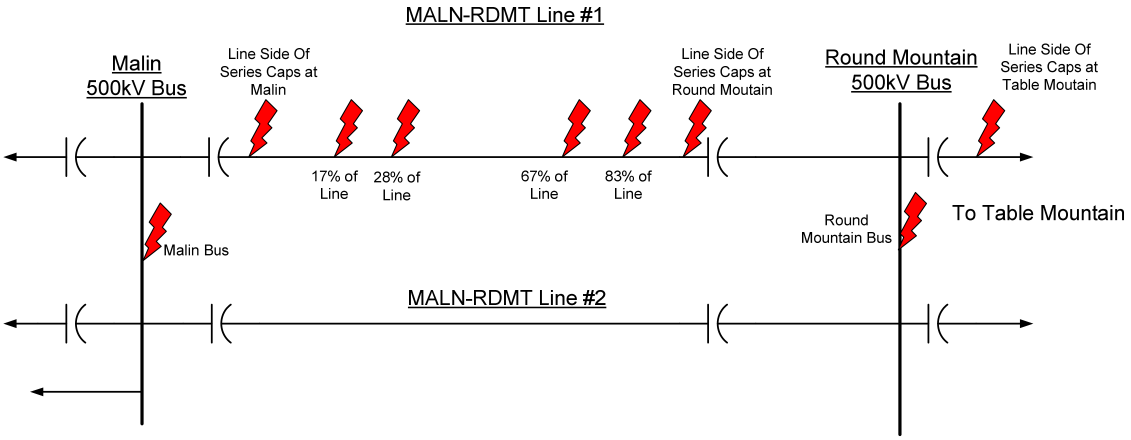

Figure 12 Fault Locations for Test Cases

Table 1 Fault Cases

Fault Number	Fault Type	Fault Location	Fault Resistance	Load Level per Line	Series Caps I/S or Bypassed or MOV Protec.	Location of Measured V & I
1	A-B-G	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #1
2	A-B-G	#1 Line – Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #1
3	A-ph	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #1
4	A-ph	#1 Line – Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #1
5	B-C-G	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #1
6	B-C-G	#1 Line – Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #1
7	B-ph	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #1
8	B-ph	#1 Line – Line Side of Caps at RdMT	5 ohm	1065 MW	Bypassed	Line #1
9	C-ph	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #1
10	C-ph	#1 Line – Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #1
11	C-ph	#1 Line – Line Side of Caps at Malin	30 ohm	700 MW	MOV	Line #1
12	B-ph	#1 Line – 17% of Line from Malin	1 ohm	2300 MW	MOV	Line #1
13	B-ph	#1 Line – 28% of Line from Malin	10 ohm	2300 MW	MOV	Line #1
14	B-ph	#1 Line – 28% of Line from Malin	40 ohm	2300 MW	MOV	Line #1
15	B-ph	#1 Line – 28% of Line from Malin	100 ohm	2300 MW	MOV	Line #1
16	B-ph	#1 Line – 67% of Line from Malin	10 ohm	2300 MW	MOV	Line #1
17	B-ph	#1 Line – 67% of Line from Malin	40 ohm	2300 MW	MOV	Line #1
18	B-ph	#1 Line – 67% of Line from Malin	100 ohm	2300 MW	MOV	Line #1
19	B-ph	#1 Line – 83% of Line from Malin	1 ohm	2300 MW	MOV	Line #1
20	A-B-G	#1 Line - Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #2
21	A-B-G	#1 Line - Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #2
22	A-ph	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #2
23	A-ph	#1 Line - Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #2
24	B-C-G	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #2
25	B-C-G	#1 Line - Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #2
26	B-ph	#1 Line – Line Side of Caps at Malin	5 ohm	1065 MW	Bypassed	Line #2
27	B-ph	#1 Line - Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #2
28	C-ph	#1 Line – Line Side of Caps at Malin	5 ohm	700 MW	Bypassed	Line #2
29	C-ph	#1 Line - Line Side of Caps at RdMT	5 ohm	700 MW	Bypassed	Line #2
30	C-ph	#1 Line – Line Side of Caps at Malin	30 ohm	700 MW	MOV	Line #2
31	B-ph	#1 Line – 17% of Line from Malin	1 ohm	2300 MW	MOV	Line #2
32	B-ph	#1 Line – 28% of Line from Malin	10 ohm	2300 MW	MOV	Line #2
33	B-ph	#1 Line – 28% of Line from Malin	40 ohm	2300 MW	MOV	Line #2
34	B-ph	#1 Line – 28% of Line from Malin	100 ohm	2300 MW	MOV	Line #2
35	B-ph	#1 Line – 67% of Line from Malin	10 ohm	2300 MW	MOV	Line #2
36	B-ph	#1 Line – 67% of Line from Malin	40 ohm	2300 MW	MOV	Line #2
37	B-ph	#1 Line – 67% of Line from Malin	100 ohm	2300 MW	MOV	Line #2
38	B-ph	#1 Line – 83% of Line from Malin	1 ohm	2300 MW	MOV	Line #2
39	3-ph-G	Line Side of Caps at TbMT	10 ohm	2300 MW	MOV	Line #1
40	A-B-G	Line Side of Caps at TbMT	0 ohm	2300 MW	MOV	Line #1
41	B-C	Line Side of Caps at TbMT	Ungrounded	2300 MW	MOV	Line #1
42	C-ph	Line Side of Caps at TbMT	0 ohm	2300 MW	MOV	Line #1
43	B-C-G	Malin Bus	0 ohm	700 MW	In Service	Line #1
44	B-C-G	Malin Bus	0 ohm	700 MW	In Service	Line #1
45	A-ph	Malin Bus	0 ohm	700 MW	In Service	Line #1
46	A-ph	Malin Bus	0 ohm	700 MW	In Service	Line #1
47	A-C-G	Round Mountain Bus	0 ohm	700 MW	Bypassed	Line #1
48	A-C-G	Round Mountain Bus	0 ohm	700 MW	Bypassed	Line #1
49	B-ph	Round Mountain Bus	0 ohm	700 MW	In Service	Line #1

50	B-ph	Round Mountain Bus	0 ohm	700 MW	In Service	Line #1

Test Bed

The test bed consisted of a digital model power line simulator, a 5 volt signal generator and contact repeater, two line distance relays, a multiplexer, and one micro-processor BFR programmed as a four breaker simulator. Figure 11 provides a visual description of how the hardware components are arranged.

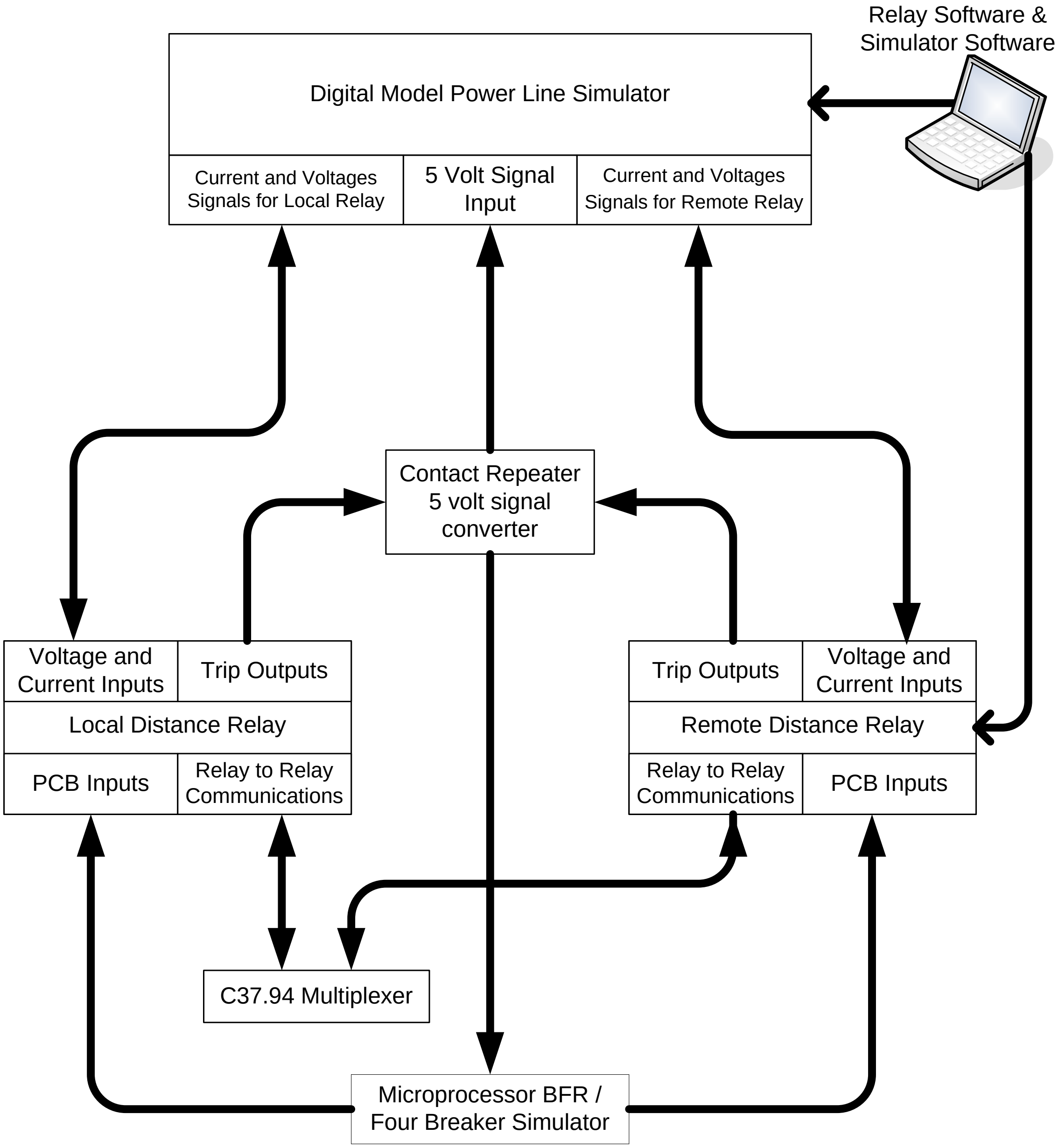

Figure 11 Distance Relay Test Bed

The digital model power line simulator is a digital-to-analog waveform reconstruction system that plays fault data from the EMTP COMTRADE files.[18] Using the simulator software, waveforms are replayed directly from PC files. Fault start times of each case and the expected relay action is inputted into simulator software. The simulator software than replays the fault and records the trip output time from the 5 volt signal generated of the contact repeater. The contact repeater receives the outputs directly from the line distance relays then converts the outputs to 5 volt signals for the digital power simulator while repeating the trip outputs to the 4 breaker simulator. A 200 micro-second latency time from contact repeater was recorded. The two distance relays received the voltage and current inputs from the two sources on the line simulator, outputted trips to the contact repeater, sent relay to relay signals over fiber through a C37.94 multiplexer, and received breaker status inputs for two breakers per relay from the microprocessor BFR. Note: Relay to relay communications hardware was not available for pair of relay B models during BPA's evaluation. Therefore transfer trip functions were performed using hardware contacts that were wired back to back on the local and remote relays. The BFR relay was programmed to be a 4 breaker simulator. The simulated breakers were programmed as single pole breakers with single phase trip inputs, three pole trip input, a close input, three single pole 52A output status, and a three pole 52A contact status. Having the BFR breaker simulator allowed BPA protection engineers to program and test the trip and close logic of each vendors relay. Vendor software was loaded on the PC and used to program the relays and download fault events for evaluation.

Configuring and Setting the Relays

Three vendors that met the BPA hardware and application requirements submitted the required local and remote relays. The primary instantaneous protection elements that were enabled in each relay are the communications independent zone 1 and the permissive overreaching zone 2 phase and ground distance elements. Zone 1 elements were set at 70% or lower of the compensated line impedance. Because the PTs are located on the line side of the capacitor the compensated line impedance only included the total line impedance plus the capacitance of the remote capacitor and not the capacitance of the local capacitor. Zone 2 phase elements were set to 150% of the uncompensated line impedance. Zone 2 ground elements were set to 200% of the uncompensated line impedance. The instantaneous zone 2 elements were set to key the permissive tripping logic. This logic set to transmit the permissive signal to the remote terminal and trip locally when the permissive signal is received from the remote terminal. The permissive scheme trips three-phase for multi-phase faults and trips single-phase for line to ground faults. Permissive tripping operates in parallel with zone 1, but because the zone 2 elements have much more sensitive settings, the permissive elements not only protect 100% of the line, they also operate for greater values of ground resistance in the fault loop. Zone 3 elements were set reverse for POTT transient blocking. Specifically they were used to set the current reversal transient blocking logic timer during fault clearing operations on parallel lines, and to block the echo back logic for all reverse faults that are detected by the remote zone 2. Zone 4 elements were set to over reach for a time delayed back up tripping similar to a conventional zone 2. Zone 5 elements when available were set for switch on to fault tripping. The distance elements in all of the relays had load encroachment supervision which was set according to the current NERC CIP load encroachment criteria.[20] Reclosing in each relay was blocked for backup trip operations and detection of multiphase faults.

The tripping logic, transfer trip logic and echo back logic in each relay were programmed around single phase tripping for single-line-to-ground faults and three phase tripping for all other fault types. Single phase direct tripping was enabled as a complement to zone 1 protection, to the echo back logic, and for direct tripping. For single phase tripping conditions, the relays were set to sequentially reclose the opened phases. Three phase tripping was programmed in each relay was set to trip for all multi-phase faults and for backup trip operations such as for time delayed tripping and for evolving faults. Backup three phase direct tripping is in addition to the single phase direct trip functions. Backup trip operations include tripping from time delayed distance elements, time delayed tripping from directional ground over current elements, evolving fault trips, reclosing into a fault, any fault that occurs before the reclosing relays are reset, and breaker phase discordance trips (failure to reclose).

Vendor specific permissive echo back logic was enabled in each relay to increase ground fault coverage for single line to ground faults when there is additional resistance in the ground fault path (tower footing resistance, trees, etc.). Echo back logic is needed when one terminal detects a fault and transmits its permissive signal to the remote terminal, but the remote terminal does not detect the fault. The remote terminal will echo the permissive signal back to the sending terminal, allowing it to trip. An echo back trip can be either a single phase trip or a three phase trip depending on the fault. The goal is to maintain proper single phase operation on heavily loaded lines, and allow for as much ground resistance as possible. For relay B and relay C, a logic variable was created to supervise the logic such that the echo back logic will only be enabled for single line to ground faults.

Depending on the vendor specific logic the relays were either programmed to use 8-function transfer trip or 7-function transfer trip. The 8-function transfer trip included one permissive signal per phase, a multi-phase permissive signal, one direct trip signal per phase, and one three phase backup direct trip. The 7-function transfer trip included one permissive signal per phase, one direct trip per phase, and one three phase backup direct trip. The direct tripping occurs when ever a relay trips a phase open locally, it will also send a single phase trip to the remote terminal. The idea is to trip the proper phase of the remote breakers, even when the remote relay does not operate for the fault. BPA philosophy is to never intentionally allow the line relays to trip the breakers at one terminal without sending an associated trip to breakers at the remote terminal. The backup three phase direct trip signal is sent to the remote terminal for all backup trip operations, and for three phase trips due to multi-phase faults. Its purpose is to trip all three phases at the remote terminal and block the remote reclosing relays. The direct trip signal is also sent to the remote terminal for breaker failure relay operations. When a backup direct trip is received from the remote terminal, the relay outputs a three phase trip, blocks reclosing, and keys an output to the remedial action scheme.

Each relay was programmed to use it’s vendor specific permissive over-reaching transfer trip scheme for the tests. In general the logic for each vendors’ relay consisted of phase segregated permissive scheme that utilizes one permissive signal for each phase and is designed for parallel lines where cross country faults can occur. Phase segregated permissive tripping allows only the faulted phase on each line to trip, maintaining load on the transmission path. If one phase on one line faults to another phase on another line near a line terminal, the relays that are closest to the fault will correctly identify the faulted phase and send the proper permissive signal to the remote terminal. The remote terminal may detect this fault as a phase to phase fault. This will result in an undesirable three phase trip of both lines. False three phase tripping is avoided because only the phase that receives the proper permissive signal will be enabled to trip, thus maintaining load on the transmission path.

The phase segregated scheme also increases the security of the permissive tripping function on long, heavily loaded, series compensated lines where sub-harmonic oscillations that occur during fault operations can cause distance elements in the un-faulted phases or in parallel lines to momentarily pickup and drop out. As mentioned before these oscillations also occur on the un-faulted phases which may cause the permissive distance elements in adjacent lines to momentarily pickup and drop out. If a zone 2 element momentarily picks up at one terminal, the remote zone 3 elements must also pickup and set the remote transient blocking timer in order to prevent false permissive tripping. The sub-harmonic oscillations in the individual phases may not be the same at any given point in time. This can cause a zone 2 / zone 3 coordination problem if only one permissive signal is transmitted between terminals. Since zone 3 elements must always coordinate with remote zone 2 elements, phase segregated permissive logic allows the zone 2 and zone 3 permissive elements to be coordinated on a per phase basis.

BPA engineers determined that each of these relays can be programmed to operate with standard four function transfer tip equipment using the BPA five function transfer trip scheme, but for parallel lines, particularly if they are series compensated, a minimum of a seven transfer trip scheme is necessary. Each vendor relay had four direct tripping functions programmed into the logic; backup direct trip, direct trip A, direct trip B, and direct trip C. The backup direct trip function is sent for all backup trip operations where the local breakers are tripped three phase and the local reclosers are blocked. When backup direct trip is received, the breakers are tripped three phase and the reclosers are blocked. The single phase direct trip functions are used in conjunction with the single phase tripping logic including single phase trip operations from the echo back logic. The direct tripping functions provide assurance that the relays on both ends of the line trip the same for all faults even when one terminal does not detect an internal fault.

With the general settings established, the ongoing testing required multiple setting changes and refinements as the relays made their way through the performance testing, making it an iterative process. If one group of settings provided successful results in measuring the reliability of the relay for the internal faults but failed for the external faults then adjustments would be made to address the misoperations and the relay would be ran through the battery of tests again. This iterative process was repeated until BPA protection engineers were satisfied with each of the relays performance. At that point the final relay settings were settled on and the relay were ran through the test one last time while their operations were recorded.

Tests Results:

The protection engineers were able to set the relays to operate reliably for all but two of the internal fault cases and to dependently not operate for all external fault cases. Table 2 contains the correct relay action and trip times of the local and remote relays of each relay pair that was listed.

Table 2 Relay Trip Times for Internal Faults

Fault Case	Relay A Results			Relay B Results			Relay C Results		
	Correct Relay Action	Local Trip Time	Remote Trip Time	Correct Relay Action	Local Trip Time	Remote Trip Time	Correct Relay Action	Local Trip Time	Remote Trip Time
1	Trip3	0.0173	0.0204	Trip3	0.0112	0.0175	Trip3	0.0172	0.0137
2	Trip3	0.0225	0.0225	Trip3	0.0162	0.0096	Trip3	0.013	0.0159
3	A/RI	0.016	0.0229	A/RI	0.0263	0.0219	A/RI	0.017	0.0157
4	A/RI	0.0229	0.0204	A/RI	0.0215	0.0223	A/RI	0.0201	0.0187
5	Trip3	0.0176	0.0209	Trip3	0.0105	0.0162	Trip3	0.0155	0.0143
6	Trip3	0.0243	0.0224	Trip3	0.0195	0.0135	Trip3	0.0128	0.0158
7	B/RI	0.0067	0.0098	B/RI	0.013	0.0193	B/RI	0.018	0.019
8	B/RI	0.0246	0.0213	B/RI	0.0226	0.0241	B/RI	0.0188	0.0174
9	C/RI	0.0127	0.0156	C/RI	0.0193	0.0155	C/RI	0.0117	0.0125
10	C/RI	0.02164	0.01924	C/RI	0.02004	0.02054	C/RI	0.0122	0.01724
11	C/RI	0.038	0.029	C/RI	0.0559	0.0626	C/RI	0.0287	0.0352
12	B/RI	0.0185	0.0253	B/RI	0.0274	0.0237	B/RI	0.0173	0.0203
13	B/RI	0.0255	0.0255	B/RI	0.026	0.0201	B/RI	0.0201	0.0219
14	B/RI	0.0651	0.0762	B/RI	0.048	0.0545	B/RI	0.0805	0.0754
15	NOP	N/A	N/A	B/RI	0.0582	0.0647	NOP	N/A	N/A
16	B/RI	0.0266	0.0265	B/RI	0.0247	0.0232	B/RI	0.0199	0.0208
17	B/RI	0.0685	0.0602	B/RI	0.026	0.0237	B/RI	0.0263	0.0209
18	NOP	N/A	N/A	NOP	N/A	N/A	NOP	N/A	N/A
19	B/RI	0.028	0.0239	B/RI	0.0247	0.024	B/RI	0.0161	0.0189

Figure 13 and Figure 14 are graphical displays of the trip times for the local and remote relays of each vendor.

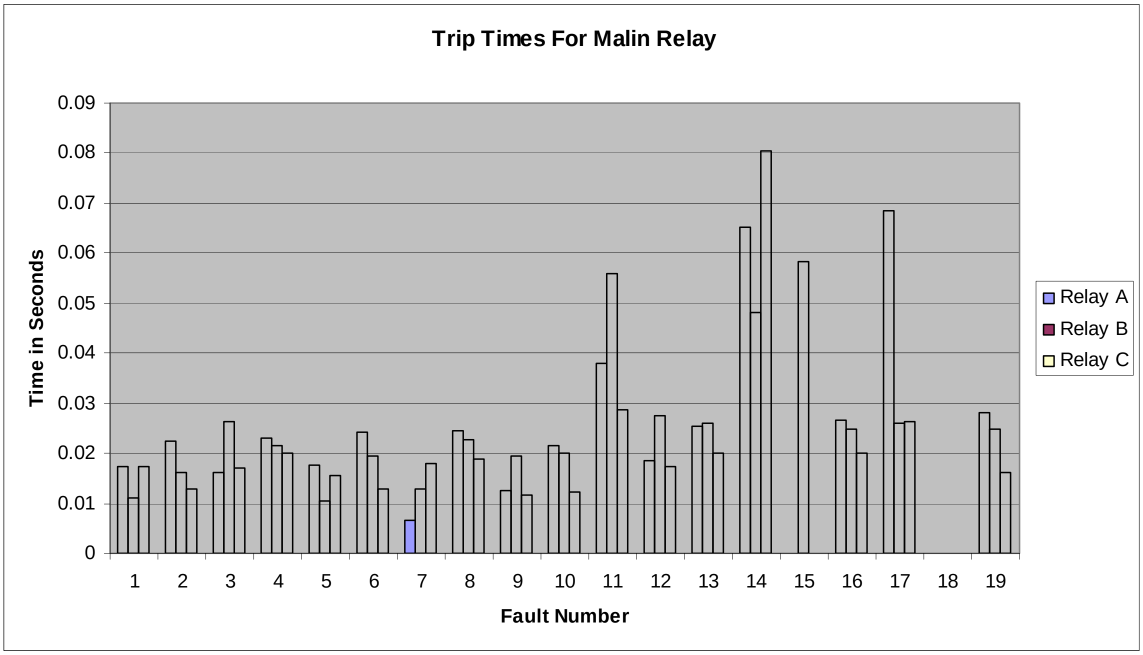

Figure 13 Local Relay Trip Times

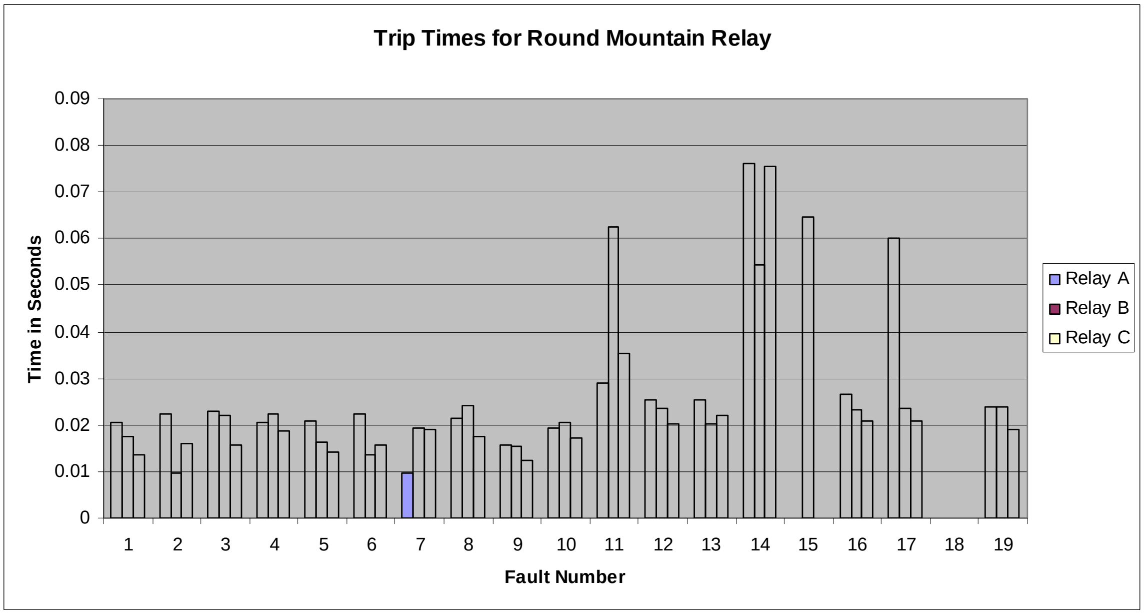

Figure 14 Remote Relay Trip Times

As shown in Figure 13 and 14, BPA engineers were not able to set Relay A and Relay C relays to detect the fault for case 15, or set any of the three vendors to detect fault in case 18. Cases 15 and 18 are heavy load high resistance (100 ohm) faults where the series caps were MOV protected only and not bypassed that occurred at 28% and 67% of the line length. In addition to missing the high resistance cases the engineers had difficulty setting relays to trip faster for the other medium resistance cases. Case 11 is a medium load and medium resistance fault (30 ohm) on the line side of the capacitors at Malin. Cases 14 and 17 were heavy load medium resistance faults (40 ohm cases). In all of these fault resistance cases the series capacitors were either not bypassed at all or bypassed only by the MOVs. Figure 15 displays the 4 cycles of prefault currents and voltages and 4 cycles of the faulted currents and voltages seen from the Malin Relays for fault case 18, the fault that all of the relays missed.

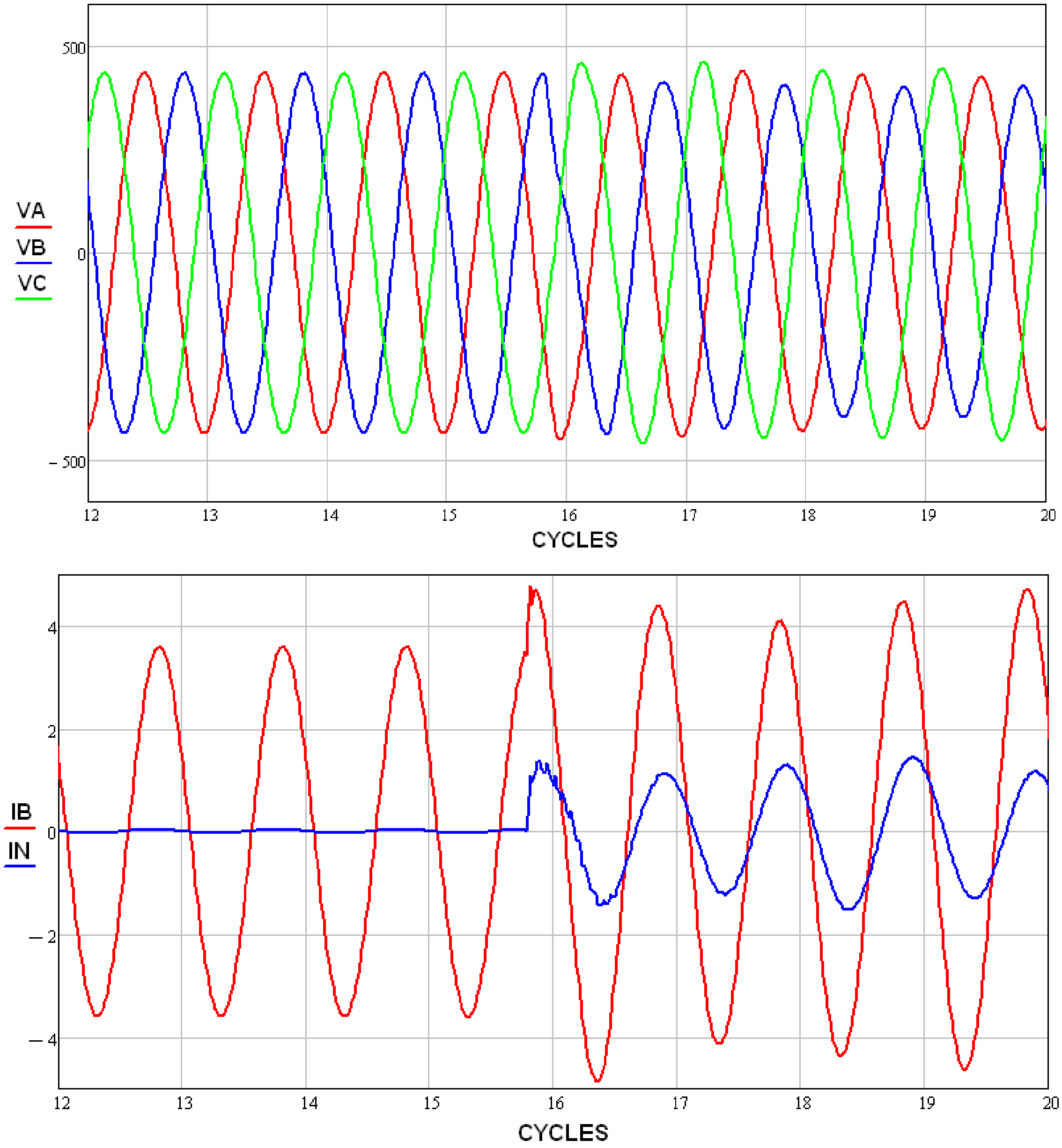

Figure 15 Current and Voltage for Fault Case 18 as Seen From Malin Relays

Figure 16 shows the fault trajectory against the Zone 1 and Zone 2 quadrilateral characteristic for the Malin Relays. The impedance values are given in secondary ohms and distant elements are based on the actual relay settings for zone 1 and 2 quad characteristic.

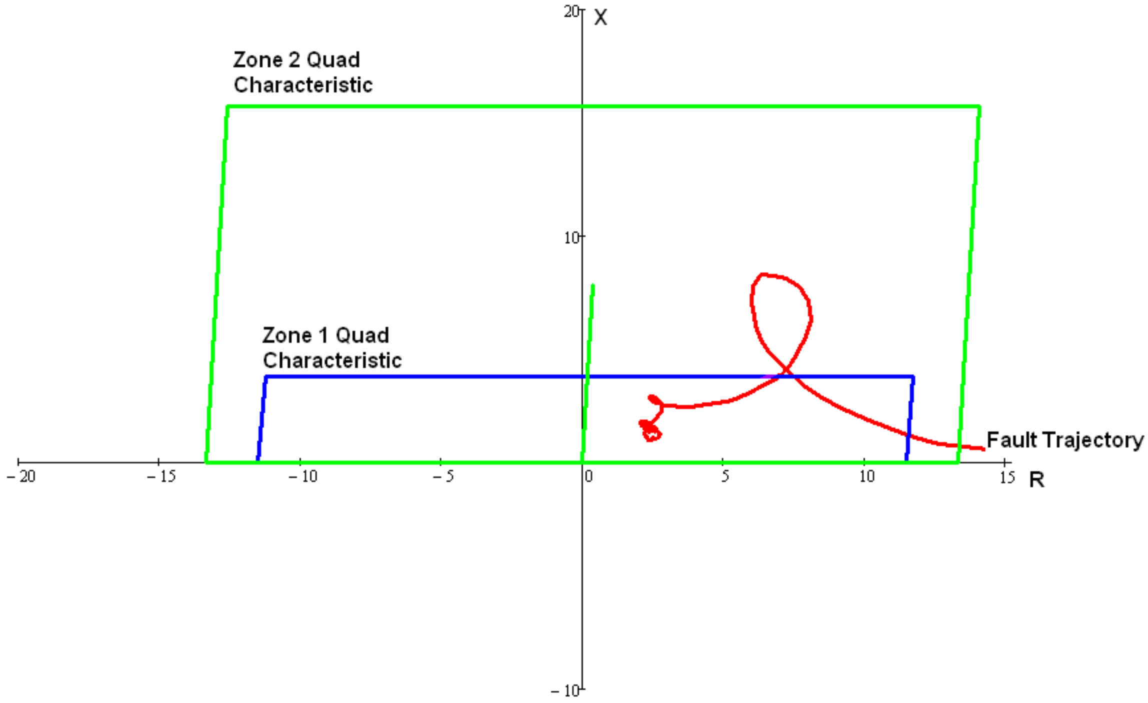

Figure 16 Impedance Trajectory for Fault Case 18 as Seen From Malin Relays

Figure 17 displays the 4 cycles of prefault currents and voltages and 4 cycles of the faulted currents and voltages seen from the Round Mountain Relays for fault case 18, the fault that all of the relays missed. The spiral shape trajectory is a result of the decaying low frequency component that comes from the series capacitors on the line.[11] Because the fault impedance trajectory is a spiral shape it takes longer to move from the load point to the fault point. The fault trajectory does appear to cross into the zone 1 quad characteristic, however it never reaches the line impedance characteristic. As mentioned before a heavy load high resistive fault may cause the relay characteristic to shift.

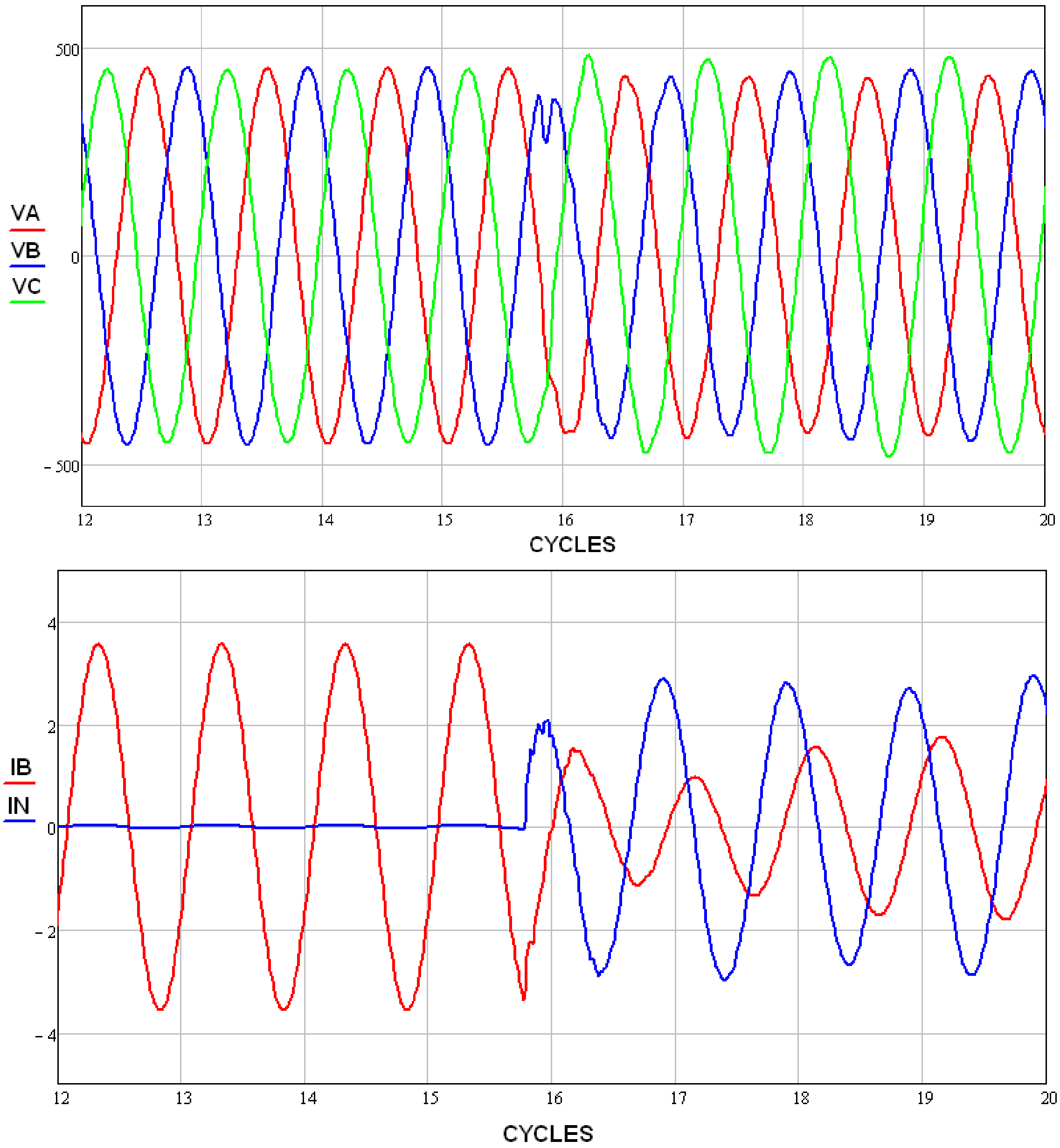

Figure 17 Current and Voltage for Fault Case 18 as Seen From Round Mountain Relays

Figure 18 shows the fault impedance trajectory against and the Zone 1 and Zone 2 quad characteristic for the Round Mountain Relays.

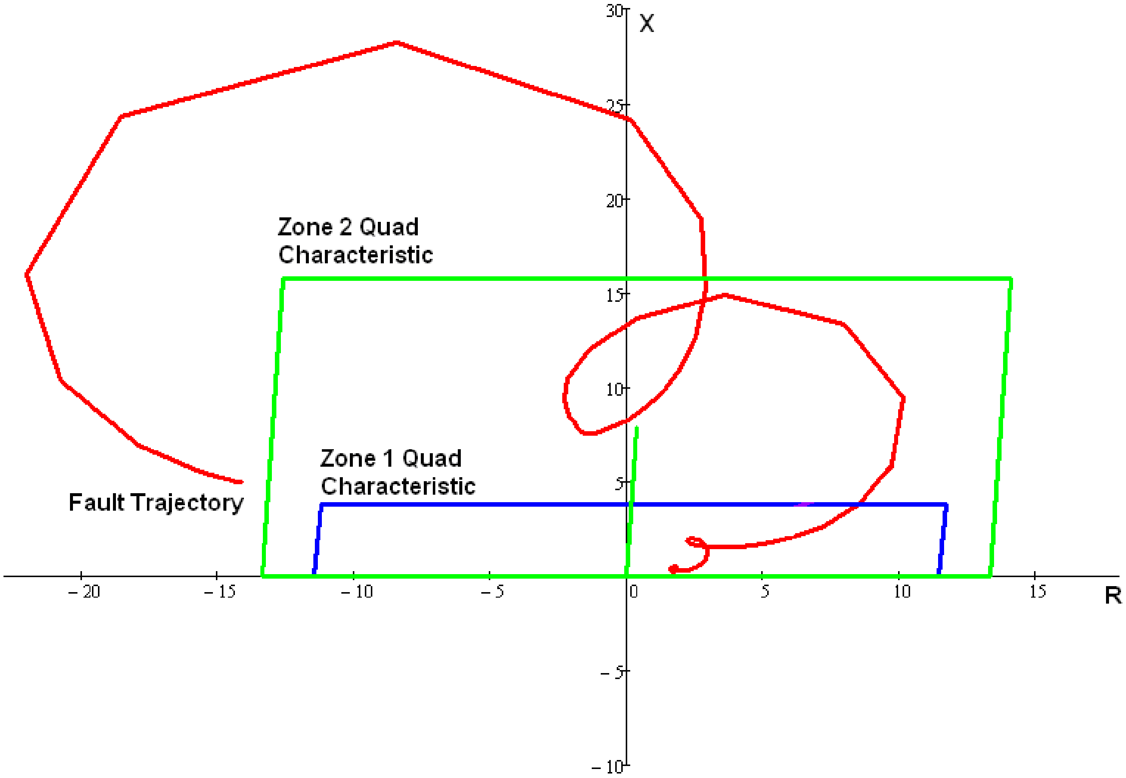

Figure 18 Impedance Trajectory for Fault Case 18 as Seen From Round Mountain Relays

Except for fault case 39, an external three phase fault located on the line side of the series capacitors of the Round Mountain-Table mountain line, BPA engineers were able to set the relays to securely not operate for the rest of the external cases. The fault of case 39 is well within the reach of the zone 2 permissive elements in the Round Mountain #1 line relays at Malin. Figure 19 displays approximately 2 cycles of prefault currents and voltages and 8 cycles of the faulted currents and voltages seen from the Malin relays.

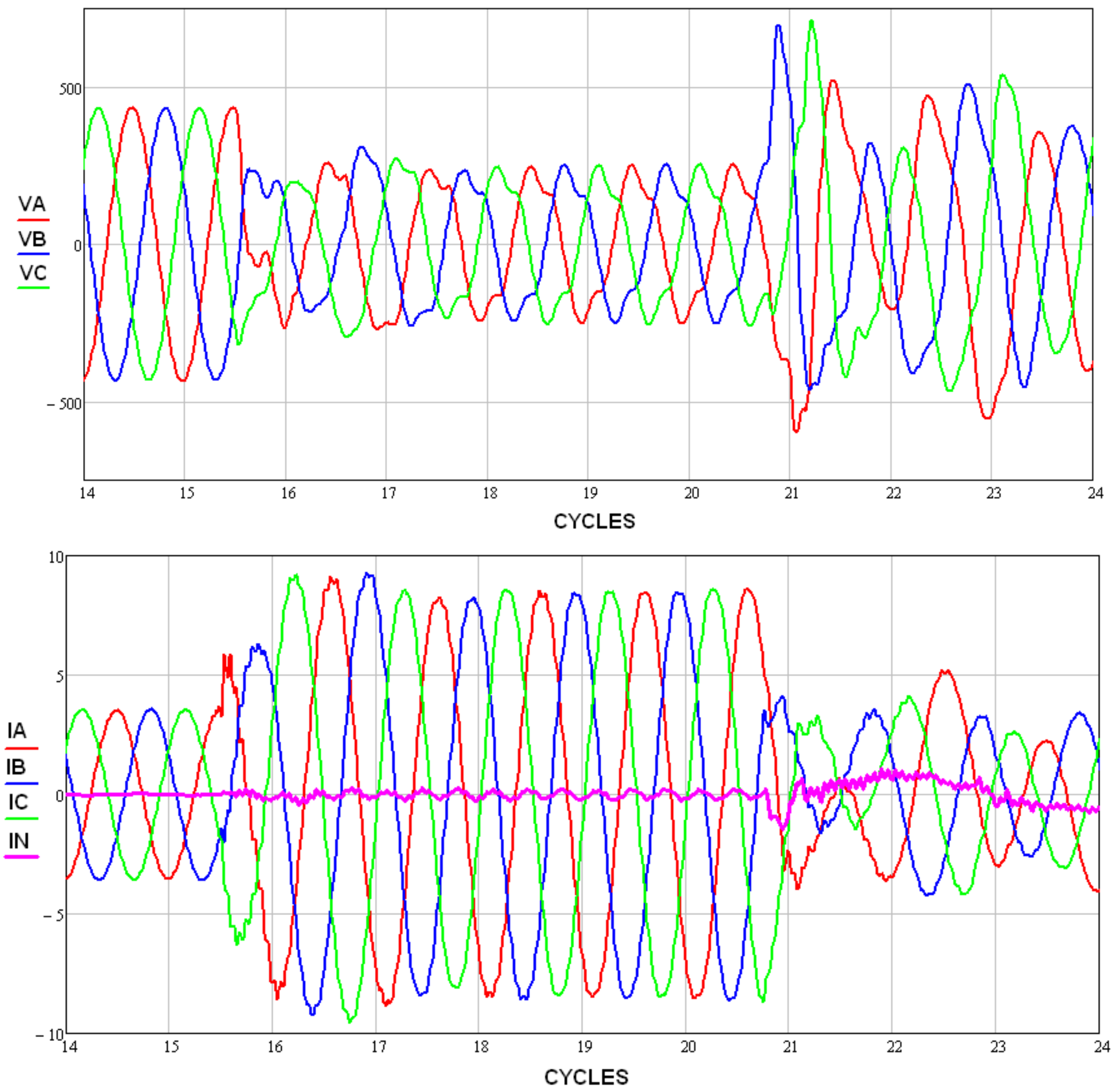

Figure 19 Current and Voltage for Fault Case 39 as Seen From Malin Relays

Figure 20 shows the fault impedance trajectory against the Zone 1 and Zone 2 Mho characteristics, the forward load encroachment characteristic for the Malin Relays.

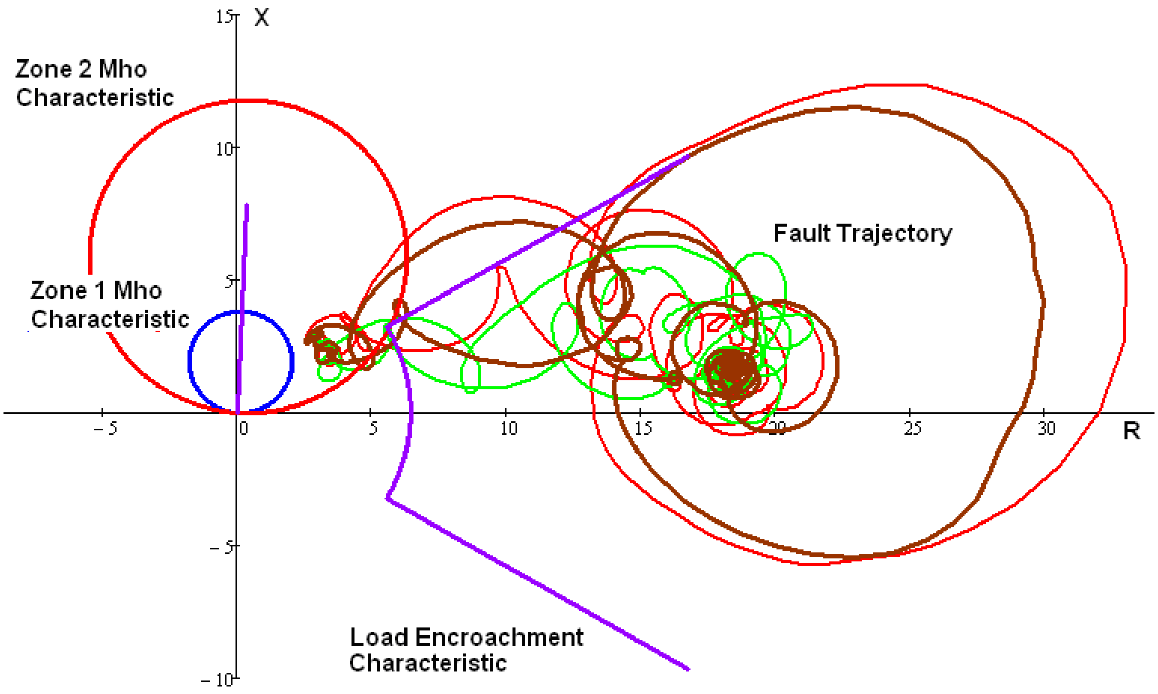

Figure 20 Impedance Trajectory for Fault Case 39 as Seen From Malin Relays

The relays at the Round Mountain terminal must detect the reverse, mainly capacitive fault and block the permissive echo back logic in order to prevent a false trip at Malin. Two of the three test relays on the Malin line #1 terminal at Round Mountain unexpectedly had problems detecting the reverse three phase fault and failed to block the echo back signal. The relays at the Malin terminal tripped for this external fault. The reverse zone 3 element at the Round Mountain terminal operates considerably slower than the forward zone 2 element at Malin. Because of the sub harmonic system oscillations, the zone 2 element picks up and drops out before the zone 3 element picks up. As a result, the Round Mountain relay echoed the permissive signal back to the Malin relay causing it to output a trip. This problem was analyzed and could not be resolved by settings. The option of disabling the echo back logic compromised the relay operation for the much more common high resistance ground faults. To overcome this problem logic was written to only allow the relay to echo a received permissive signal back to the remote terminal if the fault is a single line to ground fault. After this logic was added to the two problem relays, they operated correctly. The third relay did not have a problem detecting this fault.

The testing of power swing detection was limited to testing whether reliability and security of the relay were affected if it was enabled. In all cases the power swing detection did not affect the operation of any of the relays.

Conclusion:

When BPA engineers evaluated the latest line protection relays from three vendors, their goal was not to see where these products would fail, but to see the products work to their very best potential. The goal of the testing was to test the ac transient performance of the distance elements and determine the limits of the resistive and reactive settings of the ground and phase distance elements, measure the overall operating times, confirm the operating logic including reclosing and the backup tripping schemes, and verify the operation of the transfer trip logic under extreme system conditions. All relay pairs had very different hardware, protection algorithms, filtering algorithms, and fault line protection logic schemes, yet for this battery of tests they all performed on a level that was equitable with each other. With this in mind BPA engineers met their goal and concluded that the performance limitations from the any of the relays were minimal and would not prevent them from using any of these distance relays on the BPA EHV system.

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Tom Roseburg received a BSEE from Washington State University in 1971. He began his career with Bonneville Power Administration in 1972 as a field engineer in the Branch of Substation Construction. In 1975 he became a field engineer in system protection maintenance where he worked in substations at various locations in the states of Washington and Idaho. In 1988 he transferred to BPA’s Branch of System Protection Maintenance in Vancouver, Washington. His main duties involve system protection issues on 115kv, 230kv, and 500kv transmission systems. He is currently working in that position.