Design and Testing of a System to Classify Faults for a Generation-Shedding RAS

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***Abstract*—The PacifiCorp Jim Bridger Power Plant has 2.2 GW of installed capacity and is connected to the main grid by three 345 kV series-compensated lines. These lines are, on average, over 200 miles long. In order to operate at full capacity and maintain stability during a system contingency, Jim Bridger requires a generation-shedding remedial action scheme (RAS). PacifiCorp is modernizing and upgrading this scheme. The design of the RAS requires inputs from the protection systems and a special RAS logic relay on critical lines near Jim Bridger. This relay communicates the severity of the fault so that the proper amount of generation is shed, maintaining stability without overshedding. The RAS logic relay must quickly and accurately classify the fault in one of three categories: three phase, multiphase, or single line to ground. It must also accurately classify the fault as severe or nonsevere, as determined by the distance from the Jim Bridger bus.**

This paper discusses the design of the RAS system, the challenges faced in designing the RAS logic relay, the novel method that was developed for classifying the fault type, and the validation and optimization of the RAS logic relay using a real-time digital simulator.

I. Introduction

The Jim Bridger Power Plant, jointly owned by PacifiCorp and Idaho Power Company, has 2.2 GW of installed capacity and is connected to the main grid by several 230 kV lines and three 345 kV series-compensated lines. The 345 kV lines are approximately 200 miles long. The system requires a generation-shedding remedial action scheme (RAS) to allow it to operate at full capacity and maintain stability during a system contingency.

An improved RAS logic relay was developed as part of a project to modernize the RAS. The RAS logic relays classify faults on the power system as severe or nonsevere and three-phase (balanced) or multiphase (unbalanced). These inputs are used by the RAS to optimize the amount of generation that has to be shed to maintain stability. Three-phase, severe faults have the most impact on system stability and require more generation shedding than a multiphase, nonsevere fault.

Quickly and accurately determining the correct classification for system faults proved to be more challenging than originally thought. The initial RAS logic relay design was tested using a real-time digital simulator, and the results were deemed to be unsatisfactory. This led to the development of a novel method for classifying the fault type. Extensive testing using the real-time digital simulator verified that the new system provided excellent results. The validation testing was also used to develop easy setting criteria for the RAS logic relay that could be used by the relay engineers setting up each installation.

Many lessons were learned in analyzing the problems that needed to be overcome in order to create a system that met the design objectives. This paper discusses the lessons learned and the development and validation of the final system design.

II. Jim Bridger Generating Station Remedial Action Scheme

A. System Overview

The Jim Bridger Power Plant is located forty miles east of Rock Springs, Wyoming, and is a typical mine-mouth, coal-fired, electrical generating station. It is equipped with four 550 MW units and is connected through three 345 kV lines to the eastern Idaho transmission system. There are three 345 kV/230 kV transformers at the Jim Bridger Power Plant and three 230 kV lines connecting it to the Wyoming transmission system. The bulk of the output from Jim Bridger is transferred west, across southwest Wyoming to southeast Idaho. Fig. 1 provides a geographic overview of the transmission system involved.

Loss of any of the lines heading west from Jim Bridger can cause a surplus of generated power and result in system instability, depending on the total generation at the time. The RAS was developed to quickly drop a block of generation (one or two machines) upon the loss of one or more of the critical transmission lines, if the plant output at the time exceeds the remaining transmission capacity.

The benefits of a correctly operating scheme include higher generation and higher power transfer levels throughout the transmission system. Without an operational RAS, the output of the Jim Bridger Power Plant is restricted to 60 percent of its capacity. In addition, the transfer limit of the Bridger West transmission path is restricted when the RAS is not in service. Failure of the scheme to operate correctly can cause unnecessary tripping of generators, in the case of overtripping, or widespread tripping of transmission lines, loads, and other generators when there is a failure to trip.

B. System Modernization Project

The first RAS for Jim Bridger was installed in 1985. This scheme was a solid-state, component-based system that measured line loading and generation levels. In 1992, a new microprocessor-based system (RAS A) was installed and operated as the primary scheme. The older, solid-state system (RAS B) became a failover backup system. Over the next

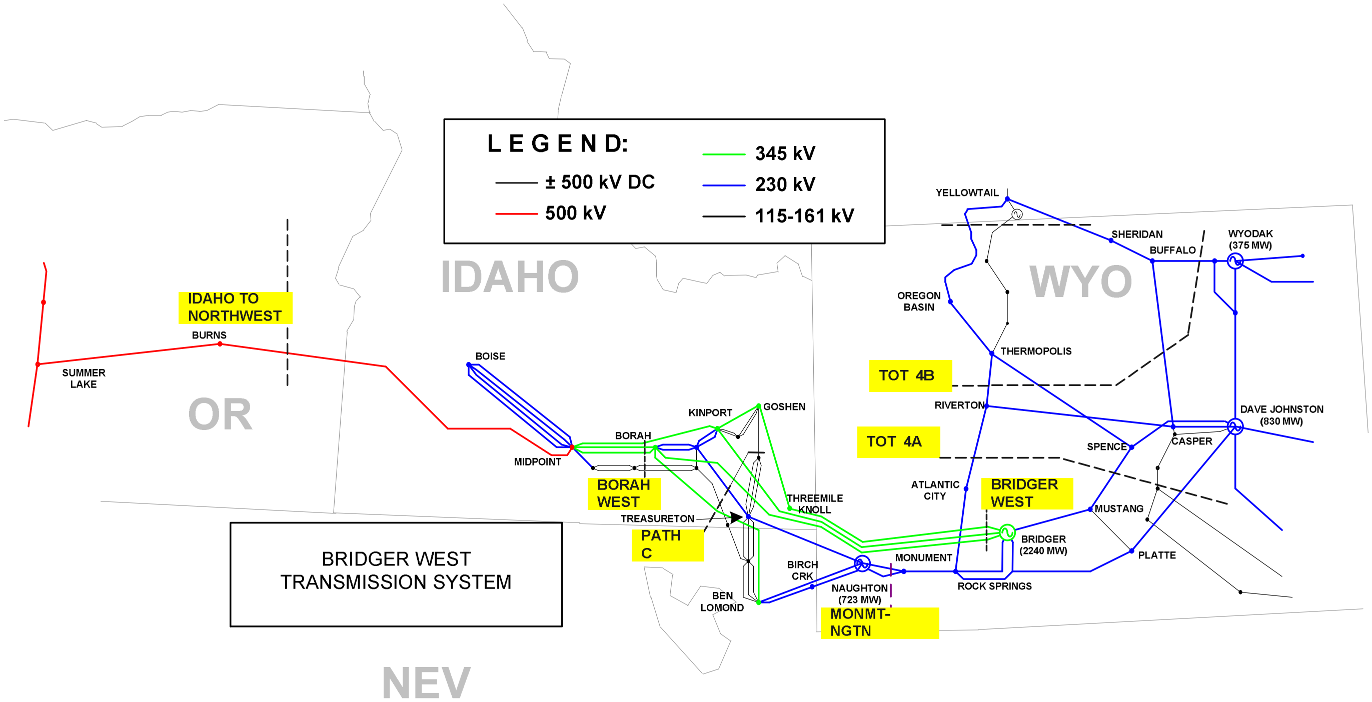

Fig. 1. Jim Bridger transmission system

several years, RAS A was occasionally updated to reflect more refined logic. A few years ago, PacifiCorp decided to upgrade the system as replacement hardware became increasingly difficult to locate. In addition, planned transmission upgrades called for the RAS to be adaptable to changing system stability requirements. The new scheme is composed of dual, identical, triple modular redundant control systems operating in parallel (RAS C and RAS D).

Based on the results of deterministic technical studies, the Jim Bridger RAS control system monitors the status of critical system facilities, including the following:

- Five transmission lines originating from the Jim Bridger Power Plant
  (three 345 kV and two 230 kV)
- The Goshen to Kinport 345 kV line
- Four generating units at Jim Bridger Power Plant
- The Jim Bridger shunt capacitor banks
- Series compensation of the 345 kV lines

The RAS control system takes action by shedding generation for any event that causes system instability, as illustrated in Fig. 2. The RAS control system calculates the amount of generation to be shed and selects the appropriate unit to shed.

Upon selection, generation has to be shed quickly. For the most severe fault events, generation must be shed within five cycles. For less severe fault events, generation must be shed within ten cycles. The classification of a fault as severe is based on the results of dynamic stability studies. The single largest benefit of the new RAS versus the old RAS is the ability to classify faults by type and relative distance from Jim Bridger.

The Jim Bridger RAS control system performs the following critical functions:

- Generation tripping
  - Calculation of arming levels
  - Calculation of generation tripping requirement
  - Selection of unit(s) to trip
- Burns 525 kV reactive station series capacitor bypass control (capacitor provides 30 percent compensation on the Midpoint to Summer Lake 525 kV line)
- Kinport 345 kV and Goshen 161 kV shunt capacitor bank insertion
- Jim Bridger 345 kV line series capacitor insertion permission
  - Lag segment (one-third of the total installed series compensation) of each 345 kV capacitor must receive permission from Jim Bridger to be inserted
  - This is part of the subsynchronous resonance (SSR) protection for the generating units at the Jim Bridger Power Plant

C. Background Theory

When a power system is operating in a steady-state condition, equilibrium exists between the mechanical torque input to a generator and the resulting electrical torque output. In this steady-state condition, all the synchronous machines connected to the power system are operating very close to their nominal speed. When there is a power system disturbance, the rotors of synchronous machines may accelerate or decelerate, resulting in an angular difference between them. Power system instability may result from lasting torque imbalance and angular separation of the connected synchronous machines.

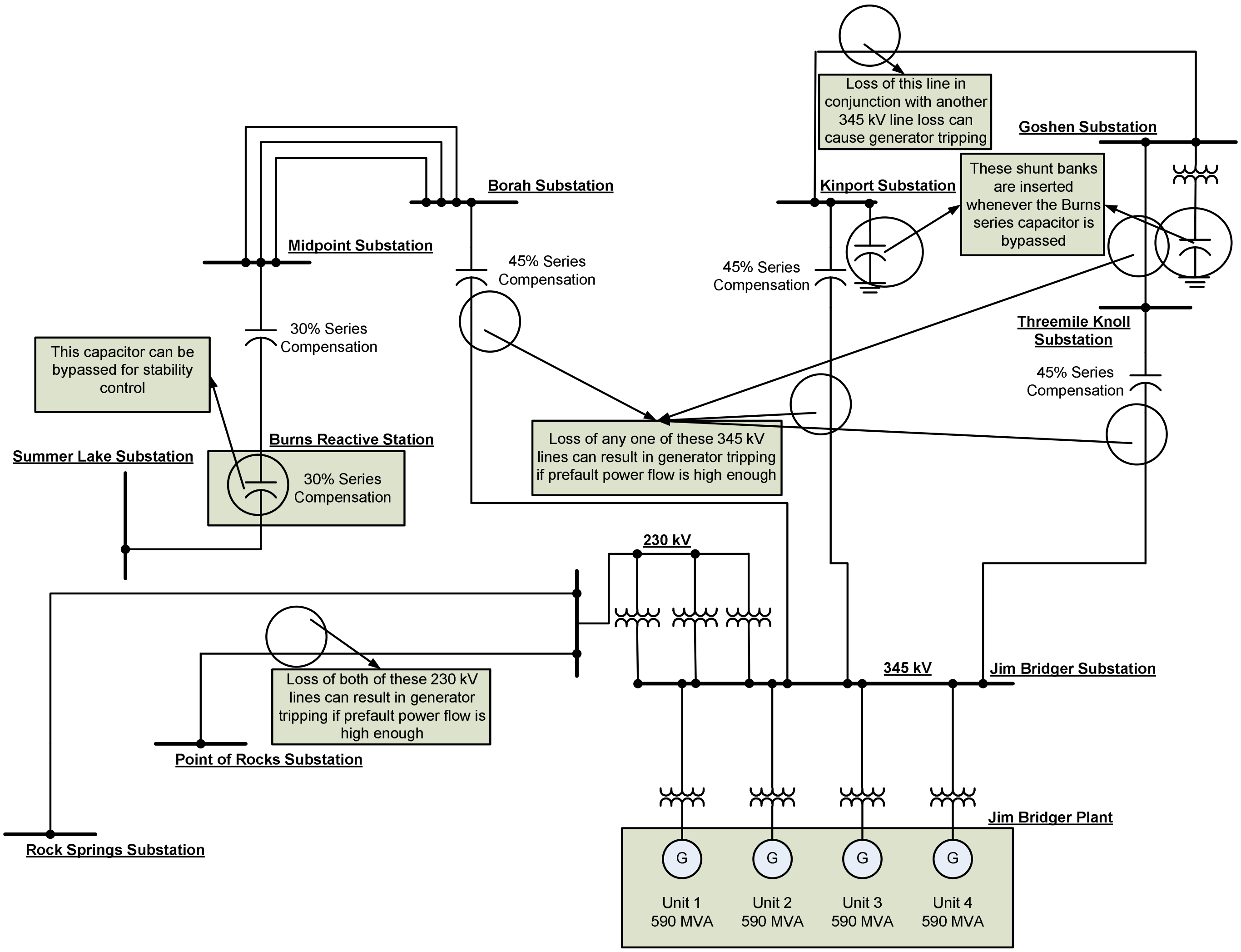

Fig. 2. RAS system overview

The equilibrium between power generated and power used can be disrupted by several types of power system disturbances. Regular changes in system loading create relatively small disturbances to the balance of power generated and power consumed. Power system faults, however, result in much more severe oscillations in machine rotor angles. Faults result in rapid changes in the amount of electrical power transferred, but the mechanical input power to system generators cannot be suddenly changed to accommodate the change in electrical power transfer. The ability of the power system to maintain synchronism during a power system fault disturbance is known as transient stability [1].

When a fault occurs, the amount of electrical power that can be transmitted is reduced. This results in a decrease of the electrical torque, which opposes the mechanical input torque of the generators. If the mechanical input power is maintained during the period of reduced electrical power transmission, generator rotors will accelerate rapidly. The time necessary for a generator rotor to accelerate past the critical stability angle depends on several power system factors. One significant factor is the amount by which transmitted electrical power has been decreased by the initiating event.

In general, compared to single-phase faults, faults involving two or more phases require significantly faster clearing times to avoid instability. In the case of a single-phase fault, power is still being transmitted by the two nonfaulted phases. This is unlike the most extreme case—a close-in, three-phase fault where no power continues to be transmitted [2].

Although the mechanical input power to all the generators in one power plant cannot be rapidly changed to meet the change in electrical torque output, rapidly removing a subset of generators from the power system electrically can solve the instability problem. By determining the type of fault that has occurred, the RAS can appropriately select the amount of electrical power generation that must be removed from the system in order to maintain stability as a result of the decrease in electrical power transmission. In this discussion, it should be noted that we also assume there is spinning reserve available at the receiving end of the transmission system to offset the shed generation. Otherwise, load shedding at the receiving end would also be required in order to maintain stability.

III. RAS Logic Relay Functional Requirements

The RAS design optimizes planned generation-shedding levels based on system status, as previously described. It also requires inputs from the protection systems on the critical lines to classify the severity of the initiating event. To provide these inputs, a new RAS logic relay was developed and tested as part of the modernization project.

The RAS logic relay is applied on critical circuits in the Jim Bridger transmission system. It classifies power system faults to trigger the optimal level of generation shedding when a line is tripped. The four possible fault types are as follows:

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

Per the RAS design specifications, these four fault types must be classified as one of the following:

- SLG fault (SLG)
- PP fault (DLG or PP)
- 3PH fault (3PH)

A fault must further be classified as severe or nonsevere based on how close it is to the Jim Bridger bus. A close-in fault will depress the Jim Bridger bus voltages more than a remote fault. This causes a more severe reduction in the power transfer capability via the remaining unfaulted lines while the fault is on. A more severe reduction in the power transfer capability results in a larger rotor swing, which must be controlled.

Table I details the desired outputs of the RAS logic relay. The RAS logic relay must issue only one of the four outputs for any single power system fault event. It is not permissible for the fault classification output to change once a classification has been made. A further design goal is that the RAS logic relay must be biased to err on the side of choosing the more severe classification if it misclassifies a fault.

Table I
RAS Logic Relay Outputs

	Single Line to Ground	Multiphase Unbalanced	Multiphase Balanced
Nonsevere	No Output *	PP Nonsevere	3PH Nonsevere
Severe	No Output *	PP Severe	3PH Severe

* The RAS waits ten cycles for an output from the RAS logic relay. If no output is seen, the RAS assumes that the fault is SLG or nonfault opening and takes the appropriate action for that contingency.

In addition to an output from the RAS logic relay classifying the fault as one of the four types that initiate some level of generation shedding, the RAS also requires an output from the line protection systems to indicate that the fault is internal to the protected line (the line is to be tripped).

The timing specifications for the RAS allow two cycles for the protection systems to initiate generation shedding. Because the RAS logic relay is running in parallel with the line protection systems, it must make its fault classification decision nearly as fast as the high-speed protection systems make their decision to trip the line. This proved to be a significant challenge.

IV. Challenges in Classifying Fault Severity

A severe fault is classified as one that is within the first 25 percent of the uncompensated line length from the Jim Bridger bus. This would appear to require rather simple logic. Set two phase distance zones: Zone 1 (M1P) set at 25 percent of the uncompensated line length and Zone 2 (M2P) set at 150 percent of the uncompensated line length. Then, use (1) and (2), as shown below.

$$\text{Nonsevere} = \text{M2P AND NOT M1P} \tag{1}$$

$$\text{Severe} = \text{M1P} \tag{2}$$

The problem with these simple logic equations is that there is an inherent inverseness to the speed characteristics of a distance element relative to the multiple of reach of the fault. A fault close to the balance point (multiple of reach approaches one) of a distance element will take longer to reach the trip threshold than a close-in fault (multiple of reach approaches zero). A fault 25 percent distant from the Jim Bridger bus will be at 100 percent of the M1P element reach and 17 percent of the M2P element reach.

The main reason for this inherent timing characteristic is that the speed of a microprocessor-based relay is dominated by the signal processing filter window [3]. As the filter window fills with fault samples, the phasor measurements transition from their prefault values to their fault values. If the fault location is near the reach setting, all prefault samples must have exited the filter window in order for the phasor estimation to reach its final fault value and cross the reach threshold. Most microprocessor-based relays use a one-cycle filter window for a good balance between transient behavior and speed.

In a high-performance, subcycle distance relay, the inverse timing characteristic, relative to multiples of reach, is compounded. As previously mentioned, the speed of a microprocessor-based relay is dominated by the filter window. One way to achieve subcycle performance is to use a shorter filter window. However, less filtering results in poorer transient overreach performance. The high-speed and full-cycle distance elements run in parallel, but the high-speed Zone 1 element has a shorter reach than the full-cycle Zone 1 element [4]. Thus, for faults between the limit of reach of the high-speed element and the reach of the full-cycle element, the inverse timing characteristic increases by approximately an additional half cycle.

In summary, the problem with (1) and (2) is that they lack a timer to introduce a delay that would allow M1P an opportunity to assert. Once a delay timer is added, it is necessary to determine an acceptable setting for the timer. The timer must be set longer than the worst-case timing difference between the assertion of the overreaching element versus the assertion of the underreaching element. The timer setting must also consider that if the delay is too long, the scheme will not meet its speed performance requirements; if the delay is too short, the scheme will tend to declare severe faults as nonsevere. This violates one of the design objectives.

To reduce the additional variability in timing between the assertion of the overreaching element versus the assertion of the underreaching element caused by the high-speed elements, the logic was switched to use the M4P and M5P elements. These elements do not have high-speed elements running in parallel with them. This made it easier to optimize the delay setting during scheme validation testing.

V. Challenges in Classifying Fault Type

The RAS logic relay has to reliably and quickly classify the following four possible fault types into one of three categories:

- SLG faults, which initiate no output
- DLG faults, which initiate "PP fault" output
- PP faults, which initiate "PP fault" output
- 3PH faults, which initiate "3PH fault" output

Determining SLG faults was easy, given that the relay platform used for the RAS logic relay is designed for single-pole trip (SPT) applications. Differentiating between balanced and unbalanced multiphase faults proved to be more difficult.

A. Limitation of Faulted Phase Identification Logic

The faulted phase identification logic in the relay platform used for the RAS logic relay only operates during faults involving ground (SLG and DLG). This function serves two main purposes. The first purpose is to prevent overreach of the leading-phase ground loop during a DLG fault. The second purpose is to prevent phase loops from operating during SLG faults [5]. In SPT applications, the relay must reliably identify SLG faults and correctly trip only the faulted phase. When a phase loop asserts, the relay issues a three-pole trip (3PT). It is not necessary for an SPT relay to distinguish between any of the multiphase fault types, because all multiphase faults initiate the same output—3PT.

B. Using Phase Loop Assertion Logic

The relay platform used for the RAS logic relay includes separate output logic bits for each of the six distance element loops. One idea, which was later discarded, was to declare a 3PH fault when all three-phase loops asserted per (3) and (4).

$$\text{3PH severe} = \text{MAB4 AND MBC4 AND MCA4} \quad (3)$$

$$\text{3PH nonsevere} = \text{MAB5 AND MBC5 AND MCA5} \quad (4)$$

This method proved to be very unreliable for distinguishing between 3PH and PP faults. In some cases, not all three-phase loops would assert for 3PH faults—especially for boundary conditions. In other cases, all three-phase loops would assert for PP faults. For multiphase faults involving ground (DLG), the previously described faulted phase identification logic provided reliable operation of this method.

Fig. 3 shows how the three-phase fault loops respond to a PP fault (in the example, a BC fault). The figure shows the dynamic characteristics of the various mho elements and the apparent impedance for each phase loop plotted on the RX diagram. The fault is located at the reach point of the mho element [6].

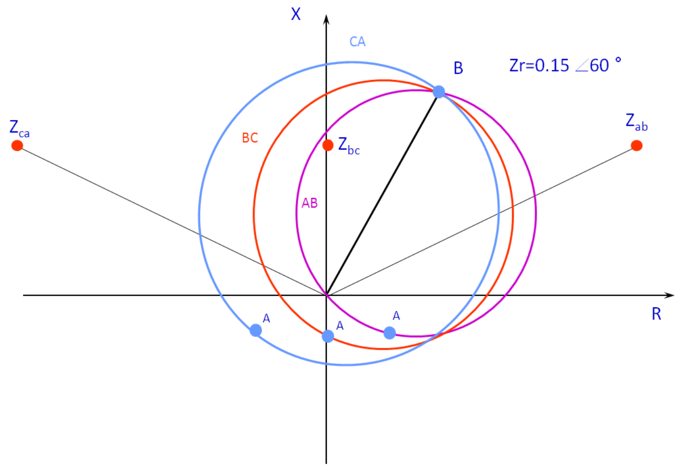

Fig. 3. Response of all phase loops to a BC fault

It can be seen that the apparent impedance ZAB would plot inside the MAB mho element characteristic for this BC fault if the fault were located at approximately two-thirds of the reach setting. Similarly, it can be seen that the apparent impedance ZCA would plot inside the MCA mho element characteristic if the fault were located at approximately one-third of the reach setting.

C. Using Presence of Negative Sequence to Discern Unbalanced Faults From Balanced Faults

Microprocessor-based relays can easily calculate the symmetrical components present during a shunt unbalance (short-circuit fault) on the power system. In reviewing symmetrical component theory, we know that negative-sequence current is present in all unbalanced fault types. For a balanced three-phase fault, only positive-sequence current is present. Therefore, it would seem that an unbalanced fault could be declared if the negative-sequence current (3I2) magnitude is above a threshold, as determined by assertion of relay element 50Q. The problem then comes with determining a suitable pickup setting for 50Q.

The problem with this solution is that negative-sequence current can be present during balanced faults due to natural unbalances in the power system. The two main sources of natural negative-sequence current in this application are as follows:

- Transmission lines that are not perfectly transposed
- Series capacitor protection elements that will not bypass all three phases exactly the same

The normal solution to prevent response of the negative-sequence elements to these natural system unbalances is to require that the ratio of negative-sequence current to positive-sequence current exceed a threshold. A good default setting that deals with normal system unbalances is 10 percent. When series capacitors are present on the system, it is recommended to increase this setting to 15 percent [7]. On the other hand, the setting should not be set too high. Otherwise, the positive-sequence load flow may overly restrain the element, making it insensitive to high-impedance ground faults where the negative- and zero-sequence currents can be relatively low compared to the positive-sequence current.

Filter transients were another problem that needed to be addressed when using negative-sequence current to make the decision for fault classification. The finite impulse response (FIR) filters used by most microprocessor-based relays are theoretically valid only during steady-state conditions. During the time that the filter window has a mixture of samples from two different power system states (unfaulted and faulted), the output of the filter has a transient error in both magnitude and angle measurement. The angle measurement error is compounded when used by the negative-sequence filter because the angles must be multiplied by the complex numbers a or a^2 ($1\angle 120°$ and $1\angle 240°$ respectively). The false negative-sequence current caused by the filter transient can last a little over one cycle. Fig. 4 shows a plot of positive-sequence current (I1) and negative-sequence current (I2) for the first two cycles after initiation of a close-in fault on the Jim Bridger to Threemile Knoll line.

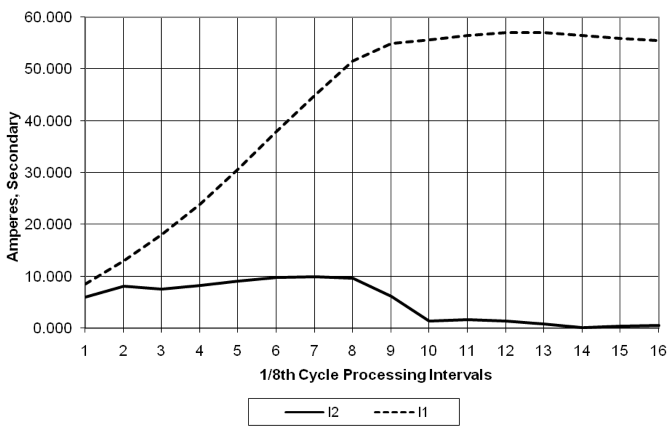

Fig. 4. Plot of I1 and I2 for the first two cycles after initiation of a close-in ABC fault

Thus, it was necessary to delay the fault classification decision longer than the filter transient time. Otherwise, the logic would be biased to falsely classify balanced faults as unbalanced faults due to the presence of this transient false negative-sequence measurement. This violates the design objective that the system be biased to err on the side of choosing the more severe classification. This amount of delay was unacceptable to meet the operating speed requirements of the RAS logic relay.

VI. New Method for Classifying Fault Types

Testing of the various methods for fault type classification resulted in unsatisfactory results. It was not possible to find a suitable 50Q pickup setting that would provide good results for all fault types and work for close-in and remote faults along the length of the lines out of Jim Bridger without introducing too much delay before a fault classification could be made.

Another design goal that became apparent during the testing was the need for an algorithm that could be set without extensive trial and error testing using a transient power system simulator. The testing regimen used in validating the RAS logic relay is described in Section VIII of this paper. The settings for the RAS logic relay had to be able to be calculated from information obtained from the phasor-based, fault study analysis tools available to the relay engineers.

A. *New Algorithm for Rapid Determination of Fault Type*

The new algorithm borrows its concept from another well-known element used in power system protection—the variable percentage-restrained (dual-slope) differential element. A variable percentage-restrained differential element requires a low ratio of differential to restraint (through-fault) current when the restraint current is low and requires a higher ratio of differential to restraint current when the restraint current is high. Thus, when through-fault current is high and transient false differential caused by CT saturation is more likely, it takes a higher percentage of differential current to declare an internal fault.

In this case, the design goal is to make a determination as quickly as possible as to whether the negative-sequence current is high enough to classify the fault as unbalanced. The percentage ratio of interest is the ratio of I2/I1, with I1 as the restraint quantity and I2 representing the operate quantity. See Fig. 5 for a plot of the Fig. 4 fault data—now plotted as a ratio of I2/I1 versus a variable percentage comparator characteristic.

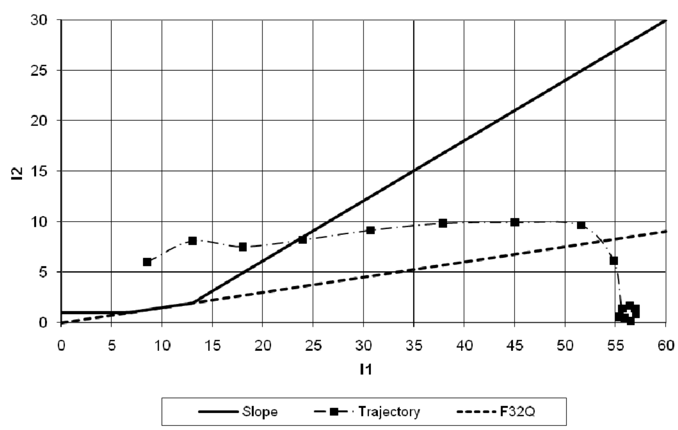

Fig. 5. Plot of I2/I1 ratio for the data contained in Fig. 4 versus a variable percentage comparator characteristic

In Fig. 5, the dashed line, F32Q, represents the fixed ratio setting of 15 percent. The solid line is a composite of the minimum pickup, the 50Q setting (the horizontal line), the fixed ratio setting, and the new variable percentage ratio characteristic. The graph shows that the ratio of I2/I1 does not drop below the fixed ratio setting of 15 percent for this high-magnitude balanced fault until nine-eighths of a cycle after the fault is first detected. However, it crosses below the variable percentage characteristic after only four-eighths of a cycle. These results looked promising, so the new scheme was further developed.

The variable percentage characteristic line is described by (5) and is of the classic y = mx + b form.

$$I2 = mI1 + b \quad (5)$$

where: m is the slope of the line
b is the y (I2 axis) intercept

B. Developing Setting Criteria

It was then necessary to determine the setting criteria for the new variable percentage I2/I1 ratio element. The scheme must be easily set based on values available from the fault study program. Settings for both *m* and *b* need to be determined that provide reliable determination of balanced versus unbalanced fault type.

The unbalanced faults of interest for the RAS logic are for PP and DLG faults. For PP faults, the ratio of I2/I1 should theoretically be 100 percent (neglecting load flow). For DLG faults, the sequence networks are connected, as shown in Fig. 6, such that the zero-sequence network shunts current away from the negative-sequence network [8]. This can reduce the ratio to below 100 percent. In the case of Jim Bridger, the grounding resistors on the generating units reduce this effect such that the worst-case ratio is around 50 percent for a close-in fault per the phasor-based fault study program, using the Threemile Knoll line as an example. As the fault gets further away, the ratio increases to around 75 percent for a DLG fault on the line side of the series capacitor at Threemile Knoll.

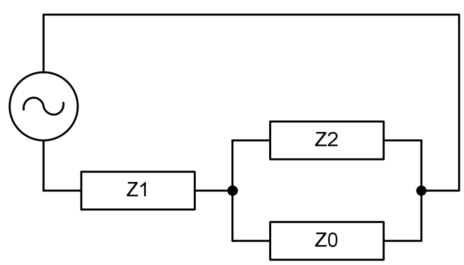

Fig. 6. Sequence networks for DLG fault

Fig. 7 shows a plot of I2/I1 for a close-in DLG fault. For this case, the ratio of I2/I1 stays above the variable percentage characteristic, and the RAS logic relay correctly classifies this as an unbalanced fault.

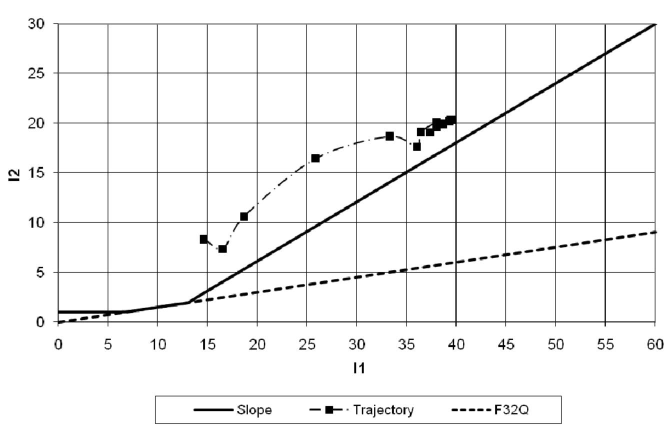

Fig. 7. Plot of I2/I1 ratio for a close-in DLG fault versus a variable percentage comparator characteristic

C. Process for Setting the RAS Logic Relay

The process to set the RAS logic relay is as follows:

Step 1. Obtain the negative-sequence current for a close-in DLG fault and a line-end DLG fault using the fault study program.

Step 2. Choose an I2/I1 ratio for the close-in fault that is less than the ratio provided by the phasor-based fault study program. Calculate a value for I1 based on the I2 value obtained in Step 1. We used 40 percent and 45 percent for the close-in fault because the ratio (I2/I1 in this application) was around 50 percent for the close-in DLG fault.

Step 3. Choose the I2/I1 ratio for the remote fault point as equal to the fixed ratio used by the negative-sequence elements (15 percent, in this case), and calculate a value for I1 based on the I2 value obtained in Step 1.

Step 4. Create a line on the percentage-restrained element characteristic graph using the two (I1, I2) coordinate points provided by the calculations.

Step 5. Calculate the coefficients for the $y = mx + b$ form equation that describes the line created in Step 4.

D. Investigation of Cases Where Scheme Misclassified Faults

The scheme was tested and proved to be effective in improving the performance of the RAS logic relay. With the new scheme, fewer misclassifications occurred. When the logic did misclassify the fault type, it tended to err on the side of declaring a DLG fault as a 3PH fault. For some DLG fault shots, the I2 filter transients resulted in low values of I2 until after the filter transient time. Fig. 8 shows a plot of one such case. The number of times this happened was small enough that the results were deemed to be acceptable (see Table II in Section VIII, Subsection D).

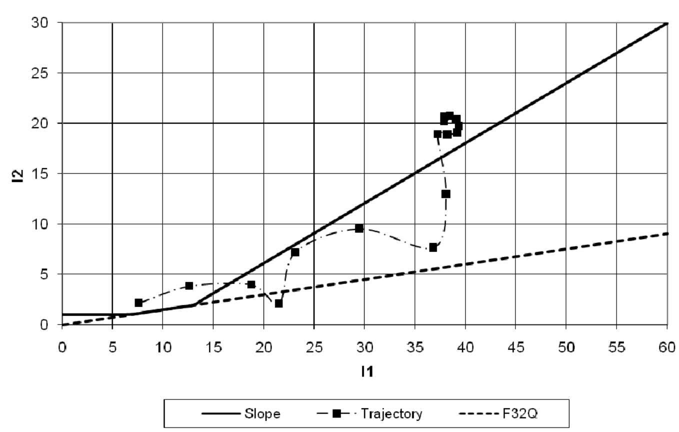

Fig. 8. Plot of I2/I1 ratio for a close-in DLG fault where the I2 magnitude remained at a low value during the filter transient

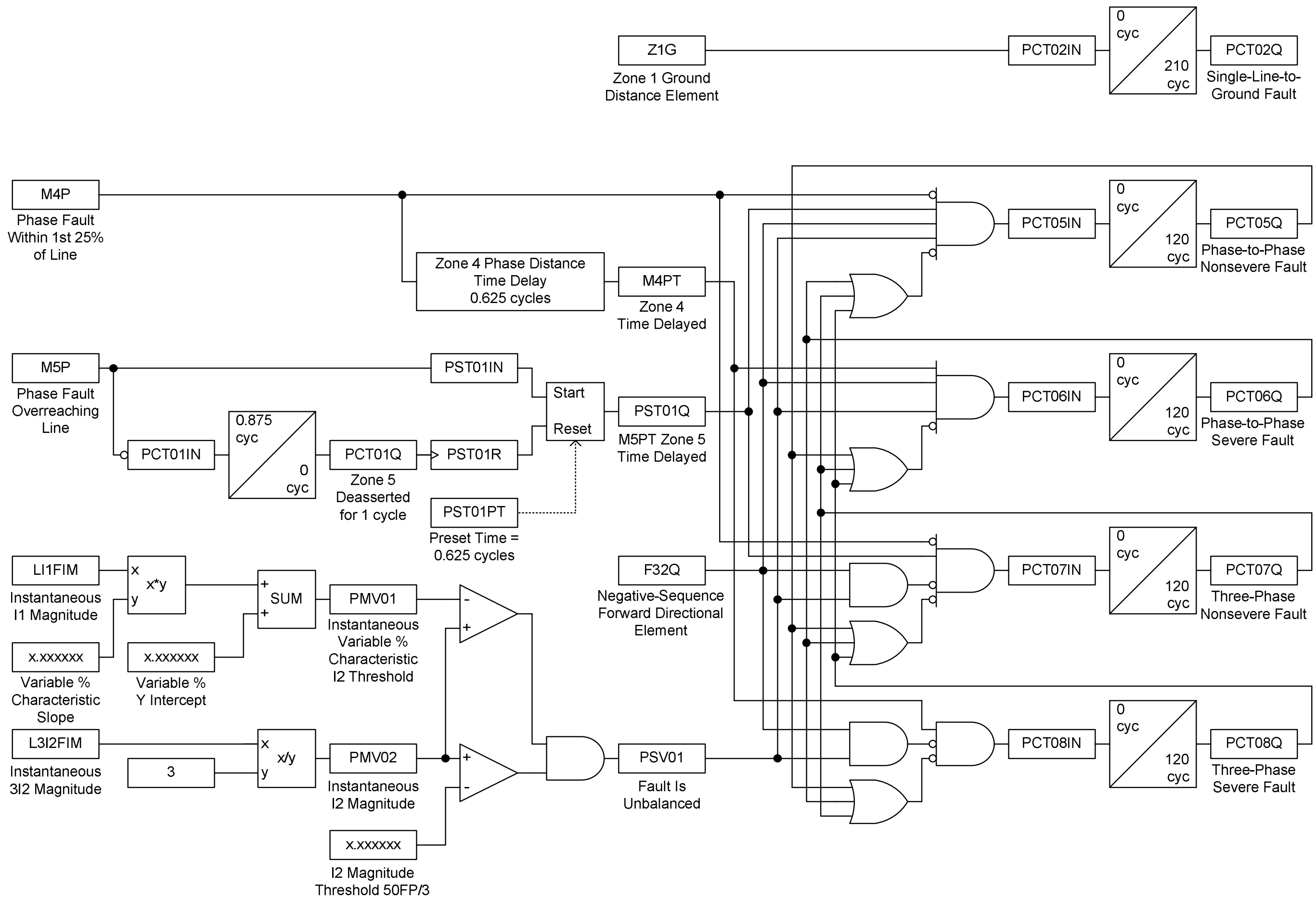

Fig. 9. RAS logic diagram

VII. Final Design of RAS Logic Relay

Fig. 9 shows a detailed logic diagram of the RAS logic relay. The zone element timers M4PT and PST01Q provide a delay to allow time for the underreaching zone element to assert and the I2/I1 ratio to cross the variable percentage threshold if it is a balanced fault. Logic variable PSV01 is the output of the variable percentage I2/I1 ratio check. This variable is ANDed with logic variable F32Q, which adds the fixed ratio check to complete the dual-slope characteristic. Once any of the four outputs assert, the remaining outputs are blocked for 120 cycles to satisfy the requirement that only one RAS logic output be made for any given fault event. The logic processing order is arranged so that logic checks are made in the order of most to least severe during each processing interval. This helps bias the logic to err on the side of classifying a fault as more severe in cases where multiple conditions may be satisfied on the same processing interval.

VIII. Validating and Optimizing the New Algorithm

A Real Time Digital Simulator (RTDS®) system manufactured by RTDS Technologies was used to test and validate the RAS logic relay.

A. RTDS System

The RTDS system allows real-time testing of electronic devices on a power system model. While resembling the Electromagnetic Transient Program (EMTP) in its use and application, the RTDS allows inputs from the device under test to affect the model in real time, much like an analog power system simulator. For example, the digital relays receive currents, voltages, and breaker status inputs from the real-time digital simulator system. The same relays return trip contact inputs to the real-time digital simulator test system, which causes the modeled circuit breaker within the model to open [9]. The system uses parallel processing architecture specifically designed for power system simulations. It performs digital electromagnetic transient power system simulations in real time. The resulting signals are continuously fed to the protective systems, with the voltage and current signals resembling a realistic environment. Fig. 10 shows the major components of a typical real-time digital simulator test setup.

Real-time digital simulation 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 testing applications such as single-pole tripping and reclosing, out-of-step conditions, and RASs [10].

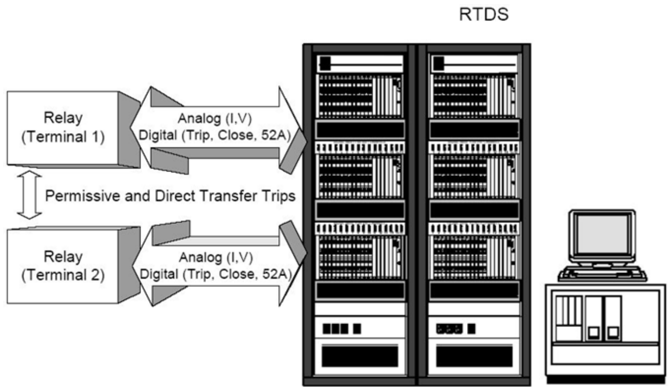

Fig. 10. Real-time digital simulator test setup

B. Modeling Jim Bridger System for Real-Time Digital Simulator Testing

A simplified system model for the tests was created in RSCAD® Software, based on a reduced network from the PacifiCorp fault study model. The network was reduced to the Jim Bridger Power Plant and 345 kV transmission network, along with system equivalent sources and transfer branches representing the rest of the system. This was necessary due to functional limitations on the number of nodes within the real-time digital simulator system. The reduced model was validated by comparing fault levels throughout the model with the results from the full system model in the fault study program.

The real-time digital simulator system provides low-level analog signals to the relays being tested. The real-time digital simulator was configured to accept digital outputs from the relays to record the RAS logic outputs. Additional output signals from the relays were connected to the real-time digital simulator to provide recording of the status of additional intermediate logic variables for analysis.

C. Test Procedure

With the complete system set up, selected faults were applied to the simulation system to explore the performance of the relays and fine-tune relay settings. Event reports and other test results were recorded to document any required settings changes. Once the settings were refined, faults were applied to the relays in an automated sequence. To fully explore the relay performance under different system conditions, batch tests were run for the following conditions:

- Five different load flow cases
- Faults located between 0 percent and 40 percent of the line length in 5 percent increments and at line end in front of and beyond the series capacitor
- All ten possible fault types: AG, BG, CG, ABG, BCG, CAG, AB, BC, CA, and ABC
- Fault inception angles of 0°, 45°, and 90° referenced to VA (Jim Bridger 345 kV Phase A bus voltage)

This resulted in 1,650 fault shots for each line. Each batch run took approximately 14 hours to run. The batch runs were repeated multiple times, using different timer and slope settings to determine the optimal settings criteria to achieve the best overall results.

The results of each test case were stored in a COMTRADE® (Common Format for Transient Data Exchange) file and a text file associated with each fault location. The COMTRADE and text result files were analyzed for correct operation and saved for reference. If any adjustments were made to improve the performance of the scheme (e.g., trying different time-delay values to determine which provides the best compromise between speed and accuracy), the batch tests were repeated to document the operation of the final configuration.

D. Final Results

Table II shows the final test results for the Jim Bridger to Threemile Knoll line. Examination of the table shows that the scheme only misclassified 1 of 1,650 shots as 3PH instead of PP and 43 of 1,650 shots as severe instead of nonsevere. The worst batch test results were for the Jim Bridger to Borah line with 5 of 1,650 shots misclassified as 3PH instead of PP and 94 of 1,650 shots misclassified as severe instead of nonsevere. These results were determined to be acceptable. These results were obtained using a time delay of five-eighths of a cycle. Shorter and longer time delays were tested, but this setting provided the best compromise of speed versus accuracy.

TABLE II
TEST RESULTS FOR JIM BRIDGER TO THREEMILE KNOLL LINE

Fault Location From Bridger	**Misclassifications: Severe vs. Nonsevere**	**Misclassifications: 3PH vs. PP**	**Comments**
0%	0 of 150	1 of 150	All misoperations classified as 3PH instead of PP
5%	0 of 150	0 of 150	
10%	0 of 150	0 of 150	
15%	0 of 150	0 of 150	
20%	0 of 150	0 of 150	
25%	0 of 150	0 of 150	
30%	43 of 150	0 of 150	All misoperations classified as severe instead of nonsevere
35%	0 of 150	0 of 150	
40%	0 of 150	0 of 150	
In front of series capacitor	0 of 150	0 of 150	
Beyond series capacitor	0 of 150	0 of 150	

IX. CONCLUSION

The RAS is important to the operation of the PacifiCorp Jim Bridger transmission and generation system to allow full use of the generation, while ensuring system stability. The design of the RAS recognizes that the severity of the initiating event affects the severity of the power swing resulting from a fault on the transmission system. Two measures of severity are recognized: distance from the Jim Bridger bus and the number of phases involved in the short circuit. By obtaining inputs from the line protection systems regarding the line to be tripped, the fault type, and the distance of the fault from the bus, the amount of generation required to be shed can be optimized to prevent over- or undershedding.

The development and testing of the RAS logic relay for use on the Jim Bridger generation-shedding RAS made for an interesting and challenging project. In the course of executing the project, the project engineers obtained a better understanding of the transient response characteristics of faulted phase identification logic, distance elements, and digital filtering algorithms to different fault conditions.

The use of a protective relay platform with powerful programmable logic capability that allows custom mathematical calculations and comparisons to be performed at protection speeds enabled engineers to think outside the box. It also allowed them to develop a completely new protective relaying element to quickly and accurately classify multiphase faults as either balanced or unbalanced.

Using a fixed ratio check of negative-sequence to positive-sequence current is a well-established means to discern normal system unbalances from faulted system unbalances and works well in most applications. Under normal SPT and 3PT protective relaying applications, both balanced and unbalanced multiphase faults result in the same tripping output (3PT), so rapid classification during the first cycle after fault initiation is not required. However, the fixed I2/I1 ratio method proved unsatisfactory for making a determination quickly enough to meet the speed requirements for the RAS logic relay.

The new element uses a variable percentage I2/I1 ratio check that requires a higher ratio of I2/I1 for high-magnitude faults (when filter transients are greater) than for low-magnitude faults to designate a fault as unbalanced. A review of symmetrical component theory for various unbalance types was required to develop easy setting criteria that could be calculated using tools available to the protection engineers who would be applying the RAS logic relays on the critical circuits near Jim Bridger.

In addition to the powerful relay platform used to run the new algorithm, the real-time digital simulator system was an enabling technology that allowed for the development, validation, and optimization of the new algorithm. The ability to run batch tests under multiple power system load flow and source-impedance states created great confidence in the integrity of the design. Being able to run these same batch tests using different settings also enabled the development of easy-to-apply settings criteria for the new algorithm.

X. References

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XI. Biographies

Kyle Baskin received his BS in electrical engineering, magna cum laude, from Washington State University in 2005. After graduation, Kyle began working at PacifiCorp in Portland, Oregon, for the protection and control engineering group, where he was involved in the development, design, and implementation of protective relaying projects as well as remedial action schemes. In September 2008, Kyle was hired at Pacific Gas and Electric Company in Sacramento, California, as a system protection engineer.

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, Inc. (SEL) in 2001, he was involved in the development of a number of numerical protective relays. Presently, he is a senior protection engineer in the Engineering Services Division at SEL. He is a senior member of the IEEE and a main committee member of the IEEE PES Power System Relaying Committee. Michael is a registered professional engineer in the States of Washington, California, and Illinois and holds a number of patents associated with power system protection and control.

Larry Lawhead received his BE in electrical engineering from Duke University in 1982. After graduation, Larry worked at Potomac Electric Power Company (PEPCO) in Washington, DC, in the substation test and system protection departments. He has worked with protective relay manufacturers since 1989 in a variety of sales, marketing, and application engineering roles. He joined the engineering services division of Schweitzer Engineering Laboratories, Inc. in late 2007 and is currently an engineering supervisor. He is a member of the IEEE-PES and has participated in several IEEE PES Power System Relaying Committees. He is a former member of the Western Protective Relay Conference planning committee and has presented papers at several industry conferences.

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