Generator Power Swing Out-of-Step Protection and Analysis of Misoperation Events

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1.0 ABSTRACT

This paper details the Power Swing and Out-of-Step (OOS) protective element as applied for generator protection. Various element characteristics and styles are compared for performance during real-world conditions including failure to trip and false trip power swing events. Planning studies and setting verifications can be used to calculate settings and provide insight into system performance during events. Setting validation using event data is reviewed. Analysis of recent events involving generator out-of-step conditions is presented, as well as a review of what protection may operate when the OOS element fails and conditions that could cause false OOS trips.

2.0 OUT-OF-STEP OR POWER SWING PROTECTION SCHEME FOR GENERATORS

Out-of-Step or Power Swing protection schemes for generators are used to detect loss of synchronism conditions between the connected generator and the power system where a pole slip can occur. An out-of-step or loss of synchronism condition can cause high currents, winding stresses, and other mechanical forces in the generator windings leading to high levels of transient shaft torques. These torques can be great enough to break the turbine generator shaft [1]. With the risk of significant damage to the generator and generator step-up transformer, the out-of-step protection is depended upon to trip the generator before this level of damage can occur.

Other generator protection elements will not detect an out-of-step condition, so dedicated protection is needed. It is generally recommended for most larger generators, that tripping occur quickly before a pole is slipped to prevent generator damage and instability in other parts of the connected power system. While quick detection and tripping is ideal due to the possible damage to the generator, generator step-up transformer, and generator breaker, it may also be beneficial to delay tripping to prevent opening the breaker when the generator and system has a 180° opening angle across the breaker. Generators can also go out-of-step during slow cleared transmission system faults and during loss of excitation events.

2.1 OOS PROTECTION SCHEMES

Various out-of-step protection schemes were examined from different protective relay manufacturers. The schemes that were looked at track positive sequence apparent impedance trajectory as seen from the generator terminals through the protection zone to detect an out-of-step condition. Blinders are used to detect when the apparent impedance enters and exits, along with associated timers to detect how long the apparent impedance takes to cross the characteristic. The common out-of-step protection schemes incorporate either single or double blinders.

During a fault, the apparent impedance trajectory will move through the element characteristic and the blinders almost instantaneously. For an unstable power swing, the apparent impedance trajectory would stay inside the element characteristic and the blinders for a time determined by a transient stability study, leading to a desirable out-of-step trip. It is important for these protection schemes to differentiate between a stable and unstable power swing. For a stable power swing, the generator should not trip offline.

When two systems are in phase with each other, the angular difference is zero. The voltage will be maximum and the current minimum. When the two systems are completely out of phase of each other, the angular difference will be 180° apart. The voltage at the terminal of the generator will be minimum and the current maximum. At 120° separation angle, it is unlikely that the generator can maintain stability and usually results in loss of synchronism. Out-of-step apparent impedance trajectories can move across the element characteristic from right to left or left to right. If the trajectory is moving from left to right this could mean that the unit is motoring. The out of step protection zone should cover from generator neutral to the high-side bushing of the generator step-up transformer.

2.2 SINGLE BLINDER SCHEME

The single blinder scheme uses one set of blinders with a supervisory mho element. A restricted pickup area is used and limited by the mho element and blinders. The apparent impedance trajectory of the power swing must start from outside the blinders and swing through the outer zone pickup area into the inner zone as seen in Figure 1. Some schemes require the impedance to plot within the outer zone for a short time (<1 cyc) while others require the trajectory to enter from the outer zone. If the impedance then remains in the inner zone for a short or settable time, the condition is considered a power swing. These schemes often have an option to trip the breaker when the angle between the generator and system voltage is 90° or less. This option stresses the breaker less when tripping due to reduced current flow and less voltage difference at the breaker for this angle difference.

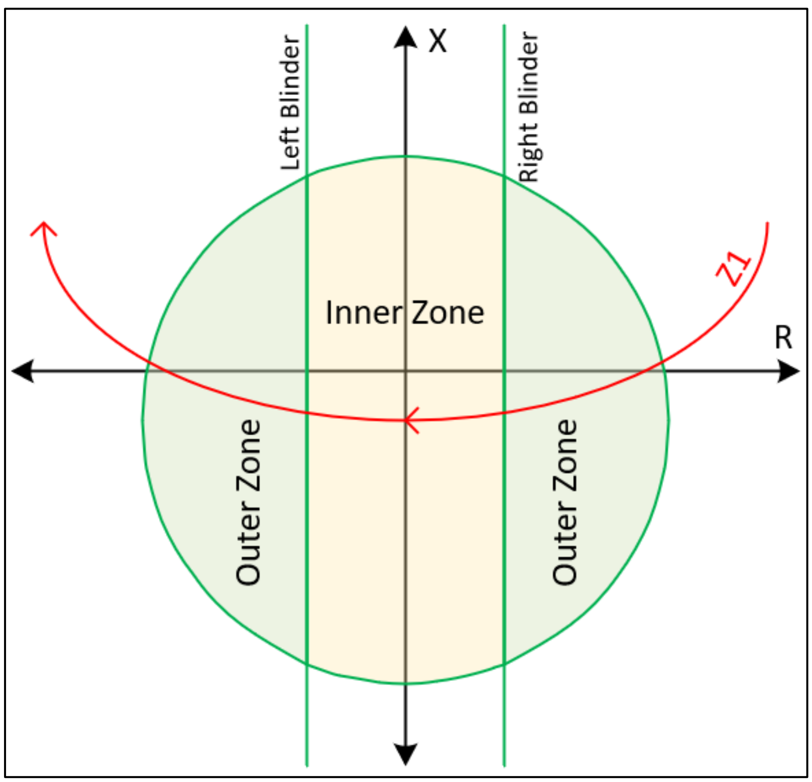

Figure 1: Single Blinder OOS Scheme

A pole slip counter can be used to trip after a specified number of pole slips. It should be noted that allowing a generator to slip more than one pole is primarily used outside of North America. For some hydro generators, it may be common practice to allow the unit to slip a certain number of poles before it is tripped. This is due to some hydro units having the possibility to still regain synchronism after a pole slip has occurred [1]. OOS conditions caused by slow clearing system faults may challenge the blinder schemes if the fault trajectory enters from the top already inside the blinders. If the blinders are set for a 120° angle separation between the generator and the system, and an external slow-clearing fault results in a separation angle of more than 120° where the impedance plots within the blinders once the fault clears (as seen in Figure 2), this scheme would not be able to detect the power swing prior to the first pole slip condition and would need to continue around to a second pole slip condition before it would be detected entering the blinders. Due to this, blinder swing detection delays may need to be set based on generator speed and frequency after a pole slip or multiple slipped pole conditions.

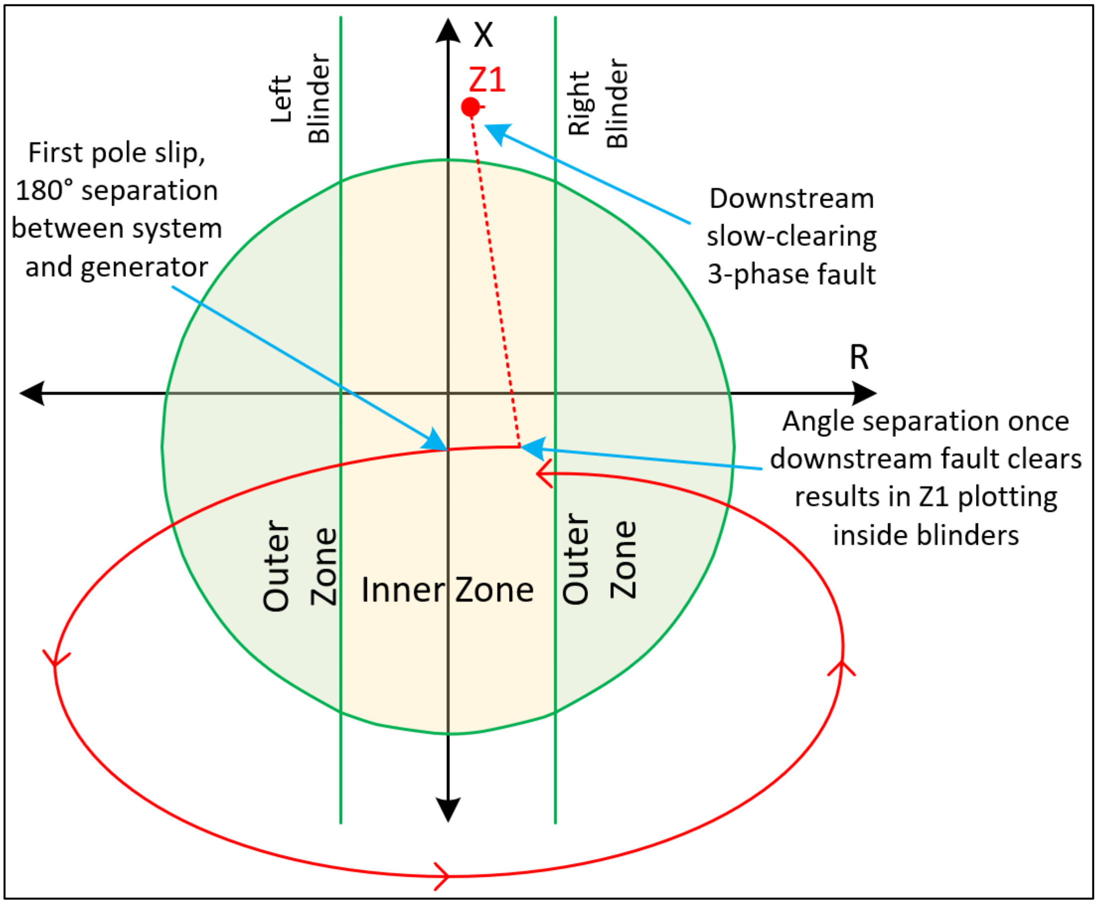

Figure 2: Failure to Detect First Pole Slip

This single-blinder scheme is considered easier to configure as it requires less analysis and system study to set as the impedance trajectory is the primary concern.

2.3 DUAL-BLINDER SCHEME

This scheme uses two pairs of impedance blinders, inner and outer, as well as a mho characteristic. An out-of-step declaration is made if the apparent impedance trajectory stays between the left two or right two blinders for a settable time delay and then advances further inside the inner blinder. An out-of-step trip is initiated when the fault impedance exits the mho characteristic. These schemes may also apply a positive sequence overcurrent supervisor. Additionally, OOS schemes may also be blocked with negative-sequence current as a power-swing event is often a balanced system condition.

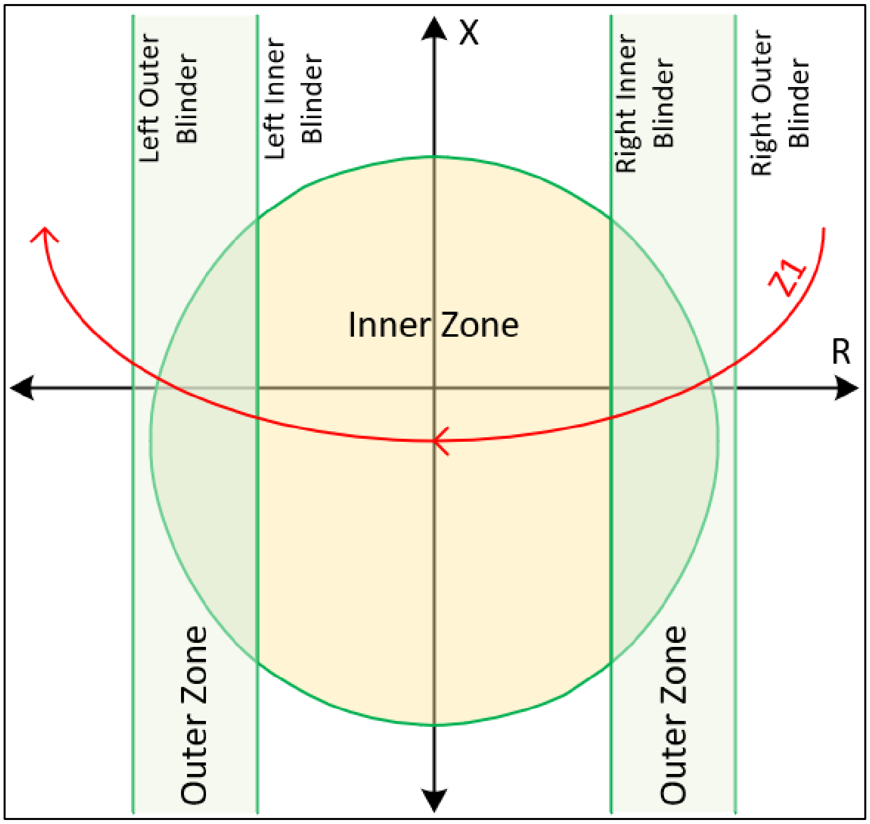

Figure 3: Double Blinder OOS Scheme

This scheme can be more involved to configure as the time delays between the inner and outer blinders is one of the defining characteristics of this element to detect a power swing. Similar to single-blinder schemes, slow-clearing fault trajectories that enter from the top may not be detected as a power swing until after the generator experiences a full pole slip. Blinder swing detection timing may need to consider the speed of the generator after a full pole slip occurs and re-enters the OOS characteristic.

2.4 CONCENTRIC IMPEDANCE ZONE SCHEME

These characteristics can be set as a lens, mho or quadrilateral zone with outer, middle, and inner zone characteristics. The apparent impedance trajectory is timed as it enters the zone characteristics via a selectable two- or three-zone configuration. These schemes can be configured to act similar to the single and double blinder schemes. One important distinction this scheme offers is the ability to have an upper zone area to determine power swing conditions. OOS tripping can occur once the swing is declared as it enters the inner zone, which can be configured for less stress on the breaker as well as issuing a trip prior to a pole slip condition. Additional time delays can also be used to reduce the stress to the breaker as well as configuring the scheme to trip on exit of one of the zones where the separation angle is smaller.

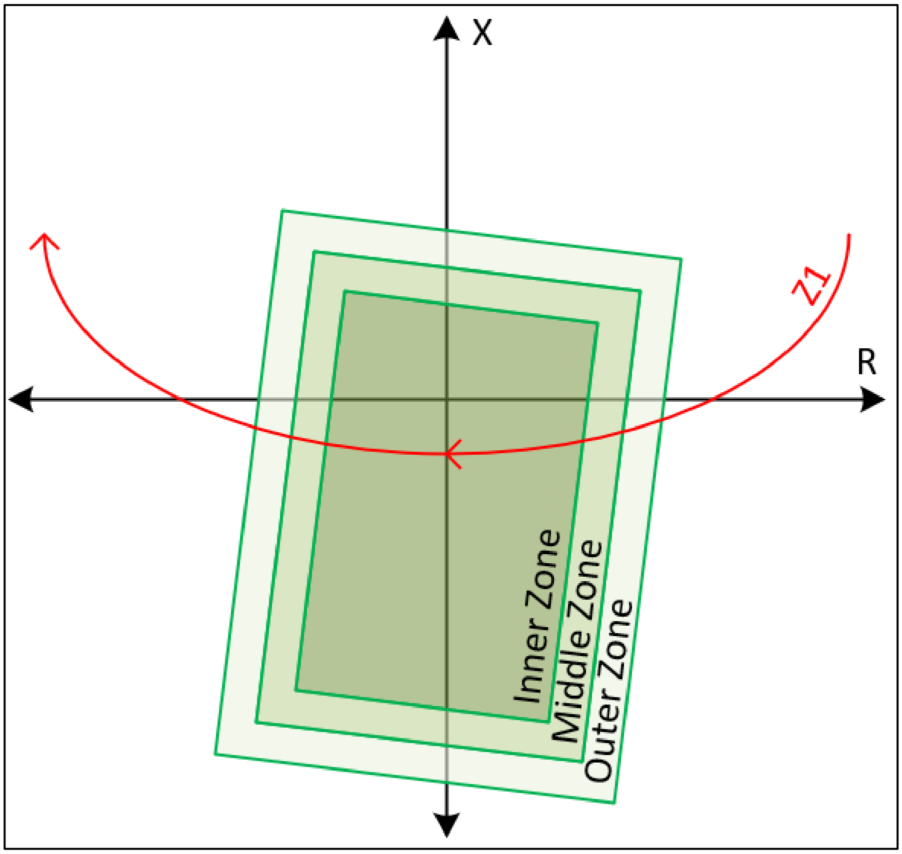

Figure 4: Impedance-Zone OOS Scheme

The two-zone characteristic uses the outer and inner zones to allow for more space in heavily loaded systems for separation between the zones. This method provides a single determination of the apparent impedance trajectory. To use the three-zone characteristic, there should be enough space between the maximum load impedances and the characteristic blinders. For this method, it is recommended to perform a transient stability study for the fastest expected power swings along with the settings of the power swing timers. Both of these methods can also apply an overcurrent supervisor for security.

3.0 TRANSIENT STABILITY AND PLANNING STUDIES

Transient stability studies provide important data needed for setting any of the out-of-step scheme elements that apply timers. A transient stability study is also needed to confirm blinder settings for double blinder schemes and to determine the out-of-step slip frequency since this is a system specific value. One of the most important values determined from the study is the shortest time that it takes the apparent impedance trajectory to cross the blinders during an out-of-step event. If the timer settings in the out-of-step scheme are not set appropriately, this can result in tripping the generator breaker while the angular difference is too large, stressing the breaker and possibly causing damage to the generator [2].

Transient stability studies consider the excitation and governor control systems responses during faults and other situations where the controls try to keep voltage and frequency steady. If the models of the equipment are detailed and accurate, faults that cause out of step conditions can be mimicked by simulations. For schemes like the double blinder and concentric zone schemes where timing between blinders is critical to detect power swings, a detailed transient study is required. Multiple simulations will be required to consider various system configurations like what adjacent generation units are online or offline. Additionally, clearing time of the adjacent line relays using both normal and backup protection as well as N-1 conditions should be considered to determine the longest clearing times. These long clearing times may result in a pole slip condition and increased speed/frequency of the unit before the OOS element can detect an unstable power swing condition.

An example occurred at a hydroelectric dam with two 33MVA generators connected to a 69 kV system. The two units were online when there was a slow to clear 30-cycle three-phase fault on a line a few miles away. The protection on both units was configured for a single-blinder OOS scheme.

The generator relay event data showed a stable power swing from the fault, and both units stayed online as seen in Figure 5 and eventually regained sync with the system. System DFR shots showed the generator oscillating at least 15 seconds after the fault. Transient stability studies showed that the units should have gone out of step and tripped for an unstable power swing. The unit's excitation systems were tested to validate the models. The existing models did not match the new test results, but the age of the excitation system prevented a valid model from being developed from the test results.

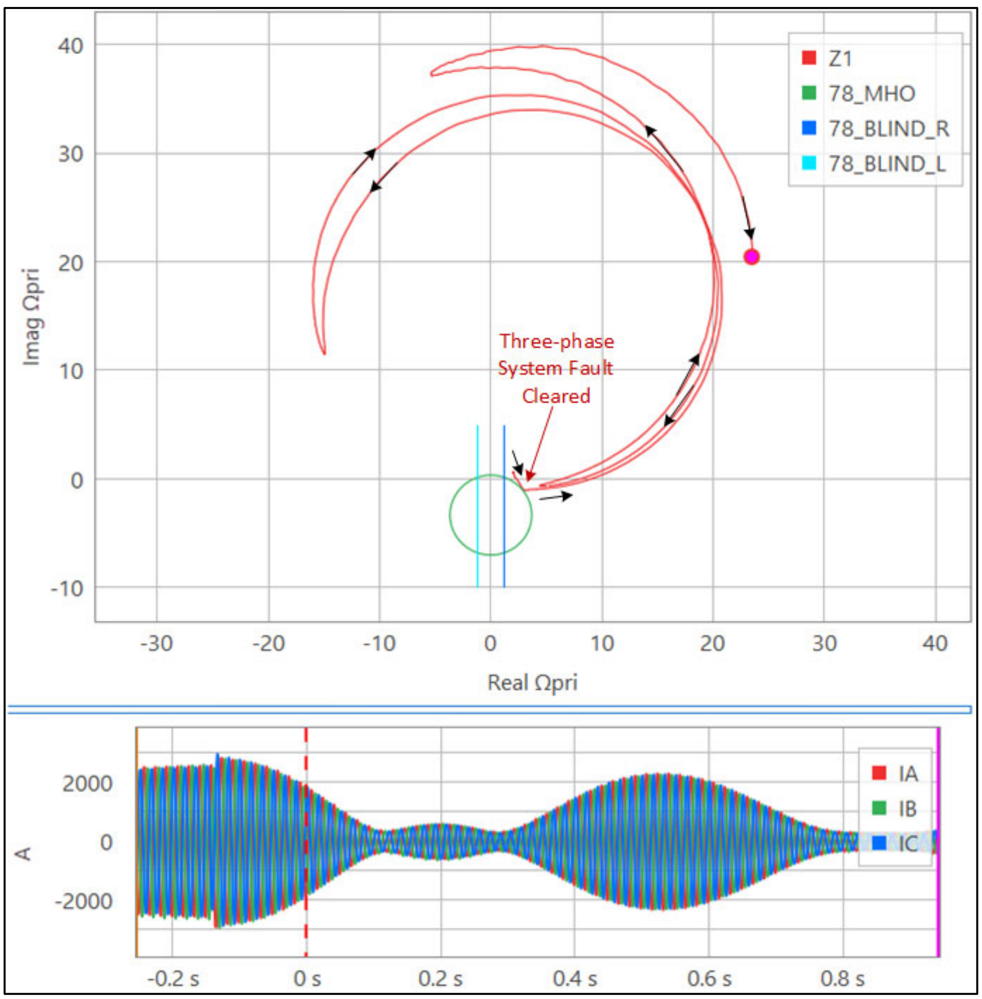

Figure 5: Stable Power Swing with No Trip

The MW power flow for this event can be seen moving positive and negative multiple times in a short period of time. The relay event trigger was due to a low voltage condition during the power swing but did not capture the subsequent oscillations. This large MW swing in such a short time presented stresses to the generators, but no damage resulted.

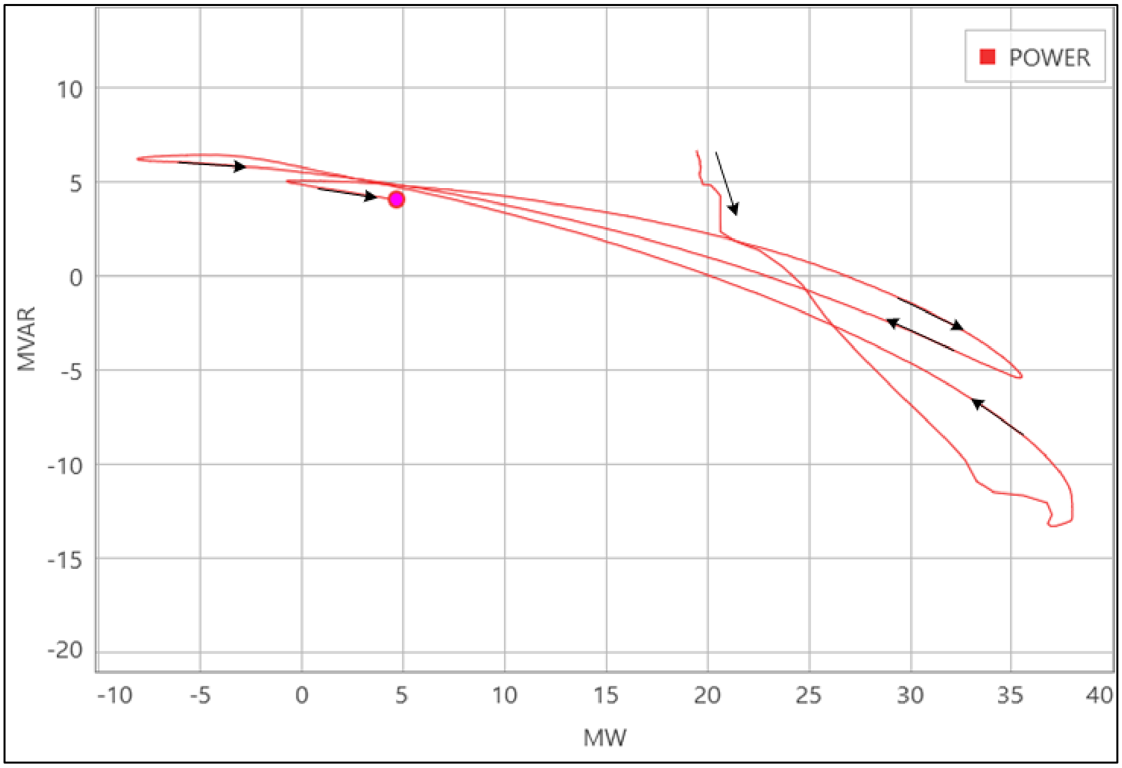

Figure 6: No Trip Power Swing, MW vs MVAR

Another case of a nearby slow to clear fault at an external Local Power Company line about 1 mile away caused an unstable power swing out of step condition on a 33MVA and two 34.5MVA hydro-generating units. The two 34.5MVA generator's protective relays had newer out of step protection which detected and tripped for this event while the 33MVA unit had an older protection system and did not trip. As part of the event investigation, this event revealed a lack of information in the models for the Local Power Company equipment. Additionally, the older protection system was replaced with newer relays to provide better OOS protection. Figure 7 shows event data from one of the 34.5 MVA units that correctly tripped on OOS, which was configured for a single-blinder scheme. The event was initially a phase-ground fault on a 46kV distribution system for 525ms, then became a phase-phase-ground fault for 551ms before being cleared at the 46kV level. The event data below shows the initial slow clearing fault between the blinders and above the mho circle. The positive sequence impedance Z1 moved back outside of the blinders once the fault was cleared as the separation angle was less than the blinder-configured 120°. Z1 then moved inside the blinders for the relay to detect the power swing prior to a pole slip. This scheme was configured to trip once Z1 left the mho circle, which occurred after a pole slip. Once the trip was issued, the signal proceeded through a lockout relay to the generator breaker and the unit was separated from the system prior to a second pole slip.

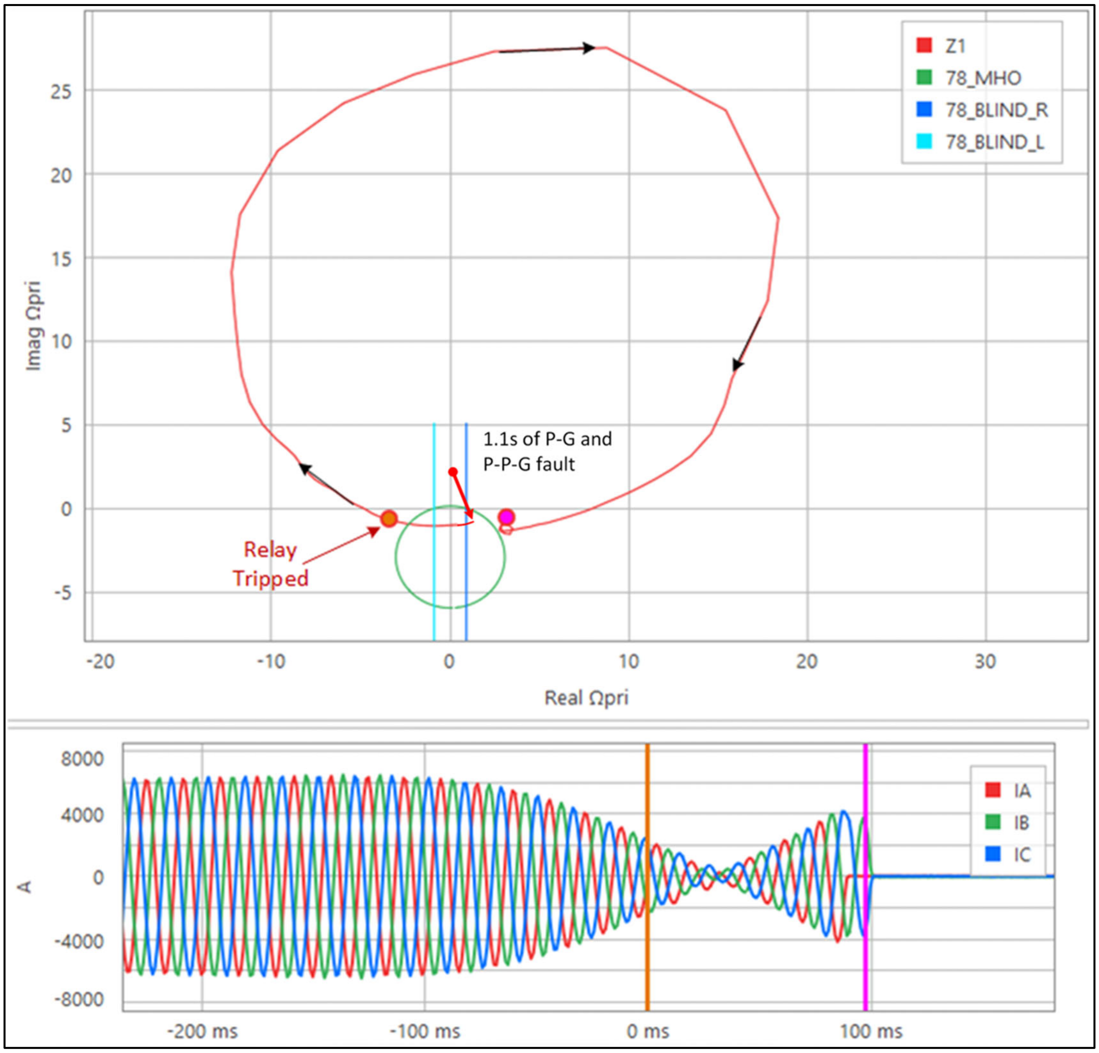

Figure 7: OOS Trip on Single Blinder Scheme

Figure 8 shows the MW power flow moving quickly from positive to negative, the trip point (dot), and moving back to positive MW flow before the unit was removed from the system.

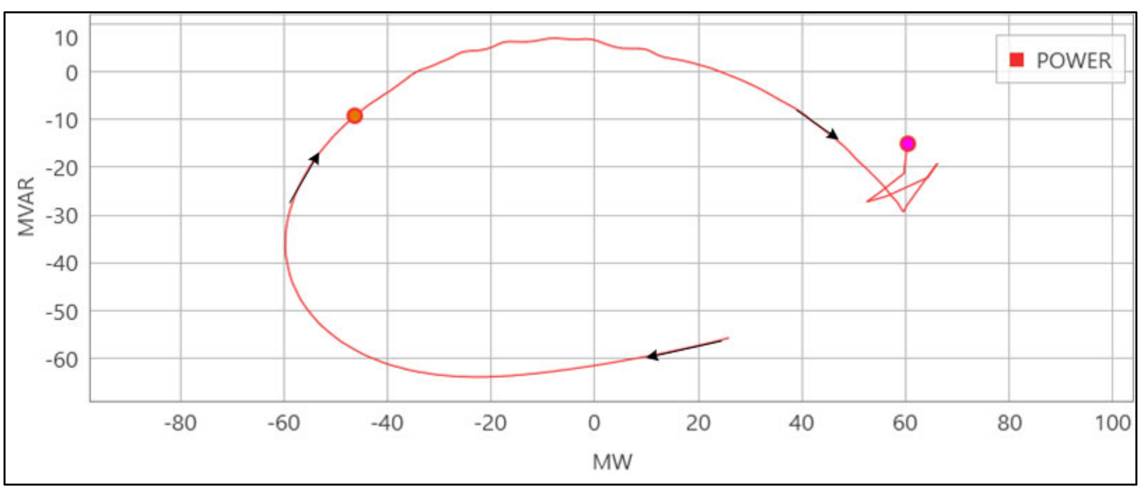

Figure 8: Out-of-Step Trip Event, MW vs MVAR

4.0 ANAYLSIS OF RECENT EVENT

The generation site is a newer combined-cycle natural gas plant with two combustion turbine generators (CTG1 and CTG2, 409MVA and 25kV) as well as a steam turbine generator (STG3, 561MVA and 19kV) that are connected to an existing fossil plant one half mile away. Figure 9 shows a simplified single line diagram of the combined-cycle plant and the fossil plant. Additional equipment is not shown on this diagram as it was disconnected or offline in order to simplify the overview.

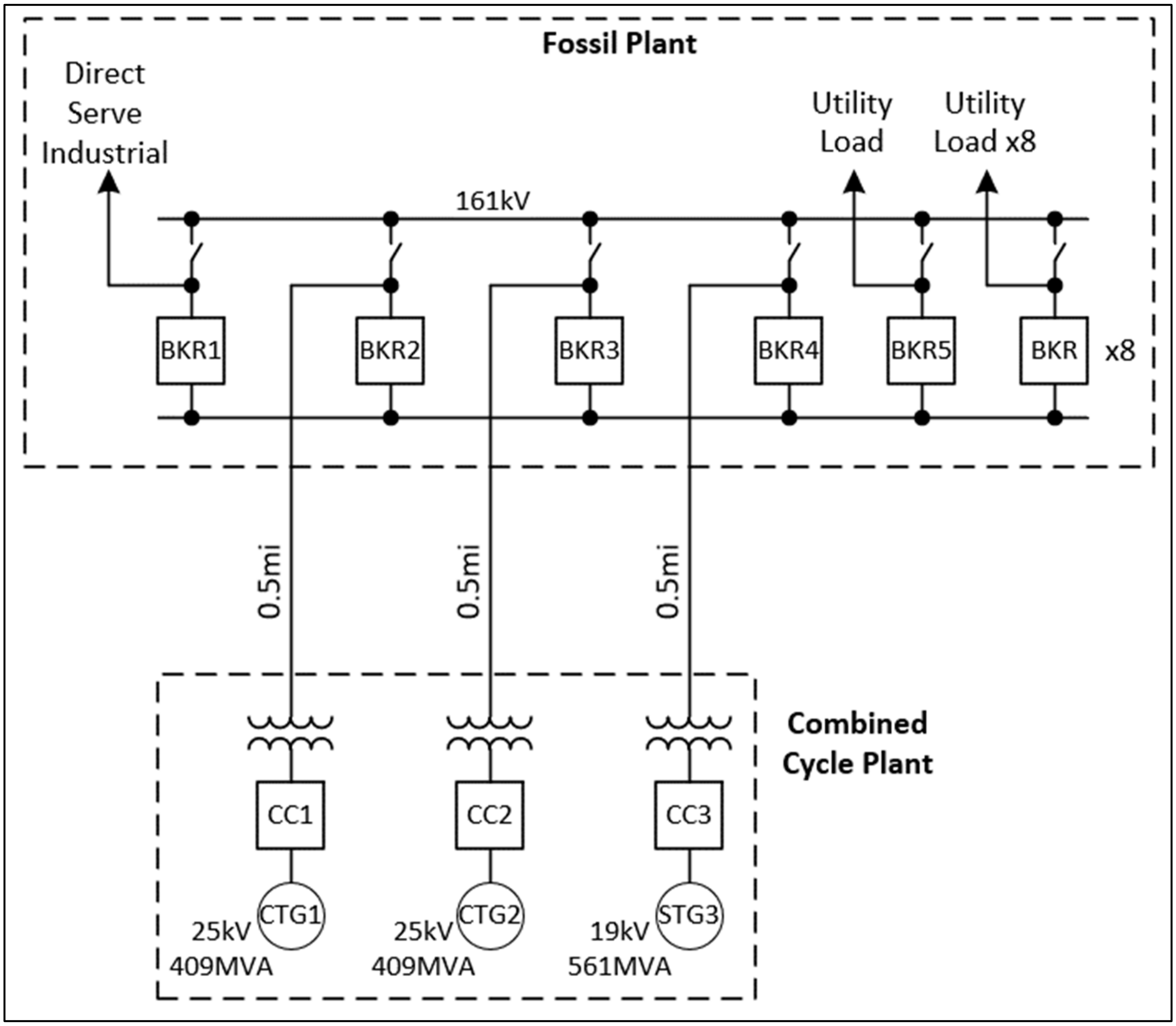

Figure 9: Simplified Single Line Diagram

The OOS element for the combined cycle units is configured for a dual-impedance concentric zone characteristic with an inner and outer zone to track the impedance locus of the generator during a swing event. The inner zone left and right reach is set to determine when the generator and system are 120° and 240° apart to detect unstable swings. The outer zone detects stable swings as well as assures that the difference between the generator and system angle is less than 60° when tripped to reduce stress on the breaker. The forward reach for both the inner and outer zones is set to 1.5x the GSU impedance while the reverse reach is set to twice the generator transient reactance. A transient stability study showed the critical clearing time for a three-phase fault on the high side of the GSU is 16 cycles. At 17 cycles the generator would go unstable and take 0.132s to shift 60° and 0.288s to shift 120°. Based on NERC recommendations

[3], a 100ms time was used as the threshold for a power swing entering the outer zone and passing to the inner zone, as well as across the inner zone. Similarly, a 50ms timer is used for power swings leaving the inner zone and crossing the outer zone. Figure 10 shows the OOS characteristic and the backup distance elements in the CTG1 protection.

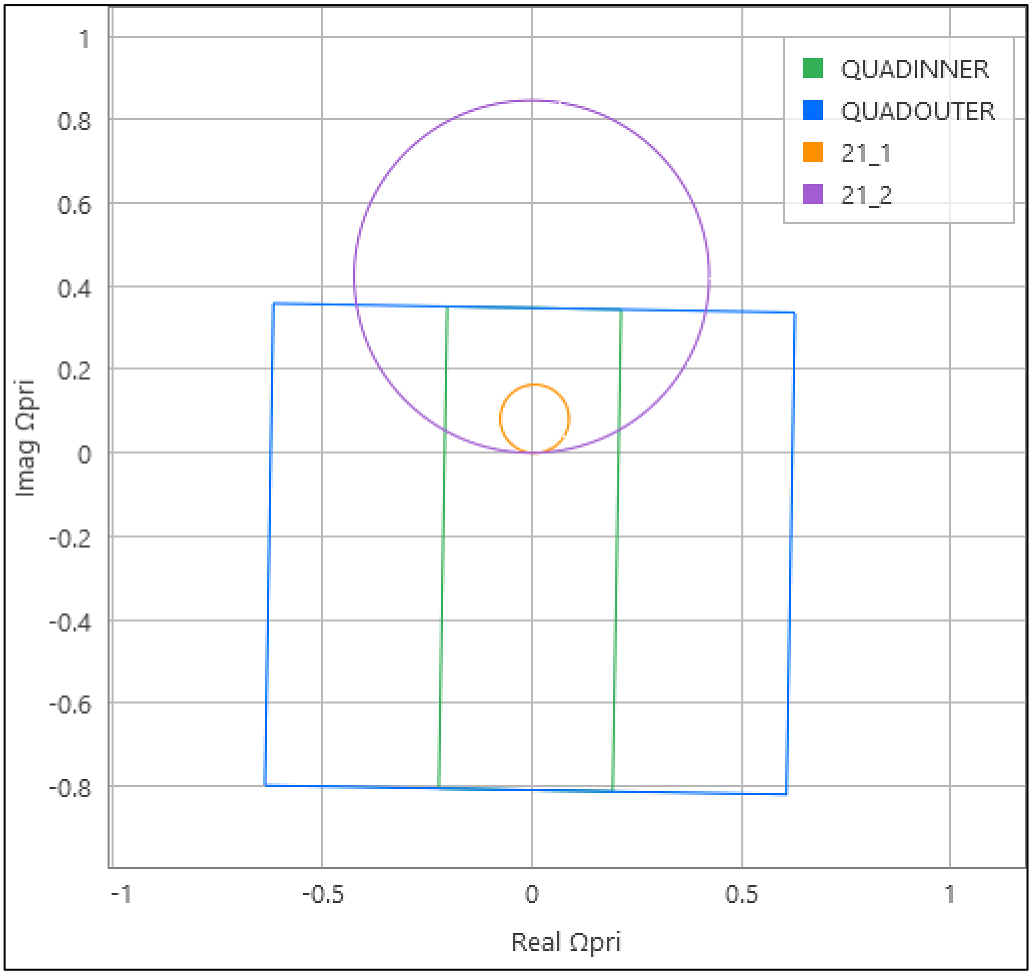

Figure 10: CTG1 Out-of-Step and Backup Distance Elements

A downstream utility fed by BKR5 experienced a slow-clearing evolving multi-phase fault due to a switch being opened under load and the primary line protection out of service. The fault evolved from BC to BCG to ABC. As a three-phase fault, it persisted 28 cycles before being cleared by backup line protection and sagged the voltage at the generator bus to 20% of nominal on all three phases. In addition to event data from the generator protection system, a Digital Fault Recorder (DFR) at the generating station on the 161kV bus recorded fault data over a longer time period and provided additional insight into the event. Figure 11 shows the 161kV GSU high-side CTG1, STG3, and combined CTG1/STG3 contribution to the fault, as well as the 161kV bus voltage. The data shows the system pre-fault, during the evolving system fault, the power swing after the transmission system breakers cleared the fault, and post trip of CTG1.

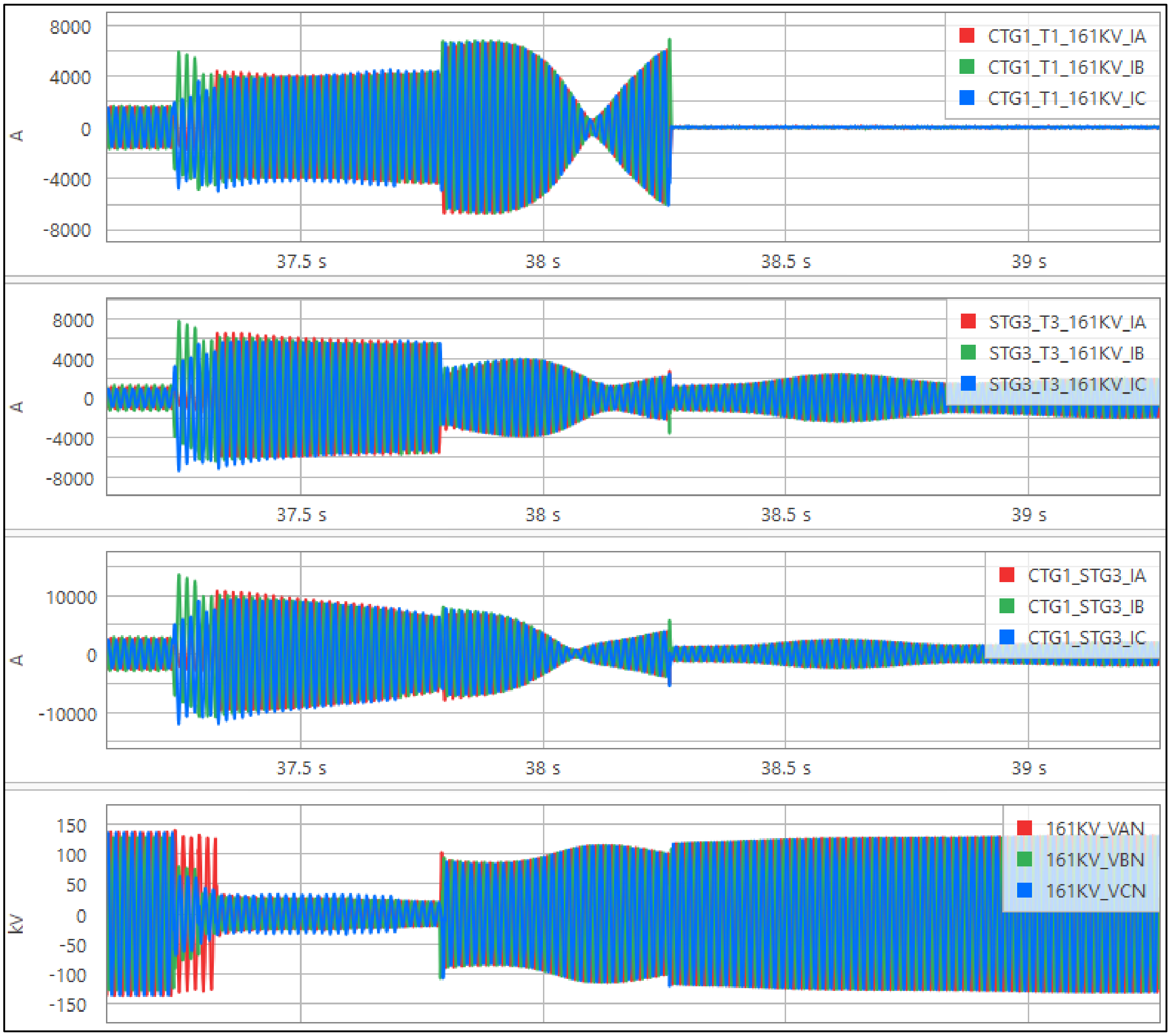

Figure 11: DFR Event Data

CTG2 was offline at the time while CTG1 and STG3 were online. The generator protection system was intended to trip on an OOS condition prior to slipping a pole but did not operate. CTG1 tripped due to the turbine control system sensing a rate-based acceleration overspeed condition of 16% per second. The control system had a communication loss and was not able to directly trip the unit or excitation system but did send a breaker failure initiate (BFI) signal to the generator protection relays. The breaker failure initiate signal immediately tripped the generator breaker through the generator protective relays as a re-trip condition. The BFI signal also acted as the trigger for event data in the generator protective relays. Due to the event trigger from BFI and not the OOS element operation, the initial fault inception and three-phase fault portion of the fault were not captured by the generator relays but was captured by the GSU relays. Additionally, due to the communication equipment power loss and failure, the CTG1 excitation system remained online for four minutes after the unit tripped, causing concern for heating and damage of the generator.

After CTG1 tripped, STG3 remained stable and online for about two additional seconds before tripping on a turbine control system permissive fast reverse power element. The different style generation systems may have helped STG3 remain stable, but as they were part of a combined-cycle system, STG3 would have been removed from service eventually.

The path of the CTG1 positive sequence impedance during the event is shown in Figure 12. The three-phase fault persisted for 28 cycles inside of the backup zone-2 distance element in the generator relays but did not trip as the time delay is configured for 75 cycles to coordinate with system protection relaying. It is assumed that a system breaker opened to clear the fault downstream to start the pole slip event. This allowed for a significant voltage recovery and possibly a power flow issue with both CTG1 and STG3 online with the loss of load. Due to the length of the three-phase fault, CTG1 sped up and lost sync with the system.

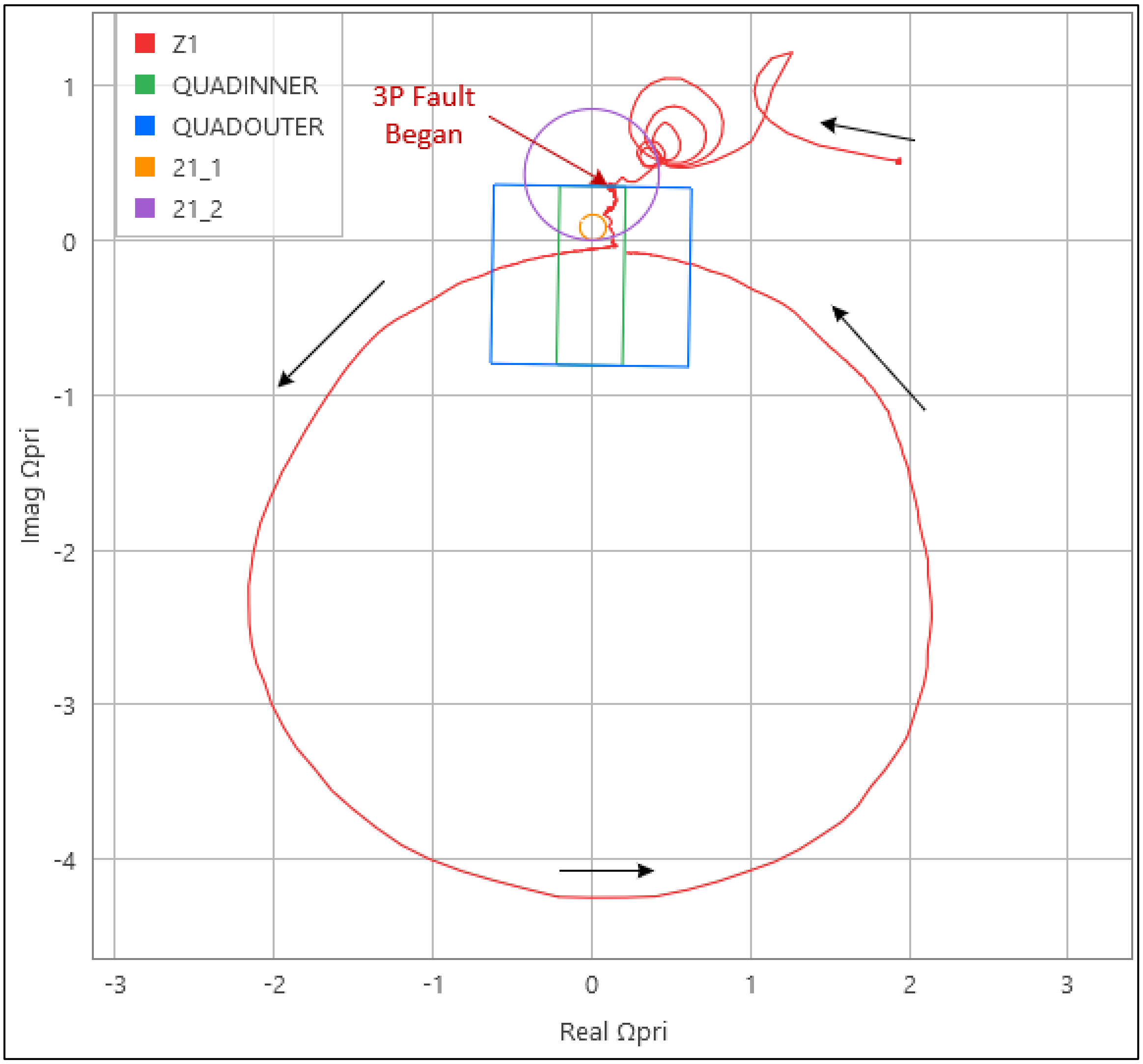

Figure 12: Z1 Impedance During Fault

The CTG1 generator shifted from a separation angle of 19° pre-fault to about 140° post-fault as seen in Figure 13. The angle continued to increase beyond the first pole slip at 180° and separated from the system just prior to the second pole slip.

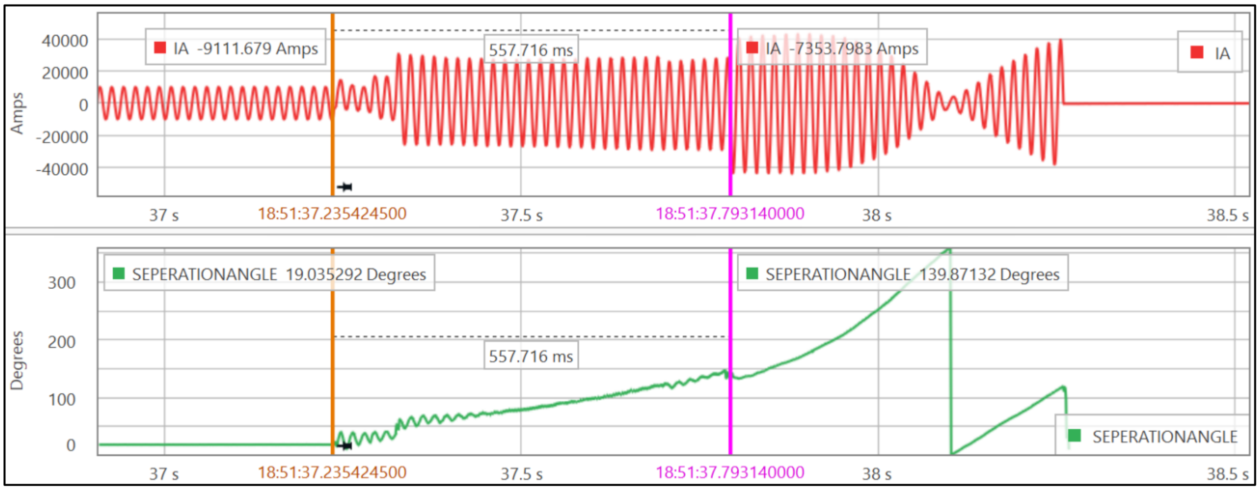

Figure 13: Generator to System Angle Difference

As the fault entered the top of the OOS impedance zones, there was no differentiation between the inner and outer blinders. The relay event data showed both blinders asserting at the same time, so the relay considered this a fault condition and not a power swing. If the generator control system had not tripped the unit, it is unlikely that the OOS element would have detected the swing after the first pole-slip as it proceeded through the impedance zones a second time. Z1 was between the outer and inner right blinders for about 80ms (shown in Figure 14 between the orange and purple cursors), short of the 100ms delay required to arm the power swing element for tripping.

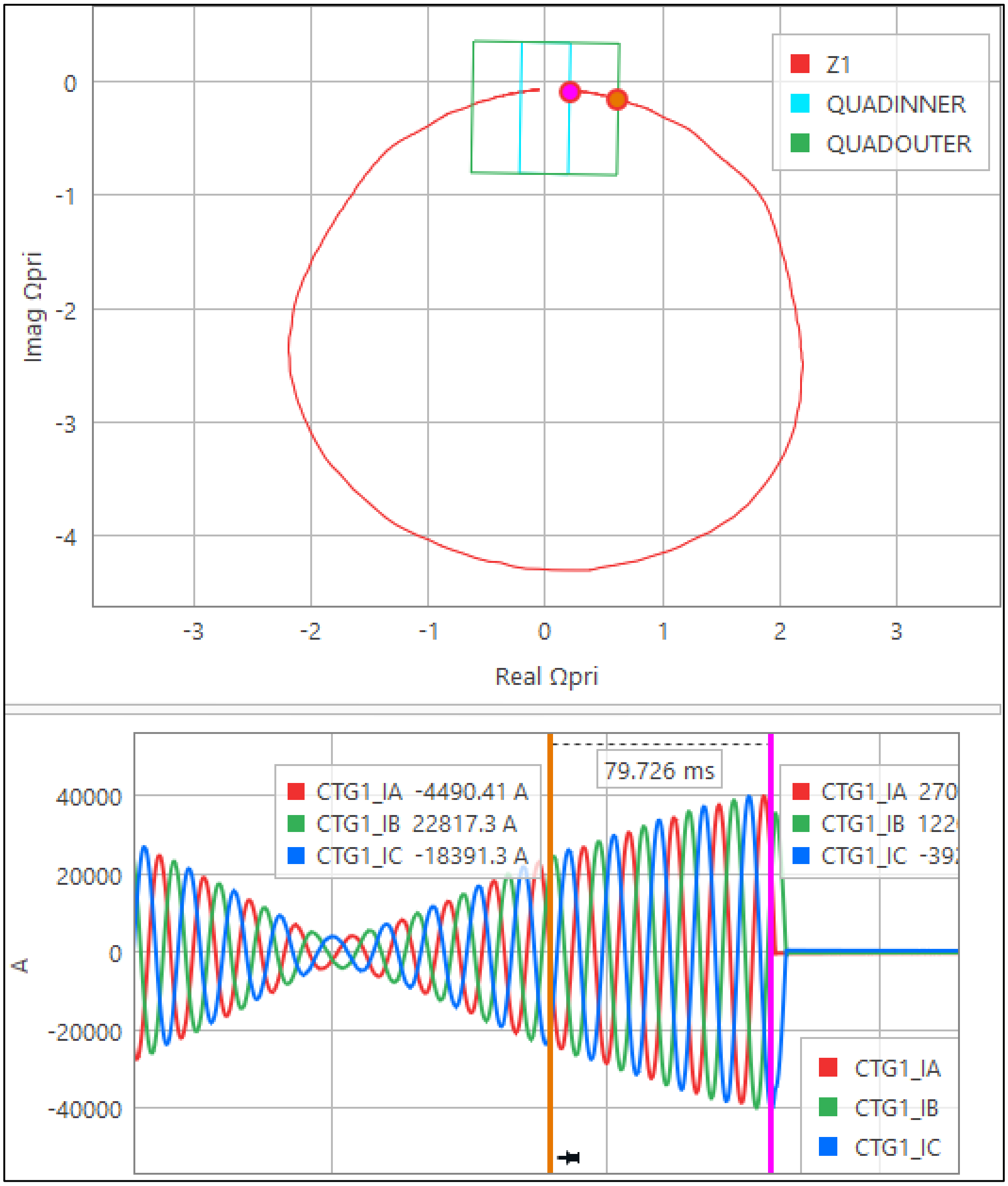

Figure 14: CTG1 Relay Event Data Showing Z1 and Power Swing Element

Using the DFR event data, one full slip cycle took 453.6ms. This translates to 1 / 0.4536s = 2.205 slip cycles per second, or 360° * 2.205 / 60Hz = 13.2° of travel per 60Hz cycle. With an outer to inner blinder separation of 120° - 60° = 60°, this results in a Z1 travel time of 60° / 13.2°per cycle = 4.536 cycles or 76ms between the two blinders. To detect this condition in the future with the same blinder impedances the OOS outer blinder delay would need to decrease from 100ms down to 70ms.

The MW power flow can be seen in Figure 15 after the system fault cleared at around +430MW, moving to -480MW, and back to +600MW in just 0.4 seconds.

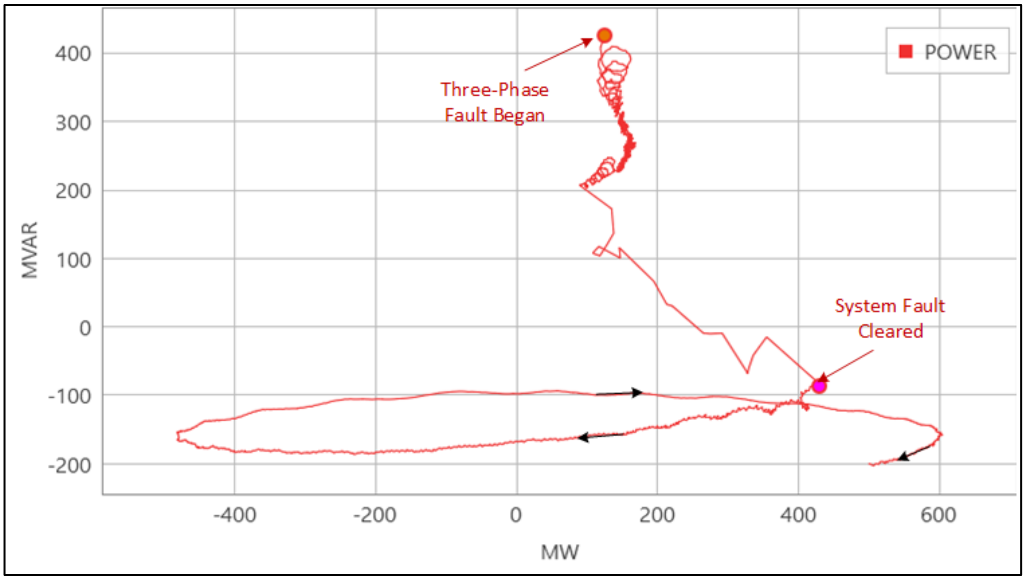

Figure 15: Power Flow During Event

The event data for CTG1 was also analyzed using the Equal Area Criterion (EAC) to determine if a power swing is stable or not. This EAC analysis assumes the mechanical power input to the generator (P_MECHANICAL) is constant, while system conditions change to require less and more electrical power from the generator as the fault and swing occurs.

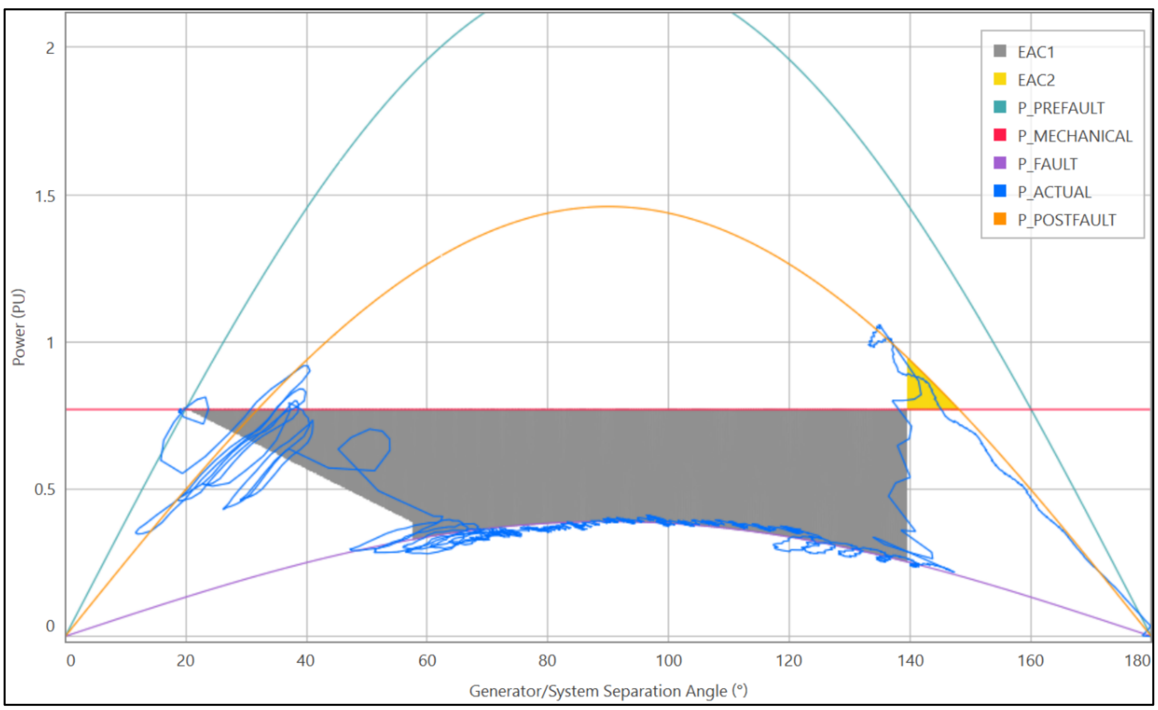

Figure 16: Equal Area Criterion

Pre-fault system conditions can be seen with the cursor at 19° where the mechanical power is equal to the required electrical power on the P_PREFAULT curve. During the fault condition, the locus drops to the P_FAULT curve around 45° once it becomes a 3-phase fault and less power is being transferred to the system. During this period, indicated by the grey area, the mechanical power is greater than the electrical power being transferred to the system, so the generator speeds up. Once the fault clears, the locus jumps up to the P_POSTFAULT curve with the separation angle around 140°. The yellow area indicates there is more electrical power required than is being supplied mechanically. Under these conditions, the generator would slow down. The EAC suggests that the amount of time the generator is increasing speed (grey area) should be less than or equal to the amount of time the generator could slow down (yellow area), which would result in a stable system [4]. Since the grey area is much larger than the yellow area for this event, there is not enough reduction in generator speed available to return to a stable system, and the unit experiences an unstable power swing.

CONCLUSIONS

Accurate modelling of the system is important to be able to perform studies that define the OOS power swing element characteristics. These models may require information from external systems or verification of the model through test to ensure the OOS element operates effectively. Additionally, the relay setter should consider all fault types and select which style OOS element characteristic is most effective for the system at hand. The setter should consider various system conditions and slow-clearing fault times when performing stability studies. This paper has shown one misoperation event where additional analysis is required to ensure dependability for all swing events. The authors encourage the readers to perform analysis of OOS element performance for all events to confirm the model and assumptions made are correct.

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[4] System Stability as a Design Problem, R. H. Park and E. H. Bancker, Transactions of the American Institute of Electrical Engineers, Volume 48, January 1929.

BIOGRAPHICAL SKETCH

Seth Barnes graduated from The University of Mississippi in 2010 with a B.S.E.E. and a M.S.E.E. from The University of Tennessee at Chattanooga in 2020. Upon graduation, he worked as a contract Telecomm Engineer for AT&T in Mississippi. Seth joined the Tennessee Valley Authority in 2013 and worked as a Telecomm Field Engineer and later a System Engineer in the North Alabama area. In 2017, he joined the System Protection & Analysis group, developing relay settings and performing post fault event analysis for the TVA power system. Seth is a member of IEEE.

Laurel Brandt is an Electric Engineer for the Tennessee Valley Authority (TVA) in Chattanooga, Tennessee. She has worked in primarily with Generating plants, performing duties in design, project management, protection and control system ownership, and operations support. Her current responsibilities are to support relay maintenance specialists for testing and troubleshooting, improving reliability of the generating fleet by identifying and correcting protection system misoperations and supporting plant operations and project implementation. She has also worked in Transmission Operations NERC Reliability and on a Battery Storage Research Project for TVA. She has a B.S.E.E from Georgia Institute of Technology. She is a member of the IEEE/PES Power System Relaying and Control Committee, Chair of the NERC Failure Modes and Mechanism Working Group, and a registered Professional Engineer in the state of Tennessee.

Joshua Hughes graduated from Tennessee Technological University with a B.S.E.E focused on digital signals. He initially worked as a System Engineer at Tennessee Valley Authority nuclear substations providing commissioning services, root cause analysis, and system data trending to predict equipment failures. Later, Joshua joined Schweitzer Engineering Laboratories, where he served as a project engineer and senior application engineer where his work included providing application and product support and technical training for protective relay users. Joshua now works for Qualus as a Lead Engineer to provide system studies, field system protection services, event root cause analysis, and technical training. Joshua is a member of the IEEE and is a registered professional engineer in the state of Tennessee.